COST OPTIMIZATION OF HYDROGEN FUEL SUPPLY CHAIN WITH ENVIRONMENTAL POLICY INTEGRATION: THE CASE FOR BRITISH COLUMBIA

by

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Abstract

By powering fuel cell electric vehicles hydrogen can contribute to greenhouse gas emissions reduction in British Columbia (B.C.) The province is well positioned to capitalize on its natural resources and policies towards the development of a hydrogen fueling supply chain (HFSC). However, such development requires significant investment with high risks of negative cash flow for years to decades.

A spatially explicit multi-period optimization model was developed to design a minimum-cost HFSC based on a mixed integer linear programming formulation. The model was applied to the light duty passenger vehicle sector in B.C. under three hydrogen demand scenarios. The model considered different capacities for all components of the supply chain, covered the on-site production and capacity expansion options as well as minimum storage requirement for fueling stations. Different combinations of the current and potential environmental mandates and the government economic instruments were integrated in the model explicitly. The model measured the effectiveness of the policies on reducing the cost and greenhouse gas (GHG) emissions of the HFSC for each demand scenario. To this end, the GHG emissions were monetized using the social cost of carbon. The results suggested that hydrogen can be cost competitive with gasoline. However, the cost optimal hydrogen infrastructure relied heavily on steam methane reforming (SMR), with small GHG emissions reduction benefits. Nonetheless, the monetary benefits of well to wheels (WTW) GHG emissions reduction justified the switch from gasoline to SMR-based hydrogen. It was found that central electrolysis can be financially justified by addition of production tax credits or electricity incentives to the current provincial carbon control policies (i.e., carbon tax and low carbon fuel standard).

This study assessed the effectiveness of current policies in emissions mitigation from the road freight transport. Moreover, the WTW energy requirement and GHG emissions reduction potential of the all-electric trucking were measured to meet the provincial emissions reduction targets. The results suggested that the B.C. hydroelectricity will fall short of generating sufficient energy to support all-electric trucking. Thus, B.C. has to undertake policies to incentivize electricity generation from diversified renewable energy resources.

Lay Summary

Hydrogen penetration into the transport sector requires sufficient initial fueling network coverage well in advance of the fuel cell electric vehicle rollout. Considering the significant capital investment which will be followed by underutilization, the hydrogen fueling supply chain may face a long period of negative cash flows.

In this work, a cost optimization framework was developed to design a hydrogen fueling supply chain for the successful deployment of fuel cell electric vehicles in British Columbia. The results suggest the share of distributed and central hydrogen production, number, location, capacity of production plants and storage facilities, the transportation links, and the number and distribution of fueling stations in different periods of market development. Moreover, a range of emissions mitigation policies and incentive plans was integrated explicitly in the model to assess their effectiveness on the accelerated adoption of low-carbon hydrogen in the province.

Preface

The original idea of investigating the hydrogen technology pathways for the transportation sector in B.C. was proposed by Walter Mérida.

Hoda Talebian is responsible for identifying the specific topics of investigation documented herein. She is responsible for: defining the knowledge gap and research questions, gathering model inputs (data collection), developing the optimization model from inception, developing policy scenarios, and dissemination of results in the form of conferences and publications.

Hoda Talebian is responsible for most of the substantive and editorial preparation of this thesis under the supervision of Walter Mérida.

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- A version of Chapter 3, 4 and 5 has been published as a peer-reviewed full article. Talebian, H., Herrera, OE., Mérida, W. 'Spatial and temporal optimization of hydrogen fuel supply chain for light duty passenger vehicles in British Columbia' *Int J Hydrogen Energy*, 44 (2019) pp. 25939-25956. Hoda Talebian was responsible for: scientific question formulation; method design; analysis of the results and discussion; and article preparation. The project manager, Omar Herrera, offered critique in article preparation and manuscript edits. Walter Mérida provided direction and feedback on the work.
- A version of Chapter 3 and 5 is submitted for publication as a peer-reviewed full article in April 2019. Hoda Talebian was responsible for: scientific question formulation; method design; analysis of the results and discussion; and article preparation. The project manager,

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Sets

A	Nominal capacity of tube tankers (120,600,1100 kg)
C	Nominal capacity of central plants and storage facilities (2,10,50,100 tonnes/day)
D	Product status (gas hydrogen (onsite production), gas hydrogen(delivered), liquid hydrogen (delivered))
G	Central production grids $g' \neq g$
$\bar{G}$	Central storage grids (Warehouses)
G'	Demand grids (Metro Vancouver)
J	Stages of capacity expansion (10, 20, 30% for SMR and 10,25,50% for electrolyzer and storage units)
NV	Demand grids (Kamloops, Kelowna, Prince George, Victoria)
RO	Demand grids (Abbotsford, hope, Whistler, Williams Lake)
T	time periods of the planning horizon (6 time-steps: every five years starting from 2020)
Y	Plant type with different production technologies (Electrolyser, SMR+CCS, SMR w/o CCS, By-Product Hydrogen purification plant)

Parameters

$ATPD\_CF_i$	After tax post depreciation cash flow in year i
AT_Tr	Truck daily availability limit (hours)
Cap_i	Capital costs occurred in year i
$CAPL\_TR$	Unloading capacity of tanker trucks delivering liquefied hydrogen
$CAPG\_TR_a$	Unloading capacity of tube trailers of size a, delivering gaseous hydrogen
$Credit\_LCFS_t$	LCFS credit in time step t (\$/tones of CO_2 displaced)
Cum_CF_i	Cumulative cash flow in year i
$Dcap\_min_s$	Minimum throughput of a fueling station with nominal capacity s
$Dcap\_max_s$	Maximum throughput of a fueling station with nominal capacity s
$DDCC\_C_{cy}$	Direct depreciable capital cost of a central plant of type y and capacity c
$DDCC\_S_{\bar{c}d}$	Direct depreciable capital cost of a central storage facility of capacity $\bar{c}$ which stores hydrogen at status d
$DDCC\_TRG_a$	Direct depreciable capital cost of a tube tanker truck of size a transporting hydrogen at gaseous status
$DDCC\_TRL$	Direct depreciable capital cost of a tanker truck transporting hydrogen at liquid status
$DDCC\_O_s$	Direct depreciable capital cost of an onsite plant of capacity s
$DDCC\_D_{sd}$	Direct depreciable capital cost of fueling station of capacity s, which delivers hydrogen at status d
Dep_ch_i	Depreciation charge in year i
$Decom$	Decommissioning costs
$DG\_V_{g't}$	Demand of hydrogen in grid g' and time step t
$DG\_NV_{n't}$	Demand of hydrogen in grid $n'$and time step t

$DG\_NV_{r't}$	Demand of hydrogen in grid r' and time step t
DT_t	Demand of hydrogen in B.C. in time step t
E_Cost	Emission cost (Carbon tax) ($/tonnes of CO_2 displaced)
EER_t	Energy efficiency ratio in time step t
F_C_{cy}	Fixed cost of a central plant of type y and capacity c per year
F_D_{sd}	Fixed cost of a fueling station of capacity s which delivers hydrogen at status d per year
F_O_s	Fixed cost of an onsite plant of capacity s per year
F_Opr_i	Fixed operating costs in year i
$F\_S_{\bar{c}d}$	Fixed cost of a central storage facility of capacity $\bar{c}$ which stores hydrogen at status d per year
F_TR_d	Fixed cost of a truck transporting hydrogen at status d per year
$Fuel\_TR\_PS_{d\bar{g}g}$	Cost of diesel to transport hydrogen at status d from production grid g to storage grid $\bar{g}$
$Fuel\_TR\_V_{dg'\bar{g}}$	Cost of diesel to deliver hydrogen at status d from storage grid $\bar{g}$ to demand grid g'
$Fuel\_TR\_NV_{dn'\bar{g}}$	Cost of diesel to deliver hydrogen at status d from storage grid $\bar{g}$ to demand grid n'
$Fuel\_TR\_RO_{dr'\bar{g}}$	Cost of diesel to deliver hydrogen at status d from storage grid $\bar{g}$ to demand grid r'
Gas_CI	WTW Gasoline Carbon Intensity (g CO_2/MJ)
GHG_C_y	GHG emission of a central plant of type y (gCO_2eq/kg H_2)
GHG_S_d	GHG emission of a central storage facility which stores hydrogen at status d (gCO_2eq/kg H_2)
GHG_TR	GHG emission of a truck transporting hydrogen at status d (gCO_2eq/kg H_2)
GHG_D_d	GHG emission of a fueling station delivers hydrogen at status d (gCO_2eq/kg H_2)
GHG_O	GHG emission of an onsite plant (gCO_2eq/kg H_2)
$H2\_D$	Hydrogen density (MJ/kg) in 1 atm,298K
$IDCC\_C_{cy}$	Indirect depreciable capital cost of a central plant of type y and capacity c
$IDCC\_S_{\bar{c}d}$	Indirect depreciable capital cost of a central storage facility of capacity $\bar{c}$ which stores hydrogen at status d
$IDCC\_O_s$	Indirect depreciable capital cost of an onsite plant of capacity s
$IDCC\_D_{sd}$	Indirect depreciable capital cost of fueling station of capacity s, which delivers hydrogen at status d
$IDep\_Cap_i$	Initial equity depreciable capital (for units installed in year i)
$Labor\_TR\_PS_{d\bar{g}g}$	Driver wage of a truck delivering hydrogen at status d from production grid g to storage grid $\bar{g}$
$Labor\_TR\_V_{dg'\bar{g}}$	Driver wage of a truck delivering hydrogen at status d from storage grid $\bar{g}$ to demand grid g'
$Labor\_TR\_NV_{dn'\bar{g}}$	Driver wage of a truck delivering hydrogen at status d from storage grid $\bar{g}$ to demand grid n'
$Labor\_TR\_RO_{dr'\bar{g}}$	Driver wage of a truck delivering hydrogen at status d from storage grid $\bar{g}$ to demand grid r'

$LG_{g'}$	Distance from Langley Township to demand grid g'
$LH\_NV_{\bar{g}n'}$	Distance from central storage grid $\bar{g}$ to demand grid n'
$LH\_RO_{\bar{g}r'}$	Distance central storage grid $\bar{g}$ to demand grid r'
$LH\_PS_{g\bar{g}}$	Distance from central production grid g to central storage grid $\bar{g}$
$LH\_V_{\bar{g}}$	Distance from central storage grid $\bar{g}$ to Langley Township
$Lifetime\_C$	Lifetime of a central plant
$Lifetime\_S$	Lifetime of a central storage facility (warehouse)
$Lifetime\_O$	Lifetime of an onsite plant
$Lifetime\_D$	Lifetime of a fueling station
$Lifetime\_TR$	Lifetime of a truck
$Loadingtime_d$	Time to load a truck transporting hydrogen at status d
LR_S_t	Learning rate of a central storage facility (warehouse) in time step t
LR_C_t	Learning rate of a central plant in time step t
LR_O_t	Learning rate of an onsite plant in time step t
LR_D_t	Learning rate of a fueling station in time step t
N	Number of years being studied
$NDCC\_C_{cy}$	Non-depreciable capital cost of a central plant of type y and capacity c
$NDCC\_S_{\bar{c}d}$	Non-depreciable capital cost of a central storage facility of capacity $\bar{c}$ which stores hydrogen at status d
$NDep\_Cap_i$	Non depreciable capital costs in year i
OP_C_{cy}	Operating cost of a central plant of type y and capacity c ($/kg)
$OP\_S_{\bar{c}d}$	Operating cost of a central storage facility of capacity $\bar{c}$ which stores hydrogen at status d ($/kg)
OP_O_s	Operating cost of an onsite plant of capacity s ($/kg)
OP_D_{sd}	Operating cost of a fueling station of capacity s which delivers hydrogen at status d ($/kg)
Opr_i	Operating costs in year i
$Pcap\_min_c$	Minimum production rate of a central plant with nominal capacity c
$Pcap\_max\_prin_c$	Nominal production capacity of a central plant
PD_Inc_i	Pre depreciation income in year i
Per_t_z	Percentage of demand in the last year of each time step
PR_cap_{jy}	Capacity expansion of a central plant of type y at stage j (%)
r	Discount rate
Rev_H2_i	Revenue from hydrogen per year
$Salv$	Salvage value
$Scap\_min_{\bar{c}}$	Minimum storage rate of a central storage unit (warehouse) with nominal capacity $\bar{c}$
$Scap\_max\_prin_{\bar{c}}$	Nominal storage capacity of a central storage unit (warehouse)
SR_cap_j	Capacity expansion of a central storage facility at capacity expansion stage of j (%)
Tc	Tax credit
Tr	Tax rate
Tt_i	Total taxes in year i

$unLoadingtime_d$	Time to unload a truck transporting hydrogen at status d
V_Opr_i	Variable operating costs in year i
VG	Speed of a truck in demand regions g
VH	Speed of a truck in highways (from regions g' to Langley Township)
W_Cap_i	Cash from working capital reserves in year i
Y_Rep_i	Replacement costs per year
α	Wage for truck driver (C$/hour)
α_LR_C	Learning index of a central plant
α_LR_D	Learning index of a fueling station
α_LR_O	Learning index of an onsite plant
α_LR_S	Learning index of a central storage facility (warehouse)
β	Fuel cost (C$/litre)
γ	Fuel economy of the truck (litre/km)
ε	Small number
ω	Percentage of maximum capacity

Continuous Variables

$DI\_V_{sdg't}$	Dispensing rate of a fueling station with capacity s, delivering hydrogen at status d, in region g' and time step t
$DI\_NV_{sdn't}$	Dispensing rate of a fueling station with capacity s, delivering hydrogen at status d, in region n' and time step t
$DI\_RO_{sdr't}$	Dispensing rate of a fueling station with capacity s, delivering hydrogen at status d, in region r' and time step t
PC_{cydgt}	Production rate of a central plant with capacity c, type y, producing hydrogen at status d, in region g and time step t
$Pcap\_max_{cydgt}$	Production capacity (maximum production rate) of a central plant with capacity c, type y, produces hydrogen at status d, in region g and time step t
$PO\_V_{sdg't}$	Production rate of an onsite plant with capacity s, producing hydrogen at status d, in region g' and time step t
$PO\_NV_{sdn't}$	Production rate of an onsite plant with capacity s, producing hydrogen at status d, in region n' and time step t
$PO\_RO_{sdr't}$	Production rate of an onsite plant with capacity s, producing hydrogen at status d, in region $r'$and time step t
$STR\_V_{sdg't}$	Storage rate of a fueling station with capacity s, delivering hydrogen at status d, in region g' and time step t
$STR\_NV_{sdn't}$	Storage rate of a fueling station with capacity s, delivering hydrogen at status d, in region n' and time step t
$STR\_RO_{sdr't}$	Storage rate of a fueling station with capacity s, delivering hydrogen at status d, in region r' and time step t
$TS_{\bar{c}d\bar{g}t}$	Storage rate of a central storage facility (warehouse) with capacity $\bar{c}$, storing hydrogen at status d, in region $\bar{g}$ and time step t
$TS\_E_{\bar{c}d\bar{g}t}$	Storage rate of a central storage facility (warehouse) for emergency with capacity $\bar{c}$, storing hydrogen at status d, in region $\bar{g}$ and time step t

Integers

$NNTRG\_PS_{g\bar{g}at}$	Number of new tube trailers of size a transporting gas hydrogen from a central plant in region g to a central storage in region $\bar{g}$ in time step t
$NNTRG\_V_{\bar{g}g'ast}$	Number of tube trailers of size a delivering gas hydrogen from a central storage in region $\bar{g}$ to demand region g' , stations of size *s*, in time step t
$NNTRG\_NV_{\bar{g}n'ast}$	Number of new tube trailers of size a delivering gas hydrogen from a central storage in region $\bar{g}$ to demand region n' , stations of size *s*, in time step t
$NNTRG\_RO_{\bar{g}r'ast}$	Number of new tube trailers of size a delivering gas hydrogen from a central storage in region $\bar{g}$ to demand region r' , stations of size *s*, in time step t
$NNTRL\_PS_{g\bar{g}t}$	Number of new tanker trucks transporting liquid hydrogen from a central plant in region g to a central storage in region $\bar{g}$ in time step t
$NNTRL\_V_{\bar{g}g't}$	Number of new tanker trucks delivering liquid hydrogen from a central storage in region $\bar{g}$ to demand region g' in time step t
$NNTRL\_NV_{\bar{g}n't}$	Number of new tanker trucks delivering liquid hydrogen from a central storage in region $\bar{g}$ to demand region n' in time step t
$NNTRL\_RO_{\bar{g}r't}$	Number of new tanker trucks delivering liquid hydrogen from a central storage in region $\bar{g}$ to demand region r' in time step t
$NTRG\_PS_{g\bar{g}at}$	Number of tube trailers of size a transporting gas hydrogen from a central plant in region g to a central storage in region $\bar{g}$ in time step t
$NTRG\_V_{\bar{g}g'ast}$	Number of tube trailers of size a delivering gas hydrogen from a central storage in region $\bar{g}$ to demand region g', stations of size *s*, in time step t
$NTRG\_NV_{\bar{g}n'ast}$	Number of tube trailers of size a delivering gas hydrogen from a central storage in region $\bar{g}$ to demand region n' , stations of size *s*, in time step t
$NTRG\_RO_{\bar{g}r'ast}$	Number of tube trailers of size a delivering gas hydrogen from a central storage in region $\bar{g}$ to demand region r' , stations of size *s*, in time step t
$NTRL\_PS_{g\bar{g}t}$	Number of tanker trucks transporting liquid hydrogen from a central plant in region g to a central storage in region $\bar{g}$ in time step t
$NTRL\_V_{\bar{g}g't}$	Number of tanker trucks delivering liquid hydrogen from a central storage in region $\bar{g}$ to demand region g' in time step t
$NTRL\_NV_{\bar{g}n't}$	Number of tanker trucks delivering liquid hydrogen from a central storage in region $\bar{g}$ to demand region n' in time step t
$NTRL\_RO_{\bar{g}r't}$	Number of tanker trucks delivering liquid hydrogen from a central storage in region $\bar{g}$ to demand region r' in time step t
$YD\_NV_{sdn't}$	Number of fueling stations with capacity s, delivering hydrogen at status d, in region n' and time step t
$YD\_RO_{sdr't}$	Number of fueling stations with capacity s, delivering hydrogen at status d, in region r' and time step t
$YD\_V_{sdg't}$	Number of fueling stations with capacity s, delivering hydrogen at status d, in region g' and time step t
$YO\_NV_{sdn't}$	Number of onsite plants with capacity s, producing hydrogen at status d, in region n' and time step t
$YO\_RO_{sdr't}$	Number of onsite plants with capacity s, producing hydrogen at status d, in region r' and time step t

$YO\_V_{sdg't}$	Number of onsite plants with capacity s, producing hydrogen at status d, in region g' and time step t
$YPO\_NV_{sdn't}$	Number of new onsite plants with capacity s, producing hydrogen at status d, in region n' and time step t
$YPO\_RO_{sdr't}$	Number of new onsite plants with capacity s, producing hydrogen at status d, in region r' and time step t
$YPO\_V_{sdg't}$	Number of new onsite plants with capacity s, producing hydrogen at status d, in region g' and time step t
$YPD\_NV_{sdn't}$	Number of new fueling stations with capacity s, delivering hydrogen at status d, in region n' and time step t
$YPD\_RO_{sdr't}$	Number of new fueling stations with capacity s, delivering hydrogen at status d, in region r' and time step t
$YPD\_V_{sdg't}$	Number of new fueling stations with capacity s, delivering hydrogen at status d, in region g' and time step t

Binaries

YC_{cydgt}	1 if a central plant with capacity c, type y, producing hydrogen at status d exists in region g and time step t, 0 otherwise
YPC_{cydgt}	1 if a new central plant with capacity c, type y, producing hydrogen at status d is established in region g and time step t, 0 otherwise
$YPE_{cydg\bar{t}}$	1 if electrolyzer undergoes a 10-year replacement, 0 otherwise
$YPS_{\bar{c}d\bar{g}t}$	1 if a new central storage facility with capacity $\bar{c}$, storing hydrogen at status d, is established in region $\bar{g}$ and time step t, 0 otherwise
$YS_{\bar{c}d\bar{g}t}$	1 if a central storage facility with capacity $\bar{c}$, storing hydrogen at status d, is existing in region $\bar{g}$ and time step t, 0 otherwise
$Y'C_{jcydgt}$	1 if a central plant with capacity c, type y, produces hydrogen at status d in region g and time step t, has an increased capacity with status of j, 0 otherwise
$Y'C\_O_{cydgt}$	1 if a central plant with capacity c, type y, produces hydrogen at status d in region g undergoes no capacity expansion until time step t, 0 otherwise
$Y'PC_{jcydgt}$	1 if capacity expansion at stage j is implemented at time step t for a central plant with capacity c, type y, producing hydrogen at status d in region g, 0 otherwise
$Y'PS_{j\bar{c}d\bar{g}t}$	1 if capacity expansion at stage j is implemented at time step t for a central storage facility with capacity $\bar{c}$, storing hydrogen at status d, in region $\bar{g}$ and time step t, 0 otherwise
$Y'S_{j\bar{c}d\bar{g}t}$	1 if a central storage facility with capacity $\bar{c}$, storing hydrogen at status d, in region $\bar{g}$ and time step t, has an increased capacity with status of j, 0 otherwise
$Y'S\_O_{\bar{c}d\bar{g}t}$	1 if central storage facility with capacity $\bar{c}$, storing hydrogen at status d in region $\bar{g}$ undergoes no capacity expansion until time step t, 0 otherwise

List of Abbreviations

BAU	Business as Usual
B.C.	British Columbia
BEV	Battery Electric Vehicle
CCA	Capital Cost Allowance
CCS	carbon Capture and Storage
CHP	Combined Heat and Power
CLF	Current Legislation Fulfillment
DDCC	Direct Depreciable Capital Cost
DP	Dynamic Programming
FCEV	Fuel Cell Electric Vehicle
FOC	Fixed Operating Cost
GDP	Gross Domestic Product
GHG	Greenhouse Gas
HDT	Heavy Duty Truck
HFSC	Hydrogen Fueling Supply Chain
H2SCOT	Hydrogen Supply Chain Cost Optimization Tool
ICE	Internal Combustion Engine
IDCC	Indirect Depreciable Capital Cost
IRR	Internal Rate of Return
LCFS	low-carbon Fuel Standard
LDT	Light Duty Truck
LFG	Landfill Gas
LOHC	Liquid Organic Hydrogen Carriers
MDT	Medium Duty Truck
MEA	Monoethanolamine
MILP	Mixed-integer linear Programming
NDCC	Non-depreciable Capital Cost
NEB	National Energy Board
O&M	Operation and Maintenance
PEM	Proton Exchange Membrane
PSA	Pressure Swing Adsorption
PTC	Production Tax Credit
REPC	Replacement Cost
RNG	Renewable Natural Gas
SMR	Steam Methane Reforming
TTW	Tank-to-Wheel
VOC	Variable Operating Cost
WCSB	Western Canadian Sedimentary Basins
WTT	Well-to-Tank
WTW	Well-to-Wheels

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Dedication

To Amin.

Chapter 1: Hydrogen as an Energy Carrier

Hydrogen, as an energy carrier, could help tackle climate change. Like fossil fuels, hydrogen can be stored, transported, combusted and combined in chemical reactions. Hydrogen can be produced from a wide range of energy sources, thus increasing the flexibility and sustainability of the energy system. If produced from renewable energy sources, hydrogen could decouple carbon emissions from the energy supply, while maintaining the same user experience as fossil fuels. Hydrogen, as a low-carbon chemical energy carrier, can deliver significant emissions reduction where direct electrification faces technological or economic obstacles.

1.1 Hydrogen applications

To date, hydrogen has mainly been used as a feedstock in the refining and chemical industries (i.e., oil refining (33%), ammonia production (27%), methanol production (11%) and steel production (3%)) [1]. Hydrogen or hydrogen-based fuels (synthetic methane, methanol and ammonia), can be used for industrial purposes, transportation, indoor heating and power generation.

In the transportation sector, light-duty fuel cell electric vehicles (FCEVs) have received significant public attention due to longer driving ranges and refueling processes that are similar to those in gasoline vehicles. FCEVs could complement battery electric vehicles (BEVs) as zero-emission vehicles capable of reducing GHG emissions and local air pollution in cities. On the heavy-duty sector, fuel cells have so far powered forklifts and buses at a commercial scale, and medium- to heavy-duty trucks in demonstration projects.

Hydrogen can be used to provide heating, cooling and on-site electricity generation for buildings or local district energy networks. In the short term, blending hydrogen into existing natural gas networks can reduce emissions from the built environment. Longer-term prospects may include the direct use of hydrogen for heat generation via hydrogen boilers or combined heat and power (CHP) via stationary fuel cells [2].

Ammonia can partially substitute coal in coal-fired power plants. This can reduce emissions if ammonia is produced from low-carbon hydrogen. Ammonia and hydrogen provide flexible and low-carbon power generation options in gas turbines. Fuel cells can provide back-up for power outages and electricity generation for off-grid communities. Hydrogen and hydrogen based-fuels can be used as mediums for large-scale seasonal energy storage to balance renewable electricity supply and demand [1], [2].

1.2 Current status and international targets

At the COP23 meeting in Bonn, the Hydrogen Council estimated that hydrogen could contribute approximately to 20% of the total abatement required by 2050 under the Paris targets [3]. By 2019, there were around 50 global targets, mandates and policy incentives in place that directly support hydrogen deployment in industry, transport, built environment and power generation. National hydrogen roadmaps have been developed in 9 countries among the Group of Twenty (G20) and the European Union [1]. Countries like Germany, Japan, China, Australia, France, Korea, Norway and the United Kingdom have devoted billions to the deployment of hydrogen infrastructure for mobility, cogeneration, and renewable storage. For example, China and the State of California are planning to build more than 1000 hydrogen refueling stations to support 1 million FCEVs by 2030; and Korea is targeting a shift to hydrogen of all conventional commercial vehicles by 2025. Japan launched Japan H2 mobility and targets to build 80 hydrogen fueling stations by 2021. Japan has invested on different large-scale hydrogen storage technologies such as chemical hydrides and is a leader in stationary fuel cell technology for micro-cogeneration. Germany developed H2mobility program to support the development of hydrogen fueling stations in national level and the first commercial hydrogen-powered train. Germany supports hydrogen-based seasonal energy storage projects to get the most benefit from renewable energy integration. United Kingdom is planning to blend up to 20% hydrogen in a regional natural gas network and secured funding for seasonal hydrogen storage including power-to-X [1], [4].

1.3 Hydrogen potential in British Columbia

Canada is one of the world's largest producers of industrial hydrogen, which is mostly used in the chemical and refinery industries [5]. British Columbia (B.C.) has been a Canadian fuel cell hub for more than three decades. However, the fuel cell market has been focused on exports, with a modest domestic growth [6]. B.C. has a potential to benefit from its world-class fuel cell industry to empower the hydrogen economy in the province. Moreover, B.C. has abundant access to low-cost natural gas and hydroelectricity, as well as renewable energy sources (wind, geothermal, biomass) to produce hydrogen. Hydrogen can help B.C. to meet its decarbonization target, which requires 80% greenhouse gas (GHG) emissions reduction by 2050 from 2007 levels [7]. It should be mentioned that from 2007 to 2016, the total GHG emissions reduction was around 3% in B.C. [8]. Thus, the province must accelerate its effort to stay on the targeted carbon reduction path. Hydrogen's role is critical, especially for road transportation, the hard-to-abate energy sectors (long-range transportation, heating and energy-intensive industries) and off-grid communities in B.C. The injection of renewable hydrogen to the natural gas grid and production of hydrogen-based synthetic fuels are potential short-term enablers for the province to meet its GHG emissions reduction target. Hydrogen export to California, Japan, South Korea and China may also be considered due to B.C.'s coastal access to those emerging markets. Hydrogen export is an opportunity for the province to attract international investment, empower the hydrogen industry in B.C., and decrease the hydrogen price in the domestic market.

1.4 Hydrogen role in B.C.'s road transportation sector

Based on 2016 data, the transportation sector accounts for the largest portion of the total GHG emissions in B.C. (39%), and more than two thirds of these emissions originate from on the road vehicles [9]. The GHG emissions from the road transport sector increased by 14 % from 2007 to 2016. It is projected that the transportation demand increases as it is directly driven by the economic and population growth [10]. In 2019, the B.C. government passed the Zero-Emission Vehicles Act, which requires all new light-duty cars and trucks sold in the province to be zero-emission by 2040 [11]. All-electric vehicles are the only available options with zero-tailpipe emissions. Thus, FCEVs can complement BEVs to meet this target.

B.C. is ready to adopt hydrogen in the road transport sector. The province deployed the world's largest fleet of hydrogen fuel cell buses for the 2010 Winter Olympic Games [12]. The hydrogen fuel infrastructure program started in B.C. in 2015 through the Clean Energy Vehicles for British Columbia [13], a policy initiative that provides incentives at the vehicle's point of sale and for the development of fueling stations. As a result, the first two fully public hydrogen fueling stations in Canada launched in Vancouver, B.C., in 2018 and 2019 as part of a plan to deploy a 6-station network in the Lower Mainland and Victoria [14]. As of July 2019, certain light duty FCEV models are available for purchase in B.C. (e.g., the Toyota Mirai and the Hyundai Nexo), and the first FCEV fleet was announced recently [15]. The province has not yet announced a plan to deploy fuel cell electric trucks to decarbonize the road freight transport. As a very first attempt to incorporate hydrogen in the freight sector, the hydrogen-diesel co-combustion class 8 trucks are being tested in B.C [16].

In order to expedite the FCEV market growth in B.C., the government must develop favorable policies to support the purchase of these vehicles and the development of the hydrogen fueling supply chain (HFSC). As discussed in the next chapter, this infrastructure precedes vehicle adoption. It requires substantial capital investment and is subjected to a negative cash flow that may last for years to decades. This work is a first attempt to develop the most cost effective HFSC plan for B.C. to insure the successful deployment of FCEVs in the province.

Chapter 2: Hydrogen Supply Chain for Mobility

2.1 Hydrogen supply chain structure

A supply chain is a network of interlinked facilities, engaged in the consistent flow of goods from production to the end user. The hydrogen fueling supply chain (HFSC) consists of a network of integrated facilities to produce, transport, store, distribute, and dispense hydrogen. This infrastructure is similar to the current petroleum-based supply chain. Unlike the petroleum counterpart, hydrogen can also be produced at the fueling stations to fulfill demand.

The main building blocks of an HFSC are as follows:

2.1.1 Production facilities

Hydrogen can be produced via thermochemical, electrolytic, photoelectrochemical and biological processes. The thermochemical processes use thermal energy to extract hydrogen from the hydrocarbon-based fuels. Steam reforming of natural gas, partial oxidation of hydrocarbons and coal and biomass gasification are the thermochemical mature technologies for hydrogen production [17]. The electrolytic process uses electricity to split water into hydrogen and oxygen. Alkaline electrolysis, proton exchange membrane electrolysis, and solid oxide high-temperature electrolysis are the industrial water-electrolysis technologies. The electrolytic process creates an opportunity to utilize renewable energy sources such as hydropower, wind, and solar energy for hydrogen production. In photoelectrochemical processes the solar energy dissociates water using semiconductor materials. In biological processes hydrogen is produced as a by-product of microorganism metabolism using sunlight to breakdown water or organic matter. The photoelectrochemical and biological processes are in the early stages of development [18]. Biomass gasification is a mature technology; however, the capital costs of equipment and biomass feedstocks restricts the commercial adoption of this technology to date. Among the aforementioned technologies, steam methane reforming, oil and naphtha reforming, coal gasification and water electrolysis are commercially viable for large scale hydrogen production. Carbon capture and storage (CCS) may also be integrated to reduce the GHG emissions from the hydro-carbon based production pathways. CCS is a process in which the CO_2 generated from industrial activities is separated and transported to storage locations. CO_2 is then injected into subterranean geological formations for long-term isolation from the atmosphere [19].

2.1.2 Terminals and storage facilities

Hydrogen terminal includes the storage and conditioning facilities to feed hydrogen into the distribution network.

Hydrogen storage technologies can be divided into two groups: physical-based and material-based. Hydrogen can be stored physically as a gas or a liquid. As a compressed gas, hydrogen is stored in high-pressure cylindrical vessels for short-term and low demand and in large underground caverns for seasonal demand coverage [20]. Spherical double isolated cryogenic tanks are used for liquid hydrogen storage. In this case, a liquefaction unit is required to convert gas to liquid hydrogen. Compressors and high-pressure cryogenic pumps are also required at the terminal to load gas and liquid hydrogen onto the tube trailers and tankers, respectively [21].

Material-based storage has two main sub-groups of chemical sorption and physical sorption [22]. Hydrogen can be stored in solid-state at moderate pressures and temperatures. This is achieved by an exothermic process in which hydrogen is absorbed in the interstices of metallic alloys or adsorbed on high surface area materials such as activated carbons. An endothermic process is then required to separate the hydrogen from the metal. This reversible process happens in a metal hydride tank. The tank is loaded with hydrogen storage alloy powder, and consists of heat exchange parts and gas transport components [23]. The organic chemical hydride method uses chemical sorption, in which an aromatic compound like toluene is used to convert hydrogen to a saturated cyclic compound. The aim is to store and transport hydrogen medium in atmospheric pressure and temperature. Pure hydrogen is generated by dehydrogenation reaction at the point of use [24].

2.1.3 Hydrogen delivery network

Hydrogen delivery consists of hydrogen transmission from the central production to terminals and hydrogen distribution from terminals to the fueling stations. Gaseous hydrogen is delivered on the road by high pressure tube trailers (long steel tubes or composite storage vessels stacked on a trailer) when low volume of hydrogen is required in short distances. Pipeline is a suitable option for gaseous hydrogen delivery in large demand sizes and to dense areas. Liquid hydrogen is transported on the road in super-insulated, cryogenic tanker trucks. This mode of delivery is suitable for moderate demand and long-distances (the range of hydrogen flow and transport distance for each delivery mode is presented in [25]). Other potential hydrogen transport modes are rail, barge, and ship; however, they are not yet at a commercial scale [26].

2.1.4 Hydrogen fueling stations

Hydrogen fueling stations dispense hydrogen in a form of compressed gas to vehicles. The dispensers may accommodate both 70 MPa and 35 MPa, depending on the type of vehicle being served. The components of a hydrogen fueling station vary with respect to the state of hydrogen received. Compression unit is required when gaseous hydrogen is delivered via tube trailers or pipelines. Liquid pump and evaporation unit (or evaporation and compression unit) are required when liquid hydrogen is delivered to the station. The fueling station may be equipped with a steam methane reformer or electrolyzer to produce hydrogen at the station in small scales. At very early stages of hydrogen penetration to the market, mobile hydrogen fueling stations can be used to provide self-contained hydrogen dispensing capabilities (on-board compression, storage, dispensing and power) to serve low-demand and remote areas [27].

2.2 Deployment challenges

Hydrogen fueling supply chain (HFSC) represents a capital-intensive investment, facing high risks of negative cash flow for years to decades. The network of fueling stations along with the upstream supply infrastructure (i.e., production, storage, transport and distribution facilities) must be developed in advance of the fuel cell vehicle roll-out. This is to assure the hydrogen demand satisfaction for the vehicle manufacturers and potential customers [28]. Even at the early stages of demand growth, HFSC faces underutilization, which threatens its economic viability. Moreover, the hydrogen supply chain pathways are diverse. Each combination of technology, scale and location of the components imposes varying costs on the entire supply chain. The network design process is time-dependent and region-specific [29]. The investment decisions which are not supported by rigorous analysis of the spatial and temporal factors (e.g., available energy sources, demand characteristics, local energy prices and decarbonization policies) may face serious financial consequences.

2.3 Hydrogen supply chain design approaches

The supply chain network design, also known as supply chain planning, is the process of modeling a supply chain based on strategic targets of the project and the available resources.

The network design of a HFSC has been studied extensively [30], [31]. These studies have been oriented to the strategic decision phase, aimed to generate spatial and temporal decisions on the configuration of the HFSC.

Simulation and optimization are the formal quantitative approaches to design an HFSC. Typical simulations assess predefined pathways, from production to distribution of hydrogen. These simulations usually target economic or environmental performance metrics [32], [33]. Optimization approaches can be used to scan a superstructure that embeds all the possible configurations of a supply chain in an integrated mathematical framework. The optimization models identify the optimal pathway, with respect to the desired performance measures and a set of technical, spatial, temporal, and environmental constraints. These models can be categorized with respect to the spatial measure in to national, regional and local scale. When embedded in a national or global energy system optimization, the hydrogen supply and demand are endogenously optimized through interactions within all energy sectors [34]. For instance, the Energy Technology Systems Analysis Program-MARKet Allocation Model and its successor, the Integrated MARKAL-EFOM, are popular bottom-up linear optimization tools for entire energy system cost minimization [35]. Hydrogen pathway assessments have been integrated within these tools at national and large regional scale for the UK [36], California [37], Italy [38], Japan [39], Spain [40] and Norway [41]. The regional-scale HFSC models optimize the spatially explicit supply chain configurations, considering the demand as an exogenous parameter. These models cover the spatial dynamics of transitions in more detail, while ignoring the dependency of the hydrogen demand to the techno-economic specifications of the overall energy system [42]. The local scale models have been focused on the hydrogen fueling station siting problem. These models optimize the location of hydrogen fueling stations in a relatively small region (e.g., cities) [43], [44], based on the classical facility location optimization techniques such as generalized approach, the p-median and flow intercepting [45].

The optimization models have been widely developed in the literature using mixed-integer linear programming (MILP) techniques. Only one study has been found using dynamic programming (DP) technique to optimize the HFSC [46].

The HFSC models adopt mono- or multi-objective frameworks. The most desired performance measure for mono-objective models is minimizing the total cost of the system [47]–[50] or maximizing the profit [51], [52]. The multi-objective frameworks assess the cost in conjunction with other performance measures such as safety risk [53], [54] and environmental impact minimization [55], [56]. The ε-constraint method dominates the solution approaches to solve multi-objective HFSC problems. This method generates a full set of trade-off solutions based on optimizing one objective function while considering the other objectives as constraints [57].

The HFSC optimization models are also categorized into deterministic and stochastic (or probabilistic) classes based on the nature of input parameters. All spatial, temporal and operational parameters are fixed in a deterministic setting. In stochastic models, uncertainty is introduced in at least one parameter. Uncertainties are classified in three distinct categories: demand uncertainty, process uncertainty and supply uncertainty. The demand uncertainty is the parameter used most frequently, introduced via scenarios with known probabilities [58], [59]. The two-stage linear stochastic programming technique is used to deal with the scenario-based uncertainty inclusion [60].

The HFSC can also be analyzed as static or multi-period models. The static models optimize the HFSC at a point in time [47], [61]**,** while the multi-period models optimize the evolution of the supply chain over a predefined planning horizon [59], [62].

2.4 Environmental considerations in the hydrogen supply chain design

Fuel cell electric vehicles have zero tailpipe emissions; though, the upstream GHG emissions from the hydrogen supply chain may limit its benefits as a low-carbon fuel. Emissions are mostly involved in the production and distribution stages of this supply chain.

2.4.1 Low-carbon hydrogen pathways

The emission reduction potential of hydrogen can only be exploited fully when it is produced through low-carbon pathways. On the production side, conventional fossil fuel-based technologies must be equipped with carbon capture and utilization or storage (CCU or CCS). Currently, low-carbon hydrogen production technologies such as anaerobic digestion, photo fermentation, bio electrochemical systems, and artificial photosynthesis are at the laboratory scale or demonstration stage [63], [64]. Only water electrolysis has increased its share to 4% of the global hydrogen production in the last decade [1]. Only low- or zero carbon electricity (e.g., from renewable sources) can enable significant emissions reduction in hydrogen production from water electrolysis.

On the distribution side, the GHG emissions from the diesel trucks, transporting hydrogen from production facilities to the fueling stations, must be reduced. This is achievable through performance improvement of the diesel trucks in the short term and switching to all-electric trucking in the long term [65]. Moreover, hydrogen pipeline transport is economically and environmentally competitive for concentrated large-scale demand [25].

Because hydrogen production from fossil sources (without CCS integration) is still the most economically viable solution, external incentives are required to empower the low-carbon hydrogen production as discussed in the next section.

2.4.2 Enabling low-carbon hydrogen production

The following factors could contribute to enhance the economic viability of low-carbon hydrogen production:

- Expansion of the hydrogen market

Learning-by-doing and economies-of-scale can reduce the costs and increase the effectiveness of the low-carbon hydrogen pathways [1]. Market expansion could be achieved by considering applications beyond transportation. A wider energy system could, for example, include hydrogen injection into natural gas grids [66], or hydrogen use as an energy storage medium for heat and power generation [67].

- Government financial support and favorable regulations

Government policies could accelerate the transition toward green hydrogen, especially if they target hydrogen technologies explicitly and promote the renewable energy capacity installations. The policies can apply economic instruments (fiscal and financial, direct investment or market measures), regulations, standards, long-term targets, and RD&D support [68].

Thus far, national policies on transport decarbonization have focused on energy efficiency improvement for combustion engines, biofuel adoption and modal switches (e.g., public transport, biking, walking, etc.) [69]. So far, the hydrogen policies in transport sector have attempted to decrease the risk and cost of early stage FCEV adoption, without considering low-carbon hydrogen production explicitly. The current policies can be separated into financial and regulatory frameworks, and categorized with respect to consumers, automakers and fuel providers.

Consumer-side policies include vehicle purchase subsidies, vehicle purchase tax exemption, free parking, access to high-occupancy vehicle (HOV) lanes and free fueling. Such policies exist in California, Denmark, Germany, South Korea, and the UK [70]–[72]. Automakers are affected by zero emission vehicle regulation and fuel economy targets [73]. Fuel suppliers are affected by low carbon fuel regulation [74], renewable fuel standard [75], and direct subsidies for infrastructure development. In Japan, Germany and California, subsidies up to \$61m, \$466m and \$100m, respectively, have been allocated for the development of hydrogen fueling stations [76]. Low-carbon hydrogen production regulations and subsidies may encourage fuel suppliers to develop a sustainable hydrogen fueling network.

- Regional energy profile

A favorable regional energy profile is critical for the long-term economic feasibility of low carbon hydrogen pathways. Such profile may include the type and amount of renewable energy available, domestic or imported natural gas, geological suitability for CO_2 storage, and access to adequate supplies of water for electrolysis.

2.4.3 Low-carbon hydrogen integration in supply chain optimization

With no emissions constraints or incentives in place, the HFSC model favors the fossil-fuel hydrogen production technologies in a cost optimal pathway. So far, the optimization models included emissions reduction targets as constraints on the HFSC operation or added the carbon tax as a cost parameter to the cost minimization objective function. Almansoori and Betancourt-Torcat [61] developed a mono-objective optimization framework to minimize the total cost of HFSC in Germany by 2030. The effect of carbon tax and CO_2 emissions target scenarios was investigated on the configuration of the optimal supply chain. In a study by Moreno-Benito et al [77], the carbon tax was included in the economic objective function of a multi- period model to optimize the HFSC in the UK. Yang and Ogden [37] used the TIMES modeling framework to assess the long-term development of HFSC for California. The model was subjected to carbon tax as well as a number of emissions reduction constraints, including various scenarios on the regulatory part of the low carbon fuel policy (as a carbon intensity constraint), the renewable hydrogen mandate, which requires a minimum contribution of renewably produced hydrogen to the total hydrogen supply, and prohibition on coal gasification without CCS inclusion.

A number of other studies justified the cost optimal inclusion of low-carbon hydrogen pathways by assuming large hydrogen demand penetration into different energy sectors [20], [78], [79].

2.5 Hydrogen fuel supply chain design in British Columbia

The HFSC planning in Canada is still in its infancy and has not yet been supported by formal optimization modeling. The only regional-based study was performed by Liu et al. [80] for the province of Ontario. Three FCEV market penetration scenarios were projected, and the cost of hydrogen production, storage, and distribution was calculated for a distinct pathway in each demand scenario. As discussed in chapter 1, among Canada’s provinces and territories, British Columbia is well positioned to take advantage of its abundant natural resources and carbon policies to develop a hydrogen fueling network.

2.5.1 Objectives

The objectives of the current work are listed as follows:

- Development of a comprehensive hydrogen supply chain cost optimization tool (H2SCOT) for the long-term investment planning of hydrogen fuel supply chain (HFSC) at low demand. This model was applied to a case study of light duty passenger vehicles in British Columbia [81].

- Explicit integration of a range of emissions mitigation policies to the HFSC optimization model.
- Efficiency assessment of the current policies in road freight transport and the potential contribution of zero-emissions trucks to meet the provincial GHG emissions reduction targets [65].

2.5.2 Contributions

- This study is a first attempt to develop a hydrogen supply chain cost optimization tool (H2SCOT) in Canada and British Columbia.
- From the modeling perspective, H2SCOT includes a more comprehensive representation of the HFSC components compared to previous models, as summarized in Table 2.1. The multi-period, spatial-explicit MILP model by Moreno-Benito et al. [82] has the closest superstructure to the current model. Moreover, H2SCOT supports fueling stations and on-site hydrogen production with varying capacities, considers three alternative capacities for gaseous delivery, and includes a capacity expansion option (capacity expansion) for central production and storage facilities. H2SCOT deals with the low hydrogen demand in B.C., as opposed to large demands reported previously (Table 2.1). The aforementioned features enabled proper facility sizing to avoid underutilization costs. Moreover, H2SCOT supports storage facilities for fueling stations and ensures minimum storage requirements will be met. This option was included to cover hourly demand fluctuations at the fueling station. H2SCOT considers the lifetime of all components and the yearly replacement cost of facilities.
- Policies aimed at reducing greenhouse gas emissions and improving air quality are often designed to promote the adoption of low-carbon fuels, or zero emission technologies. Hydrogen and its related technologies are often included indirectly, ignored, or excluded explicitly. The lack of specificity in generic policies implies that their impact on hydrogen adoption can be masked by financial or technological artefacts. In this study, a wide range of economic instruments and regulatory measures was included explicitly in H2SCOT. Compared to the previously developed models, H2SCOT is the first attempt to quantify the

effectiveness of existing and potential policies on the accelerated adoption of low-carbon hydrogen in the transport sector.

- This work is the first contribution to measure the effectiveness of current policies in road freight transport and the potential of zero-emission trucking to meet the provincial GHG emissions reduction targets in B.C.

2.5.3 Approach (thesis outline)

The superstructure of the HFSC, considered in this work, is presented in Figure 2.1. This diagram incorporates the potential pathways to produce, transport, store, distribute, and dispense hydrogen for the province of B.C. These pathways were developed based on the availability of local energy sources to produce hydrogen, the commercially available technologies and the projected level of hydrogen demand in the province.

The HFSC superstructure was used to develop the optimization model, as shown in Figure 2.2. The inputs of H2SCOT were defined and formulated in **Chapter 3**. These inputs are the capital and operational costs and the fuel-side GHG emissions of all alternative components of this supply chain; Hydrogen demand which is exogenously determined by a sub-model for each region over the studied time frame; and the potential supply and demand regions and corresponding distances. Moreover, a number of economic and regulatory instruments (emissions mitigation policies) with various stringencies were defined and formulated in **Chapter 3**.

The formulation of H2SCOT is presented in **Chapter 4**. H2SCOT has been developed based on a MILP formulation and is subjected to a number of constraints including mass balance, demand satisfaction, technology capacity limits, and non-negativity. The objective function is to minimize the discounted total cost of infrastructure, which includes the discounted cost of technology and the discounted cost of environmental policies. H2SCOT incorporates 6 equal time steps for the development of an HFSC from 2020 to 2050. The model output comprises of the optimal configuration of HFSC including location, number, type of technology, and capacity of the supply chain’s production, storage, and dispensing components, the average annual hydrogen production, storage, and dispensing rates, as well as the number and type of transportation and distribution trucks between the supply and demand regions.

Chapter 5 compares the cost optimal configuration of the HFSC for three demand scenarios in case of light duty passenger FCEVs penetration in B.C. **Chapter 5** also includes the efficiency assessment of current and potential financial and regulatory policies on the environmental and economic performance of the HFSC.

Chapter 6 assesses the potential contribution of battery electric and fuel cell electric trucks to meet GHG emissions reduction targets in road freight transport in B.C. The analysis was based on the efficiency assessment of current policies and the availability of regional resources to support all-electric trucking in B.C.

Chapter 7 provides the main conclusions and limitation of this study along with recommendations for a future work.

Table 2.1. Modeling details of the previously developed platforms compared with H2SCOT.[1]

Study	Supply chain components[2]	Time evolution	On-site production	Capacity alternative: Fueling station	Capacity alternative: On-site production	Capacity alternative: Gaseous delivery	Storage levels of fueling station	Capacity expansion	Assess Component Lifetime[2]	Yearly replacement cost	Emission policy
Guillén-Gosálbez et al. [55] Sabio et al. [83]	CP, CS, TN	Multi-period	No	No	No	No	No	Yes[3]	No	No	No
Almansoori & Shah [59] De-León Almaraz et al. [54]	CP, CS, TN, FS	Multi-period	No	No	No	No	No	No	CP, CS	No	No
Han et al. [84]	CP, CS, TN	Time-invariant	No	No	No	No	No	No	No	No	Emissions trading[4]
Dayhim et al. [85]	CP, CS, TN	Multi-period	No	No	No	No	No	No	No	No	Carbon tax
Almansoori & Betancourt-Torcat [61]	CP, CS, TN	Time-invariant	No	No	No	No	No	No	No	No	Carbon tax[5]
Moreno-Benito et al. [82]	CP, CS, TN, FS	Multi-period	Yes	Yes	No	No	No	No	CP, CS, TN, FS	No	Carbon tax, Carbon intensity constraint
Yang & Ogden [37]	CP, CS, TN, FS	Multi-period	Yes	No	No	No	No	No	No	No	Carbon tax, Carbon intensity constraint, Technology ban
H2SCOT (this study)	CP, CS, TN, FS	Multi-period	Yes	Yes	Yes	Yes	Yes	Yes	CP, CS, TN, FS	Yes	Carbon tax, Credit trading, Production tax credit, Capital subsidy, Accelerated depreciation, Utility subsidy, Technology ban

[1] This table excludes studies that only contain a qualitative description of the model and present very limited or no information on the formulation, such as Kamarudin et al. [86], Ball et al. [62], Hugo et al. [87], Konda et al. [88], and Stiller et al. [89]).

[2] CP: central production, CS: central storage, TN: transportation network, FS: fueling station.

[3] The continuous capacity expansion of facilities over time and within certain limits was considered. The shortfall is that constant capacity cannot be maintained for the successive time steps (the capacity expands at each time step or new facilities will be built).

[4] Production emissions only.

[5] The CO_2 emission target was enforced to the constraints of the model.

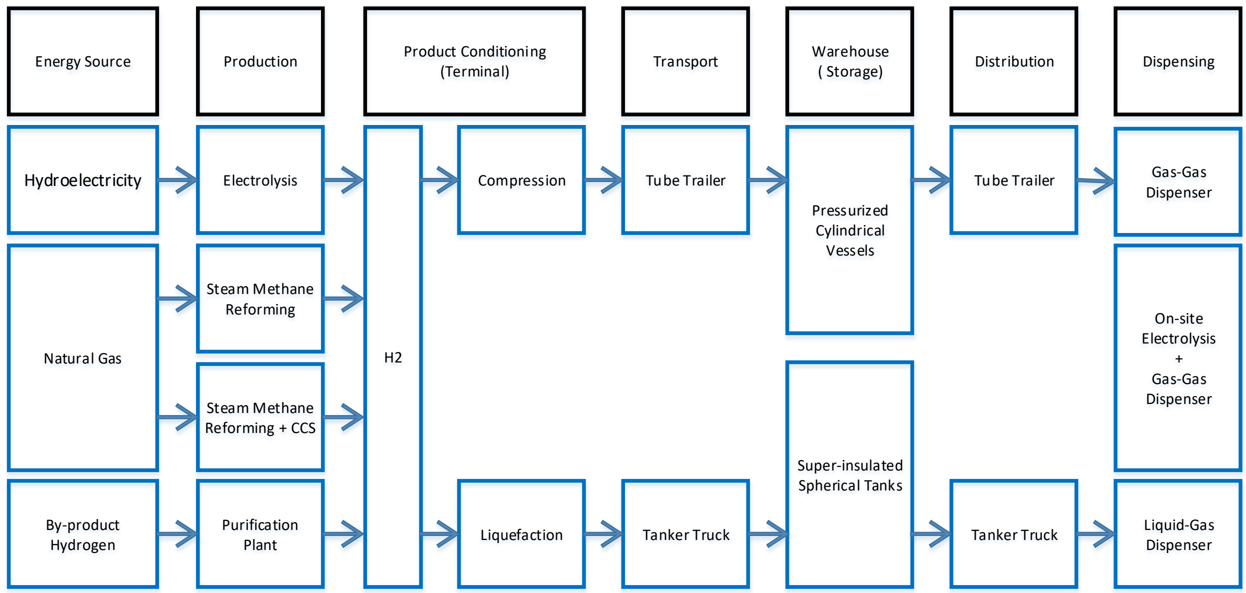


Figure 2.1. Superstructure of the HFSC infrastructure in B.C. (CCS: carbon capture and sequestration)

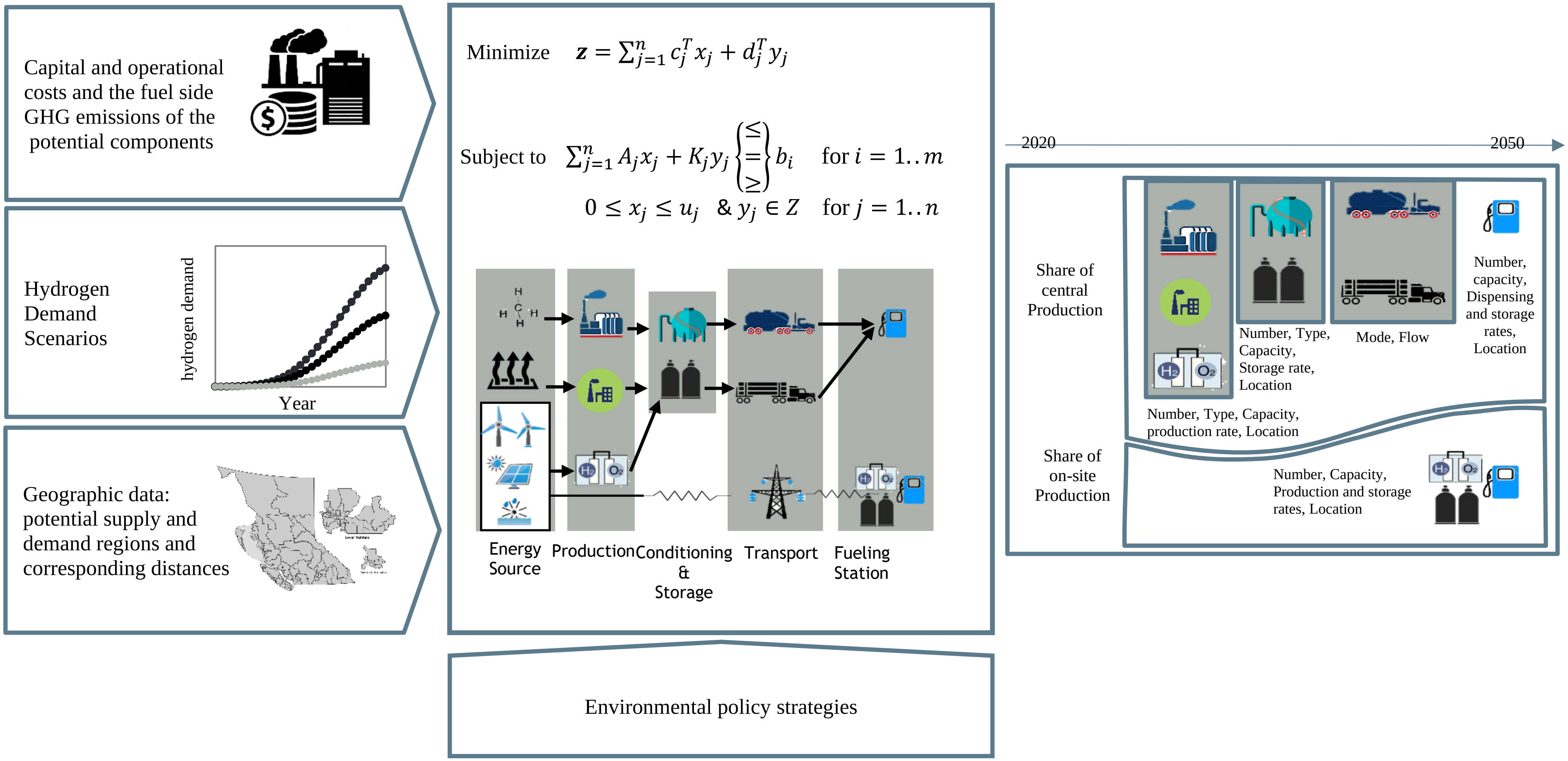


Figure 2.2. Schematic of H2SCOT

Chapter 3: Hydrogen Supply Chain Cost Optimization Model (H2SCOT): Model Inputs

3.1 Assessment of energy sources

A wide range of energy sources can be used to produce hydrogen. In this work, hydrogen pathways were developed based on the availability assessment and economic advantages of the local energy sources in B.C.

3.1.1 Hydrogen production from renewable energy sources

Electricity generated from renewable energy sources can be used for electrolytic hydrogen production. Hydropower is responsible for around 92% of the total electricity generation in B.C [10]. The National Energy Board (NEB) projections [10] stated that the total electricity generation in B.C. will be around 81.1 TWh in 2040, of which 86% will be generated from large-scale hydroelectric dams. As B.C. is expected to rely heavily on the affordable hydroelectric power for a long time, harvesting other renewable resources for electricity generation is dependent on their economic viability. The latest BC hydro integrated resource plan [90] assessed the long-term electricity generation potential of several renewable resources like wind, geothermal, biomass, solar, tidal and wave energy based on the technical and cost attributes. The results indicated that the wind, geothermal, and biomass resources have the least levelized[1] energy costs. The total technical onshore and offshore wind potential in B.C. was estimated at 102 TWh, of which 43% can be harvested for less than $200 per MWh. The geothermal resource potential was estimated at around 12 TWh, of which 50% is below $200 per MWh. It is worth mentioning that only conventional hydrothermal resources using flash or binary technologies are considered within BC Hydro's resource assessment. The wood-based biomass resources available for bioenergy production were estimated at 3.22 million tonnes of dry wood [91] which translates to the technical electricity generation potential of 4.5 TWh, mostly below $200 per MWh. It should be mentioned

[1] The levelized cost of a unit of energy ($/MWh) from a resource is the ratio of the present value of the total annual cost of an energy resource to the present value of its annual average energy benefit. The levelized cost is dependent on the accessibility of the generation sites to powerlines.

that available biomass for bioenergy production is referred to as the part of wood waste supply that are surplus to the demand of existing forest industry. From the NEB projection database [10], 1.4% of B.C.'s wind resource potential and 40% of the combined biomass and geothermal potential will be used for electricity generation in 2040. These projections also stated that the electricity generation in B.C. will surpass the demand by 14% in 2040. This potentially translates to 226,000 tonnes of electrolytic hydrogen (32 PJHHV) produced at a rate of 50.2 kWh/kgH_2. To put this into perspective, the total energy demand from the light duty passenger vehicles in B.C. was around 258 PJ in 2017 [9].

Biomass can be used directly to produce hydrogen through a gasification process. The availability of standing timber, pulp logs, roadside wood waste and sawmill wood waste in B.C. was forecasted to 2040 [91] using B.C.'s fibre model [92]. Different types of available wood-based biomass feedstock in B.C are categorized in Table 3.1 based on the percentage distribution and the average delivered fibre cost. The road-side logging residues may contribute to a larger share of hydrogen production compared to the other wood-based feedstock considering both the distribution percentage and the delivered cost. The available wood-based biomass in B.C. for bioenergy production translates to the technical hydrogen production potential of 334 and 233 kilotons per year (47 and 32 PJHHV/ year), considering 13.8 kg dried wood biomass is required to produce 1 kg of hydrogen.

Table 3.1. Distribution and delivered cost of the wood-based biomass feedstock in B.C. [91]

Type	Distribution		Average delivered fibre cost (C$/tonne of dry wood)
	2016-2025	2026-2040	
Standing sawlog timber	72.5%	62%	170.7
Pulp logs	8%	8%	129
Road-side logging residues	15.5%	23%	77
Sawmill hog fuel	4%	7%	30.3

Biogas is another source of potential hydrogen production made up primarily of 50%–70% bio-methane. Feedstocks for renewable natural gas (RNG) production are organic wastes from farms, forests, landfills, and water treatment plants. The landfill gas (LFG) and was considered as a source of biogas in this work. In order to avoid double counting the resource potential, the available biomass in B.C. was not considered as a source of RNG. A report from Golder Associates [93] is the only available resource for LFG assessment in the province. This report considered all the operating municipal solid waste landfills in 2006 in B.C. with a minimum disposal rate of 10,000 tonnes per year and projected methane generation potential from the landfills to 2020. In this work, the "business as usual" projection was used to calculate the methane generation potential in 2050. It should be noted that only the landfills with minimum methane flow rate of 200 cfm were selected as they provide sufficient economic incentives for developing LFG projects. The steam methane reforming (SMR) technology was adopted to assess the potential hydrogen production from the bio-methane captured from LFG recovery units with 75% recovery factor [94]. The bio methane recovery potential was estimated at 128000 tonnes in 2050, which translates to around 38000 tonnes of hydrogen (5.4 PJHHV) using the conversion rate of 3.4 kg methane per kg of hydrogen. It should be noted that there is a target of 5 percent RNG-blended natural gas in the pipeline distribution system by 2025 and 10 percent by 2030 [10]. This is equivalent to 50 PJ in 2030 as the projected natural gas demand in B.C. is around 500 PJ in 2030. Thus, it is unclear if the limited resource potential of RNG could practically contribute to hydrogen production.

By-product hydrogen vented from chemical plants can also be considered renewable if renewable electricity is used for the electrolytic process in the plant. In B.C, a sodium chlorate plant in Prince George and a chlor alkali plant in North-Vancouver use grid-connected hydroelectricity and vent 18500 kg/ day hydrogen [95]. By-product hydrogen can be captured and purified for a range of applications.

3.1.2 Hydrogen production from non-renewable energy sources

B.C. is Canada's second largest natural gas producer [96]. In this work, B.C.'s raw gas established reserve potential was targeted to assess hydrogen production using SMR technology. The ultimate potential for marketable natural gas (NG) in B.C. is estimated at 15547 billion m^3. This is equivalent to 3.3 billion tonnes of hydrogen (468000 PJHHV) using the conversion factor of 4.74 m^3 NG per kg of hydrogen in an SMR unit. Based on the NEB projection [10], local demand of natural gas in B.C. will be around 20% of the total production between year 2020 and 2040 from both conventional and unconventional deposits. NEB presented different scenarios for natural gas production in B.C. The available natural gas for hydrogen production in 2040 was calculated at 76 billion m^3 based on the average value of different natural gas production scenarios, and the local NG demand projection (roughly equivalent to 16 million tonnes of hydrogen (2270 PJHHV)).

Coal is B.C.'s most valuable mined commodity in terms of annual sale. The coal mines in the province mostly produce a metallurgical grade coal, which is exported to Asia, Europe and South for steel manufacturing. The demonstrated mineable coal resource is around 8400 million tonnes [97], which is equivalent to 853 million tonnes of hydrogen (121040 PJHHV), using the conversion factor of 10 kg of coal per kg of hydrogen in a gasification process. Using the "business as usual" projections, the coal production reaches 30.6 million tonnes annually by 2040. This is equivalent to 3 million tonnes of annual hydrogen production (426 PJHHV /year). It should be noted that the thermal coal with 5% hydrogen content is preferable for hydrogen production compared to the metallurgical coal with 2% hydrogen content. Only 20% of the total coal resources in B.C. are thermal grade coal.

3.1.3 Selected energy sources for hydrogen production

In this work, the grid-connected renewable electricity and natural gas was selected along with the available by-product hydrogen from the chlor alkali plant in North-Vancouver. As the hydrogen demand in this work was restricted to the light duty passenger vehicles (section 3.4), it can be fulfilled with widely available natural gas and extra hydroelectricity generation in the next decades. In case of a wider market penetration, the resource assessment showed that wind, geothermal power and biomass can also be harvested to fulfill the hydrogen demand. It should be noted that the Clean BC plan set GHG intensity limit for gasoline and diesel by 2030. This may restrict biomass availability for hydrogen production, as biomass-based fuels (corn ethanol, methanol and biodiesel) are required to increase the renewable content of the fossil fuels. Moreover, coal gasification has a narrow window of opportunity in B.C., due to the small share of mineable thermal coal and the dependency on CCS integration.

3.2 Geographic divisions

Fourteen supply regions in B.C. were selected as potential locations for central production facilities and central storage facilities as shown in Figure 3.1. The type of production technology in each region depends on the accessibility to major natural gas pipelines, BC Hydro power transmission lines, by-product hydrogen, and potential carbon sequestration sites. Accordingly, the electrolysis and SMR option were not considered for regions 1 and 5, respectively. The western Canadian sedimentary basins (WCSB), regions 1 and 2, are considered as the potential carbon storages sites. The WCSB composed of depleted gas reservoirs and saline aquifers with the aggregate storage potential of more than 3000 Mt CO_2 per year [98]. Thus, SMR plants with CCS integration could potentially be built in these regions.

Demand regions in this study are confined to the major metropolitan areas (early adopters are more likely to live in urban areas where the first fueling stations will be built due to a higher population density and per-capita income [99]). Based on the population size, 10 municipalities in Metro Vancouver, Victoria on Vancouver Island, Kelowna and Kamloops in the Southern Interior, Prince George in the North Central area were selected as demand regions. Abbotsford, Hope, Whistler, and Williams Lake were also added because they are located on the busiest roads. The distribution of hydrogen demand among those municipalities over time is discussed in section 3.5.

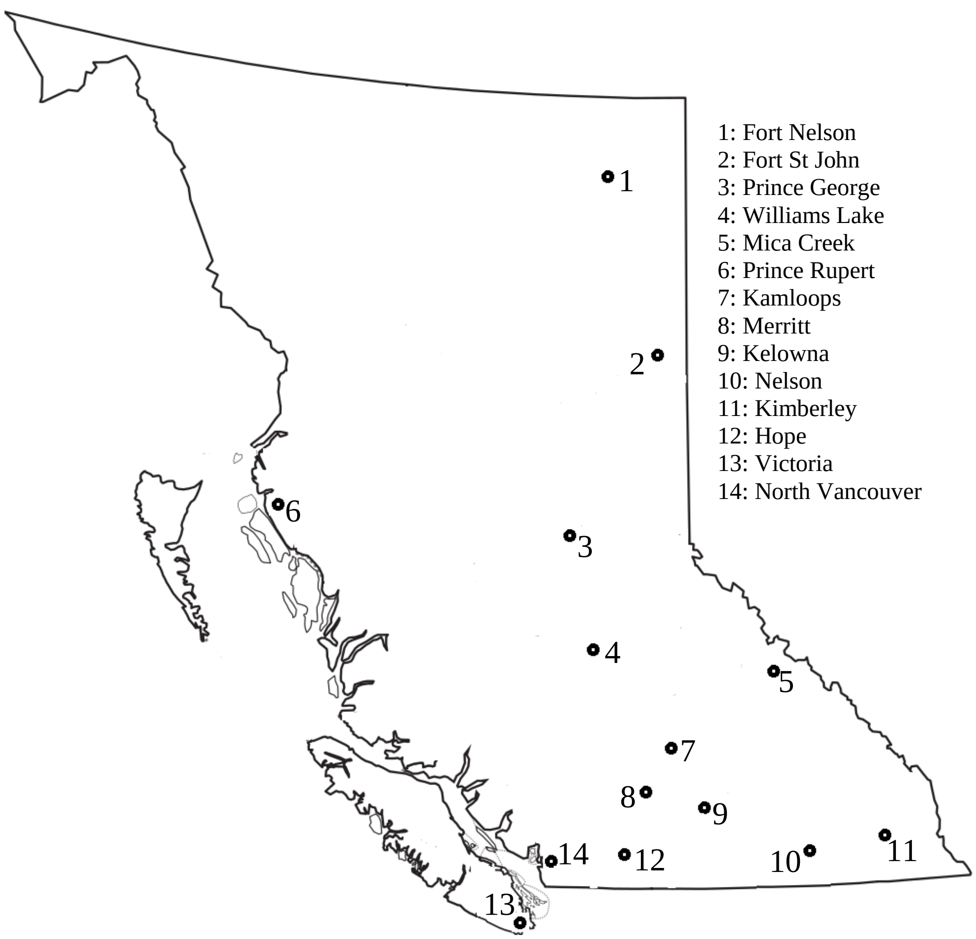


Figure 3.1. Hydrogen supply regions in British Columbia

3.3 Techno-economic and environmental data

In this section, the capital and operating costs of each potential component of the hydrogen supply chain is derived alongside the GHG emissions associated with the flow of hydrogen through the supply chain.

3.3.1 Derivation of the techno-economic parameters

3.3.1.1 SMR plant

A steam methane reforming (SMR) plant consists of a steam reforming furnace, shift reactors and a pressure swing adsorption (PSA) unit. The furnace converts the mixture of steam and desulfurized natural gas to syngas (mainly H_2 and CO) over a nickel-based catalyst. The syngas then passes through a heat recovery step and is fed into a water gas shift reactor, where it converts to H_2 and CO_2 over promoted iron oxide catalyst. The final hydrogen purification is accomplished via a PSA system, where the impurities are adsorbed on the surface of adsorbents at relatively high pressure [100].

Table 3.2 details the capital and operating cost of an SMR plant with a capacity of 100 tonnes/day. The direct depreciable capital cost (DDCC) of an SMR plant without carbon capture and sequestration (CCS), consists of the cost of the reformer and the balance of plant and off-sites.

Table 3.2. Capital and operating cost of SMR plant (100 tonnes/day) [101]

Capital Expenses		Annual expenses	
DDCC* (100 tonnes/day)	USD (2013)	**REPC***	**0.5% of DDCC**
Reformer	28,726,000	**FOC***	**5% of DDCC**
Balance of plant and off-sites	11,477,000	**VOC***	
Process CO_2 removal	3,491,000	plant non-fuel O&M	4% of DDCC
Stack CO_2 removal	3,070,000	O&M CO_2 compressor	4% of Eq. 3.4
CO_2 compressor (Eq. 3.4)	21,282,000	O&M CO_2 injection	Eq. 3.8 to 3.11
CO_2 injection equipment (Eq. 3.6)	103,000	O&M CO_2 pipeline	2.5% of Eq. 3.6
Drilling capital cost (Eq. 3.7)	436,000	Natural gas	Eq. 3.2
Site screening and evaluation	2,177,000	Electricity	Eq. 3.3
CO_2 pipeline cost (Eq. 3.5)	51,144,000	Water	Eq. 3.2 with modification
IDCC*	**% of DDCC**		
Site preparation	2%		
Engineering & design	10%		
Project contingency	15%		
Up-front permitting costs	15%		
NDCC*	3,200,000		

*DDCC: direct depreciable capital costs, IDCC: indirect depreciable capital costs, NDCC: non-depreciable capital costs, REPC: replacement costs, FOC: fixed operating costs, VOC: variable operating costs

The installation cost factor of 1.92 was applied to all direct depreciable capital costs except for the CO_2 compressor (1.2) and CO_2 injection equipment (1.5).

As the cost parameters were reported for large-size (LS) plants (200 to 400 tonnes/day), the scaling factor (α) of 0.88 was used to derive the cost parameters applicable to the medium-size (MS) plants (10 to 100 tonnes/day):

$$Cost_{MS} = Cost_{LS}\left(\frac{Size_{MS}}{Size_{LS}}\right)^{\alpha} \quad 3.1$$

The scaling factor of 0.7 was used for a plant of size 10 to 50 tonnes/day.

The annual cost of feedstock (i.e., natural gas (NG), water (W), and electricity (Elec)) for the SMR plant and the CCS facilities were calculated as follows:

$$Cost_{NG} = 365 Price_{NG} NUsage_{Ref} Av_{Plant} Pro\_rate_{Plant} \quad 3.2$$

In which $NUsage_{Ref} = 0.164 \frac{GJ}{kgH_2}$ is the NG consumption in the reformer and $Av_{Plant} = 0.98.$ is the plant availability.

Equation 3.2 was used to calculate the annual cost of water by substituting $NUsage_{Ref}$with $WUsage_{Ref} = 4.8 \frac{gallon}{kgH_2}$ and $Price_{NG}$ with $Price_w$.

$$Cost_{Elec} = 365 Price_{Elec}\left(EUsage_{Compr} + EUsage_{Ref}\right) Av_{Plant} Pro\_rate_{Plant} \quad 3.3$$

In which the energy consumption of the compressor and reformer are $EUsage_{compr} = 0.81 \frac{KWh}{kgH_2}$ and $EUsage_{ref} = 0.6 \frac{KWh}{kgH_2}$, respectively. $EUsage_{compr}$ was not considered for plants without carbon capture technology.

CO_2 capture and sequestration (CCS)

CO_2, which is present in the syngas and flue gas, is captured by different technologies including: PSA, absorption technologies, membranes and cryogenic processes [102]. In this study, it was assumed that the monoethanolamine (MEA) absorption unit was installed on the syngas stream, following the shift reactor, and a secondary MEA treatment unit was installed on the reformer stack to capture CO_2 from the flue gas. The CO_2 capture efficiency was considered at 90% [103]. The CO_2 sequestration is accomplished in three stages: CO_2 compression, CO_2 transportation to the sequestration site, and CO_2 injection into the geological reservoir. At the compression stage, CO_2 is compressed from atmospheric pressure to 15 MPa, which is suitable for pipeline transport. This could be accomplished via 9-stage compression. The capital cost of the compressor in U.S. dollars (2005) was calculated using the following formula:

$$C_{compr} = m_{train} N_{train} \left[0.13 \times 10^6 (m_{train})^{-0.71} + 1.4 \times 10^6 (m_{train})^{-0.6} ln\left(\frac{P_{final}}{P_{initial}}\right)\right] \qquad 3.4$$

In which m_{train} (kg/s) is the CO_2 mass flow rate through each compressor train, and N_{train} is the number of compressor trains. m_{train} was calculated by multiplying the CO_2 produced from the SMR process (kg/s) by the carbon capture efficiency of the plant. N_{train} equals to 1 in this study, as the compressor power was less than the maximum size of each compressor train, i.e., 40,000 KW.

The operation and maintenance (O&M) cost of the compressors was calculated by multiplying the O&M factor of 0.04 by the capital cost of the compressor.

The capital cost of pipelines to transport the captured CO_2 to the injection wells was calculated as follows (USD 2005):

$$C_{pl} = 9970 F_{loc} F_{ter} Length_{pl}{}^{1.13} m_{pl}{}^{0.35} \qquad 3.5$$

In which F_{loc} and F_{ter} are the location and terrain factors, with values of 1 and 1.3, respectively. $Length_{pl}$ and m_{pl} are the length of the pipeline and the CO_2 mass flow rate (tonne/day) through the pipeline, respectively. The pipeline length was assumed at 60 km in this study [98].
The O&M cost of the pipelines was calculated by multiplying the O&M factor of 0.025 by the capital cost of the pipeline.

The capital cost of CO_2 injection is composed of site screening and evaluation, equipment, and drilling per well. Each well is needed for the injection of 10,000 metric tonnes per day or less.

The injection equipment cost includes supply wells, distribution lines, headers, and electrical services, calculated as follows (USD 2005):

$$C_{inject} = 49433 \times N_{well} \times \left(\frac{m_{well}}{280 \times N_{well}}\right)^{0.5} \quad 3.6$$

In which N_{well} is the number of wells, and m_{well} is the CO_2 mass flow rate delivered to each injection site (tonnes/day).

The drilling cost of an onshore injection well was estimated as follows (USD 2005):

$$C_{drill} = N_{well} \times 10^6 \times 0.1063e^{0.0008d_{well}} \quad 3.7$$

In which d_{well} is the well depth, which was assumed at 1524 m [101].

The O&M cost of injection is composed of normal daily expenses ($O\&M_{daily}$), consumables ($O\&M_{cons}$), surface maintenance ($O\&M_{sur}$), and subsurface maintenance ($O\&M_{subsur}$), calculated as follows (USD 2005):

$$O\&M_{daily} = 7596 \times N_{well} \quad 3.8$$

$$O\&M_{cons} = 20295 \times N_{well} \quad 3.9$$

$$O\&M_{sur} = 15420 \times N_{well} \times \left(\frac{m_{well}}{280 \times N_{well}}\right)^{0.5} \quad 3.10$$

$$O\&M_{subsur} = 5669 \times N_{well} \times \left(\frac{d_{well}}{1219}\right) \quad 3.11$$

3.3.1.2 Electrolyzer

Water electrolysis is an electro-chemical process for splitting water into hydrogen and oxygen. Currently there are three types of electrolyzers available: alkaline, polymer electrolyte membrane and high temperature solid oxide electrolyzers. In alkaline electrolyzers, the electrolysis cell consists of two electrodes separated by a gas-tight diaphragm, which is immersed in a liquid electrolyte. The solid oxide electrolyzers are based on a ceramic electrolyte sandwiched in between two electrically connected porous electrodes. In proton exchange membrane (PEM) electrolyzers, the electrolyte is a solid ion conducting membrane which allows protons to be transferred from the anode side of the membrane to the cathode side, where it forms hydrogen. In this study the PEM electrolyzers were considered as they have higher flexibility and better coupling with a limited industry experience compared to solid oxide electrolyzers [104]. Table 3.3 details the capital and operating cost of a PEM electrolyzer.

Table 3.3. Capital and operating cost of a PEM electrolyzer [101].

Capital expenses	Central	On-site	Annual expenses	Central/on-site
DDCC*	% of total DDCC		**REPC***	0.5% of DDCC
Stacks (PEM)	37%	38%	**FOC***	5% of DCC*
Hydrogen gas management system—cathode system side	1%	6%	**VOC***	
Oxygen gas management system anode system side	1%	2%	non-fuel O&M	1% of DCC*
Water reactant delivery management system	1%	5%	Electricity	Eq. 3.13
Thermal management system	7%	5%	Water	Eq. 3.13 with modification
Power electronics	44%	26%		
Controls & sensors	1%	6%		
Mechanical balance of plant	2%	5%		
Item breakdown—other	3%	2%		
Item breakdown—assembly labor	3%	5%		
PEM replacement (every 10 years)	12%	N/A		
IDCC*	% of total DDCC			
Site preparation	2%	18%		
Engineering & design	8%	50,000		
Project contingency	15%	15%		
Up-front permitting costs	15%	30,000		
NDCC	1,200,000**	N/A		

*DDCC: direct depreciable capital costs, IDCC: indirect depreciable capital costs, DCC: depreciable capital cost (DDCC+IDCC), NDCC: non-depreciable capital costs, REPC: replacement costs, FOC: fixed operating costs, VOC: variable operating costs
**For the central plant with capacity of 50t/day (6 acres)

The total direct depreciable capital cost is calculated as follows:

$$DDCC_{Elec} = Power_{Elec} Ucost_{Elec} CF_{Elec} \quad 3.12$$

In which $Power_{Elec}$ is the electrolyzer power (kW), which was calculated by multiplying the capacity of the plant by the electricity usage ($EUsage_{Elec}$= 50.2 $\frac{kWh}{kg\ H_2}$ for central and 50.3 $\frac{kWh}{kg\ H_2}$ for on-site production), $Ucost_{Elec}$ is the uninstalled cost of the plant (i.e., \$400/kW for central and \$450/kW for on-site production), and CF_{Elec} is the installation cost factor (i.e., 1.1).

The annual cost of electricity usage is calculated as follows:

$$Cost_{Elec} = 365 Price_{Elec} EUsage_{Elec} Av_{Plant} Pro\_rate_{Plant} \quad 3.13$$

In which $Av_{plant} = 97\%$.

Equation 3.13 was used to calculate the annual cost of water by substituting $EUsage_{Elec}$with $WUsage_{Elec} = 15\ \frac{lit}{kgH_2}$ and $Price_{Elec}$ with $Price_{water}$.

In DDCC calculation, the scaling factor of 0.9 and 0.85 was used for central (10 to 100 tonnes/day) and on-site (100 to 1500 kg/day) electrolyzers, respectively.

3.3.1.3 By-product hydrogen purification from the chlor-alkali industry

In the chlor-alkali industry, chlorine, sodium hydroxide and hydrogen are produced via the electrolysis of a concentrated solution of sodium chloride. Hydrogen as a by-product can be captured and purified. In the purification plant, different adsorbents are filled in classification and heated to separate hydrogen from the main impurity gases such as chlorine, oxygen, nitrogen and water. The PSA is also adopted to strengthen the regeneration effect [105].

In the district of North Vancouver, ERCO WorldWide's sodium chlorate plant and Chemtrade Electrochem's chlor-alkali facility produce by-product hydrogen streams. The total by-product hydrogen generated by those two operations exceeds 1000 kg/h, with over 600 kg/h being vented.

Table 3.4. Capital and operating cost of a hydrogen capture and purification facility (10 tonnes/day).

Capital expenses		Annual expenses	
DDCC*	USD (2013)	**REPC***	0.5% of DDCC
Liquid ring compressor	2,600,000	**FOC***	5% of DCC*
Contaminant removal system	2,800,000	**VOC***	
PSA	1,300,000	Non-fuel O&M	1% of DCC*
IDCC*	% of DDCC	Electricity	Eq. 3.14
Site preparation	2%		
Engineering & design	8%		
Project contingency	15%		
Up-front permitting costs	15%		
NDCC*	1,000,000		

*DDCC: direct depreciable capital costs, IDCC: indirect depreciable capital costs, DCC: depreciable capital cost (DDCC + IDCC), NDCC: non-depreciable capital costs, REPC: replacement costs, FOC: fixed operating costs, VOC: variable operating costs

The reported capital investment was based on vendor quotes for a plant size of 2 tonnes/day. The scaling factor of 0.6 was used to derive the numbers for a plant size of 10 tonnes/day.

The annual cost of electricity for the purification plant is calculated as follows:

$$Cost_{Elec} = 365 Price_{Elec} EUsage_{Plant} Av_{Plant} Pro\_rate_{Plant} \tag{3.14}$$

In which $Av_{plant} = 98\%$. The electricity usage of the hydrogen purification plant ($EUsage_{Plant}$) was considered at 3 kWh/kgH_2, which includes the electricity usage of the PSA unit, the containment removal system, and the liquid ring compressor.

3.3.1.4 Liquefier

Series of refrigerants and a sequence of compression and expansion processes (Joule-Thompson liquefaction cycle) are used in a hydrogen liquefier to convert the gaseous hydrogen to the liquid state. The liquefaction facilities use the ortho-para conversion reactors to convert hydrogen to the para form via a series of catalyst beds. The energy required for liquefaction is around 30 percent of the heating value of hydrogen, which is mainly consumed by the ortho/para conversion process. The capital cost of the liquefier is as follows [106]:

$$C_{Liq} = UC_{Liq} N_{Liq} \left(Cap_{Liq}\right)^{0.8} \tag{3.15}$$

In which UC_{Liq} is the unit cost of a liquefier (6,655,000 USD (2013)), N_{Liq} is the number of equally sized liquefiers in operation, and Cap_{Liq} is the capacity of a liquefier.

$$N_{Liq} = \left\lceil \frac{Cap_{Liq}}{Cap_{max,Lig}} \right\rceil \tag{3.16}$$

$Cap_{max,Lig}$ is the largest practical size of a liquefaction plant, i.e., 200 tonnes/day.

The owner's cost provides the funds necessary for engineering studies, permits, training, licensing fees, etc., and was assumed at 12% of the capital cost of the liquefier plant [106].

The average electricity requirement of the plant was assumed at 9.05 kWh/kgH_2.

3.3.1.5 Terminal and central storage

3.3.1.5.1 Gas delivery terminal (GH2 storage)

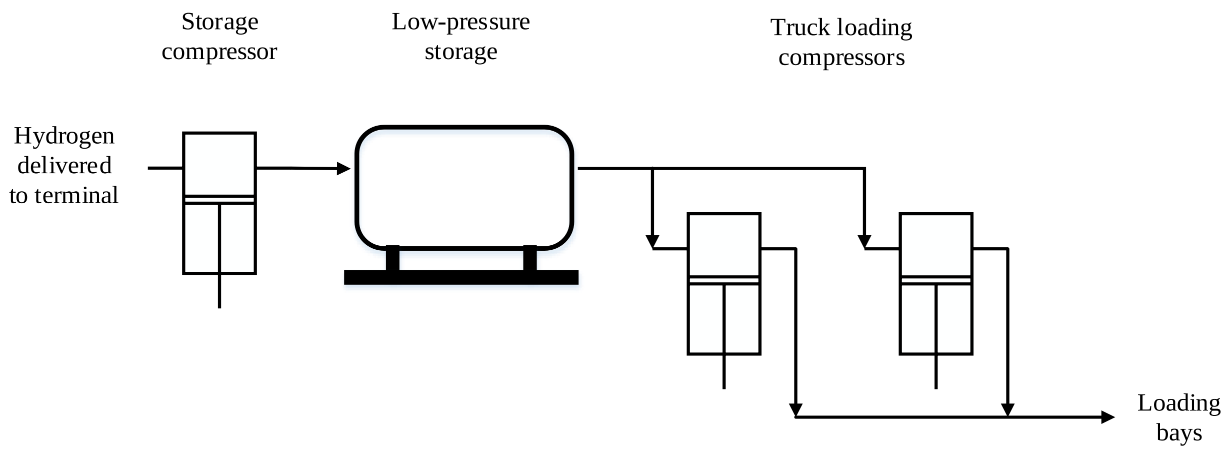


Figure 3.2. Schematic of gaseous hydrogen central storage.

Truck loading and storage compressors

The reciprocating compressors are suitable for medium and large flow of hydrogen, as opposed to centrifugal machines which are commonly used for natural gas [107]. The installed capital cost of the reciprocating compressors was calculated as follows (USD 2013) [106]:

$$C_{Compr} = 44402 \times N_{Compr} \left(\frac{TPower_{compr}}{IsoEff_{compr}} \right)^{0.6038} \quad 3.17$$

$$N_{Compr,truck} = \frac{UCap_{tubes} N_{Bays}}{LTime_{tubes} \bar{\dot{m}}_{compr}} \quad 3.18$$

$$N_{Compr,storage} = \frac{Cap_{terml}}{24 \times 35} \quad 3.19$$

In which $UCap_{tubes}$ is the usable capacity of the tubes, $LTime_{tubes}$ is the loading time of the tubes, Cap_{terml} is the terminal capacity, N_{Bays} is the number of filling bays, and $\bar{\dot{m}}_{compr}$ is the compressor flow rate at the average storage pressure.

$$N_{Bays} = \left\lceil \left\lceil \frac{Cap_{terml}}{UCap_{tubes}} \right\rceil \times (LTime_{tubes} + LinTime)/24 \right\rceil \quad 3.20$$

$$\bar{m}_{compr} = 85\left(P_{min,T} + 0.25\left(P_{max,T} - P_{min,T}\right)\right)/250 \tag{3.21}$$

$LinTime$ is the lingering time of the truck. $TPower_{comp}$ was calculated using Eq. 3.36, with the number of compression stages calculated as follows:

$$N_{st} = \left\lceil \frac{\log P_{max} - \log P_{min}}{\log CR} \right\rceil \tag{3.22}$$

In which P_{max} and P_{min} are the maximum and minimum pressure for the truck loading compressors (55 MPa and 20 MPa), and the maximum and minimum pressure for storage compressors (40 MPa and 5 MPa). CR is the allowable compression ratio per stage, set at 2.1.

<u>Compressed gas storage</u>

The installed capital cost of the short-term storage unit is calculated as follows [106]:

$$C_{LPS} = UC_{LPS} \left\lceil \frac{TScap_{LPS}}{Cap_{LPS}} \right\rceil Cap_{LPS} \tag{3.23}$$

In which UC_{LPS} is the unit capital cost of storage, set at 1220 (USD 2013), Cap_{LPS} is the capacity of a storage cylinder (Eq. 3.32), and $TScap_{LPS}$ is the design storage capacity, calculated as follows:

$$TScap_{LPS} = \frac{Cap_{terml} Days_{str}}{UCap_{cld}} \tag{3.24}$$

In which $Days_{storage}$ is the days of storage, set at 0.25, and $UCap_{cld}$ is the usable cylinder capacity, i.e., 46% of the central storage capacity.

The capital cost of the other components of the GH2 central storage, including piping, supply, discharge and headers, plumbing, electrical and instrumentation, building and structure, and truck scale was considered at 1% of the total DDCC.

3.3.1.5.2 Liquid delivery terminal (LH2 storage)

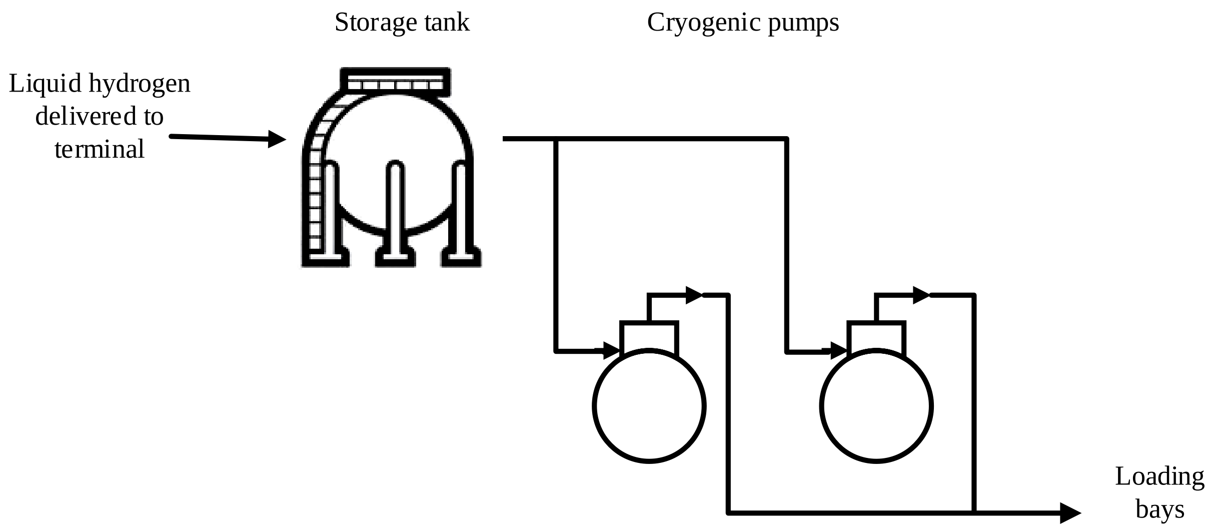


Figure 3.3. Schematic of liquid hydrogen central storage.

<u>Liquid hydrogen storage tank</u>

Most cryogenic tanks are spherical, which minimizes the heat transfer surface area per unit of storage volume. The installed capital cost of a spherical tank is calculated as follows (USD 2013) [106]:

$$C_{S,liq} = N_{S,liq}\left(5646600 + 3100 * \frac{V_{S,liq}}{N_{S,liq}}\right) \qquad 3.25$$

$$N_{S,liq} = \frac{V_{S,liq}}{V_{max,liq}}$$

In which $N_{S,liq}$ is the number of storage spheres, $V_{max,liq}$ is the maximum volume of single storage sphere, i.e., 1000 m^3, and $V_{S,liq}$ is the total volume of storage, calculated as follows:

$$V_{S,liq} = \frac{1}{D_{H2}}\left(\frac{UCap_{ustr}}{UPer_{str}} + 0.0028 \times Cap_{terml}\right) \qquad 3.26$$

In which $UPer_{str}$ is the usable percent of liquid storage, i.e., 95%. $UCap_{str}$ is the storage usable capacity:

$$UCap_{str} = (1 - surge)Cap_{terml}Outage_{plant} \qquad 3.27$$

The storage must be large enough to handle plant outages and peak demand.

<u>Low-head liquid pump</u>

The installed capital cost of a low-head cryogenic pump is calculated as follows (USD 2013) [106]:

$$C_{Pump,LH} = 4423 \times N_{Pump,LH}Cap_{Pump,LH}{}^{0.3431} \qquad 3.28$$

$Cap_{Pump,LH}$ is the design capacity of each low-head pump:

$$Cap_{Pump,LH} = \frac{1.5 \times Cap_{terminal}}{24} \qquad 3.29$$

$N_{Pump,LH}$ is the number of required low-head pumps:

$$N_{Pump,LH} = \left\lceil \frac{Cap_{Pump,LH}}{\dot{F}_{max,Pump}} \right\rceil \qquad 3.30$$

$\dot{F}_{max,Pump}$ is the maximum pump throughput, considered at 12000 kg/hr.

IDCC and FOC were calculated as a percentage of DDCC for GH2 and LH2 central storages (Table 3.5). The annual cost of electricity for compressors and low-head pump was calculated using Eq. 3.38 and Eq. 3.48, respectively.

Table 3.5. IDCC and operating cost of GH2 and LH2 central storage.

IDCC*	**% of DDCC***
Site preparation	5%
Engineering & design	10%
Project contingency	10%
Up-front permitting costs	3%
Owner's costs	12%
FOC *	5% of DCC*
VOC *(electricity)	

*DDCC: direct depreciable capital costs, IDCC: indirect depreciable capital costs, DCC: depreciable capital cost (DDCC + IDCC), NDCC: non-depreciable capital costs, REPC: replacement costs, FOC: fixed operating costs, VOC: variable operating costs

3.3.1.5.3 Transportation

Tube trailers

The hydrogen payload of a tube trailer is greater than the off-loaded amount. The tubes cannot be completely depressurized (hydrogen at 5 MPa or lower remains in the tubes), so that the actual usable capacity of tubes is less than the rated capacity. Also, there are losses associated with dropping the trailers and removing the empty ones. Gas losses during these operations was assumed to be 3%.

Table 3.6. Capital cost of gas trucks with different payloads [108].

Hydrogen payload (off-loaded + 3% losses + remained hydrogen in vessels below 5 MPa)	Trailer + vessels cost (USD 2013)	Tractor cost (USD 2013)
120 kg (steel vessels)	180,000	100,000
600 kg (composite vessels)	700,000	100,000
1000 kg (composite vessels)	1,300,000	100,000

Tanker trucks

The total amount of hydrogen discharged to the storage tanks is less than the payload of the truck. When all the liquid is discharged from the tank, the saturated hydrogen vapor, which weighs 2% of the total payload, remains in the tank. Also, there are losses associated with loading and offloading the trailer, which may amount to 6–10% of the total payload.

The capital cost of the tanker with the rated capacity of 4100 kg and the tractor was estimated at 1,000,000 and 100,000 (USD 2013), respectively [106].

3.3.1.5.4 Fueling station

The components of a fueling station and the associated DDCC depend on whether hydrogen is produced on-site or delivered in gas or liquid form **(**Figure 3.4**)** [106], [109]. Other cost parameters, except the annual electricity use, were calculated from DDCC, as mentioned in Table 3.7.

Table 3.7. Capital and operating cost of a fueling station.

IDCC*	**% of DDCC***
Site preparation	5%
Engineering & design	10%
Project contingency	5%
Up-front permitting costs	3%
FOC*	5% of DCC*
VOC*	
Non-fuel O&M	1% of DCC*
Electricity	

*DDCC: direct depreciable capital costs, IDCC: indirect depreciable capital costs, DCC: depreciable capital cost (DDCC + IDCC), NDCC: non-depreciable capital costs, REPC: replacement costs, FOC: fixed operating costs, VOC: variable operating costs

In an on-site production and dispensing facility, hydrogen is produced with an on-site electrolyzer at a low pressure of 2 MPa and stored in low-pressure storage tank. When needed, hydrogen is compressed in the cascade storage system via a high-pressure compressor and pre-cooled by a refrigeration unit before being dispensed into the vehicle tank. For stations with gaseous hydrogen delivery, the trailer acts as the low-pressure storage tank and the succeeding components are similar to the on-site production facility. For stations with liquid hydrogen delivery, hydrogen is stored in cryogenic tanks at −252°C. When hydrogen is needed, a high-pressure cryogenic pump is used to pass it through a vaporizer. Hydrogen is stored in a high-pressure cascade system before being dispensed into the vehicle tank.

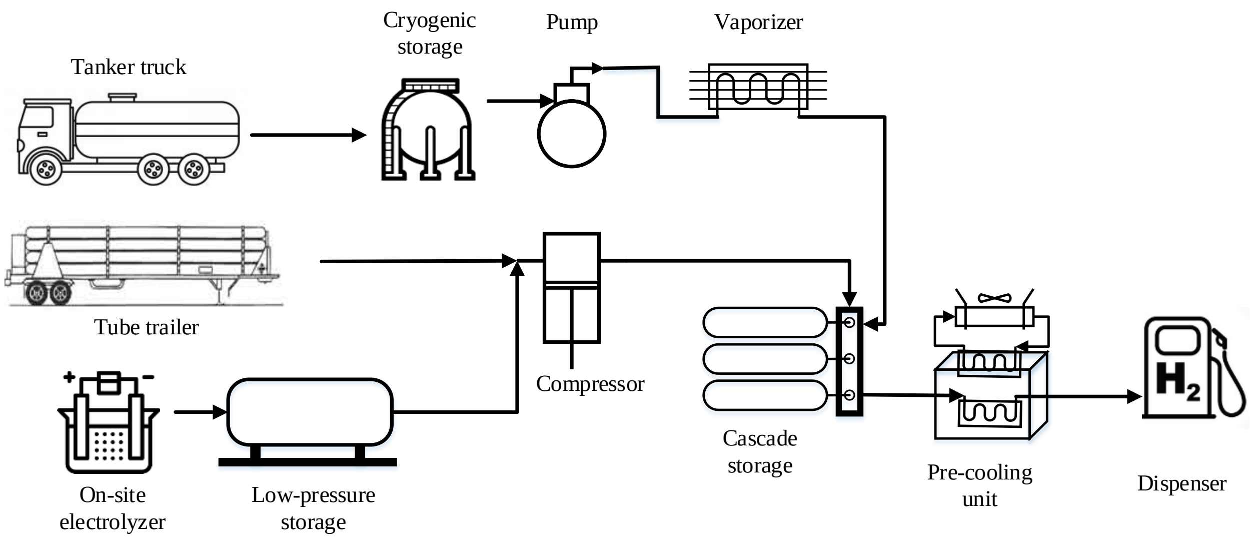


Figure 3.4. Schematic of a hydrogen fueling station with on-site production, gas delivery, and liquid delivery components.

The capital cost of the components of a fueling station is described as follows:

<u>Low-pressure storage for hourly surge</u>

Hydrogen that is produced on-site is stored at 2 MPa in a low-pressure storage unit. The capital cost of the storage unit was calculated as follows:

$$C_{LPS} = UC_{LPS} \times \left[\frac{PD_{LPS}}{Cap_{LPS}}\right] \times Cap_{LPS} \times CF_{LPS} \tag{3.31}$$

UC_{LPS} is the unit cost of the low-pressure storage unit per kilogram of hydrogen stored, i.e., 1252 (USD 2013), PD_{LPS} is the amount of hydrogen needed at a refueling station for peak hours, which was set at 30% of the of the station capacity. CF_{Elec} is the installation cost factor, set at 1.3. Cap_{LPS} is the low-pressure storage vessel capacity, calculated as follows:

$$Cap_{LPS} = \left[\frac{\pi}{4}(D_{LPV} - 2T_{LPV})(L_{LPV} - 2T_{LPV}) - 0.083\pi(D_{LPV} - 2T_{LPV})^3\right]\frac{2 \times 101325\ P_{max,LPV}}{Z \times 8314 \times T_{opr}} \tag{3.32}$$

D_{LPV}, T_{LPV}, and L_{LPV} are the outer diameter, thickness, and length of the low-pressure storage vessel, $P_{max,LPV}$ is the maximum storage pressure, i.e., 25 MPa, T_{opr} is the hydrogen temperature at operating condition, and Z is the hydrogen compressibility factor at $P_{max,LPV}$ and T_{opr}.

<u>Compressor</u>

The installed capital cost of the compressor is calculated as follows (USD 2013) [106], [110]:

$$C_{Compr} = 44402 \times N_{Compr} \times \left(\frac{MR_{Compr}}{N_{Compr}}\right)^{0.6038} \quad 3.33$$

In which N_{Compr} is the number of compressors in operation at any time and MR_{Compr} is the motor rating:

$$MR_{Compr} = \frac{TPower_{Compr}}{IsoEff_{Compr}} \times \frac{SF_{Motor}}{Eff_{Motor}} \quad 3.34$$

$$N_{Comp} = \left\lceil \frac{\dot{m}_{Compr}}{35} \right\rceil \quad 3.35$$

In which $\dot{m}_{Compr}$ is the compressor flow rate in peak demand, selected at 7% of the fueling station maximum capacity. The maximum compressor capacity was fixed at 35 kg/hr at a pressure ratio of 45 (2–95 MPa); for higher flow rates, multiple compressors were used. $IsoEff_{Compr}$ is the isentropic efficiency of the compressor (i.e., 75%), SF_{Motor} is the sizing factor of the motor (i.e., 110%), $TPower_{Compr}$ and Eff_{Motor} are the theoretical power of the compressor and the motor efficiency, respectively.

The theoretical power of the compressor was calculated considering equal work by all stages and intercooling back to the original feed temperature:

$$TPower_{Compr} = \frac{\dot{m}_{Compr}}{3600 \times 2.0158} \times Z \times R \times T_{max} \times N_{st} \times \left(\frac{k}{k-1}\right) \times \left[\left(\frac{P_{outlet}}{P_{inlet}}\right)^{\frac{k-1}{k \times N_{st}}} - 1\right] \quad 3.36$$

The motor efficiency is calculated as follows:

$$Eff_{Motor} = 0.0008(\ln X)^4 - 0.0015(\ln X)^3 + 0.0061(\ln X)^2 + 0.0311 \ln X + 0.7617 \quad 3.37$$

$$X = \frac{TPower_{Compr}}{IsoEff_{Compr} \times N_{Compr}}$$

In which Z is the compressibility factor (i.e., 1.253 for 25 MPa and 1.282 for 54 MPa, which are the maximum pressures in tube tankers), R is the gas constant (i.e., 8.314), T_{max} is the maximum hydrogen temperature at the station (i.e., 40°C), N_{st} is the number of compression stages (i.e., 2), k is the ratio of specific heats (i.e., cp/cv=1.42), and P_{outlet} and P_{inlet} are the outlet and inlet pressure of the compressor, respectively, i.e., 97 and 5 MPa.

The annual energy requirement of the compressor is given as follows:

$$E_{Comp} = 365 \times \frac{1}{Eff_{Motor} \times IsoEff_{Compr}} \times \frac{f_{\dot{m}} \times \dot{m}_{Compr}}{3600 \times 2.0158} \times Z \times R \times T_{max} \times N_{st} \times \left(\frac{k}{k-1}\right) \times \left[\left(\frac{P_{outlet}}{Pave_{inlet}}\right)^{\frac{k-1}{k \times N_{st}}} - 1\right] \quad 3.38$$

In which $f_{\dot{m}}$ is the percentage of maximum capacity that is used to calculate the average annual flow rate of hydrogen, set at 0.8. The inlet average pressure of the compressor, $Pave_{inlet}$ was calculated as follows:

$$Pave_{inlet} = \frac{\left(P_{max,tube} - P_{min,tube}\right)}{\ln\left(\frac{P_{max,tube}}{P_{min,tube}}\right)} \quad 3.39$$

In which $P_{max,tube}$ and $P_{min,tube}$ are the maximum and minimum pressure of the tube trailer, i.e., 55 and 5 MPa, respectively.

In case of on-site hydrogen production, the following formula is used:

$$E_{Compr} = 365\left(1+\frac{PD_{LPS}}{Cap_{station}}\right)\frac{1}{Eff_{Motor}\times IsoEff_{Compr}}\frac{f_{\dot{m}}\times \dot{m}_{Compr}}{3600\times 2.0158}\times Z\times R \times T_{max}N_{st}\left(\frac{k}{k-1}\right)\left[\left(\frac{P_{outlet}}{P_{inlet}}\right)^{\frac{k-1}{k\times N_{st}}}-1\right] \quad 3.40$$

The capital cost of the power transmission system to the compressor is calculated as follows:

$$C_{PT} = CF_{PT}\left(-0.0051816\left(\frac{MR_{Compr}}{0.746}\right)^2+55.416\left(\frac{MR_{Compr}}{0.746}\right)+24868.8\right) \quad 3.41$$

In which CF_{PT} is the installation cost factor of the power transmission system, set at 2.24.

Cascade storage

Cascade storage includes banks of storage vessels at different pressures, individually controlled by valves that are switched in sequence. When the dispenser is connected to the on-board tank, hydrogen starts flowing from the lowest-pressure bank. When the mass flow rate drops to a pre-set level, the valves sequentially switch to the medium and finally high-pressure bank until the fill is completed.

The capital cost of the cascade storage vessel was calculated as follows [110]:

$$Cap_{vessel} = \frac{0.028317\times V_{vss}N_{csc}(6894.757\times P_{max})N_{vss}}{Z\times 4124.86\times T_{csc}} \quad 3.42$$

V_{vss} is the volume of the cascade storage vessel (9.9 ft^3), N_{csc} is the optimum number of banks, set at 5, 2, and 1 for stations with maximum capacity of 1000–1500, 500, and 150 kg/day, respectively. P_{max} is the maximum pressure in the cascade storage vessels, set at 95 MPa, N_{vss} is the number of vessels in each bank, set at 1, 2, and 2 for high-, medium-, and low-pressure vessels. T_{csc} is the operating storage temperature (K), Z is the compressibility factor for hydrogen at T_{csc} and P_{max}.

The cascade storage includes banks of storage vessels at different pressures. The capital cost of the storage system is calculated as follows:

$$C_{csc} = CF_{csc}(UC_{csc}[(Cap_{vss})_{LP} + (Cap_{vss})_{MP} + (Cap_{vss})_{HP}]) \quad 3.43$$

In which UC_{csc} is the unit cost of the cascade storage system per kg of hydrogen stored, set at 1800 USD/kgH_2, CF_{csc} is the installation cost factor with a value of 1.3, and $(Cap_{vss})_{LP}$, $(Cap_{vss})_{MP}$, and $(Cap_{vss})_{HP}$ are the capacity of low-, medium-, and high-pressure vessels, respectively.

Pre-cooling unit

The pre-cooling unit is placed between the cascade storage and the dispenser to chill the hydrogen during a fast fill at 70 MPa and keep the on-board tank temperature below 85°C. For this study, the precooling unit consists of a large cooling block with a low cooling capacity and a refrigeration unit to maintain the temperature of the block below -40 C.

The total capital cost of the pre-cooling system is calculates as follows [111]:

$$DDCC_{PCS} = cf_{Ref}\left[\frac{Cap_{Ref} \times N_{Hose}}{Tout_{H2}}\right]^{\alpha} + N_{Hose}cf_{HX}\left[\frac{m_{HX}}{M_{HX}}\right]^{\beta} \quad 3.44$$

In which cf_{Ref}=13865 is a constant factor. Cap_{Ref} is the capacity of refrigeration unit per hose. At four back-to-back fills per hose, Cap_{Ref} is 3.4 tonnes for refueling stations of size 500–1000 kg/day and 3.1 tonnes for fueling station of size 150 kg/day. N_{Hose} is the number of hoses, with a value of 4 for a 1000 kg/day station, assuming 16 fills during peak hours, with an average filling time of 7 min per vehicle and an average hose occupied fraction of 50% during peak hours. $Tout_{H2}$ is the hydrogen outlet temperature from the system (i.e., -40°C) and α is the power sizing exponent, with a value of 0.8579. For the cooling block, cf_{HX} is 35,500 USD (2013) for a reference 1000 kg aluminum block (M_{HX}), and m_{HX} is the actual aluminum mass. The power sizing exponent is given by β with a value of 0.9 for a cooling block of 1330 kg. The installation cost factor of 2 was applied to the total cost calculated. All costs are in USD (2013).

The annual electricity requirement of the pre-cooling unit was calculated, using the refrigeration-specific energy use of 0.325 kWh/kgH_2 and the overhead pre-cooling energy use of 0.305 kWh/kgH_2.

Dispenser

The capital cost of a dispenser is calculated by multiplying the number of hoses by the cost of one hose (104,000 USD 2013), assuming each dispenser has one hose. The result is multiplied by the installation cost factor of 1.3.

Hydrogen cryogenic storage tank

The cryogenic storage tanks are sized to satisfy the station average daily demand, with the capital cost as follows:

$$CS_{cryo} = CF_{cryo}\left(UCS_{cryo}{Cap_{cryo}}^{0.6929}\right) \quad 3.45$$

In which UCS_{cryo} is the unit cost of a storage tank per kg of hydrogen, i.e., 992 USD (2013), Cap_{cryo} is the capacity of the cryogenic storage tank, i.e., 4020 kg for the station capacity of 1000–1500 kg/day. CF_{cryo} is the installation cost factor with a value of 1.3.

Pump

The high-pressure low-temperature pump raises the pressure and transfers the liquid hydrogen from the low-pressure cryogenic storage tank to the high-pressure cascade storage system.
The capital cost of the pump was calculated as follows:

$$C_{pump} = CF_{pump}\left(UC_{pump}N_{pump}\right) \quad 3.46$$

In which UC_{pump} is the unit cost of the pump per kilogram hydrogen, i.e., 712,000 USD (2013), CF_{pump} is the installation cost factor of the pump with a value of 1.3, and N_{pump} is the number of pumps required.

$$N_{pump} = \left\lceil \frac{\dot{m}_{max,evap}}{Output_{max,pump}} \right\rceil \quad 3.47$$

In which $\dot{m}_{max,evap}$ is the required evaporator flow rate for peak hours, i.e., 65 kg/hr for a station with 1000 kg/day capacity, and $Output_{max,pump}$ is the maximum pump output, i.e., 120 kg/hr. The annual electricity consumption of the high-pressure pump was calculated as follows:

$$E_{pump} = \frac{365 \times TPower_{pump} Cap_{station}}{IsoEff_{pump} Eff_{motor} \dot{m}_{max,evap}} \quad 3.48$$

The capital cost of the power transmission system was calculated as follows:

$$C_{EV} = CF_{PT}\left(-0.0051816\left(\frac{MR_{pump}}{0.746}\right)^2 + 55.416\left(\frac{MR_{pump}}{0.746}\right) + 24868.8\right) \quad 3.49$$

In which CF_{PT} is the installation cost factor of the transmission system with a value of 2.24 and MR_{pump} is the motor rating of the pump, calculated as follows:

$$MR_{pump} = \frac{TPower_{pump} SF_{motor}}{IsoEff_{pump} Eff_{motor}} \quad 3.50$$

$IsoEff_{pump}$ and SF_{motor} are the isentropic efficiency of the pump, i.e., 75%, and the size factor of the pump motor, i.e., 110%. $TPower_{pump}$ is the theoretical power of the pump, calculated as follows:

$$TPower_{pump} = \dot{m}_{max,evap} \times \frac{\left(P_{max} + 25 - P_{supply} \times 14.696\right)}{522 \times D_{H_2}} \quad 3.51$$

P_{max} is the maximum pressure in the cascade storage, i.e., 13,688 psi, P_{supply} is the supply pressure from Dewar, i.e., 6 MPa, and D_{H_2} is the liquid hydrogen density, i.e., 70.8 g/l.

$Eff_{pump}$is the efficiency of the pump motor, which was calculated using Eq. 3.37 with a corrected value of X.

$$X = \frac{TPower_{pump}}{IsoEff_{pump}} \quad 3.52$$

Evaporator

Evaporator is placed after the high-pressure pump to gasify the liquid hydrogen and to heat it to the cascade operating temperature. The capital cost of the evaporator was calculated in USD 2013:

$$C_{evap} = CF_{evap}\left(N_{evap}\left(1000 \times \dot{m}_{max,evap} + 15000\right)\right) \tag{3.53}$$

In which N_{evap} is the number of evaporators, set to 1 for capacities below 250 kg/hr. CF_{evap} is the installation cost factor of the evaporator, with a value of 1.3.

3.3.2 Derivation of the GHG emissions parameters

The fuel-side Well-to-Wheels (WTW) GHG emissions were analyzed from the primary energy source extraction to the point of fuel utilization. The life-cycle effects of vehicle manufacturing and infrastructure construction/decommissioning were not covered in this analysis. The unit GHG emissions associated with hydrogen production, CCS, storage, transport and dispensing is dependent on the electricity consumption of the facilities, the natural gas consumed in SMR plants and GHG emissions associated with the diesel exhaust products from the trucks. The CCS efficiency was considered at 90% [103]. The GHG emissions from the flare system of a hydrogen liquefaction plant was not considered, as the only vented by-product is water vapor. The GHG emissions of hydroelectricity production in B.C. was considered at 11 gCO_2eq per kWh [112]. As the share of hydroelectricity is projected to stay above 86% of total electricity generation in B.C.[10], the GHG intensity was assumed to stay constant for the study time-frame.

Table 3.8. GHG emissions associated with each component of the HFSC [103], [113]–[115]

Central Production	By product purification	SMR	SMR+CCS	Electrolysis
GHG_C_y (g CO_2/kg H_2)	33	11400	1140	552
On-site production	On-site electrolysis			
GHG_O (g CO_2/kg H_2)	601			
Central storage	Compression	Liquefaction+ cryo-pumping		
GHG_S_d (g CO_2/kg H_2)	17	99		
Transport				
GHG_TR (g CO_2/km)	1000			
Dispensing	On-site H_2 production	Compression+ Refrigeration	Cryo-pumping+ Refrigeration	
GHG_D_d (g CO_2/kg H_2)	22	22	10	

3.4 Hydrogen demand scenario development

The development of a hydrogen fuel supply chain in a region is subjected to the spatial and temporal projection of hydrogen demand. In the road transport sector, hydrogen demand relies on the market share projection of fuel cell electric vehicles. A method is introduced in this section to project the allocation of hydrogen demand for the passenger light duty sector in British Columbia for the time period of 2020–2050.

3.4.1 Temporal projection of hydrogen demand

Hydrogen demand scenarios was developed based on the projection on the number of new passenger vehicles in the market and the logistic demand diffusion model, as discussed below.

3.4.1.1 New passenger vehicle projection

The number of new passenger vehicles was projected based on the variation of the gross domestic product (GDP) per capita. As Figure 3.5 shows, the historical data on the annual growth rate of real GDP per capita may not be quantitatively correlated to the annual growth rate of new passenger vehicles in B.C. However, a qualitative relationship could be found between their moving averages. Figure 3.6 shows that 80% of all points fall on the first and the third quadrants, where the growth rate of GDP has a positive relationship with the growth rate of new vehicles. Thus, we could strongly argue that the purchasing power drives the number of new passenger vehicles in B.C. The annual GDP growth rate is projected to stay relatively constant [10] with an average value of 0.0075% from 2017 to 2050 in B.C. (Figure 3.5). This is around half of the historical average value from 1995 to 2016 (0.0152%). Accordingly, we assumed that the growth rate of new passenger vehicles will also remain constant at an average value of 0.0027%, which is half of its historical value. This growth rate was then used to project the annual number of new passenger vehicles from 2017 to 2050.

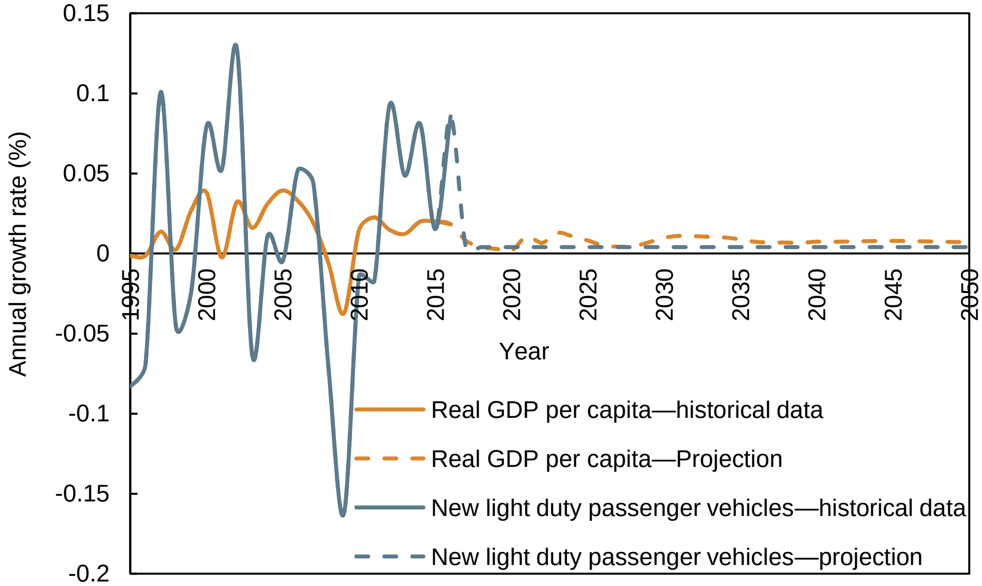


Figure 3.5 Comparison of the annual growth rate of GDP per capita and new passenger vehicle in BC.: projection vs historical data

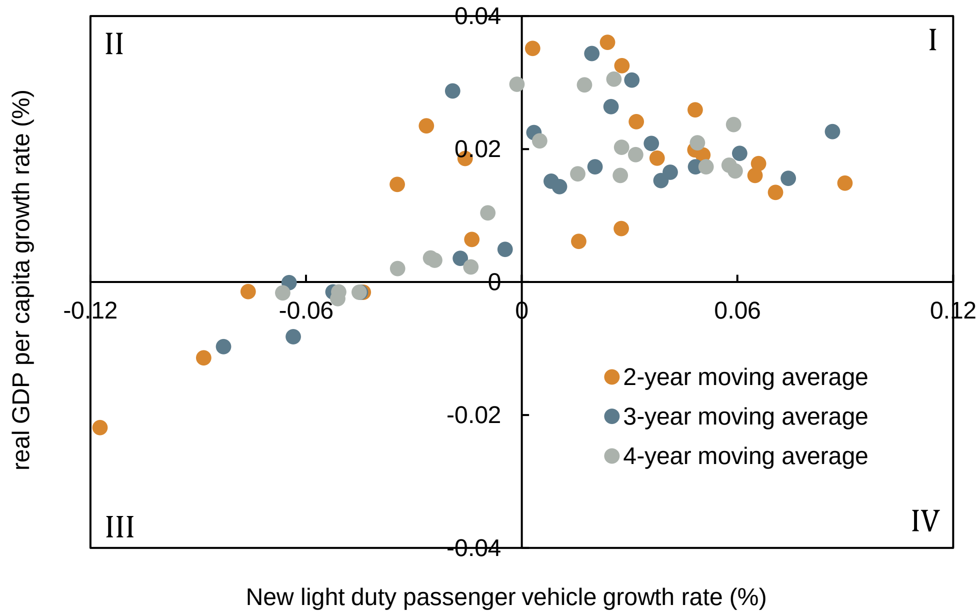


Figure 3.6 Comparison of the moving average of GDP per capita and new passenger vehicle growth rates in BC. (1995 -2016)

3.4.2 FCEV penetration to the market (scenario development)

The penetration percentage of FCEVs for the study period (2020–2050) was calculated using the logistic demand diffusion model [116]:

$$\left(\frac{n_t}{N}\right)_{FCEV} = \frac{1}{1 + exp\left[-\left(\alpha_{FCEV} + \beta_{FCEV}(t - t_0)\right)\right]} \qquad 3.54$$

In which n_t is the fraction of the new vehicle market that the FCEVs possess at time t, N is the fraction of the new vehicle market that the passenger FCEVs can potentially capture, and α characterizes the time it takes for a diffusion process to start ramping up. β characterizes the steepness of the central portion of the curve, as shown in Figure 3.8 (a). Assuming that by 2035 half of the ultimate market will be reached, α and β were calculated as −9.21 and 0.34, respectively. The demand scenarios were developed by assigning different values to the maximum penetration percentage of new passenger FCEVs in B.C. (N in Eq. 3.54). The contribution of passenger FCEVs to the new vehicle market in 2050 was assumed to be 10%, 30%, and 50% for pessimistic, moderate, and optimistic scenarios, respectively. The annual number of new passenger FCEVs in each demand scenario was calculated using the annual penetration percentage (n_t), calculated from Eq. 3.54, and the projected total new passenger vehicles in the market (Figure 3.8 (a)).

3.4.2.1 Passenger vehicle stock projection

The stock of passenger vehicles was calculated each year (t) based on the number of new light duty passenger vehicles and the average vehicle lifetime. The average passenger vehicle lifetime in B.C. was calculated annually based on the maximum vehicle age (Y) and total kilometers traveled (K) [65]:

$$Stock_t = Stock_{t-1} + New\,Vehicle_t - New\,Vehicle_{t-i}$$

$$\left\{ i | 0 \le i \le Y, \sum_{k=i}^{t} U_k \ge K \middle\| t - i \ge Y \right\} \qquad 3.55$$

In which U_k is the annual average vehicle use intensity. This method was validated in B.C. by back calculating the historical stock of passenger vehicles [9], and the error was less than 4%.

The share of passenger trucks from the stock of light duty passenger vehicles was projected, assuming that the future trend follows the business as usual scenario as shown in Figure 3.7. It was also assumed that the market share of the new passenger trucks follows the same trend as the stock of passenger trucks.

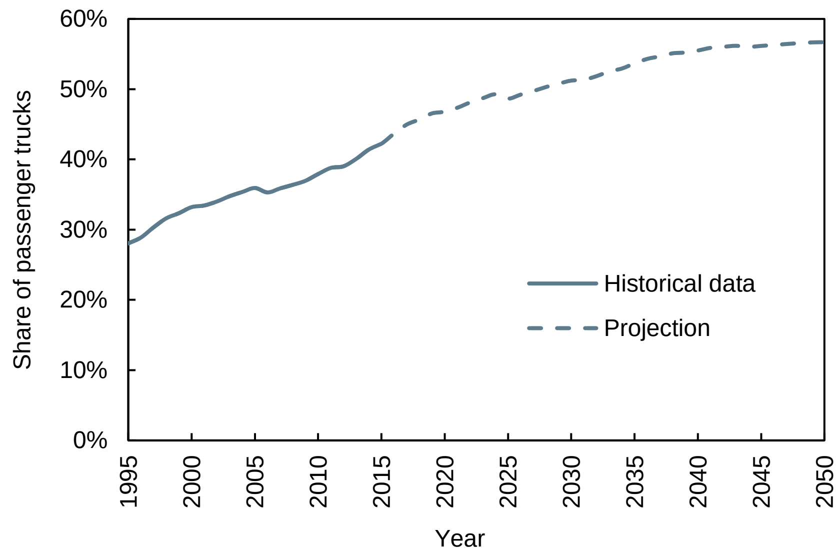
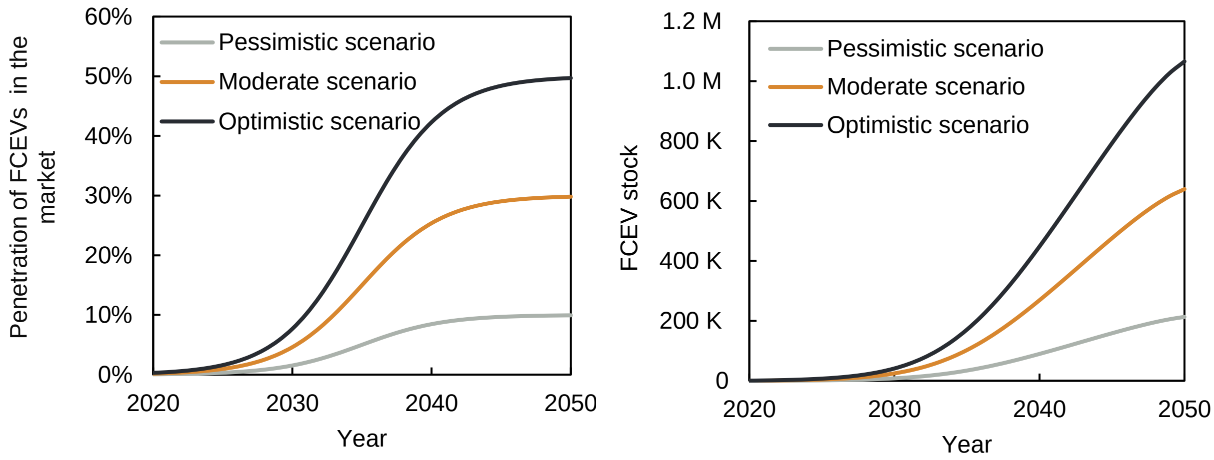


Figure 3.7. Share of passenger trucks from the total passenger vehicles: projection versus historical data [9]

3.4.2.2 FCEV stock projection

The stock of passenger FCEVs for each demand scenario was projected with the same method as discussed for total passenger vehicles, using the scenario-based FCEV market share and the lifetime of 18 years (Figure 3.8 (b)). The share of passenger FCE trucks from the total passenger FCEVs was assumed to be similar to Figure 3.7**.**



(a) (b)

Figure 3.8. (a) Penetration percentage of the new passenger FCEVs to the B.C. market for different demand scenarios over time. (b) Passenger FCEV stock for different demand scenarios in B.C. over time.

3.4.2.3 Annual hydrogen demand calculation

The annual hydrogen demand in year *t* for passenger vehicles was calculated by:

$$H_{2_{Demand_t}} = \overline{VUse\_Int_t}|_{FCE\_Car} \times \overline{F\_Eff_t}\Big|_{FCE\_Car} \times Stock_t|_{FCE\_Car} + \overline{VUse\_Int_t}|_{FCE\_Ptruck} \times \overline{F\_Eff_t}\Big|_{FCE\_Ptruck} \times Stock_t|_{FCE\_Ptruck} \quad 3.56$$

In which $Stock_t|_{FCE\_Car}$ and $Stock_t|_{FCE\_Ptruck}$ are the stock of FCE cars and passenger trucks in year t, respectively. The $\overline{VUse\_Int_t}$ (km/year) stands for the vehicle average use intensity and is projected using a quadratic polynomial regression with the minimum mileage value extending over the studied time frame (Figure 3.9).

The average fuel efficiency of passenger vehicles $\overline{F\_Eff}_t$(MJ/km) in each year was calculated based on the historical data [9] and a projected annual 1.5% fuel efficiency improvement (*impv*) in the new vehicles of the previous year ($NewF\_Eff_{t-1}$) [117]:

$$\overline{F\_Eff}_{t+1} = \overline{F\_Eff}_t \times \left(1 - \frac{New\_V_{t+1}}{Stock_{t+1}}\right) + \left(\frac{New\_V_{t+1}}{Stock_{t+1}}\right) \times impv \times NewF\_Eff_{t-1} \tag{3.57}$$

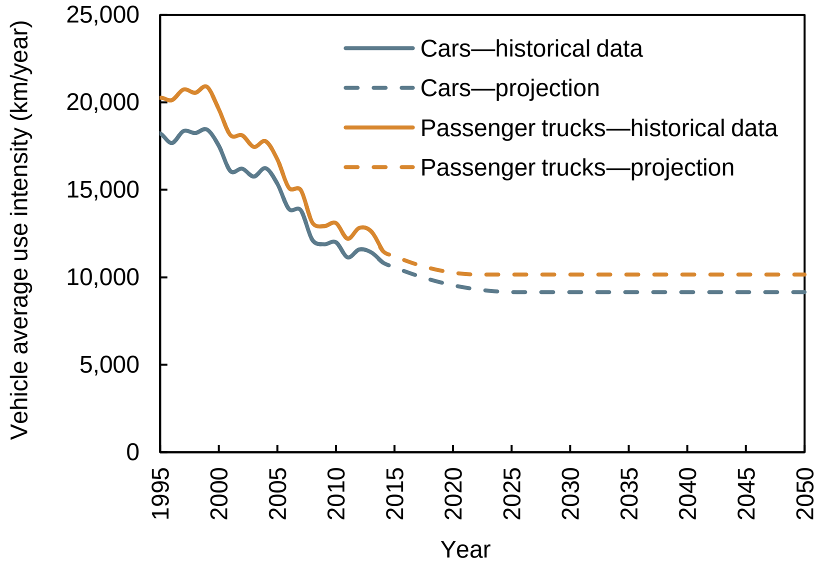


Figure 3.9. Vehicle average use intensity for cars and passenger trucks in BC: projection versus historical data [9][1].

It should be noted that in all calculations, FCEVs were assumed to have the same vehicle use intensity as conventional vehicles, driving on the same road and climatic conditions, and with comparable loads.

Figure 3.10 shows the calculated annual hydrogen demand from the stock of light duty FCEVs for three demand scenarios.

[1] According to NRCan data [9] the annual vehicle use intensity in BC decreased by 36% and 43% for cars and light duty passenger trucks respectively, from 2000 to 2015. The stock of cars and light duty passenger trucks increased by 35% and 93%, respectively. Considering fuel efficiency improvement, the GHG emissions decreased by 24% from cars, however emissions increased by 8% from light duty passenger trucks from 2000 to 2015.

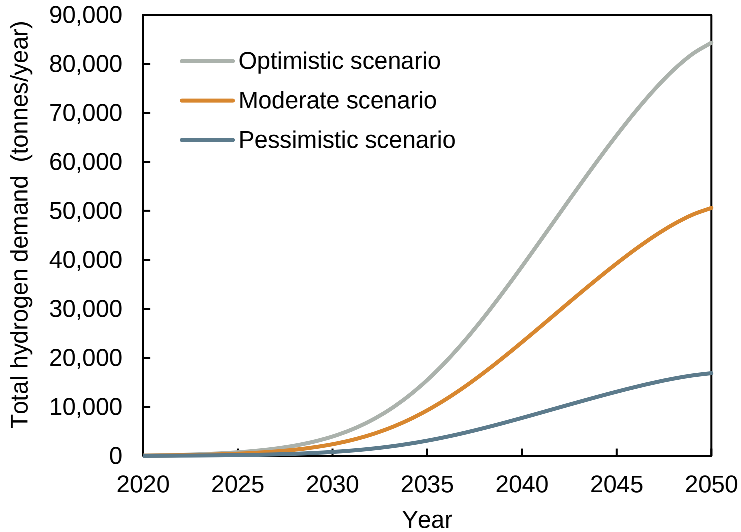


Figure 3.10. Annual hydrogen demand in B.C. for different demand scenarios over time.

3.4.3 Spatial projection of hydrogen demand in B.C.

From 2013 to 2017, the distribution of internal combustion engine (ICE) passenger vehicles in different regions of B.C. remained relatively unchanged with a mean value of 56% in Metro Vancouver, 17% on Vancouver Island, 16% in the Southern Interior, 6% in the North Central area, and 5% in all remaining areas [118]. In this study, it was assumed that the FCEVs in B.C. have the same distribution as ICE vehicles and are confined to metropolitan areas. For Metro Vancouver, 10 municipalities were selected as hydrogen demand regions. Based on the population size, Victoria on Vancouver Island, Kelowna and Kamloops in the Southern Interior, and Prince George in the North Central area were also selected as demand regions. Additionally, 4 municipalities (Abbotsford, Hope, Whistler, and Williams Lake) located on the busiest roads connecting Metro Vancouver to the other metropolitan areas were selected as demand regions. The demand in these regions was calculated based on the traffic volume. In 2016, the average daily traffic volume passing through Abbotsford, Hope, Whistler, and Williams Lake was approximately 2%, 0.8%, 0.6%, and 0.7% of the total passenger vehicles, respectively [119]. These shares were adopted to account for the hydrogen demand on the major roads in B.C.

The temporal variation of hydrogen demand distribution among the 10 municipalities in Metro Vancouver was calculated based on the projected population density. For other regions, the hydrogen demand distribution was assumed to remain constant over the time frame of this study.

3.4.3.1 Hydrogen demand distribution in Metro Vancouver

Metro Vancouver was divided into 10 major municipalities: Surrey and White rock, Vancouver, Burnaby and New Westminster, City of Langley and Langley Township, Coquitlam, North Vancouver, West Vancouver, Maple Ridge and Pitt Meadows, Richmond, and Delta.

The term *PD* was introduced as an indicator of population density for each municipality g in time t, as follows:

$$PD_g\big|_t = \frac{Dw_g + Emp_g}{UCB_g} \qquad 3.58$$

In which Dw_g and Emp_g stand for the total dwelling units and total employment, respectively, in municipality g in time t. UCB_g stands for the urban containment boundary for municipality g. Dw_g and Emp_g were projected to 2040 by [120], and were extrapolated to 2050 to cover the time frame of this study. UCB_g was considered constant over time, as stated by [120]. The distribution of hydrogen demand among these municipalities was assumed to be consistent with the distribution of PD_g in each t, as shown in Figure 3.11.

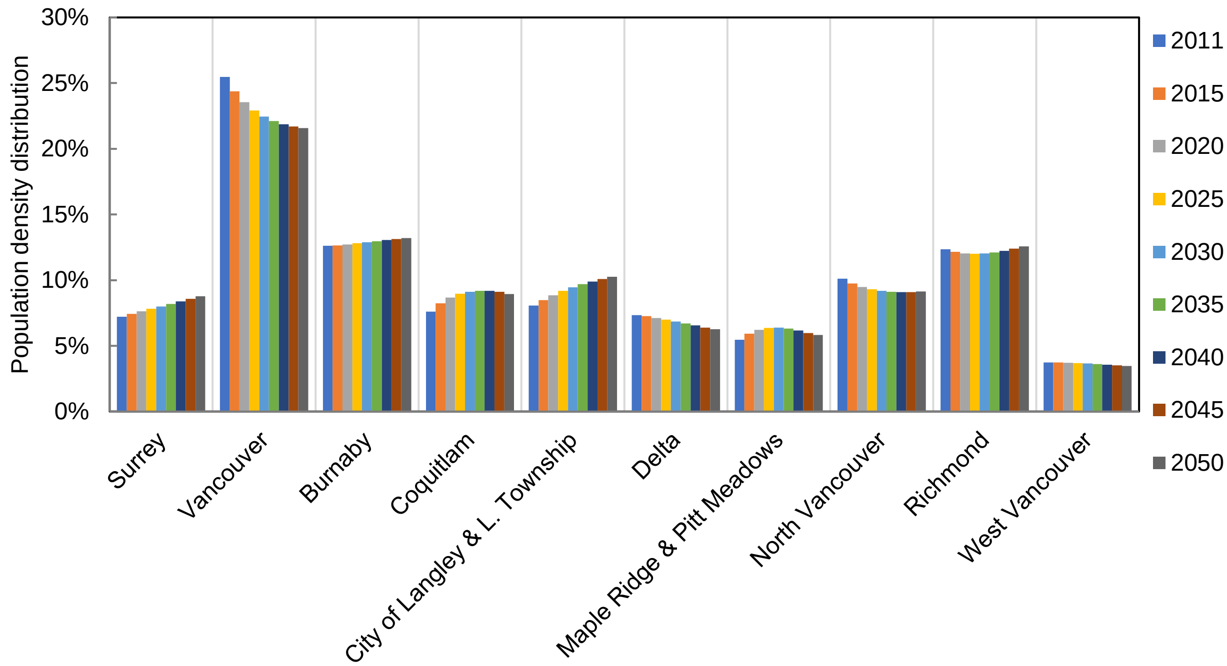


Figure 3.11. Distribution of population density among 10 municipalities in Metro Vancouver over time.

3.5 Policy scenario development

This work incorporates different combinations of the current and potential provincial environmental mandates to assess their effect on the hydrogen price and environmental performance of the HFSC.

3.5.1 Current provincial policies

The low-carbon fuel standard (LCFS) and carbon tax are the environmental mandates that influence the evolution of the low-carbon fuel infrastructures by monetizing CO_2 emissions. The HFSC optimization was performed for three cases in which carbon tax, BC-LCFS, and both policies were included in the model. The carbon tax fees and LCFS revenues were modelled as part of the objective function, as described in chapter 4.

It was also assumed that the hydrogen infrastructure is eligible for accelerated depreciation deduction. To this end, the capital cost allowance (CCA) deduction was calculated using the declining balance method, based on 30% CCA rate for production plants, storage facilities and dispensers and 40% CCA rate for tube trailer and tanker trucks [121].

3.5.1.1 B.C. low carbon fuel standard (LCFS)

In 2010, the government of B.C. included the LCFS as part of its Renewable and Low Carbon Fuel Requirements [122]. The LCFS is both a regulatory and a market-based policy to reduce the transportation fuel carbon intensity. The regulatory part enforces a carbon intensity target with which all the producers and importers of transportation fuels must comply. The market-based policy permits the fuel providers to trade and bank emission credits to remain compliant with the regulation. Hydrogen fuel suppliers can benefit from selling the emission credits on an open market to suppliers who incur debits from providing fuels with carbon intensities beyond the limit. Each credit accounts for the tonnes of CO_2 avoided on a WTW basis by substituting hydrogen for gasoline. Thus, HFSCs, which have lower emissions, generate more revenue while imposing higher capital and operating costs. As a result, the HFSC incorporates lower-emitting components if the revenues surpass the investment. No long-term projection for carbon credit price was found in the literature nor in the governmental resources. Thus, we assumed that the credit price starts at C$167 (the average price from 2015 to 2017 [123]) in 2020 and decreases over time until it reaches 0 at the final time step (167, 154, 112, 47, 11, and 0 for the 1st to 6th time steps, respectively). The logistic demand diffusion model was used with the same α and β values calculated for the adoption rate of new FCEVs in the market (section 3.4). This assumption was based on the reasoning that the increasing rate of adoption of low-emission technologies increases the number of credits in the market, which decreases the credit price accordingly. Currently, hydrogen producers in B.C. do not receive LCFS credits for using renewable content from the grid. However, this model was developed with the assumption that the electrolyzer pathway allowances were increased to include renewable electricity. Moreover, the credits that may be awarded through a Part 3 Agreement [124] were not considered in this study. This is mainly due to the limited total credits available annually, which must be distributed among all Part 3 fuel suppliers on a case-by-case basis.

3.5.1.2 B.C. carbon tax

The B.C. carbon tax, introduced in 2008, covers greenhouse gas emissions resulting from the combustion of all fossil fuels used within the province [125]. The tax started at C$10 per tonne of carbon dioxide equivalent when introduced in 2008. It then rose C$5 per tonne each year until it reached C$30 per tonne in 2012. On April 1, 2018, B.C.'s carbon tax rate was C$35 per tonne of carbon dioxide equivalent emissions. This tax rate increases each year by C$5 per tonne until it reaches C$50 per tonne in 2021. At the time of this study, no carbon pricing scheme has been announced in B.C. beyond 2021. It was assumed that the carbon tax will start at C$45 in 2020 and increase annually until 2050 with a value equal to the estimated social cost of carbon [126]. As the carbon tax imposes a cost on a WTW basis to the hydrogen infrastructure, the lower-emissions components may become economically viable despite their higher investment cost.

3.5.2 Potential financial and regulatory policies

No study was found in literature to devise targeted fiscal and financial policies for the accelerated adoption of low-carbon hydrogen in the transport sector. For the purpose of this study, the policies were adopted from a range of economic instruments that has been used to promote renewable energy worldwide. Based on Table 3.9, production tax credit (PTC), capital subsidy (grant) and utility incentive for electrolytic hydrogen were adopted with varying stringency over time. These policies were added to the objective function of H2SCOT in the base case. The base case already includes the BC-LCFS and carbon tax in the objective function. The HFSC was also optimized for cases with higher carbon tax rates (compared to the current policy) as well as for the case in which SMR based hydrogen production without CCS integration is banned for transportation sector.

Table 3.9. Economic instruments to promote renewable energy worldwide.

Category	Policy Type	Description	Example
Fiscal /financial incentives	Carbon Tax	A carbon tax is a fee levied on each tonne of carbon dioxide emitted from burning carbon-based fuels.	Manitoba Emissions Tax on Coal Act (Canada) [127] Carbon tax (Japan [128], British Columbia (Canada) [125]
	Capital subsidy, Grants	One-time payment to cover a fraction of the capital cost of the investment	Wood-to-Energy Grants (USA) [129] Smart Grid Investment Grants (USA) [130] California Solar Initiative [131] Ontario saveONenergy (Canada) [132]
	Feed-in Tariff /premiums	A long-term purchase agreement for the sale of renewable electricity. Feed-in tariff sets a minimum price guaranteed which is above the standard market price. Feed-in premiums establishes a constant or sliding premium on existing market price.	Ontario Feed-in Tariff Programme (Canada) [133] Residential Net Feed-in Tariff for Western Australia [134] Renewable Energy Act (Germany) [135] Feed-in premium tariffs for renewable power (Denmark) [136] Renewable Energy Feed-In Tariff (France) [137]
	Loan guarantees	A guarantee that allows a lender (financial institutions or utilities) to recover a fraction of the principal and accrued interest on a loan that may go into default from the government	Future Fuels Initiative (Canada) [138] Green Loan Guarantee Program (Alberta-Canada) [139] RenovAr program (Argentina) [140]
	Production tax credit	PTC provides an income tax rebate based on the amount of production by a qualified business for a specified period of time	Cellulosic Biofuel Producer Tax Credit (USA) [141] The Renewable Electricity Production Tax Credit (USA) [142]
	Investment tax credit	ITC provides an income tax rebate based on the capital investment volume in a qualified business	Clean Coal Facility Tax Credit (USA) [143] Solar Investment Tax Credit (USA) [144] San Francisco Solar Energy Incentive Program [145] Tax credit for energy transition (France) [146] Capital Investment Tax Credit (Alberta-Canada) [147]
	Reduced excise taxes	It provides consumption tax exemptions or reduction on the sale of qualified products	Preferential Tax Regimes for Biofuels (UK) [148] Renewable Energy Tax Excise (Poland) [149]
	Accelerated depreciation	any method of depreciation used for income tax purposes that allows greater deductions in the earlier years of the life of an asset	Enhanced Capital Allowances (UK) [150] Accelerated Capital Cost Allowance (Canada) [121] Modified Accelerated Cost Recovery System (USA) [151]

	Policy Type	Description	Example
	Soft loans	Provided by governments with preferential terms such as lower interest rates, longer loan terms, etc. to reduce the costs of capital.	Energy Provisioning (Germany) [152] Preferential loans for energy saving measures (France) [153] Green Municipal Fund (Canada) [154] Advanced Technology Vehicle Manufacturing Loan Program (USA) [155]
	Utility rebates and incentives	Financial incentives from utilities to customers to replace inefficient products or improve the energy efficiency of the existing systems	BC Hydro's Power Smart Partners Express (PSP) (Canada) [156] Efficiency Incentives for Large Electricity Consumers (Greece) [157]
Market-based	GHG emissions trading (Cap-and-Trade & Baseline-and-Credit)	A central authority creates tradable pollution permits which can be bought and sold in an open market to meet emission reduction objectives	Quebec Cap & Trade System for Greenhouse Gas Emissions Allowances [158] Regional Greenhouse Gas Initiative (USA) [159] EU Emissions Trading System [160]
	Renewable Energy Certificates	Renewable energy certificates are proof that energy has been generated from renewable sources. These certificates are classified as a commodity and allow the renewable attributes of energy to be sold or traded separately from the physical unit of energy.	White Certificate Scheme & Obligation (France) [161] Renewable Energy Green Certificate and Trading Mechanism (China) [162] Norway-Sweden Green Certificate Scheme for electricity production [163]
	Low carbon fuel standard (LCFS)	The LCFS includes a credit trading system that allows providers to generate tradable credits through the use of low carbon fuels, and in turn imposes deficits for the use of higher-carbon fuels.	Renewable and Low Carbon Fuel Requirements Regulation (B.C-Canada) [122] ARB's Low Carbon Fuel Standard (California-USA) [164]

3.5.2.1 Production tax credit (PTC)

Production tax credit (PTC) is a preferential tax treatment that was included in the US Energy Policy Act of 1992 [142]. PTC provides an inflation-adjusted tax credit on every kilowatt-hour of electricity generated by the qualified energy sources for a limited time period. PTC has been one of the major drivers of wind power development in the US which resulted in quadrupling capacity, and the 40 % of cost reduction between 2007 and 2014 [165].

In this study, PTC has been applied to hydrogen produced from i) water electrolysis, ii) SMR equipped with CCS and iii) by-product hydrogen purification. The credits were allocated through different multi-stage settings over time, as shown in Figure 3.12 (a). The maximum tax credit was assumed at C$2/kg adjusted downwards over time in PTC_Step. This setting is designed to assure the overall transition proceeds from policy-driven to market-driven. The same strategy was also considered for PTC_Delay, with an exception that the effective date has a 10-year delay. Constant tax credit at C$2/kg and C$1/kg was assumed for PTC_$2 and PTC_$1, respectively. The maximum C$2/kg was adopted such that it is less than the applicable tax on the optimal hydrogen price in in the optimistic scenario for the base case.

It is likely that the amount of depreciation deductions exceeds the taxable income in the first years of HFSC operation. Thus, HFSC may owe no income tax, which means that earned PTCs potentially go unused. It was assumed that the value of the production tax credits was captured by monetizing tax benefits. This could happen by applying the deductions and credits against outside income, carrying the tax benefits forward over time, or through a third-party tax equity investor [166].

3.5.2.2 Capital subsidy

A capital subsidy is a one-time lump-sum payment that covers a portion of the upfront capital cost of an asset. This subsidy is not repayable and aims to enhance the financial viability of an investment.

In this study, water electrolysis and CCS technologies were assumed to be eligible for cash subsidy. The upfront cash payment was allocated in different multi-stage settings over time, as shown in Figure 3.12 (b). In Grant_Step, it was assumed that the grant covers the total capital cost of the eligible facilities and steps down in value over the years, until it phases out completely in 2040. Grant_100% provides the maximum support in which the total capital cost of facilities was offset by the government over the 30-year period. Grant_Delay has a stepwise fund allocation similar to Grant_Step, except for the 10-year delay on the effective date of policy.

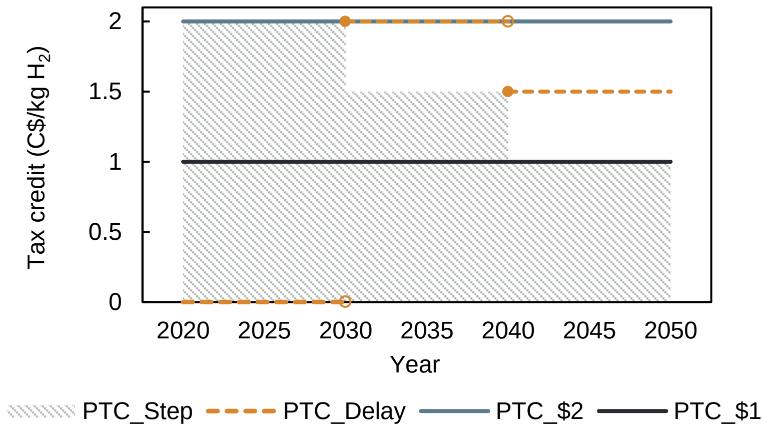
3.5.2.3 Utility incentives on electrolytic hydrogen

Favorable utility rates could encourage certain investments to develop or to pursue energy efficiency. The electricity generation in B.C. is hydro dominated. Thus, the power subsidies could potentially encourage low-carbon electrolytic hydrogen.

In this study, it was assumed that the utility subsidizes the electricity rate for central and on-site electrolyzers in four different multi-stage settings as shown in Figure 3.12 (c). In EC_Step, the subsidy covers the total electricity cost of electrolyzers and steps down in value over the years, until it disappears in 2040. EC_100% provides the maximum support in which the total electricity cost was offset by the utility over the 30-year period. EC_25% has the minimum support in which 25% of the electricity rate is covered by the utility over the entire study period. EC_Delay has a stepwise subsidy allocation similar to EC_Step, except for the 10-year delay on the effective date of policy.

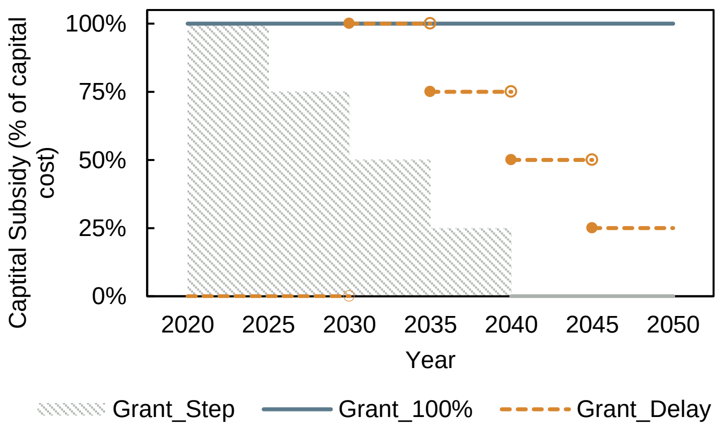
3.5.2.4 Higher rates of carbon tax

In the base case and all the policy cases, the carbon tax rate for the time period of 2020 to 2050 was adopted from values of the social cost of carbon (SCC), estimated by the Canada Treasury Board Secretariat's Analysis Guide [126]. However, it is likely that current estimates of SSC are biased downwards [167], [168]. Thus, Environment Canada suggested to use higher SCC values for sensitivity analysis and updated the "95th percentile" SCC value to C$167/tonne [126]. In this study, two cases were assessed with the annual carbon tax increase at C$2.04/tonne (CT_2X) and C$4.08/tonne (CT_4X), which is two and four times the annual increase of the base case, as shown in Figure 3.12 (d).



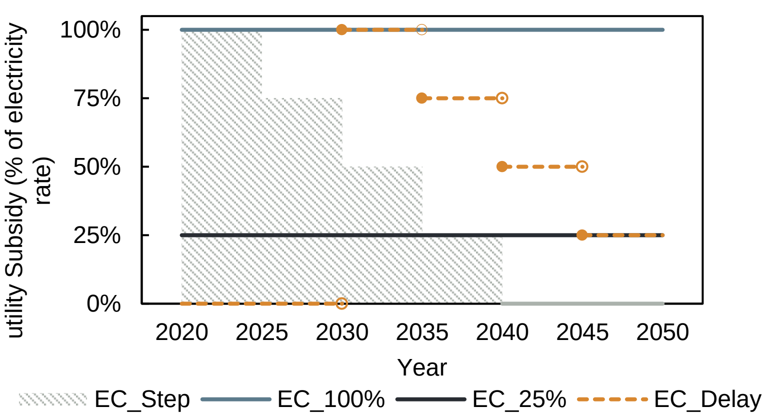
Tax credit (C$/kg H_2)
2
1.5
1
0.5
0
2020 2025 2030 2035 2040 2045 2050
Year
PTC_Step
PTC_Delay
PTC_$2
PTC_$1

(a)



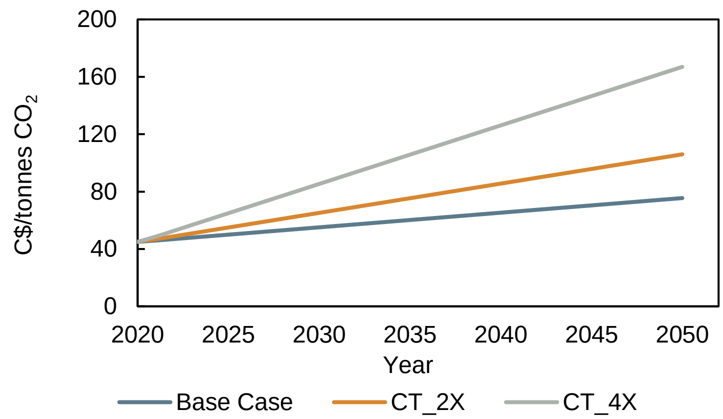
Captital Subsidy (% of capital cost)
100%
75%
50%
25%
0%
2020 2025 2030 2035 2040 2045 2050
Year
Grant_Step
Grant_100%
Grant_Delay

(b)



utility Subsidy (% of electricity rate)
100%
75%
50%
25%
0%
2020 2025 2030 2035 2040 2045 2050
Year
EC_Step
EC_100%
EC_25%
EC_Delay

(c)



(d)

Figure 3.12. Environmental policies with various deployment strategies over time (a) production tax credit (PTC), (b) capital subsidy, (c) utility incentives on electrolytic hydrogen, (d) carbon tax rate

3.5.2.5 Ban on the SMR hydrogen production without CCS integration

Because SMR is the most cost-efficient technology to produce hydrogen, it may delay the adoption of lower-carbon production technologies. Thus, a scenario was developed in which the SMR plants which were not equipped with CCS were banned from hydrogen production for the transportation sector. The HFSC was optimized to assess the extra cost imposed on the infrastructure as well as the GHG emissions reduction benefits.

Chapter 4: Hydrogen Supply Chain Cost Optimization Model (H2SCOT): Formulation

This chapter represents the model's assumptions, constraints, and objective function. H2SCOT was developed based on mixed integer linear programming (MILP), implemented in AMPL and solved using CPLEX v12.7.0.

4.1 MILP basics

A MILP model minimizes (maximizes) a linear function over all n-dimensional vectors x (continuous) and y (integer) subject to a set of linear equality and inequality constraints as well as integrality restrictions on the variables in y.

Minimize (Maximize) $z = \sum_{j=1}^{n} c_j^T x_j + d_j^T y_j$ 4.1

Subject to $\sum_{j=1}^{n} A_j x_j + K_j y_j \begin{Bmatrix} \leq \\ = \\ \geq \end{Bmatrix} b_i$ for $i = 1..m$

$0 \leq x_j \leq u_j$ & $y_j \in Z$ for $j = 1..n$

MILP is popular in capital budgeting where investment selection is made based on cash-flow constraints, warehouse location optimization which involves the decision on the number of facilities and scheduling problems which involve the sequencing and routing decisions.

MILP problems are generally solved using a linear-programming based branch-and-bound algorithm. First, the integer constraints are dropped to find the optimal solution to the "relaxation" of the problem via a standard linear optimization method. If the integer values are found for the decision variables with integer constraints, then those values are selected as optimal. If non-integral solutions are found for integer variables, this method branches on one of such variables and creates two new sub problems where the value of that variable is more tightly constrained. These sub problems are solved, and the process is repeated, until a solution is found which satisfies all the integer constraints.

4.2 H2SCOT basic assumptions

- H2SCOT did not include the possibility of industrial hydrogen sources nor the import of hydrogen into the province.
- The number of HFSC components was initialized at a null value.
- No lead time was considered for building plants or storage facilities and fueling stations.
- The natural gas resources and hydro-electricity generation could support the maximum demand in this study [65], [169].
- The projected price of electricity and natural gas was adopted from the National Energy Board projections [10] for the operating cost calculation.
- Large-scale storage options such as salt caverns, liquid organic hydrogen carriers (LOHC) and pipeline distribution networks were not considered in this analysis. The salt cavern (100s of GWh of capacity) is suitable for high demand, especially when seasonal storage is required to deal with the intermittent energy resources (wind and solar energy) [50], [78]. The LOHC pathways are also suitable candidates in case of intermittent renewable electricity generation [20]. The electricity generation in B.C. is almost exclusively from hydro power. The hydrogen delivery via pipelines is a low cost option for large hydrogen demand in dense cities as discussed by Yang and Ogden [170]. Unlike many regions in Europe, B.C represents a 944,735 km^2 jurisdiction (2.6 times larger than Germany) with a population of 5 million people (similar to Ireland). Gas and liquid truck delivery were selected in this study because the hydrogen flow rates and the population density of the demand regions were much lower than the suitable limits for pipeline distribution [170].

4.3 H2SCOT constraints

4.3.1 Production facilities

Hydrogen can be produced at central plants or on-site at the fueling stations. As discussed in chapter 3, SMR with carbon capture and sequestration (CCS), SMR without CCS, water electrolysis, and by-product hydrogen purification were considered for central production. Water electrolysis was used for on-site production. The maximum primary capacity was selected at 50 and 100 tonnes/day for SMR plants and 10, 50, and 100 tonnes/day for central electrolyzers. The maximum capacity for on-site electrolyzers was selected at 150, 500, 1000, and 1500 kg/day. The capacity of a plant for by-product hydrogen purification was at 10 tonnes/day. In case of liquid hydrogen delivery, the liquefaction plant was attached to the central production plant. The liquefaction plant was not considered for on-site production facilities. The following constraints were considered for the production facilities:

- The production rate of a central plant is constrained by the maximum and minimum production capacities:

$$Pcap\_min_c YC_{cydgt} \leq PC_{cydgt} \leq Pcap\_max_{cydgt} YC_{cydgt} \quad 4.2$$

$$\forall\, c \in C, y \in Y, d \in D, g \in G, t \in T$$

In which $Pcap\_min_c = 0.1 \times Pcap\_max\_prin_c$.

- The production rate of an on-site electrolyzer is bound within certain limits and is equal to the sum of dispensing and storage rates for the corresponding fueling station. For Metro Vancouver municipalities:

$$Dcap\_min_s YO\_V_{sdg't} \leq PO\_V_{sdg't} \leq Dcap\_max_s YO\_V_{sdg't} \quad 4.3\ (a)$$

$$PO\_V_{sdg't} = DI\_V_{sdg't} + STR\_V_{sdg't} \quad 4.4\ (a)$$

$$\forall\, s \in S, d \in D, g' \in G', t \in T$$

- For major municipalities except Metro Vancouver (Kamloops, Kelowna, Prince George and Victoria):

$$Dcap\_min_s YO\_NV_{sdn't} \leq PO\_NV_{sdn't} \leq Dcap\_max_s YO\_NV_{sdn't} \quad 4.3\ (b)$$

$$PO\_NV_{sdn't} = DI\_NV_{sdn't} + STR\_NV_{sdn't} \quad 4.4\ (b)$$

$$\forall\, s \in S, d \in D, n' \in NV, t \in T$$

- For major municipalities on the connecting roads (Abbotsford, Hope, Whistler and Williams Lake):

$$Dcap\_min_s YO\_RO_{sdr't} \leq PO\_RO_{sdr't} \leq Dcap\_max_s YO\_RO_{sdr't} \quad 4.3\ (c)$$

$$PO\_RO_{sdr't} = DI\_RO_{sdr't} + STR\_RO_{sdr't} \quad 4.4\ (c)$$

$$\forall\, s \in S, d \in D, r' \in RO, t \in T$$

- Depending on the state of hydrogen (*d*), the following constraints are also applied:

$$YC_{cydgt} = 0 \quad 4.5$$

$$\forall\, c \in C, y \in Y, g \in G, t \in T, d \in D: d = 1$$

$$YO\_V_{sdg't} = 0, \qquad YO\_NV_{sdn't} = 0, \qquad YO\_RO_{sdr't} = 0 \quad 4.6$$

$$\forall\, s \in S, g' \in G', n' \in NV, r' \in RO, t \in T\ , d \in D: d \neq 1$$

- The continuous variables of ZC_{cydgt} and M (sufficiently large) was introduced to linearize $Pcap\_max_{cydgt} YC_{cydgt}$, as follows:

$$ZC_{cydgt} \geq 0$$

$$ZC_{cydgt} \leq M * YC_{cydgt}$$

$$ZC_{cydgt} \leq Pcap\_max_{cydgt}$$

$$Pcap\_max_{cydgt} - ZC_{cydgt} \leq M * (1 - YC_{cydgt})$$

4.3.2 Terminals with central storage facilities

Terminals are geographically dispersed and can be located in any supply regions. The inventory of the central storage facilities supports both the daily demand of hydrogen and provides a backup for demand fluctuation. The maximum primary capacity options of 10, 50, and 100 tonnes/day were selected for central storage facilities. The following constraints were considered for the terminals:

- The average inventory of hydrogen falls within the maximum and minimum capacity of the facility:

$$TS_{\bar{c}d\bar{g}t} \leq Scap\_max_{\bar{c}d\bar{g}t} YS_{\bar{c}d\bar{g}t} \quad 4.7$$

$$Scap\_min_{\bar{c}} YS_{\bar{c}d\bar{g}t} \leq TS_{E\,\bar{c}d\bar{g}t}$$

$$\forall\, \bar{c} \in \bar{C}, d \in D, \bar{g} \in \bar{G}, t \in T$$

In which $Scap\_min_{\bar{c}} = 0.1 \times Scap\_max\_prin_{\bar{c}}$. $TS_{\bar{c}d\bar{g}t}$ is the total inventory of the storage facility (daily demand plus backup), and $TS\_E_{\bar{c}d\bar{g}t}$ is the backup inventory.

- Terminals receive all the gaseous/liquefied hydrogen produced by central plants:

$$\sum_{cyg} PC_{cydgt} - \sum_{\bar{c}\bar{g}} TS_{\bar{c}d\bar{g}t} = 0 \qquad 4.8$$

$$\forall\ c \in C, y \in Y, \bar{c} \in \bar{C}, d \in D, \bar{g} \in \bar{G}, g \in G, t \in T$$

4.3.3 Transportation and distribution

Two hydrogen transport modes were included in the model: liquid hydrogen tanker truck with the deliverable capacity of 3800 kg and compressed-gaseous hydrogen tube trailers with three delivery capacities of 100, 500, and 900 kg. The following constraints were considered for the transportation and distribution network:

- All the hydrogen produced in each supply region was stored within the warehouses of the same region (next to the plant) or transported to the warehouses in other regions. In the former case, no transportation was considered between the plant and the warehouse.

For gaseous hydrogen:

$$\sum_{cy} PC_{cydgt} - \sum_{\bar{c}} TS_{\bar{c}d\bar{g}t} - \sum_{\bar{g}a} CAP\_G_a\ NG\_PS_{g\bar{g}at} = 0 \qquad 4.9$$

$$\forall c \in C, y \in Y, g \in G, \bar{c} \in \bar{C}, \bar{g} \in \bar{G} : \bar{g} = g, a \in A, t \in T, d \in D: d = 2$$

The notations were adjusted to develop the mass balance equation for liquid hydrogen transport.

- Hydrogen is distributed from central warehouses to the demand regions by tube tankers/tanker trucks. For gaseous hydrogen distribution:

$$\sum_{\bar{c}} \left(TS_{\bar{c}d\bar{g}t} - TS_{E\,\bar{c}d\bar{g}t} \right) = \qquad 4.10$$

$$\sum_{a} CAP\_G_a \left(\sum_{g's} NG\_V_{\bar{g}g'ast} + \sum_{n'} NG\_NV_{\bar{g}n'ast} + \sum_{r'} NG\_RO_{\bar{g}r'ast} \right)$$

$$\forall\ \bar{c} \in \bar{C}, \bar{g} \in \bar{G}, n' \in NV, r' \in RO, g' \in G', a \in A, s \in S, t \in T, d \in D: d = 2$$

For liquid hydrogen distribution:

$$\sum_{\bar{c}} \left(TS_{\bar{c}d\bar{g}t} - TS_{E\,\bar{c}d\bar{g}t} \right) = \tag{4.11}$$

$$CAPL\_TR \left(\sum_{g'} NTRL\_V_{\bar{g}g't} + \sum_{n'} NTRL\_NV_{\bar{g}n'at} + \sum_{r'} NTRL\_RO_{\bar{g}r'at} \right)$$

$$\forall\ \bar{c} \in \bar{C}, \bar{g} \in \bar{G}, n' \in NV, r' \in RO, g' \in G', t \in T, d \in D: d = 3$$

- All trucks entering a demand region serve the fueling stations of that region. It was assumed that no product transfer could occur between demand regions. The mass balance equation for gas and liquid hydrogen delivery to Metro Vancouver municipalities is as follows:

$$\sum_{s} \left(DI\_V_{sdg't} + STR\_V_{sdg't} \right) = \sum_{\bar{g}as} CAP\_G_a NG\_V_{\bar{g}g'ast} \tag{4.12}$$

$$\forall\ \bar{g} \in \bar{G}, g' \in G', s \in S, a \in A, t \in T, d \in D: d = 2$$

$$\sum_{s} \left(DI\_V_{sdg't} + STR\_V_{sdg't} \right) = CAPL\_TR \sum_{\bar{g}} NTRL\_V_{\bar{g}g't} \tag{4.13}$$

$$\forall\ \bar{g} \in \bar{G}, g' \in G', s \in S, t \in T, d \in D: d = 3$$

The notation was adjusted to develop the mass balance equation for gas and liquid hydrogen distribution to other municipalities.

- Trucks serve the plants and fueling stations within their daily availability limit.

For transportation network:

$$AT\_Tr - \left(\frac{2LH\_PS_{g\bar{g}}}{VH} + Loadingtime_d|_{d=2} \right) < 0 \ \ : \ \ NTRG\_PS_{g\bar{g}at} = 0 \tag{4.14}$$

$$AT\_Tr - \left(\frac{2LH\_PS_{g\bar{g}}}{VH} + Loadingtime_d|_{d=3} \right) < 0 \ \ : \ NTRL\_PS_{g\bar{g}t} = 0$$

For distribution to Metro-Vancouver:

$$AT\_Tr - \left(\frac{2LH\_V_{\bar{g}}}{VH} + \frac{2LG_{g'}}{VG} + unLoadingtime_d|_{d=2} \right) < 0 \ \ : NTRG\_V_{\bar{g}g'at} = 0 \tag{4.15}$$

$$AT\_Tr - \left(\frac{2LH\_V_{\bar{g}}}{VH} + \frac{2LG_{g'}}{VG} + unLoadingtime_d|_{d=3}\right) < 0 \quad : NTRL\_V_{\bar{g}g't} = 0$$

The notation was adjusted for gas and liquid hydrogen distribution to other municipalities.

4.3.4 Hydrogen fueling stations

Three types of fueling stations were considered in this study: stations that receive gaseous hydrogen, those that receive liquid hydrogen, and stations with on-site production. The maximum potential capacities were selected at 150, 500, 1000 and 1500 kg/day, and the minimum capacity was fixed at 10% of the maximum capacity. The following constraints were considered for the fueling station:

- The dispensing rate of a fueling station is constrained between the maximum and minimum capacity of the station. In case of Metro Vancouver municipalities:

$$Dcap\_min_s YD_{V_{sdg't}} \leq DI_{V_{sdg't}} \leq Dcap\_max_s YD_{V_{sdg't}} \qquad 4.16$$

$$\forall\, s \in S, d \in D, g' \in G', t \in T$$

In which, $Dcap\_min_s = 0.1 \times Dcap\_max_s$.

- The average backup inventory of a fueling station is constrained by the maximum and minimum capacity of that station. The exception is for gaseous delivery, where a tube tanker truck leaves the full tubes at the station and collects the empty tubes. Thus, the remaining gas in the tube trailers acts as the storage for the station. For Metro Vancouver municipalities:

$$STR_{V_{sdg't}} \leq Dcap\_max_s YD_{V_{sdg't}} \qquad 4.17$$

$$\forall\, s \in S, d \in D: d \neq 2, g' \in G', t \in T$$

$$Dcap\_min_s YD_{V_{sdg't}} \leq STR_{V_{sdg't}}$$

$$\forall\, s \in S, d \in D, g' \in G', t \in T$$

The notation was adjusted to develop the dispensing rate and backup inventory constraints for other municipalities.

4.3.5 Hydrogen demand

The total hydrogen demand for light duty passenger vehicles in B.C. is equal to the demand of Metro Vancouver municipalities, major municipalities outside Metro Vancouver (Kamloops, Kelowna, Prince George, and Victoria), and the municipalities on the connecting roads (Whistler, Hope, Abbotsford, and Williams Lake):

$$DT_t = \sum_{g'} DG_{V_{g't}} + \sum_{n'} DG_{NV_{n't}} + \sum_{r'} DG_{RO_{r't}} \qquad 4.18$$

$$\forall g' \in G', n' \in NV, r' \in RO, t \in T$$

The terms on the right are the hydrogen demand at the final year of each time step.

- The total hydrogen demand in each region is equal to the dispensing rate of all fueling stations in that region. In case of Metro-Vancouver:

$$DG_{V_{g't}} = \sum_{sd} DI_{V_{sdg't}} \qquad 4.19$$

$$\forall\, s \in S, d \in D,\;\; g' \in G', t \in T$$

- The total hydrogen demand (DT_t) is equal to the difference between total hydrogen production (central and on-site) and total backup storage (central and on-site):

$$DT_t = \sum_{sdg'} \left(PO\_V_{sdg't} - STR\_V_{sdg't}\right) + \sum_{sdn'} (PO\_NV_{sdn't} - STR\_NV_{sdn't}) \qquad 4.20$$

$$+ \sum_{sdr'} (PO\_V_{sdr't} - STR\_V_{sdr't}) + \sum_{cydg} PC_{cydgt} - \sum_{\bar{c}d\bar{g}} TS\_E_{\bar{c}d\bar{g}t}$$

$$\forall\, \bar{c} \in \bar{C}, \bar{g} \in \bar{G}, s \in S, c \in C, d \in D, g \in G, n' \in NV, r' \in RO, y \in Y, g' \in G', t \in T$$

4.3.6 Building new facilities and lifetime consideration

- Plants or terminals with the same technology, state of product, and capacity could not co-exist in each region, as they were considered binaries.

- A central plant existed in time step (*t*), since it was established in that time step, or it was existing from the previous time steps and was working within its lifetime.

$$YC_{cydgt} = YPC_{cydgt} + YC_{cydg(t-1)} \quad 4.21$$

$$\forall\, c \in C, y \in Y, d \in D, g \in G, t \in T\colon 2 \leq t \leq LT, LT = Lifetime\_C/timestep$$

$$YC_{cydgt} = YPC_{cydgt} + YC_{cydg(t-1)} - YPC_{cydg(t-LT)}$$

$$\forall\, c \in C, y \in Y, d \in D, g \in G, t \in T : t \geq LT + 1, LT = Lifetime\_C/timestep$$

- All plants were new in the first time step:

$$YPC_{cydgt} = YC_{cydgt} \quad 4.22$$

$$\forall\, c \in C, y \in Y, d \in D, g \in G, t \in T\colon t = 1$$

The notation was adjusted to develop the time evolution constraints for warehouses, trucks, on-site production plants, and refueling stations.

4.3.7 Capacity expansion

In case the demand exceeds the maximum primary capacity, a capacity expansion could be considered as an alternative to building a new facility. Three stages of capacity expansion (j) were considered for the plants and storage facilities. For SMR plants, the capacity expansion stages were fixed at 10%, 20%, and 30%, whereas they were 10%, 25%, and 50% for electrolyzers and storage facilities. The capacity expansion option was not considered for the by-product hydrogen purification plant. The following capacity expansion constraints were considered in the model:

- Each stage of capacity expansion could take place once during the lifetime of the facility. In case of a central production plant:

$$Y'PC_{jcydgt} \geq Y'C_{jcydgt} - Y'C_{jcydg(t-1)} \quad 4.23$$

$$Y'PC_{jcydgt} \leq Y'C_{jcydgt}$$

$$Y'PC_{jcydgt} \leq 1 - Y'C_{jcydg(t-1)}$$

$$\forall\, j \in J, c \in C, y \in Y, d \in D, g \in G, t \in T\colon t \geq 2$$

- The capacity expansion could not happen in the same time step as the facility establishment. In case of a central production plant:

$$YPC_{cydgt} + Y'PC_{jcydgt} \leq 1 \qquad 4.24$$

$$\forall\, j \in J, c \in C, y \in Y, d \in D, g \in G, t \in T$$

- Each stage of capacity expansion ($Y'C_{jcydgt}$) took place when the rate of product flow (PC_{ydgt}) exceeded the maximum primary capacity ($Pcap\_max\_prin_c$), as follows:

$$(Pcap\_\max\ \_prin_c - \varepsilon)Y'C_{jcydgt}\big|_{j=1} + \sum_{j=1}^{3}\left(\left(1 + Rev_{jy}\right)Pcap\_\max\ \_prin_c - \varepsilon\right)Y'C_{(j+1)cydgt} \leq PC_{ydgt} \leq Pcap\_max\_prin_c\left(Y'C\_O_{cydgt} + \sum_{j=1}^{3}\left(1 + Rev_{jy}\right)Y'C_{jcydgt}\right) \qquad 4.25$$

$$\forall\, j \in J, c \in C, y \in Y, d \in D, g \in G, t \in T$$

- The maximum capacity of a facility in each time step was determined based on the maximum primary capacity and the total stages of capacity expansion that happened before that time step. In case of a central production plant:

$$Pcap\_max_{cydgt} = Pcap\_max\_prin_c\left(1 + \left(\sum_{j=1}^{3} Rev_{jy}Y'C_{jcydgt}\right) + Rev_{jy}\big|_{j=3}Y'C_{jcydgt}\big|_{j=4}\right) \qquad 4.26$$

$$\forall\, j \in J, c \in C, y \in Y, d \in D, g \in G, t \in T$$

- A maximum of one stage of capacity expansion was possible for each facility in each time step. In case of a central production plant:

$$Y'C\_O_{cydgt} + \textstyle\sum_{j=1}^{3} Y'C_{jcydgt} \leq 1 \qquad 4.27$$

$$\forall\, j \in J, c \in C, y \in Y, d \in D, g \in G, t \in T$$

The capacity expansion constraints for the central storage facilities follow the same logics as plants.

4.3.8 Non-negativity constraints

Non-negativity constraints must be represented to ensure that the variables are continuous, positive integers and binaries.

4.4 H2SCOT objective function

The objective function is to minimize the discounted total cost of infrastructure (DC_{INF}), which includes the discounted cost of technology (DC_{T}) and the discounted cost of environmental policies (DC_{Policy}). It was assumed that the supply chain components were built in the first year with the maximum capacity to fulfill the demand in the last year of each time step.

$$DC_{INF} = DC_{T} + DC_{Policy} \tag{4.28}$$

4.4.1 Discounted cost of technology (DC$_{T}$)

$$DC_{T} = DCT_{est} + DCT_{rev} + DCT_{opr} \tag{4.29}$$

DCT_{est} is the capital cost of establishing an HFSC, which is composed of direct depreciable capital cost, indirect depreciable capital cost, and non-depreciable capital cost. The learning rate of the technology was calculated based on the demand growth in each time step and was applied to the unit capital cost of the facilities. For instance, the learning rate of the central plants is calculated as follows:

$$LR\_C_{t} = \left(\frac{DT_{t=1}}{DT_{t}}\right)^{\alpha\_LR\_C} \tag{4.30}$$

DCT_{est} is calculated as follows:

$$\sum_t \frac{1}{(1+r)^{timestep(t-1)}}\left[\sum_{cydg}\left[EST\_C_{cydgt} + 0.15LR\_C_t DDC\_C_{cy} YPE_{cydg\bar{t}}\right] + \sum_{\bar{c}d\bar{g}} EST\_S_{\bar{c}d\bar{g}t} + \sum_{sdg'} EST\_V_{sdg't} + \sum_{sdn'} EST\_NV_{sdn't} + \sum_{sdr'} EST\_RO_{sdr't} + \sum_a DDC\_G_a\left(\sum_{g\bar{g}} NNG\_PS_{g\bar{g}at} + \sum_{\bar{g}g's} NNG\_V_{\bar{g}g'ast} + \sum_{\bar{g}n's} NNG\_NV_{\bar{g}n'ast} + \sum_{\bar{g}r's} NNG\_RO_{\bar{g}r'ast}\right) + DDC\_L\left(\sum_{g\bar{g}} NNL\_PS_{g\bar{g}t} + \sum_{\bar{g}g'} NNL\_V_{\bar{g}g't} + \sum_{\bar{g}n'} NNL\_NV_{\bar{g}n't} + \sum_{\bar{g}r'} NNL\_RO_{\bar{g}r'}\right)\right] \tag{4.31}$$

$\forall\ c \in C, y \in Y, d \in D, \bar{c} \in \bar{C}, \bar{g} \in \bar{G}, g' \in G', g \in G, n' \in NV, r' \in RO, g' \in G', s \in S, a \in A,$
$t \in T$

In which:

$$EST\_C_{cydgt} = \left(LR\_C_t\left(DDC\_C_{cy} + IDC\_C_{cy}\right) + NC\_C_{cy}\right)YPC_{cydgt}$$

$$EST\_S_{\bar{c}d\bar{g}t} = (LR\_S_t(DDC\_S_{\bar{c}d} + IDC\_S_{\bar{c}d}) + NC\_S_{\bar{c}d})YPS_{\bar{c}d\bar{g}t}$$

$$EST\_V_{sdg't} = LR\_O_t DC\_O_s YPO\_V_{sdg't} + LR\_D_t DC\_D_{sd} YPD\_V_{sdg't}$$

$EST\_NV_{sdn't}$ and $EST\_RO_{sdr't}$ were developed with proper notation for other municipalities. $YPE_{cydg\bar{t}}$ in Eq. 4.31 considers a 10-year replacement cost of the stacks for central electrolyzers.

DCT_{rev} in Eq. 4.29 is the capital cost of capacity expansion for the central plants and warehouses, calculated as follows:

$$\sum_{t} \frac{1}{(1+r)^{timestep(t-1)}} \left[LR\_C_t \sum_{jcydg} PR_{cap_{jy}} DDC_{C_{cy}} \left(Y'PC_{jcydgt} - \sum_{p=1}^{t-1\,(t>1)} Y'PC_{jcydgp} \sum_{r=1}^{3} Y'PC_{rcydgt} \right) + LR\_S_t \sum_{j\bar{c}d\bar{g}} SR\_cap_j DDC\_S_{\bar{c}d} \left(Y'PS_{j\bar{c}d\bar{g}t} - \sum_{p=1}^{t-1\,(t>1)} Y'PS_{j\bar{c}d\bar{g}p} \sum_{r=1}^{3} Y'PS_{r\bar{c}d\bar{g}t} \right) \right] \quad 4.32$$

$$\forall\, j \in J, r \in J, c \in C, y \in Y, d \in D, \bar{c} \in \bar{C}, \bar{g} \in \bar{G}, t \in T, p \in T$$

PR_cap_{jy} is the percentage of direct depreciable capital cost of plants, for each stage of capacity expansion. $Y'PC_{jcydgt} - \sum_{p=1}^{t-1\,(t>1)} Y'PC_{jcydgp} \sum_{r=1}^{3} Y'PC_{rcydgt}$ demonstrates the stage of capacity expansion with respect to the history of capacity expansion for the specific plant. The same logic applies to the storage facilities.

DCT_{opr} in Eq. 4.29 is the sum of operating and yearly replacement costs. The operating cost of each facility consists of fixed costs and variable costs. The fixed cost is calculated based on a fixed percentage of the depreciable capital cost, while the variable costs depend on the hydrogen flow.

DCT_{opr} is calculated as follows:

$$\sum_{tt'} \frac{1}{(1+r)^{(z-1)}} \left[\sum_{d} \left(\sum_{cyg} OPR\_C_{cydgt} + \sum_{\bar{c}} OPR\_S_{\bar{c}d\bar{g}t} + \sum_{sg'} OPR\_V_{sdg't} \right. \right. \tag{4.33}$$

$$\left. + \sum_{sn'} OPR\_NV_{sdn't} + \sum_{sr'} OPR\_RO_{sdr't} \right)$$

$$+ Per\_t_z \sum_{\bar{g}} \left(\sum_{ga} OPRG\_PS_{g\bar{g}at} + \sum_{g'as} OPRG\_V_{\bar{g}g'ast} \right.$$

$$+ \sum_{n'a} OPRG\_NV_{\bar{g}n'ast} + \sum_{r's} OPRG\_RO_{\bar{g}r'ast} + \sum_{g} OPRL\_PS_{g\bar{g}t}$$

$$\left. \left. + \sum_{g'} OPRL\_V_{\bar{g}g't} + \sum_{n'} OPRL\_NV_{\bar{g}n't} + \sum_{r'} OPRL\_RO_{\bar{g}r't} \right) \right]$$

$z = timestep(t-1) + t'$

$\forall\ c \in C, y \in Y, d \in D, \bar{c} \in \bar{C}, \bar{g} \in \bar{G}, g \in G, g' \in G', n' \in NV, r' \in RO, s \in S, t \in T,$

$t' = 1 \ldots timestep$

In which:

$$OPR\_C_{cydgt} = Per\_t_z PC_{cydgt} OP\_C_{cy} + \left(F\_C_{cy} + \omega LR\_C_t DC\_C_{cy}\right) YC_{cydgt}$$

$$OPR\_S_{\bar{c}d\bar{g}t} = Per\_t_z TS_{\bar{c}d\bar{g}t} OP\_S_{\bar{c}d} + (F\_S_{\bar{c}d} + \omega LR\_S_t DC\_S_{\bar{c}d}) YS_{\bar{c}d\bar{g}t}$$

$$\begin{aligned} OPR\_V_{sdg't} = {} & Per\_t_z OP\_O_s PO\_V_{sdg't} + (F\_O_s + \omega LR\_O_t DC\_O_s) YO\_V_{sdg't} \\ & + Per\_t_z OP\_D_{sd} (DI\_V_{sdg't} + STR\_V_{sdg't}) \\ & + (F\_D_{sd} + \omega LR\_D_t DC\_D_{sd}) YD\_V_{sdg't} \end{aligned}$$

$$OPRG\_PS_{g\bar{g}at} = NG\_PS_{g\bar{g}at} \left(\left(LTR\_PS_{d\bar{g}g}\big|_{d=2} + FTR\_PS_{d\bar{g}g}\big|_{d=2} \right) + F\_G_a \right)$$

$$OPRL\_PS_{g\bar{g}t} = NL\_PS_{g\bar{g}t} \left(\left(LTR\_PS_{d\bar{g}g}\big|_{d=3} + FTR\_PS_{d\bar{g}g}\big|_{d=3} \right) + F\_L \right)$$

Per_t_z accounts for the ratio of annual hydrogen flow rate to the maximum flow rate in each time step. The yearly replacement cost of the plants, warehouses, and fueling stations (ω) accounts for 0.5% of the total depreciable capital cost of the corresponding facility.

The cost of fuel and driver wages for hydrogen transport was calculated based on the transport time, the hourly wage of the driver, the fuel cost, and the fuel economy of the truck.
For transportation network:

$$LTR\_PS_{d\bar{g}g} = \alpha\left(\frac{2LH\_PS_{g\bar{g}}}{VH} + Loadingtime_d\right) \tag{4.34}$$

$$FTR\_PS_{d\bar{g}g} = 2\gamma\beta LH\_PS_{g\bar{g}} \tag{4.35}$$

For distribution network (to Metro-Vancouver):

$$Labor\_TR\_V_{dg'\bar{g}} = \alpha\left(\frac{2LH\_V_{\bar{g}}}{VH} + \frac{2LG_{g'}}{VG} + unLoadingtime_d\right) \tag{4.36}$$

$$Fuel\_TR\_V_{dg'\bar{g}} = 2\gamma\beta\left(LH\_V_{\bar{g}} + LG_g\right) \tag{4.37}$$

The notation was adjusted to calculate the cost of fuel and driver wages for the trucks distributing hydrogen to other municipalities.

4.4.2 Discounted cost of environmental policies (DC_{Policy})

The discounted cost of environmental policies consists of the cost and revenue of currently deployed policies in B.C. (carbon tax and LCFS) and the discounted revenue of the complementary subsidy-based policies, as follows:

$$DC_{Policy} = DC_{CT} - DR_{LCFS} - DR_{sub} \tag{4.38}$$

4.4.2.1 Discounted cost of carbon tax (DC_{CT})

DC_{CT} was calculated on a yearly basis and discounted over the entire time frame. The emission from the unit hydrogen flow in each component was multiplied by the hydrogen flow rate, and the result is multiplied by the emission cost per tonne of CO_2 dispersed (i.e., the carbon tax):

$$\sum_{tt'} \frac{365Per\_t_z E\_Cost}{(1+r)^{(z-1)}} \Bigg[\sum_{cydg} GHG\_C_y PC_{cydgt} + \sum_{\bar{c}d\bar{g}} GHG\_S_d TS_{\bar{c}d\bar{g}t} + \tag{4.39}$$

$$+ GHG\_TR \Bigg(\sum_{g\bar{g}a} \big((2LH\_PS_{g\bar{g}}) NTRG\_PS_{g\bar{g}at} \big)$$

$$+ \sum_{\bar{g}g'a} \big((2LH\_V_{\bar{g}} + 2LG_{g'}) NG\_V_{\bar{g}g'at} \big)$$

$$+ \sum_{\bar{g}n'as} \big((2LH\_NV_{\bar{g}n'}) NG\_NV_{\bar{g}n'ast} \big)$$

$$+ \sum_{\bar{g}r'as} \big((2LH\_RO_{\bar{g}r'}) NG\_RO_{\bar{g}r'ast} \big) + \sum_{g\bar{g}} \big((2LH\_PS_{g\bar{g}}) NL\_PS_{g\bar{g}t} \big)$$

$$+ \sum_{\bar{g}g'} \big((2LH\_V_{\bar{g}} + 2LG_{g'}) NL\_V_{\bar{g}g't} \big) + \sum_{\bar{g}r'} \big((2LH\_NV_{\bar{g}n'}) NL\_NV_{\bar{g}n't} \big)$$

$$+ \sum_{\bar{g}r'} \big((2LH\_RO_{\bar{g}r'}) NL\_RO_{\bar{g}r't} \big) \Bigg) + \sum_{sdg'} EMN\_V_{sdg't}$$

$$+ \sum_{sdn'} EMN\_NV_{sdn't} + \sum_{sdr'} EMN\_RO_{sdr't} \Bigg]$$

$z = timestep(t-1) + t'$

$\forall\, c \in C, y \in Y, d \in D, \bar{c} \in \bar{C}, \bar{g} \in \bar{G}, g \in G, g' \in G', n' \in NV, r' \in RO, s \in S, t \in T,$
$t' = 1 \ldots timestep$

In which:

$EMN\_V_{sdg't} = GHG\_D_d(DI\_V_{sdg't} + STR\_V_{sdg't}) + GHG\_O \times PO\_V_{sdg't}$

The notations were adjusted to account for the GHG emissions in other municipalities (i.e., $EMN\_NV_{sdn't}$ and $EMN\_RO_{sdr't}$).

The vessels transporting hydrogen from the Port of Vancouver to Victoria were assumed to produce 13% of the GHG emissions of road transportation [171] per tonne-kilometer. This assumption was used for the distance of 47 km between the ports of Tsawwassen, B.C., and Swartz Bay, B.C.

4.4.2.2 Discounted revenue of LCFS (DR_{LCFS})

The LCFS revenue was calculated based on the difference between the carbon intensity of gasoline and hydrogen and their energy efficiency ratio, multiplied by the LCFS credit price per tonnes of CO_2 displaced. The carbon intensity of hydrogen was calculated on WTW basis by considering the share of each component on the final fuel-side GHG emissions of the supply chain.

$$\sum_{tt'} \frac{365Per\_t_z \times 1.2DT_t \times Credit\_LCFS_t \times 1E-6 \times H2\_D}{(1+r)^{(z-1)}} \Bigg[Gas\_CI \times EER_t$$
$$- \frac{1}{120 \times 1.2DT_t} \Bigg[\sum_{cydg} GHG\_C_y PC_{cydgt} + \sum_{\bar{c}d\bar{g}} GHG\_S_d TS_{\bar{c}d\bar{g}t} +$$
$$+ GHG\_TR \Bigg(\sum_{g\bar{g}a} \big((2LH\_PS_{g\bar{g}}) NTRG\_PS_{g\bar{g}at} \big)$$
$$+ \sum_{\bar{g}g'as} \big((2LH\_V_{\bar{g}} + 2LG_{g'}) NG\_V_{\bar{g}g'ast} \big)$$
$$+ \sum_{\bar{g}n'as} \big((2LH\_NV_{\bar{g}n'}) NG\_NV_{\bar{g}n'ast} \big)$$
$$+ \sum_{\bar{g}r'as} \big((2LH\_RO_{\bar{g}r'}) NG\_RO_{\bar{g}r'ast} \big) + \sum_{g\bar{g}} \big((2LH\_PS_{g\bar{g}}) NL\_PS_{g\bar{g}t} \big)$$
$$+ \sum_{\bar{g}g'} \big((2LH\_V_{\bar{g}} + 2LG_{g'}) NL\_V_{\bar{g}g't} \big) + \sum_{\bar{g}r'} \big((2LH\_NV_{\bar{g}n'}) NL\_NV_{\bar{g}n't} \big)$$
$$+ \sum_{\bar{g}r'} \big((2LH\_RO_{\bar{g}r'}) NL\_RO_{\bar{g}r't} \big) \Bigg) + \sum_{sdg'} EMN\_V_{sdg't}$$
$$+ \sum_{sdn'} EMN\_NV_{sdn't} + \sum_{sdr'} EMN\_RO_{sdr't} \Bigg] \Bigg] \qquad 4.40$$

$z = timestep(t-1) + t'$

$\forall\, c \in C, y \in Y, d \in D, \bar{c} \in \bar{C}, \bar{g} \in \bar{G}, g \in G, g' \in G', n' \in NV, r' \in RO, s \in S, t \in T,$

$t' = 1 \dots timestep$

4.4.2.3 Discounted cost of complementary policies

The revenues from the incentive-based policies were added to the objective function of the model, as follows:

- The PTC is calculated by multiplying the tax credits in each time step by the production rate of the eligible facilities and added as a revenue term to the policy term of the objective function:

$$DC_{Policy} = DC_{CT} - DR_{LCFS} - DR_{PTC} \quad 4.41$$

The PTC is deducted from the total annual tax in the post optimization cash flow analysis (section 4.4)

- The capital subsidy was included in the discounted cost of technology (DC_T) of the objective function as follows:

$$DC_T = (DCT_{est})_N + ((1 - Grant) \times DCT_{est})_E + NCT_{est} + DCT_{rev} + DCT_{opr} \quad 4.42$$

In which $(DCT_{est})_N$ is the depreciable capital cost of the non-eligible facilities, $(DCT_{est})_E$ is the depreciable capital cost of eligible facilities, NCT_{est} is the non-depreciable capital cost, DCT_{rev} is the cost of capacity expansion, and DCT_{opr} is the operating cost of the facilities.

In calculating the accelerated depreciation allowances, the amount of the grant was subtracted from the property's capital cost.

- The utility subsidy (U_{INC}) is included in the operating cost of objective function of H2SCOT as follows:

$$\begin{aligned} DC_T = {} & DCT_{est} + NCT_{est} + DCT_{rev} + \left(FC_{opr} + VC_{opr}\right)_N \\ & + \left(FC_{opr} + (1 - U_{INC})VC_{opr}\right)_E \end{aligned} \quad 4.43$$

In which, $\left(FC_{opr} + VC_{opr}\right)_N$and $\left(FC_{opr} + (1 - U_{INC})VC_{opr}\right)_E$ are the fixed (FC_{opr}) and variable (VC_{opr}) operating cost of non-eligible and eligible facilities for this policy, respectively.

4.5 Post optimization cash-flow analysis

Based on the optimal infrastructure in each demand scenario, the hydrogen price trends were examined over time to meet a target internal rate of return (IRR) of the investment (10%). To this end, the annual after-tax post depreciation cash flow was calculated by subtracting the annual pre-depreciation income from the total taxes and the capital cost of the infrastructure.

$$ATPD\_CF_i = PD\_Inc_i - Tt_i - Cap_i \qquad \forall i: i = 1 \dots N \qquad 4.44$$

The annual capital costs include the yearly direct and indirect depreciable capital costs, non-depreciable capital costs and yearly replacement costs. The first three terms could be nonzero only at the first year of each time step, when the establishment of infrastructure is planned. The working capital is not considered in the calculation.

$$Cap_i = DDep\_Cap_i + IDep\_Cap_i + NDep\_Cap_i + Y\_Rep_i \qquad \forall i: i = 1 \dots N \qquad 4.45$$

The annual operational cost of the supply chain is the sum of fixed and variable operating costs. It was assumed that the salvage value of the facilities and the decommissioning cost cancel each other out.

$$Opr_i = F\_Opr_i + V\_Opr_i \qquad \forall i: i = 1 \dots N \qquad 4.46$$

The annual pre-depreciation income was calculated by subtracting hydrogen revenue from the operating cost.

$$PD\_Inc_i = Rev\_H2_i - Opr_i \qquad \forall i: i = 1 \dots N \qquad 4.47$$

The total annual tax was calculated by multiplying the tax rate by the taxable income and subtracting the result from the tax credit.

$$Tt_i = Tr \times (PD\_Inc_i - Dep\_ch_i) - Tc \qquad \forall i: i = 1 \dots N \qquad 4.48$$

To assess the taxable income, the depreciation of the supply chain facilities has to be determined. To this end, the capital cost allowance (CCA) deduction was calculated using the declining balance method, based on 30% CCA rate for production plants, storage facilities and dispensers and 40% CCA rate for tube trailer and tanker trucks.

4.6 Potential contribution of FCEVs to GHG emissions reduction

The annual GHG emissions reduction was calculated by subtracting the WTW GHG emissions of the gasoline cars that were replaced by the FCEVs from the total GHG emissions of the HFSC in each demand scenario:

$$GHG_{Rn_i} = GHG\_E_i|_{Gasoline\_Car} Stock_i|_{FCE\_Car} + GHG\_E_i|_{Gasoline\_PTruck} Stock_i|_{FCE\_PTruck} - GHG_i|_{HFSC} \quad \forall i: i = 1 \dots N \tag{4.49}$$

In which $GHG_i|_{HFSC}$ represents the annual GHG emissions from the HFSC infrastructure (calculated by the optimization model), and GHG_E is the WTW annual GHG emissions per vehicle, which was calculated for gasoline passenger cars and trucks up to 2050, as follows:

$$GHG\_E_i|_{Vehicle\_type} = \overline{F\_EmmRate} \times \overline{F\_Eff_i} \times \overline{VUse\_Int_i} \quad \forall i: i = 1 \dots N \tag{4.50}$$

$\overline{F\_EmmRate}$ (g/MJ) accounts for the gasoline average WTW GHG emissions rate, which was set at 79.33 g/MJ in compliance with the low-carbon fuel standard for 2020. $\overline{F\_Eff_i}$ (MJ/km) was calculated from Eq. 3.57 and $\overline{VUse\_Int_i}$ (km/year) was derived from Figure 3.9 .

Chapter 5: Hydrogen Fuel Supply Chain Development in British Columbia: Light Duty Passenger Vehicles

This chapter focuses on the results of the optimization model for three FCEV penetration scenarios in B.C. from 2020 to 2050. The results are presented in terms of the configuration of the supply chain in each time step, the average hydrogen price and the WTW GHG emissions from this supply chain. In each demand scenario, the environmental and economic trade-offs were measured for the case where no environmental policy is included. The results were then compared with the cases where various realizations of the current provincial policies (carbon tax and LCFS) are integrated to the model. The most suitable set of current policies (in terms of economic and environmental performance) was then selected to serve as a base case for the adoption of further environmental subsidies and regulations. The aim is to identify potential financial and regulatory tools to increase low-carbon hydrogen production in the cost optimal HFSC. The effectiveness of potential policies was measured with respect to the reduction in hydrogen price and GHG emissions per unit of subsidy alongside the contribution of low-carbon hydrogen in the resultant supply chain.

The validation of supply chain optimization models at the strategic decision phase is challenging. The HFSC optimization models are predictive with limited available historical data. Thus, the validation of these models is a longitudinal activity. Furthermore, the HFSC optimization models are regionally specific. The assumptions on the network topology, demand characteristics (temporal and spatial patterns), the resource availability, and the regulatory environment makes the optimization results unique and incomparable to the models which have been developed for a different region, even with a similar modeling structure.

5.1 HFSC configuration with no environmental policy inclusion

The HFSC cost minimization was performed without considering an emission policy term in the objective function. Table 5.1 shows the development of on-site and central production plants and central storage facilities for the three demand scenarios over time. On-site electrolysis was responsible for 100% of the hydrogen production in the first time step for all demand scenarios. The addition of central production facilities, especially SMR plants, decreases the contribution of on-site production in all demand scenarios. The hydrogen purification plant in the district of North

Vancouver was selected by the model as the least capital-intensive investment in the second time step for all demand scenarios. As the hydrogen demand grew over time, SMR facilities were added close to demand regions, to reduce the transportation cost. More expensive production technologies (central electrolysis and CCS) were not selected for any demand scenario. The storage facilities were built in the same region as the production sites (attached to the production plant) to avoid the transportation cost. A capacity expansion was applied to the SMR plant and the storage unit in the optimistic scenario. This option fulfilled the growing demand by increasing the rated capacity of the existing facilities and imposed less capital expenditure than building new ones. The hydrogen state was only gaseous for pessimistic and moderate scenarios. Due to the deployment of high-capacity composite gas vessels, liquid hydrogen played a role in the optimistic scenario as higher regional demand justified the liquefaction cost.

Table 5.1. On-site and central production plants and storage facilities for three demand scenarios over time (no policy inclusion).

Demand scenario	HFSC component[1]	Supply region	Time step 1	2	3	4	5	6
Pessimistic	Central production	14		H2P, G, 10t	H2P, G, 10t	H2P, G, 10t	H2P, G, 10t	H2P, G, 10t
		8					SMR, G, 50t	SMR, G, 50t
	Central storage	14		G, 10t	G, 10t	G, 10t	G, 10t	G, 10t
		8					G, 50t	G, 50t
	On-site electrolysis[2]	V	62.5%	32.4%	6.7%	26.3%	8%	0.5%
		NV	37.5%	19.6%	15.1%	28.7%	9.7%	0 %
		R	0%	2.7%	3%	3.2%	1.4%	1%
Moderate	Central production	14		H2P, G, 10t	H2P, G, 10t	H2P, G, 10t	H2P, G, 10t	H2P, G, 10t
		8				SMR, G, 50t	SMR, G, 50t	SMR, G, 50t
		8					SMR, G, 100t	SMR, G, 100t
	Central storage	14		G, 10t	G, 10t	G, 10t	G, 10t	G, 10t
		8				G, 50t	G, 50t	G, 50t
		8					G, 100t	G, 100t
	On-site electrolysis	V	59%	11.4%	32.7%	11.7%	0.1%	2.9%
		NV	38.7%	14.2%	29.4%	9.9%	0%	1.4%
		R	2.3%	2.5%	2.8%	0.3%	0.2%	0.3%
Optimistic	Central production	14		H2P, G, 10t	H2P, G, 10t	H2P, G, 10t	H2P, G, 10t	H2P, G, 10t
		8						SMR, Gas, 50t
		12			SMR, G, 100t	SMR, G, 100t	SMR, G, 100t	SMR, G, 100t
		12				SMR, L, 50t	SMR, L, 50t	SMR, L, 50t (10%)
		12					SMR, L, 100t	SMR, L, 100t (20%)
		3				SMR, L, 50t	SMR, L, 50t	SMR, L, 50t
	Central storage	14		G, 10t	G, 10t	G, 10t	G, 10t	G, 10t
		8						G, 10t
		12			G, 50t	G, 50t (25%)	G, 50t (50%)	G, 50t (50%)
		12				L, 50t	L, 50t	L, 50t
		12					L, 100t	L, 100t (25%)
		3				L, 10t	L, 10t (25%)	L, 10t (25%)
	On-site electrolysis	V	57.6%	8.3%	2.6%	2.9%	3.8%	0.0%
		NV	39.2%	21.0%	2.6%	6.4%	0.2%	0.1%
		R	3.2%	2.7%	0.5%	0.5%	0.4%	0.0%

[1] H2P: hydrogen purification plant, SMR: steam methane reforming, C-Elec: central electrolyzer, hydrogen status (G: gas, L: liquid), maximum capacity in tonnes (% capacity expansion).
[2] Percent of on-site production to total production: V: Greater Vancouver regions, NV: Kelowna, Kamloops, Victoria, Prince George; R: Abbotsford, Whistler, Hope, Williams Lake.

As Figure 5.1 shows, the gas trailers with the lowest capacity have the highest contribution at the initial time step. As the demand grew over time, the transportation network developed toward higher capacity units. The medium-capacity delivery trucks (500 kg per load) were the dominant mode of transportation in all time steps (except the first time step), for all demand scenarios.

The transition from low to high capacity was also observed for the fueling stations over time. As Figure 5.2 shows, each capacity category is the aggregation of all fueling stations that received hydrogen in gaseous or liquid form and those with on-site production. While the lowest-capacity stations (150 kg/day) dominated the dispensing network in the first two time steps, the largest contribution in succeeding time steps was 500 kg/day for the pessimistic scenario and 1500 kg/day for moderate and optimistic scenarios.

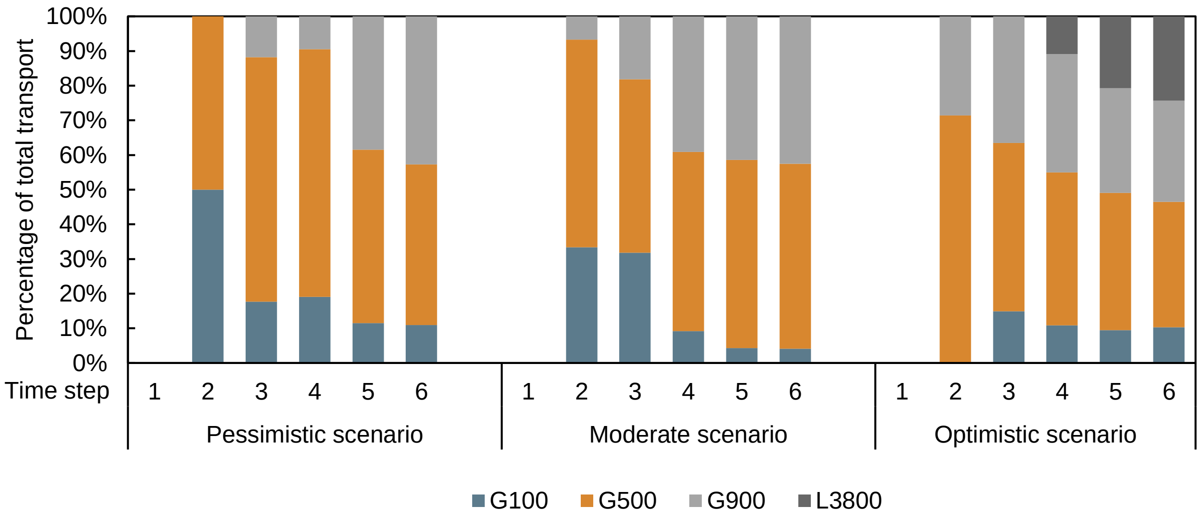


Figure 5.1. Contribution of different transportation states (G: gas, L: liquid) and deliverable capacities (100, 500, 900 and 3800 kg per truck) to the total number of transportation units for three demand scenarios over time (no policy inclusion).

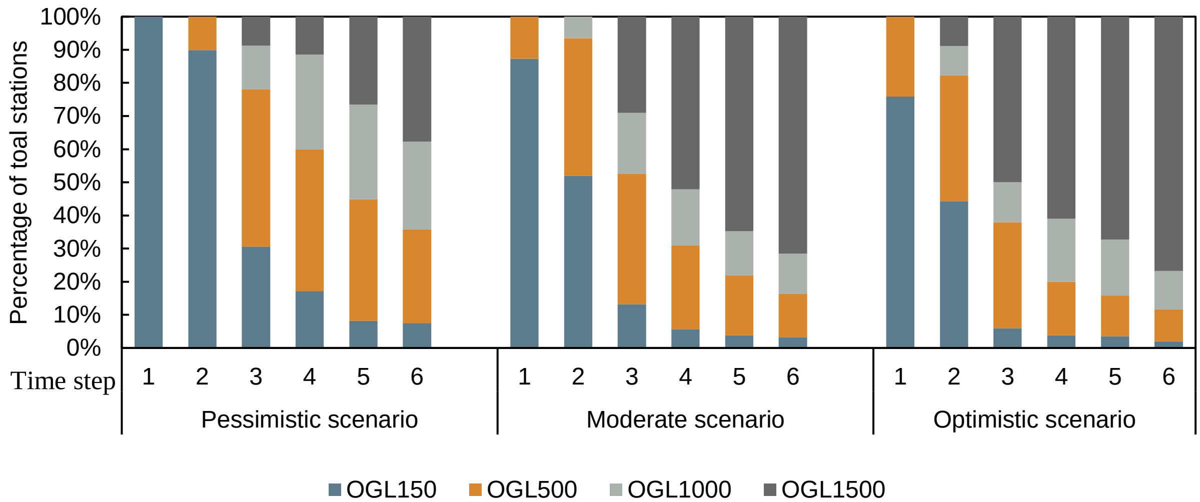
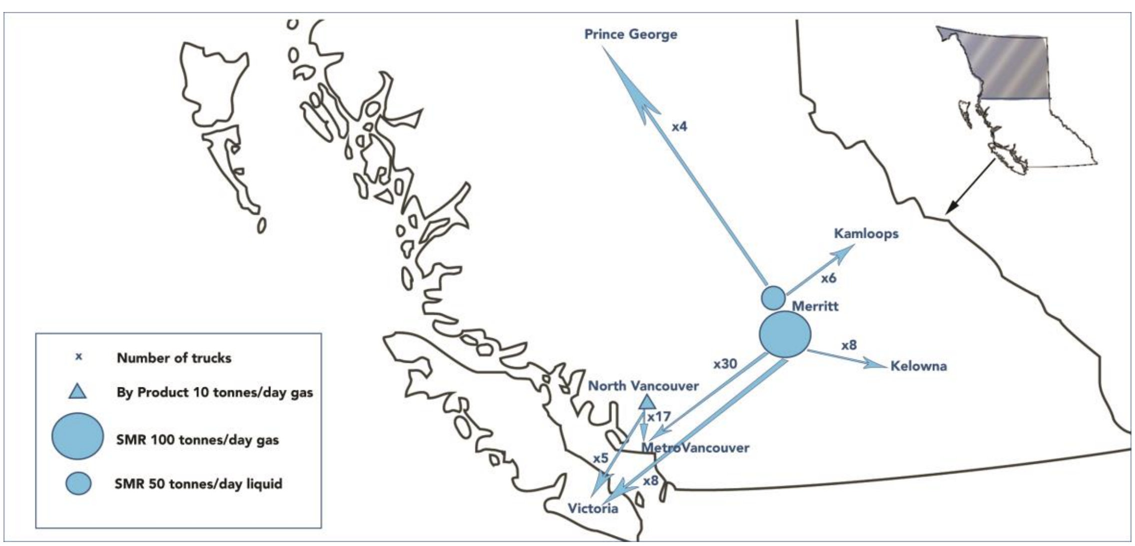
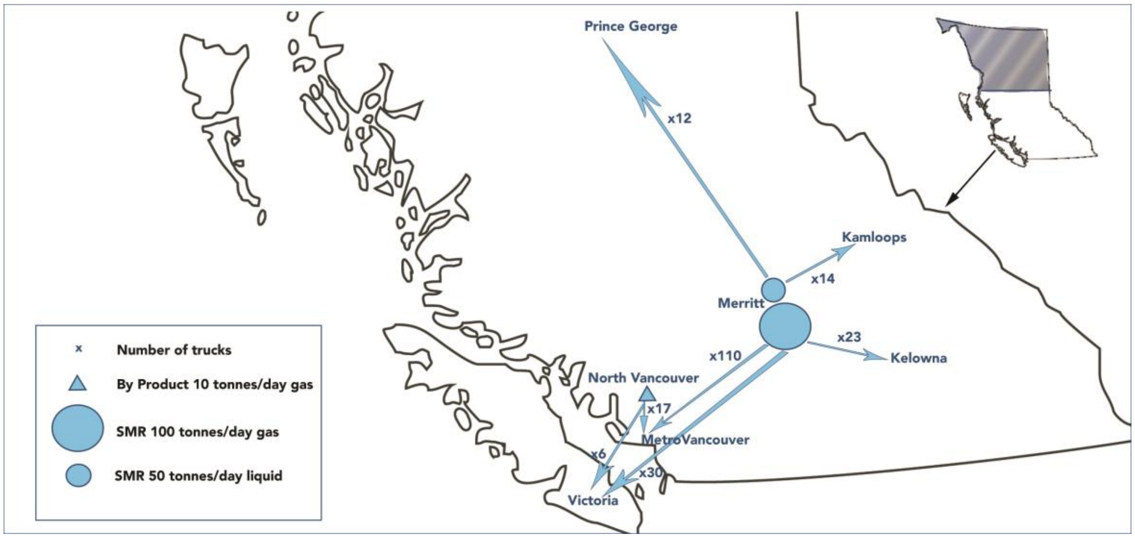


Figure 5.2. Contribution of different fueling station capacities (150, 500, 1000, and 1500 kg/day) to the total number of stations for three demand scenarios over time. Station types: O: on-site production, G: gas delivery, L: liquid delivery (no policy inclusion).

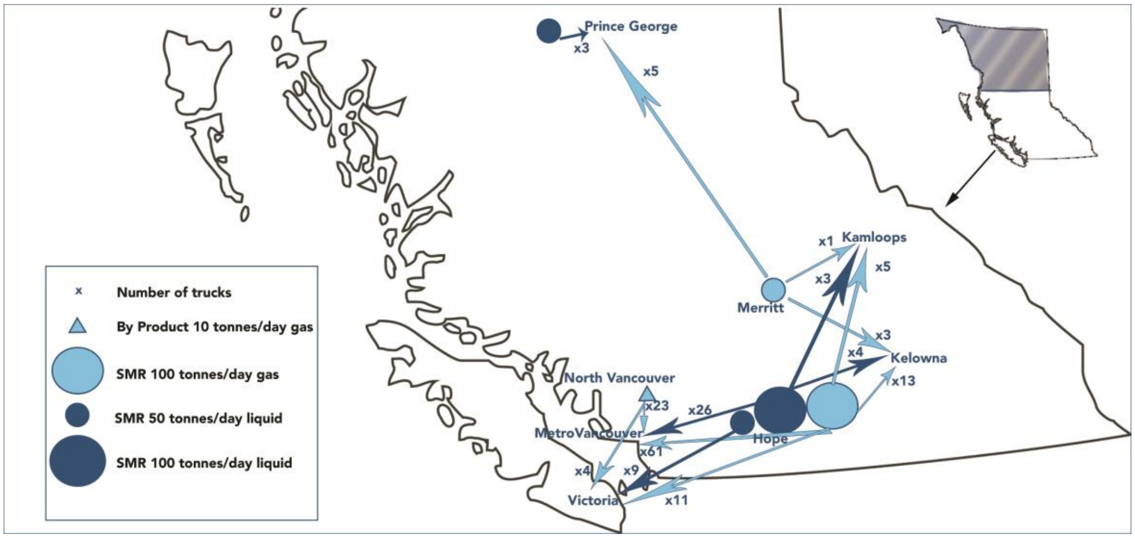
Figure 5.3 (a) to (c) show the optimal geographical distribution of production facilities and the transportation network in B.C. The central storage facilities are attached to the production units. Figure 5.4 (a) to (c) shows the fueling station network for the Metro Vancouver municipalities. These maps illustrate the last time step (2050) of the pessimistic (a), moderate (b) and optimistic (c) scenarios for the base case.



(a)

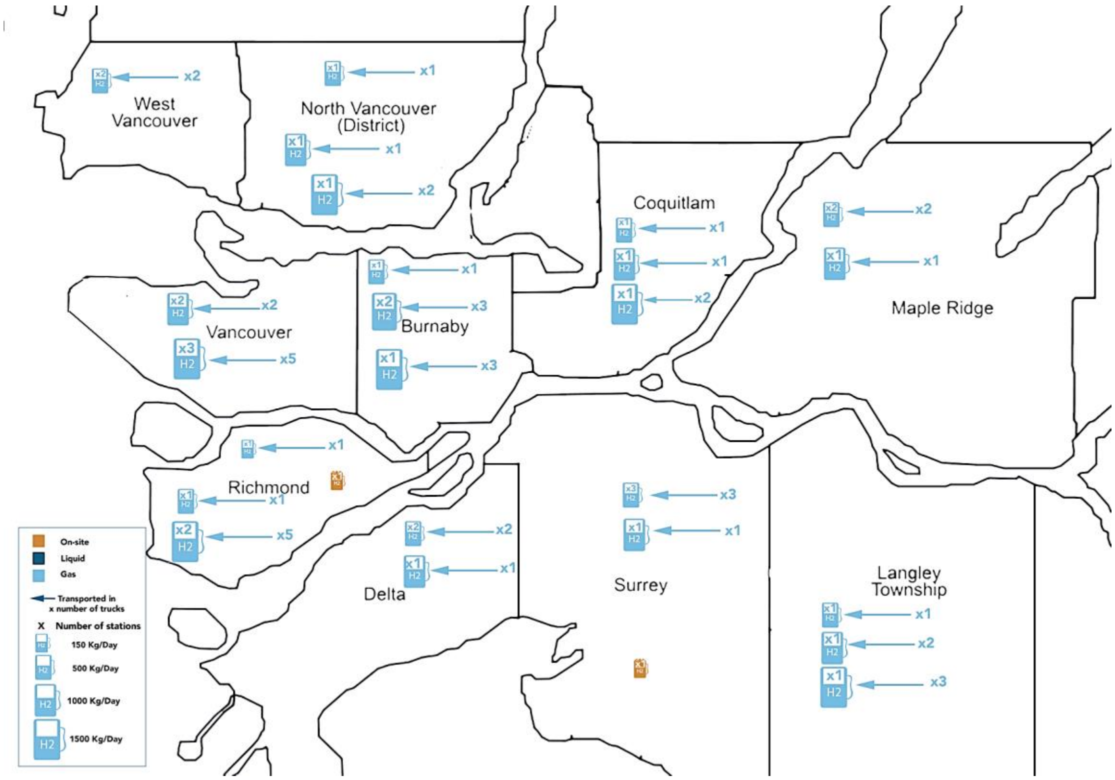


(b)

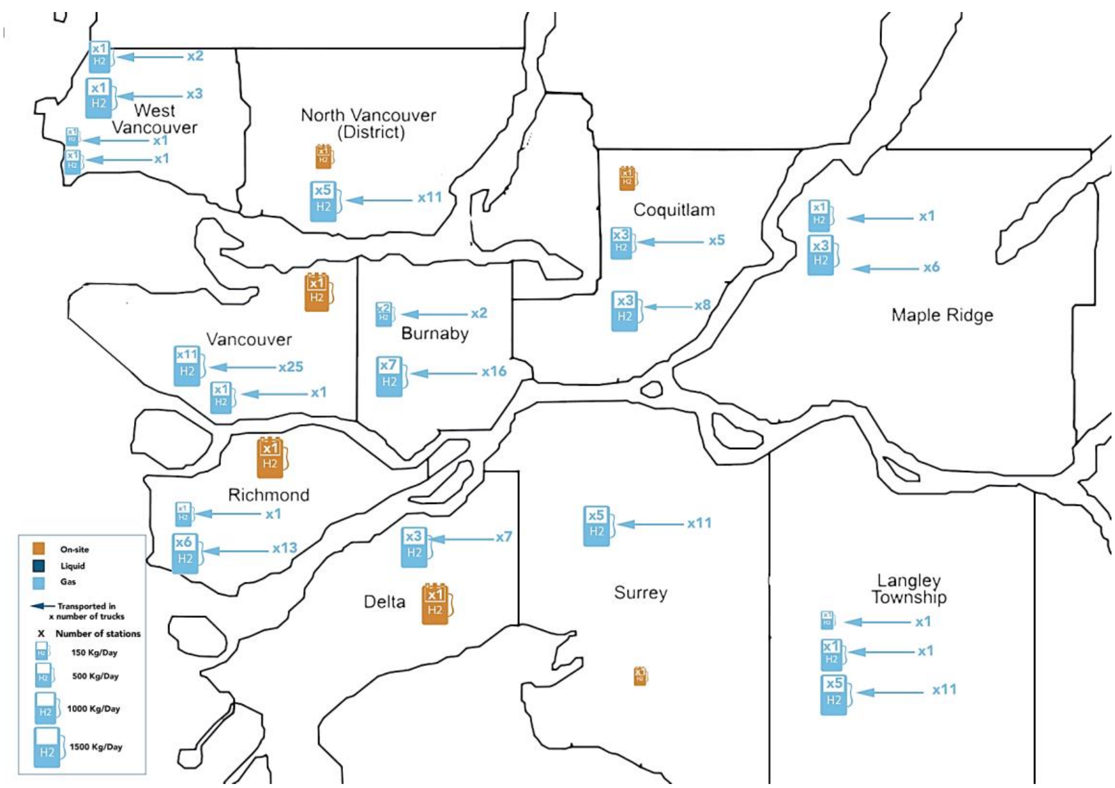


(c)

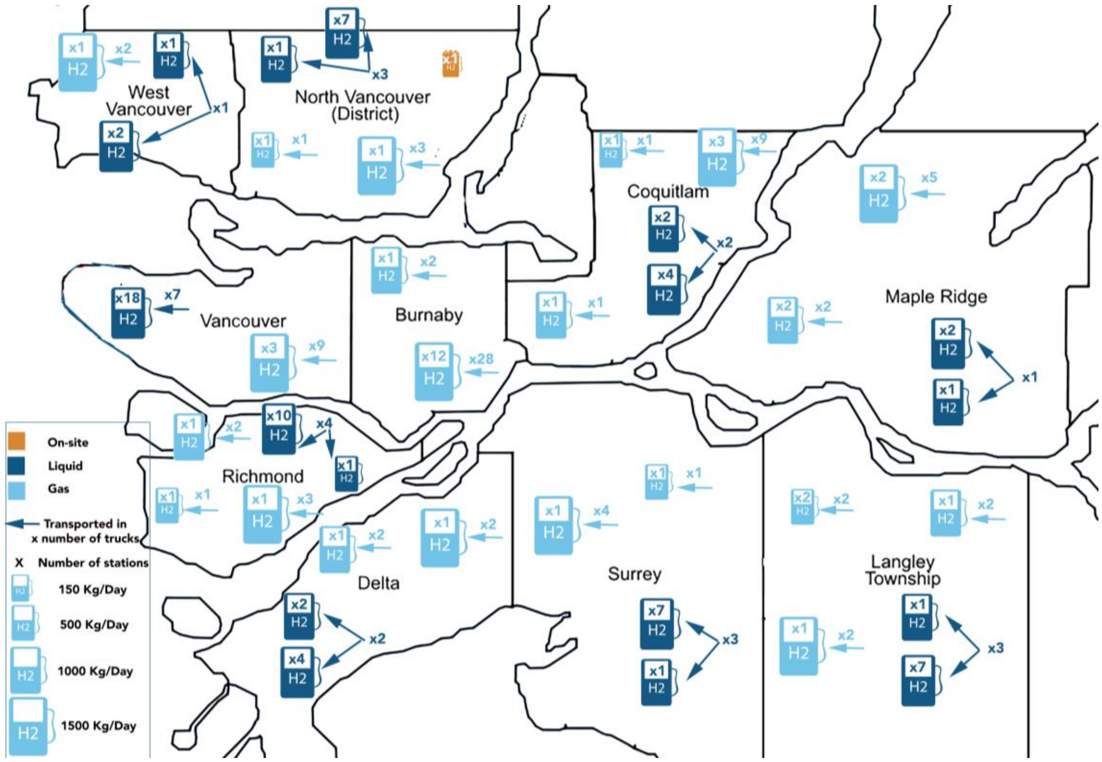
Figure 5.3. Optimal distribution of production facilities and transportation network in B.C. for (a) pessimistic (b) moderate (c) optimistic demand scenarios in time step 2045-2050 (no policy inclusion).


West Vancouver
North Vancouver (District)
Coquitlam
Maple Ridge
Vancouver
Burnaby
Richmond
Delta
Surrey
Langley Township
On-site
Liquid
Gas
Transported in x number of trucks
X Number of stations
150 Kg/Day
500 Kg/Day
1000 Kg/Day
1500 Kg/Day

(a)


West Vancouver
North Vancouver (District)
Coquitlam
Maple Ridge
Vancouver
Burnaby
Richmond
Delta
Surrey
Langley Township
On-site
Liquid
Gas
Transported in x number of trucks
X Number of stations
150 Kg/Day
500 Kg/Day
1000 Kg/Day
1500 Kg/Day

(b)



(c)

Figure 5.4. Optimal distribution of hydrogen fueling stations in Metro Vancouver for (a) pessimistic (b) moderate (c) optimistic demand scenarios in time step 2045-2050 (no policy inclusion).

In contrast to previous studies, various capacity options of the transportation network and fueling stations were incorporated into the model. As shown in Table 5.2, a fixed capacity delivers a suboptimal cost of the HFSC. The impact of assuming a fixed capacity was the largest in the pessimistic scenario (21%), while it was smaller for the moderate (13%) and the optimistic scenarios (6%). The assumption of a fixed capacity increased the chance of facility underutilization and decreased the cost advantage of economies of scale. The total cost of the supply chain was more susceptible to this extra cost at low demand.

Table 5.2. Effect of capacity alternatives on the total discounted cost of the HFSC for three demand scenarios.

		Demand scenario		
		Pessimistic	Moderate	Optimistic
Multiple capacities	Total discounted cost of HFSC (C$ million)	260.1	572.6	875.3
Fixed capacity		315.1	647.9	930.4

Multiple capacities: transportation capacities: gaseous: 100, 500, and 900 kg; liquid: 3800 kg. Fueling station capacities: 150, 500, 1000, and 1500 kg/day.
Fixed capacity: transportation capacity: gaseous: 180 kg, liquid: 3800 kg. Fueling station capacity: on-site production and gaseous delivery: 500 kg/day, liquid delivery: 1500 kg/day.
All values in Canadian dollars (2013).

5.2 HFSC configuration with current provincial policy inclusion

The low-carbon fuel standard (LCFS) and carbon tax are the environmental mandates that influence the evolution of the low-carbon fuel infrastructures by monetizing CO_2 emissions.

The HFSC optimization was performed for three cases in which carbon tax, BC-LCFS, and both policies were included in the model. Figure 5.5 shows the share of production technologies and the share of liquid hydrogen in policy-included cases alongside with the base case. In all cases, the share of SMR-based hydrogen production increased from the pessimistic to the optimistic scenario, which is mainly due to the decreasing share of by-product hydrogen and the on-site production. The decreasing share of by-product hydrogen is justified by the constant maximum capacity of the purification plant at the district of North Vancouver. The decreasing share of on-site electrolysis is associated with the dominant effect of economies of scale in reducing the cost of central production over the on-site production, which avoids the transportation cost.

The inclusion of the LCFS in the base case decreased the share of SMR technology in favor of on-site production by 1% for the pessimistic scenario and around 2% for the moderate and optimistic scenario. This technology shift shows that the higher investment cost of electrolyzers was justified by the extra revenues from the avoided GHG emissions. A slightly greater technology shift was observed when the carbon tax was included in the base case for pessimistic and moderate scenarios. However, as the demand grew (i.e., pessimistic to optimistic scenario), the transition toward low-carbon investments became more expensive than the base cost of carbon pricing. When the BC-LCFS was layered in addition to the carbon tax, the share of SMR technology was reduced in favor of on-site electrolysis for all demand scenarios. Thus, coupling the LCFS with the carbon tax was effective in encouraging providers to avoid taxes by directing the LCFS's revenues toward establishment of lower-emissions technologies.

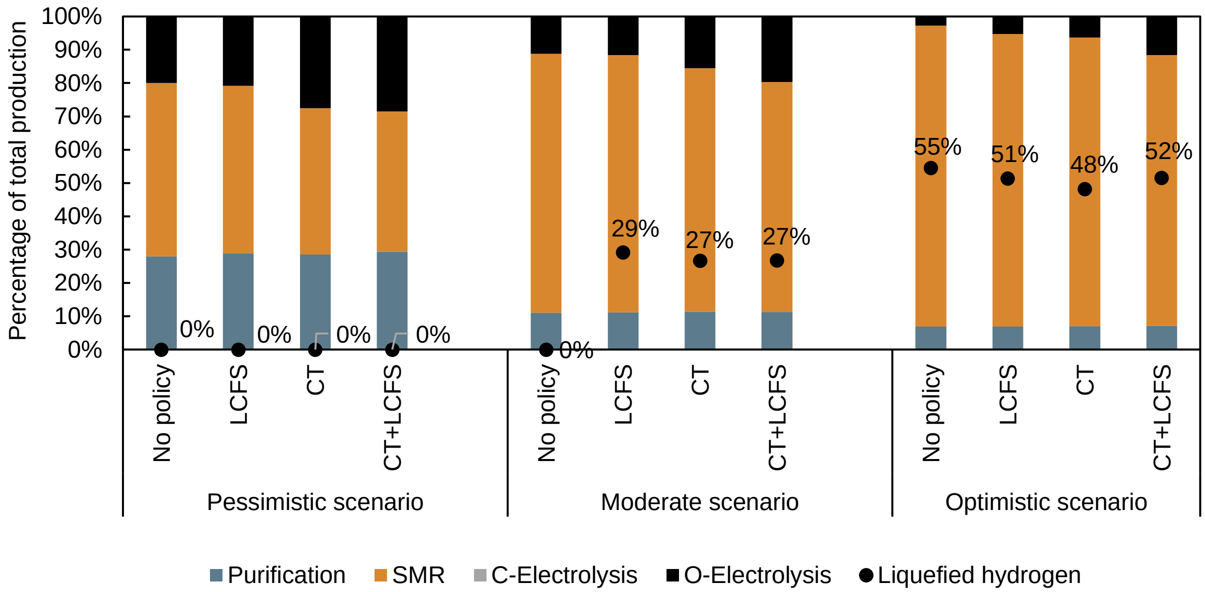


Figure 5.5. Contribution of different technologies to total hydrogen production and the share of liquefied hydrogen for three demand scenarios and policy inclusions (no policy: base case, LCFS: low-carbon fuel standard, CT: carbon tax, C-electrolysis: Central electrolysis, O-electrolysis: On-site electrolysis).

Figure 5.5 shows that in cases that included policy, liquid hydrogen delivery was required in the moderate scenario. The demand in the moderate scenario was sufficiently large in some regions to support the liquid delivery. Liquid delivery has a lower GHG emissions footprint than gas delivery, as fewer trucks are needed to transport the same amount of hydrogen but has cost as a barrier. When the policies were added to the base case, the liquefaction cost was justified by less CO_2 avoidance cost and higher revenue from LCFS. Higher demand in the optimistic scenario made the liquefaction affordable in the base case and even more attractive in policy-included cases compared to the moderate scenario. It should be noted that the percentage of liquefied hydrogen to the total production (as presented in Figure 5.5) was also affected by the variation of on-site production, which was not paired with liquefaction.

5.3 Economic and environmental evaluation of the hydrogen supply chain

The post-optimization cash flow analysis (section 4.5) was performed with a real IRR of 10%. The resulting average hydrogen price was C$12 per kg in the pessimistic scenario, while it decreased to C$9 per kg and C$8/kg in the moderate and optimistic scenarios, respectively. While similar demand gaps existed between the three scenarios (Figure 3.10), the effect of demand growth on the hydrogen price was less noticeable in a moderate-to-optimistic transition compared to a pessimistic-to-moderate transition.

The key question is whether the hydrogen fueling infrastructure is economically and environmentally competitive with its gasoline counterpart. For the economic comparison, the difference between the discounted revenue of hydrogen and gasoline infrastructure in a 30-year time frame was compared for the same vehicle stock and an IRR of 10%. The revenue of the gasoline infrastructure was calculated based on the fuel efficiency of the gasoline vehicles, mileage, number of vehicles, and the gasoline price. The trajectory of gasoline price was adopted from the National energy Board [10] as the average projected price of various scenarios presented for British Columbia. The sales tax and excise tax were not considered for hydrogen at the point of sale except for carbon tax in the corresponding scenario. For the environmental comparison, the annual WTW GHG emissions avoidance was calculated from section 4.6. The reduction in GHG emissions was monetized by adopting the social cost of carbon (SCC) for the 2020–2050 time-frame with the 3% social discount rate, as recommended by the Canada Treasury Board Secretariat's Analysis Guide [126].

As Figure 5.6 shows, for a 30-year time frame, the discounted revenue of an HFSC was less than the gasoline supply chain by C$22 million in the pessimistic scenario. However, the extra investment was justified by the avoided GHG emissions, at a discounted value of C$80 million. For moderate and optimistic scenarios, higher demand drove the hydrogen price below that of gasoline (1 kg hydrogen replaces 8 liters of gasoline). Thus, more emissions avoidance benefits are expected at the lower discounted total cost for HFSC compared to the gasoline counterpart.

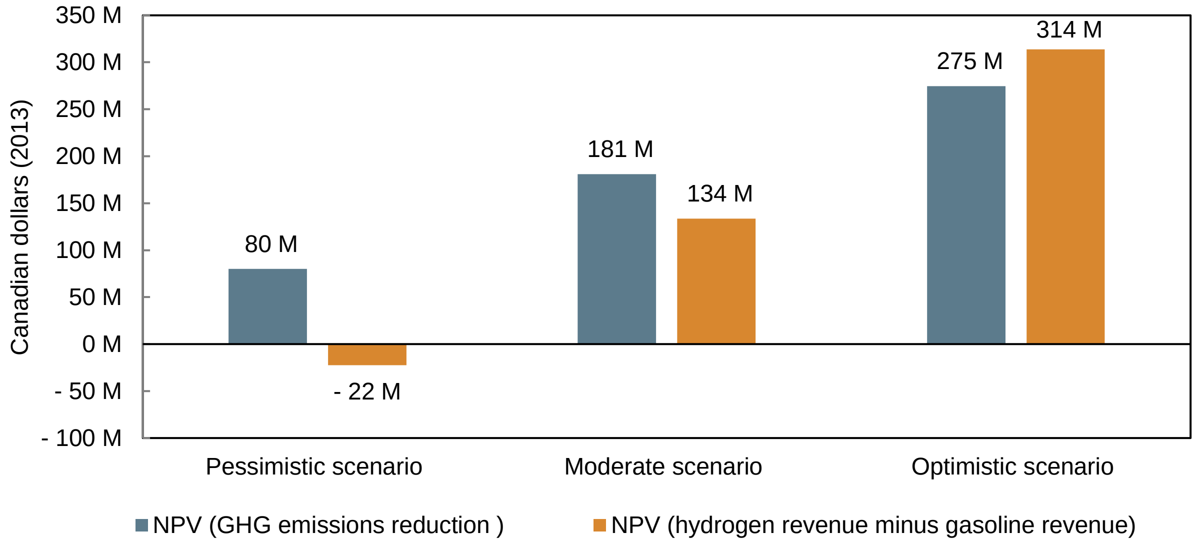


Figure 5.6. Environmental and economic comparison of hydrogen and gasoline infrastructure in the base case (no environmental policy is included) for three demand scenarios: net present value (NPV) of the reduced GHG emissions (IRR = 3%) versus the difference between the NPV of revenues (IRR = 10%).

The addition of carbon tax and LCFS affected the hydrogen price and the avoided WTW GHG emissions as shown in Figure 5.7. The inclusion of carbon tax in the pessimistic increased GHG emissions reduction value, compared to the base case, while increasing the hydrogen price by C$0.48. The inclusion of LCFS in the base case generated extra revenues that decreased the hydrogen final price. However, a negligible contribution was observed to the emissions reduction. In other words, the LCFS revenue from the lower-emissions pathways could not pay off the cost of adoption. The LCFS had a stronger additive impact on emissions reduction when implemented with carbon tax and sets the hydrogen price below the carbon tax and above the LCFS-only cases for all demand scenarios.

It is observed that the environmental policy inclusion became less effective at higher demand scenarios. This shows that the increasing credits from LCFS and the growing fees from the carbon tax cannot keep up with the growing cost of investment in lower-emissions pathways.

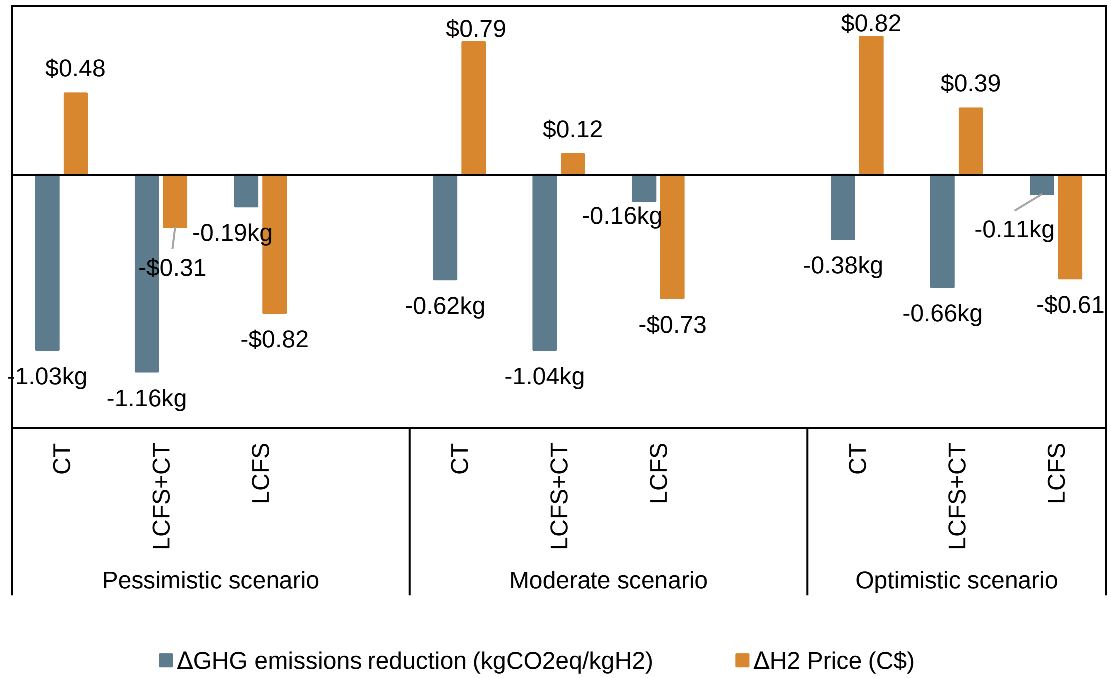


Figure 5.7. Effect of environmental policies on the GHG emissions and the hydrogen price compared to the no policy case for three demand scenarios: CT: carbon tax (C$45 to C$75 from 2020 to 2050), LCFS: low-carbon fuel standard (C$167 to C$0 from 2020 to 2050). All values in Canadian dollars (2013).

5.4 Effect of complementary policies in low-carbon hydrogen production

The results in section 5.3 showed that the combination of LCFS and carbon tax (LCFS+CT case) is a suitable option when hydrogen price and emissions reduction is equally important. The costs and revenues associated with these policies increased the contribution of the on-site electrolysis, which decreased the GHG emissions from this supply chain. However, the stringency of those policies was not sufficient to support large-scale low-carbon hydrogen production technologies (central electrolysis or CCS) for the considered demand scenarios. In this section, a set of potential economic instruments (explained in section 3.5.2), was layered on top of the LCFS+CT case. The aim was to measure effectiveness of these instruments to boost low-carbon hydrogen production in a cost optimal HFSC.

5.4.1 Optimal share of production technologies

Figure 5.8 compares the cost optimal share of production technologies for the LCFS+CT case alongside the complementary policy included cases in three hydrogen demand scenarios. The percentages represent the cumulative share of each technology over the time period of 2020-2050. All potential policies enhanced the production share of on-site electrolysis; however, not all policies provided enough support to make the central electrolysis affordable. Moreover, all the complementary policies failed to financially justify CCS adoption in the SMR-production pathway.

In the optimistic scenario, the 100% electricity rate subsidy (EC_100%) eliminated the SMR production in favor of central electrolysis. In pessimistic and moderate demand scenarios, similar technology shift was also achieved through the stepwise utility incentives with a 10-year delay (EC_Delay). This is mainly due to the larger portion of the demand that was fulfilled by the purified by-product hydrogen (compared to the optimistic scenario). The expiration of utility subsidies in the last two time steps in the EC_Step case, and the small subsidy size in the EC_25% case prevented the integration of central electrolysis in the HFSC. Thus, the size and duration of the utility subsidy are financially crucial for the technology shift.

The production tax credit at the constant rate of 2$/kg H2 (PTC_$2) resulted in similar share of production technologies as 100% electricity rate subsidy (EC_100%). A stepwise PTC, with a 10-year delay (PTC_Delay), eliminated the viability of SMR production in favor of water electrolysis in all demand scenarios. The inclusion of all PTC schemes in pessimistic scenario resulted in complete independency from SMR production; however, higher demand scenarios were still reliant on SMR in PTC_$1 and PTC_Step cases.

It was observed that different schemes of capital subsidy increased the share of on-site hydrogen production, however, they failed to justify central electrolysis, except for the Grant_100% in the optimistic scenario. In all demand scenarios, SMR was found to be the dominant technology, even with the extensive capital subsidy allocation for low-carbon hydrogen production.

In the LCFS+CT case, the carbon tax grew annually by C$1.02 per tonne. In CT_2X case, the annual tax growth was set at C$2.04 per tonne, which resulted in larger share of onsite electrolysis in all demand scenarios; however, no contribution was observed from central electrolysis nor CCS. By increasing the annual tax growth to C$4.08 per tonne (CT_4X), SMR production was eliminated from the supply chain in the pessimistic scenario. However, in moderate and optimistic scenarios, the contribution of central electrolysis was small and SMR remained the dominant hydrogen production technology.

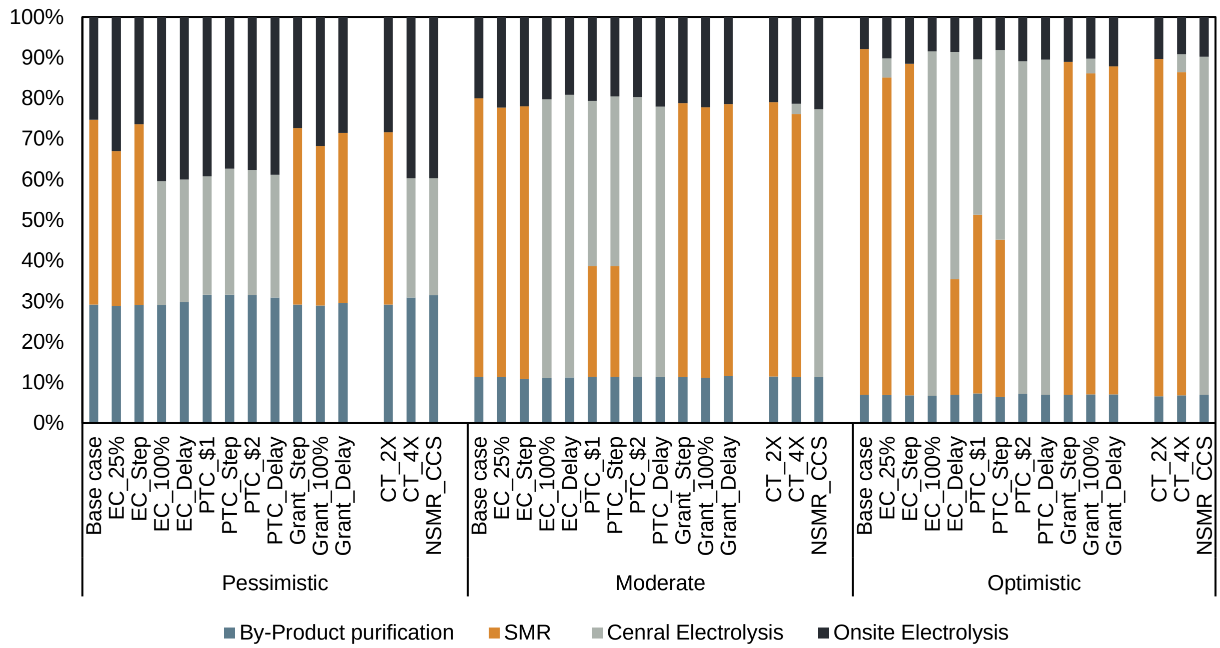


Figure 5.8. Contribution of production technologies in a cost optimal hydrogen fuel supply chain for the base case (LCFS+CT) and the potential policy included cases in three demand scenarios

Figure 5.8 shows the effect of an SMR production ban (without CCS integration) on the configuration of the cost optimal production technologies (NSMR_CCS). In all demand scenarios the production was shared between by-product hydrogen purification and electrolysis with no contribution from SMR with CCS integration.

It should be noted that the geological formations suitable for CO_2 storage are located at Northeast B.C. Hydrogen transport via trucks and tube tankers to the demand regions which are largely located in the South West of B.C. (more than1200 km distance) may become cost restrictive. The low hydrogen demand in this study did not justify the pipeline transport [25].

5.4.2 Efficiency assessment of complementary policies

It was observed that the contribution of low-carbon production technologies was directly affected by the timing and stringency of the policy schemes. However, a cost-benefit analysis is required to measure the efficiency of environmental policies in each demand scenario.

Table 5.3 compares the average hydrogen price and the GHG emissions reduction per unit of hydrogen production for three demand scenarios in the base case (LCFS+CT). The emissions reductions were calculated by replacing ICEVs with FCEVs on the well to wheels basis, divided by the total hydrogen production over a 30-year time frame.

The subsidy mechanisms were expected to decrease hydrogen price and GHG emissions from the base case. The subsidy effectiveness was defined in terms of three effectiveness indicators:

- Hydrogen price change per unit of subsidy cost. This indicator measures the effectiveness of every unit of subsidy.
- GHG emissions reduction per unit of subsidy cost. This indicator measures the effectiveness of every unit of subsidy.
- GHG emissions reduction per unit of hydrogen produced. This indicator measures the effectiveness of the full size of subsidy to shift the production technology.

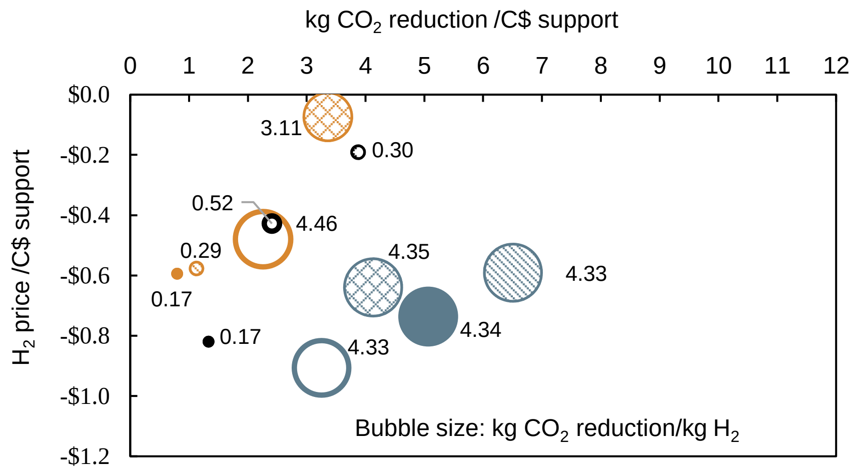
In this study, the effectiveness of each policy was presented with respect to each effectiveness indicator (Figure 5.9). The relative importance of each indicator will depend on local, regional, national or sectorial goals and priorities.

Table 5.3. Average hydrogen price and GHG emissions reduction per unit of hydrogen production over 30-year time frame for the base case (LCFS+CT)[1]

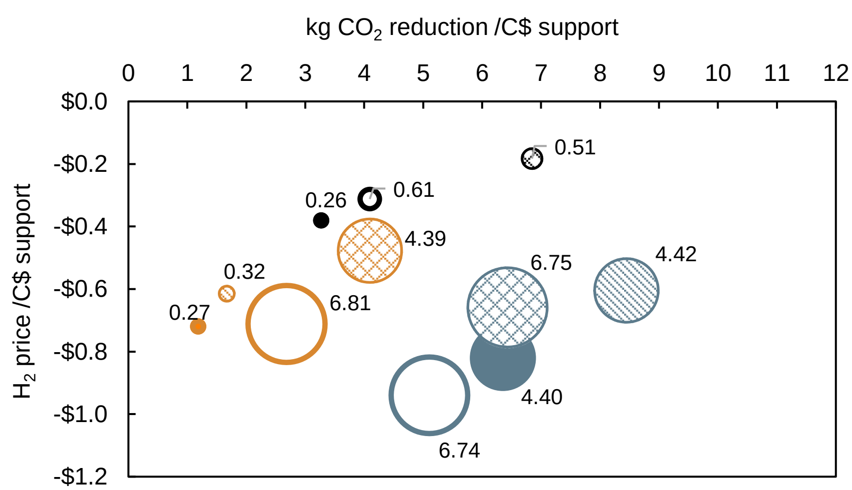
Demand scenario	H_2 Price (C$/kg)	WTW GHG emissions reduction ($kg\ CO_2eq/kg\ H_2$)
Pessimistic	11.22	14.77
Moderate	8.59	11.84
Optimistic	8.12	9.97

[1] A discrepancy between the numbers in Table 5.3 and Figure 5.7 is due to the aggregation of demand regions for Metro-Vancouver area (from 10 regions to 5) to improve the optimization speed.

Figure 5.9 shows that every unit of subsidies was more effective in GHG emissions reduction as the demand grew from pessimistic to optimistic scenario. This is consistent with the growing share of low-carbon hydrogen production in larger demand scenarios (bubble size in Figure 5.9). It was also observed that for production tax credit (PTC) and utility incentives, the effectiveness of subsidies in hydrogen price reduction improved from pessimistic to optimistic scenarios. However, capital subsidies resulted in smaller hydrogen price decline in larger demand scenarios. This is partly attributed to the economies of scale and learning by doing which weakens the effect of grants compared to the operational-based incentives.



(a)



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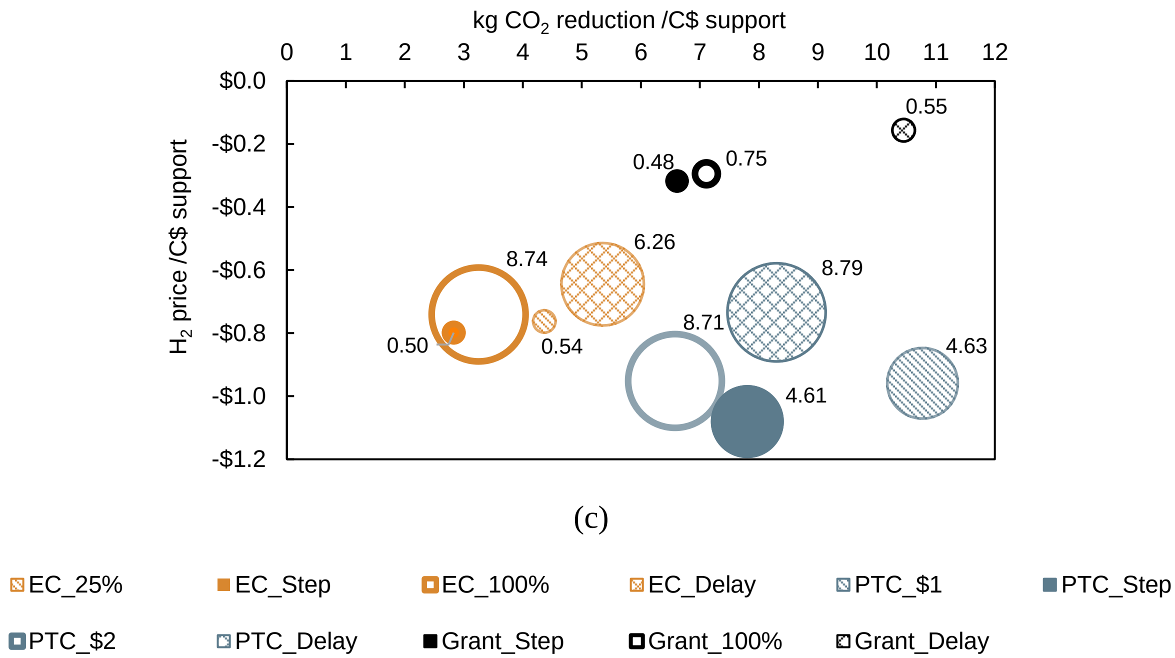


(c)

Figure 5.9. Policy efficiency assessment with respect to hydrogen price decrease and GHG emissions reduction compared to the base case: (a) pessimistic (b) moderate (c) optimistic demand scenarios

The results show that PTC in general is the most promising policy when all three efficiency factors are equally taken into consideration. This is in part a result of credit generation potential from by-product hydrogen purification, which was not the case for other policy schemes.

PTC_$1 resulted in the largest GHG emissions reduction per unit of subsidy in all demand scenarios. In the pessimistic scenario, the effect of this policy on the total emissions reduction was similar to the more cost intensive PTC schemes (Table 5.3). However, a smaller contribution was observed in hydrogen price reduction. This result shows that the low capacity of production infrastructure restricted the utilization of tax credits in favor of technology shift in pessimistic scenario. Thus, as the size of subsidy grows, the hydrogen price decreases without more investment in low-carbon hydrogen production. In moderate and optimistic scenarios, deploying PTC_$1 resulted in similar total GHG emissions reduction as PTC_Step. This shows that the duration of PTC_1$ over the last two time steps, offsets its smaller size with respect to emissions reduction.

Table 5.4 shows that the subsidy size of PTC_Delay was smaller than PTC_$2. However, larger emissions reduction was observed due to the production capacity limit.

The EC_100% resulted in a slightly higher GHG emissions reduction than PTC_$2 in all demand scenarios. However, PTC_2$ had a higher per unit effectiveness in hydrogen price and emissions reduction with a noticeably smaller subsidy size (Table 5.4). In all demand scenarios, the EC_Delay corresponds to the highest and the lowest per unit effectiveness in GHG emissions and hydrogen price reduction, respectively, compared to the other electricity incentive schemes. The per unit contribution of EC_25% and EC_Step in hydrogen price reduction is very close or even larger than EC_100%. However, the small size of these policies failed to justify a noticeable technology switch. The capital subsidy had a competitive per unit effectiveness in emissions reduction with other policies. However, the small contribution in total emissions reduction indicates that the capital expenditure is not as restrictive as the operational costs.

Table 5.4. Net present value of the total cost of subsidies in each demand scenario (all values in Millions C$2013)

	Policy case										
Demand scenario	PTC_$1	PTC_Step	PTC_$2	PTC_Delay	EC_25%	EC_Step	EC_100%	EC_Delay	Grant_Step	Grant_100%	Grant_Delay
Pessimistic	12.0	15.4	24.0	18.9	3.8	4.0	34.6	16.2	2.4	4.0	1.4
Moderate	28.6	37.9	72.4	57.0	10.3	12.2	138.0	58.4	4.4	8.1	4.1
Optimistic	40.3	55.4	124.4	98.5	11.6	16.4	251.2	109.1	6.7	9.8	4.9

Figure 5.10 compares the hydrogen price increase and the GHG emissions reduction for the cases with higher carbon tax compared with the base case. The hydrogen price and emissions reduction were compared to banning SMR production without the CCS adoption (NSMR_CCS). Moreover, the aforementioned policy schemes were compared with the case which SMR with CCS is the only central production option alongside by-product hydrogen purification (NELEC_CCS). It should be noted that the CCS option was never selected by the optimization model in this study. Hence, NELEC_CCS was introduced to assess the extent of extra cost and the emission reduction contribution, upon its potential adoption.

Higher tax rates or a restriction on the type of production technology increased the hydrogen price compared to the base case. The price difference could be subsidized to consumers at the point of hydrogen sale. Higher carbon tax rates improved the total GHG emissions reduction as well as the ratio of emissions reduction to the price increase, in all demand scenarios. In other words, it was less expensive to reduce a unit of emissions at a higher tax rate. From pessimistic to optimistic demand scenario, the emissions reduction became more expensive. Accordingly, the lower cost of emissions reduction was obtained by imposing higher carbon tax (CT_4X) on the lower demand scenario.

As Figure 5.10 shows, the case which bans SMR production without CCS integration (NSMR_CCS) contributed to the largest GHG emissions reduction per unit of hydrogen, compared to other policy cases. The emissions reduction benefit increased from pessimistic to optimistic demand scenario, and larger gap was observed between the hydrogen price increase and the emissions reduction. Thus, NSMR_CCS is more effective in emissions reduction and price control at higher demand scenarios.

NELEC_CCS required the largest amount of subsidy to keep the end-user price of hydrogen at the base case level. Moreover, the emissions reduction level was considerably lower than the NSMR_CCS case. Thus, the cost optimal HFSC based on electrolytic hydrogen (NSMR_CCS) was both economically and environmentally more beneficial than relying on carbon capture and sequestration in British Columbia.

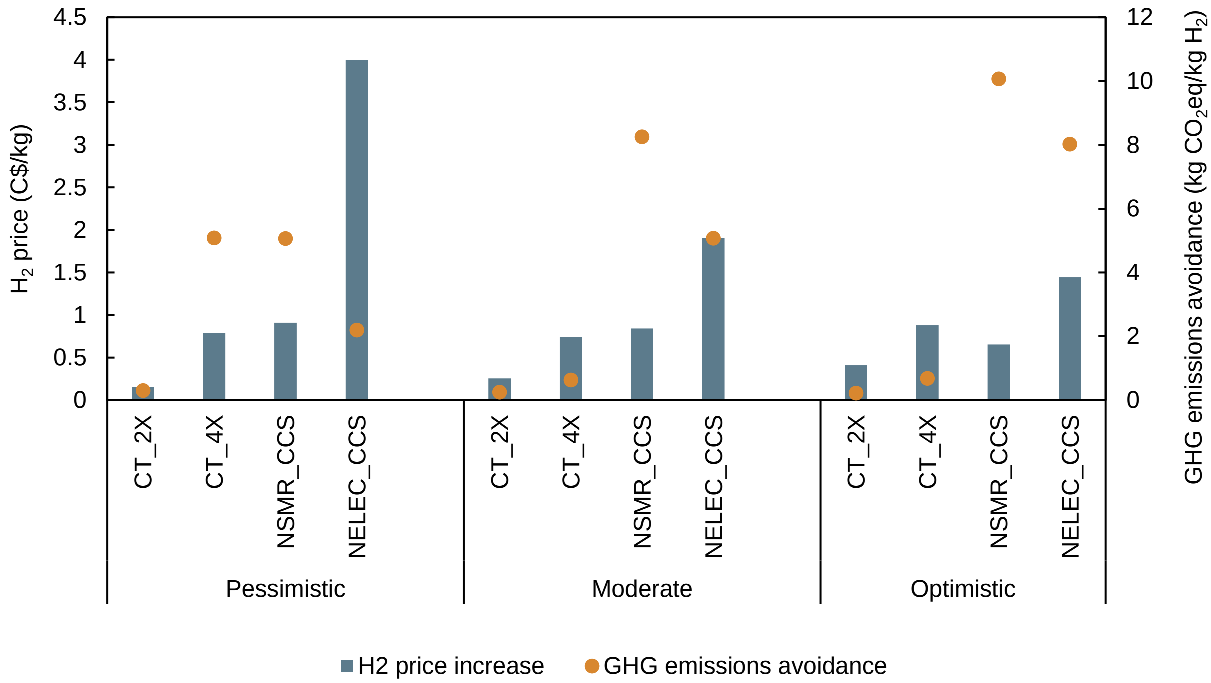
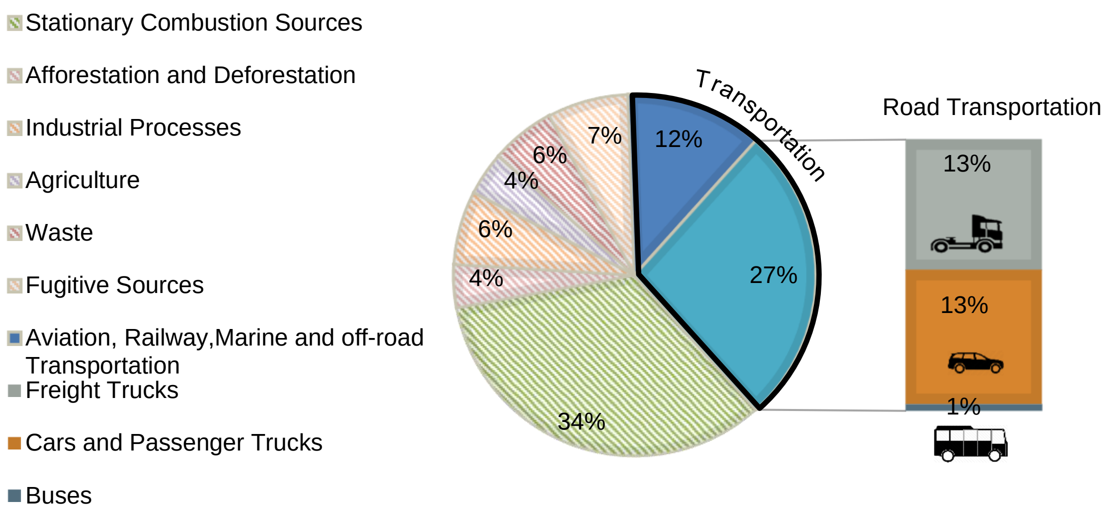


Figure 5.10. Hydrogen price increase and the GHG emissions reduction for the potential policy included cases compared to the base case (LCFS+CT). The base case values are presented in Table 5.4.

Chapter 6: Challenges and Potentials in the Heavy-duty Transport Sector

The 2016 data in B.C. shows that trucking industry had a similar contribution in GHG emissions as the light duty vehicles with a round 6% GHG emissions increase from 2007 [172]. Freight trucks are also significant sources of criteria air contaminants (CAC), like Particulate Matter (PM 10, PM 2.5), Nitrogen Oxides (NOx), Carbon Monoxide (CO) Sulphur Oxides (SOx) and Volatile Organic Compounds (VOC), which adversely affect air quality and human health.



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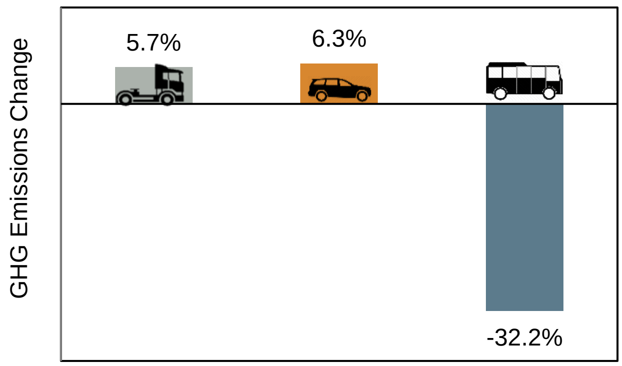


(b)

Figure 6.1. 2016 GHG emissions in B.C.: (a) GHG emissions by sector (b) GHG emissions from road transport: change from 2007

The total WTW GHG emissions of freight trucks was around 8 $MtCO_2eq$ in 2016, and the per capita Gross Domestic Product (GDP) is projected to grow in B.C. by 20% in the next 20 years [10]. Due to the direct correlation between the number of freight trucks and GDP, it may be difficult to reduce emissions in this sector while simultaneously ensuring economic growth [173].

6.1 Approaches to reduce GHG emissions from the trucking sector

Several options are suggested for reducing GHG emissions from freight trucks. The non-technical options consider the efficiency improvement of freight logistics such as load-matching and maximizing capacity, a modal shift to more energy-efficient means of transportation (e.g., rail) and the standardization of logistics-related facilities and equipment [174]. The technical improvements deal with the efficiency of internal combustion engine (ICE) trucks. In 2013, Canada began regulating on-road GHG emissions from ICE freight trucks with Gross Vehicle Weight Rating (GVWR) above 3856 kg. Under the Canadian Environmental Protection Act, two phases of regulations have been proposed for the deployment of advanced cost-effective technologies to increase the fuel efficiency and GHG emissions standards for new freight trucks. The first phase applies to 2014 and newer model vehicles, which reach full stringency with model year 2018 [175]. The second phase is built upon the first phase and reach full stringency with model year 2027 [176]. It is projected that the full deployment of this legislation will decrease the GHG emissions by 15-50% from freight trucks with model year 2027 compared to the 2010 counterparts depending on the vehicle's duty cycle.

While the legislation targets the fuel efficiency of conventional gasoline or diesel trucks, some attempts have been focused on alternative fuels. The deep-carbon reduction scenarios for road freight transport often rely on significant amounts of biofuels. The B.C. Low Carbon Fuels Regulations states that by 2020 the life-cycle GHG intensity of all transportation fuels must be reduced by 10% from 2013 levels [122]. This requirement is expected to be met using first generation biofuels in the fuel blends, ethanol from corn and grain, and biodiesel from canola. Ethanol and biodiesel are already being blended into refined petroleum fuels in B.C. and the blending percentage is rising steadily. The Ethanol content increased in the gasoline pool from 5% in 2010 to 6.3% in 2014, and the biodiesel blend reached 5.6% in 2014 [177]. One of the important challenges associated with biofuels is the indirect land use change, which can result in additional

GHG emissions and raises concerns around food security and biodiversity maintenance [178]. Moreover, the amount of sustainable biofuels which will be available beyond 2020 is uncertain [179]. Given the uncertainties and difficulties with biofuels, this option is not likely to result in significant GHG emissions reductions of road freight transport required by 2050 in B.C. [180]. The non-renewable low-carbon fuels such as CNG, LNG and propane are now being considered as transition fuels that could serve as cost-competitive, near-term solutions. The greenhouse gas reduction regulation under the Clean Energy Act offers incentives to diversify and grow the market for natural gas in B.C.'s transportation sector [181]. The incentives target medium- and heavy-duty trucks switching from diesel to natural gas, and decrease the fuel costs on a per kilometer basis [182]. Natural gas trucks can reduce tailpipe greenhouse gas emissions by as much as 20% over gasoline or diesel trucks [183]. However, climate benefits of natural gas heavily depend on the lifecycle emissions of methane [184], [185]. The hydrogen enriched natural gas (HCNG) engine is another promising technology to enhance fuel economy and decrease emissions compared with CNG counterparts. However, implementing the perfect methane/hydrogen mixture with the current CNG infrastructure and on-board storage are the major challenges facing the adaptation of this technology. Moreover, mitigating the NOx increase as a result of hydrogen enrichment is challenging and needs to be addressed effectively [186].

The large-scale GHG emissions reduction in B.C. requires that the long-term fuel portfolio shifts toward renewable or carbon-neutral fuels. The electrification of road transportation offers zero-tailpipe emission potential. Electrification could result in the large-scale GHG emissions reduction if the energy carrier is generated from renewable resources or the production facilities are equipped with carbon capturing technologies. All-Electric vehicles are classified into battery electric vehicles (BEVs) and fuel cell electric vehicles (FCEVs). To date, electrification has primarily targeted the passenger vehicle market. Commercial all-electric heavy-duty vehicles are limited to urban delivery trucks and buses at the moment [187]–[194].

The BEVs use electricity sourced from the electrical grid to recharge on-board batteries. Current battery electric trucks, using lithium-ion batteries, have a range of 150-400 km, depending on the mass of the battery. These trucks are being developed worldwide for daily based travel on defined routes with low average speeds, high idle times and high frequency of stops and starts [187], [188]. This duty-cycle makes the overnight stationary charging and battery swapping suitable for shorthaul battery electric trucks. There are a number of demonstration projects for battery electric semi-tractors that target captive truck fleets within the companies' distribution network [191], [192]. For long-haul applications, the low energy density of batteries is a barrier, as significant weight and volumes are required to address the short vehicle range and long recharging times. Even if the energy density is improved by factors of 5-10, the weight increase of a 40 tonnes GVWR truck would be approximately 2 -4 tonnes [188]. Moreover, an overnight plug-in charging unit of 19 kW can regenerate the 200 kWh battery within 10-hour, which is far beyond the acceptable idle times for long-haul trucks. To make the charging time compatible with the refueling time of a conventional truck (less than 30 minutes), a 400 kW DC charger and upgrades to the transmission network would be required. However, battery electric long-haul trucks are still part of long-term vehicle portfolio when combined with on-the-road charging technology, e.g., overhead catenary wires or dynamic inductive charging [188].

Unlike BEVs, FCEVs are comparable to conventional ICE vehicles in terms of range and fueling time. The toxicity and fire hazard properties of hydrogen rank it as the safest fuel with a safety factor of 1, while the safety factors of methane and gasoline are 0.8 and 0.53, respectively [195]. Fuel cell technology has been deployed with fuel cell buses [190] and it has successfully penetrated the forklift market [196]. Demonstrations for fuel cell trucks such as package delivery vans and semi-tractors used in refuse or drayage service are in early stages [193], [194], [197] Fuel cell durability and the volume and weight of the onboard hydrogen storage are the key technical challenges to the adoption of Fuel cell technology in heavy-duty vehicles. Moreover, hydrogen fueling stations need to be distributed and available for heavy-duty fuel cell vehicles with suitable fueling protocols. The California Fuel Cell Partnership provided an Action Plan to support the implementation of fuel cell technology in medium-duty and heavy-duty trucks in California [198].

6.2 All-Electric trucking in B.C. by 2040: feasibility study

As discussed in chapter 1 and 3, B.C. has several competitive advantages including energy resources, technologies deployments, and policies to pursue opportunities in zero-emission powertrains. In this section, we examined the potential of all-electric freight trucks to achieve 64% GHG emissions reduction by 2040. To this end, the 2040 fuel-side WTW GHG emissions from B.C. trucking sector was projected for two scenarios; named as the business as usual (BAU) and the current legislation fulfillment (CLF). The BAU scenario considers no technology improvement in ICE trucks, while the CLF considers the full deployment of current legislation targeting freight transportation. The potential of battery electric and fuel cell trucks to meet the mid-term GHG emissions reduction targets for 2040 was investigated for both scenarios. Moreover, the total WTW energy requirement for all-electric trucking was quantified and the availability of different energy resources in B.C. to support zero emission trucking was assessed.

It should be mentioned that the analysis was based on GDP projections, and forecasts of electricity and natural gas production and demand in B.C. [10], which were available until 2040, at the time of the study. It was also assumed that the mid-term target for reducing GHG emissions from freight road transportation is 64% by 2040 from the level of 2007.

6.2.1 Freight trucks stock forecasting

The first step to project the GHG emissions from road freight transport is to project the stock of freight vehicles. Natural Resources Canada (NRCan) has classified the freight trucks to Light Duty (LD), Medium Duty (MD) and Heavy Duty (HD) based on the GVWR as shown in Table 6.1. For each truck class, the NRCan comprehensive energy use database for transportation sector in B.C. [9] provided the average vehicle use-intensity (kilometers traveled per vehicle annually), number of new vehicles and the vehicle stock from 2000 to 2014. These historical trends were used to project the stock of each truck class by 2040.

Table 6.1 Freight truck classification [9]

Truck Class	GVWR Category/kg	Class Range	Icon
Light Duty Truck (LDT)	≤ 3855	1-2	
Medium Duty Truck (MDT)	3856 to 14969	3-7	
Heavy Duty Truck (HDT)	≥ 14970	8	

The historical data on the freight vehicle use-intensity in B.C. (Figure 6.2 (a)) show that the average annual distance driven per vehicle has decreased between 28% and 46% over 14 years. As there are no projections available in the literature for B.C, the vehicle use-intensity was fitted with a quadratic polynomial regression with the minimum mileage value extending over the studied time frame. The quadratic regression provides a conservative projection for this study. Linear and exponential regressions produce near zero vehicle use-intensity for year 2030 onward which is unrealistic for a freight vehicle. Due to uncertainties associated with the projections, the maximum positive and negative deviation from the polynomial fit was selected to account for the uncertainty region of the study domain.

The number of new freight vehicles has been projected based on historic trends and the real GDP per capita [199]–[201]. For B.C., the annual increase rate of new trucks per real GDP per capita was calculated from the historic data on the number of new trucks and the real GDP per capita between years 2000 to 2014 [9]. As this historic annual increase rate did not follow a traceable path, the average increase rate ($\bar{X}$) is used for the projection. Having the average increase rate of new trucks and the projections on the real GDP per capita to 2040 [10], the new vehicles of each truck class ($NewT$) were projected to 2040 as follows:

$$\bar{X} = \frac{\sum_i^n \frac{NewT_{i+1} - NewT_i}{GDP_{i+1} - GDP_i}}{n - i} \tag{6.1}$$

$$NewT_k = \bar{X}(GDP_k - GDP_{k-1}) + NewT_{k-1}$$

$$i = 2000, n = 2013, N = 2040, k = n + 2, \dots, N$$

Figure 6.2 (b) shows that the number of new freight vehicles entering B.C.'s market will increase due to the projected increase in real GDP per capita in B.C. The model presented here was calibrated to historical data and compared to the projected number of new vehicles, where the average difference was used as the range of uncertainty for the new vehicle projection.

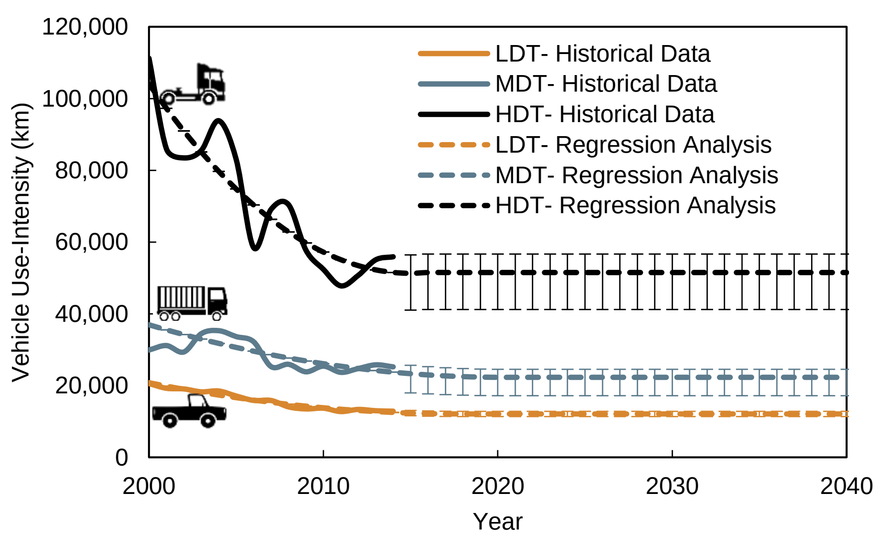
The stock of each truck class was projected using the average truck lifetime in B.C., either in years or total kilometers (Table 6.2), and the projections on the number of new trucks and the average vehicle use-intensity, as described in Equation 3.55.

Table 6.2. ICE truck characteristics [9]

ICE Trucks	Average Fuel efficiency (litre/100km)	Fuel type	Lifetime
LDT	11.7	Gasoline	300,000 km or 20 years
MDT	22,21.7	Gasoline, Diesel	450,000 km or 15 years
HDT	40	Diesel	900,000 km or 17 years

It is worth mentioning that there are several constraints for the future growth of freight movements, such as the congestion and capacity of road networks, sudden change in fuel prices and economic indicators and the availability of trucks and drivers. However, the analysis of those factors was beyond the scope of this study.

Figure 6.2 (c) shows that the stock of heavy-duty truck (HDT) grows by 100% in 2040 compared with 2014, while the growth of medium-duty (MDT) and light-duty trucks (LDT) is 34% and 42%, respectively. The uncertainties associated with the vehicle use-intensity was not reflected in the stock projections, as the vehicle lifetime constraint measured in years was met prior to the lifetime constraint measured in total distance travelled for all vehicle classes (Equation 3.55).



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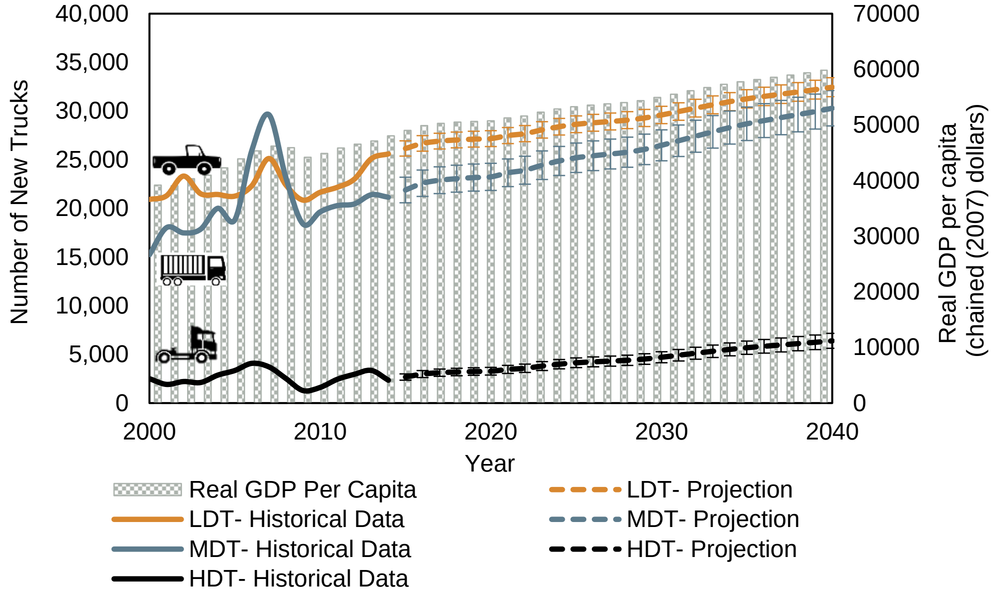

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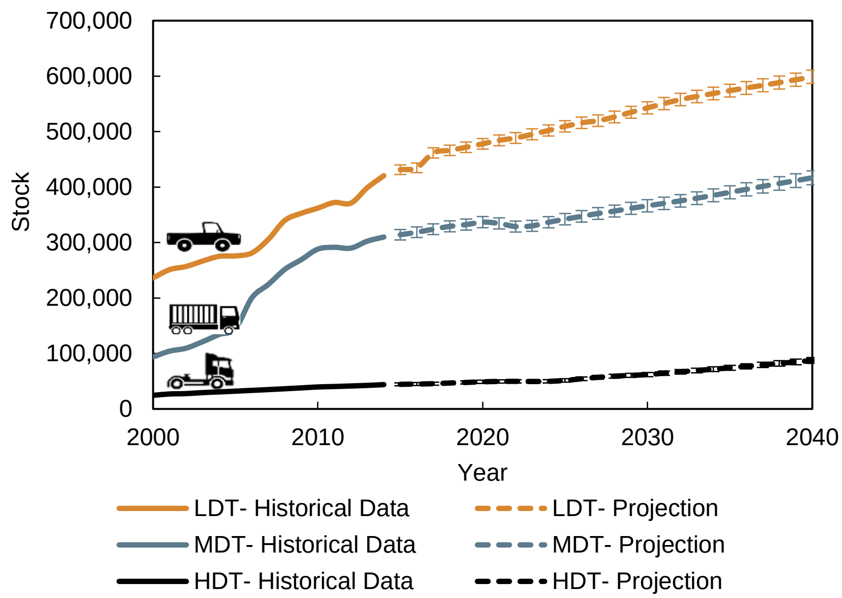


(c)

Figure 6.2. Historical data and projections to 2040 for light-duty trucks (LDT), medium-duty trucks (MDT) and heavy-duty trucks (HDT): (a) freight vehicle use-intensity in B.C. - (b) number of new freight vehicles in B.C. market – (c) stock of freight vehicles in B.C.

6.2.2 GHG emissions projections from road freight transport: BAU and CLF scenarios

The fuel-side WTW GHG emissions are analyzed from the primary energy source extraction to the point of fuel utilization. It should be noted that the life-cycle effects of vehicle manufacturing and infrastructure construction/decommissioning were not covered in the fuel-side GHG emission analysis. For the historical WTW GHG emissions calculation, the tank-to-wheel (TTW) GHG emissions for different truck classes were extracted from NRCan database [9]. The fuel average TTW GHG emissions rate was considered as 2370 and 2734 gCO_2eq/litre for gasoline and diesel, respectively [9]. The GHG emissions associated with fuel production (Well-to-Tank (WTT)), were also considered as 690 and 617 gCO_2eq/litre for gasoline and diesel, respectively [115]. Two scenarios were considered for the projections, with no alternative fuel or powertrain being added to the market, as follows:

6.2.2.1 Business as usual (BAU) scenario

This scenario gives a conservative projection, considering the current technology (Year 2014) remains unchanged. Thus, constant average fuel efficiency (Table 6.2) was used for the entire projection period. The annual WTW GHG emissions (gCO_2eq) were calculated for each ICE truck class using the fuel average WTW GHG emissions rate (gCO_2eq/litre), average fuel efficiency (litre/km), and the forecast results on the stock and vehicle use-intensity (km), as described in section 4.6.

6.2.2.2 Current legislation fulfillment (CLF) scenario

This scenario gives a favorable projection on the efficiency of ICE trucks. It reflects the full deployment of the proposed federal regulations for the GHG emissions reductions from medium and heavy-duty vehicles [175], [176]. These regulations mandate the fuel efficiency improvement of the trucks by considering a combination of engine efficiency improvements, lower rolling resistance tires, aerodynamic drag improvements, mass reduction, axle and transmission efficiency improvements and workday idle reduction systems. The regulatory standards were grouped into 8 categories based on gross vehicle weight, which include combination tractors (class 7 and 8), vocational vehicles (class 2b-8) and heavy-duty pick-ups and vans (class 2b-3). The standards for tractor trucks are classified under 9 subcategories based on weight, roof height and cab configuration. There are also separate standards targeting the engines of these vehicles. However, the available B.C.'s truck statistics are solely based on three weight categories [9] as shown in Table 6.1. In order to use these standards with the available B.C.'s statistics, fuel efficiency improvement of trucks was averaged for three weight categories as shown in Table 6.3. Moreover, as the aforementioned regulations do not cover the GVWR below 3855 kg, the legislation amending the passenger automobiles and light truck GHG emissions [202], [203] was used to represent the light-duty freight trucks.

The annual WTW GHG emissions of freight trucks were calculated for this scenario using equations in section 4.6 and considering the fuel efficiency improvement tabulated in Table 6.3.

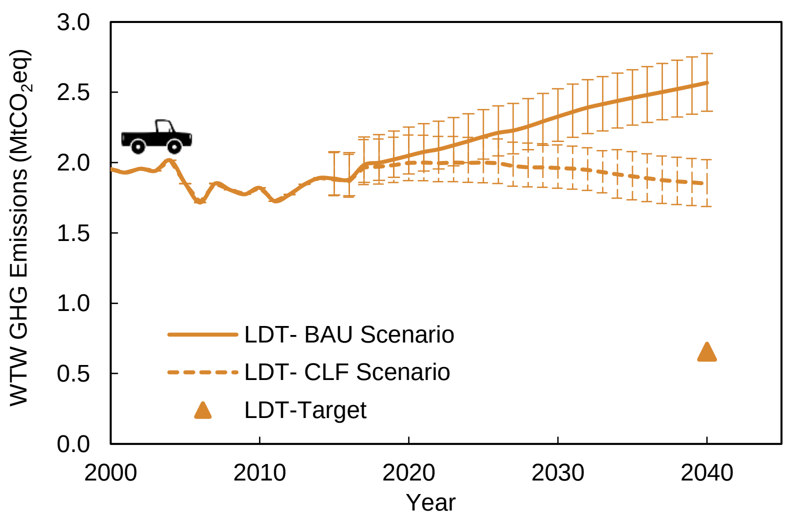
Table 6.3. Fuel efficiency improvement of freight trucks from deployment of federal regulations in the current legislation fulfillment (CLF) scenario

	Phase 1	**Phase 2**		
	2014-2020	**2021-2023**	**2024-2026**	**2027 onward**
LDT	10%	20%	25%	30%
MDT	10%	15%	20%	25%
HDT	10%	20%	30%	35%

The historical data on truck utilization and GHG emissions in B.C. are based on the number of registered trucks in the province. Thus, the share of trucks entering from other provinces or from United States borders that are not registered in B.C. was not considered as the source of GHG emissions (the Weigh2GoBC program does not track vehicles entering the province unless they are registered in the program) [204]. In order to maintain the consistency of the data in the projection, we ignored the effect of incoming trucks on the vehicle-use intensity and GHG emissions of B.C.

6.2.2.3 BAU and CLF comparison

Figure 6.3 shows the results of the fuel-side WTW GHG emissions analysis for different freight truck classes in B.C. If the current ICE technology persists, the BAU scenario projects that the 2040 GHG emissions of LDTs, MDTs and HDTs will increase by 39%, 53% and 84%, respectively, from 2007 levels (regardless of associated uncertainties). With the fulfilment of the current legislation (CLF scenario), these emissions will increase by 11%, 28% and 50% from LDTs, MDTs and HDTs, respectively (regardless of associated uncertainties). For LDTs the GHG emissions stay unchanged for around 16 years and start to decrease afterwards. For MDTs, the GHG emissions will fall modestly or stay unchanged for around 19 years, then rise gradually afterwards. For HDTs, there are periods of 2-4 years with slight GHG emissions reductions, however, a net rising trend can be observed for studied timeframe. These results suggest that the current legislation, which focuses mainly on fuel efficiency improvement of ICE powertrains, will fail to meet GHG emissions reduction targets by 2040. Thus, switching to zero tailpipe emission powertrains are required as part of the long-term solution.



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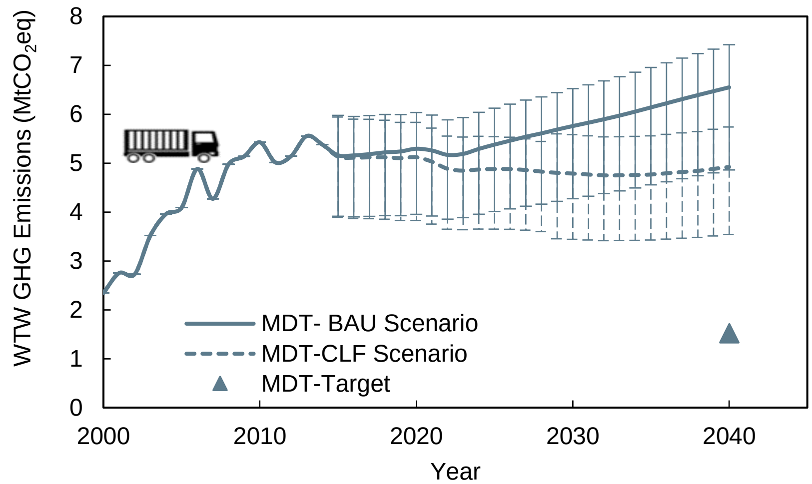

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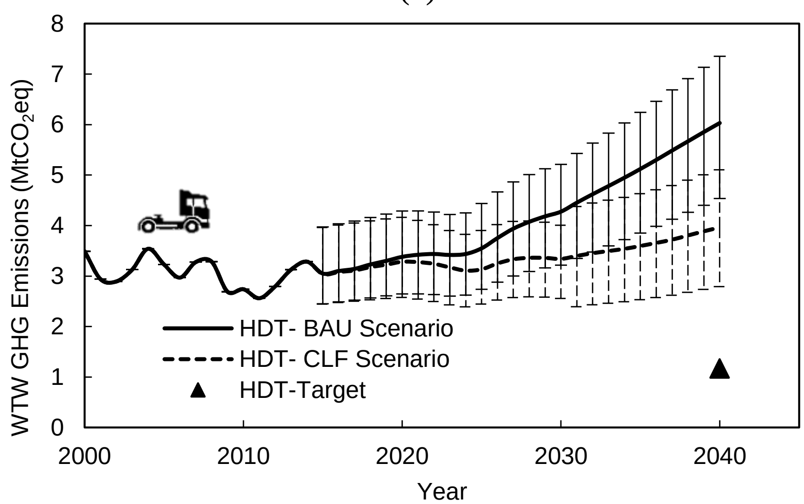

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Figure 6.3. WTW GHG emissions from road freight transportation in B.C. for business as usual (BAU) and current legislation fulfillment (CLF) scenarios - historic data and projections to 2040 (a) light-duty trucks (LDT) (b) medium-duty trucks (MDT) (c) heavy-duty trucks (HDT)

6.2.3 GHG emissions projections from road freight transport in 2040: electrification effect

As FC and BE trucks have zero tailpipe emissions, the WTW GHG emissions analysis is equivalent to the well-to-tank (WTT) evaluation. For fuel cell trucks, the WTT GHG emissions are involved in the production, transportation and distribution of hydrogen from the energy source to the on-board tank of vehicle. Figure 6.4 shows the two selected hydrogen production pathways with WTT energy requirement and GHG emissions mentioned in Table 6.4. The pathway including central natural gas reforming (NGCR) was selected as it is the predominant industrial hydrogen production technology worldwide [205], and B.C. has large reserves of commercially available natural gas [96]. The HyCE is a renewable pathway for hydrogen production using central electrolysis which is feasible in B.C. due to the dominance of relatively cheap hydroelectric power. For the battery electric trucks, the WTT analysis accounts for the emissions associated with electricity generation. The electricity loss from transmission lines was estimated to be 10% [206].

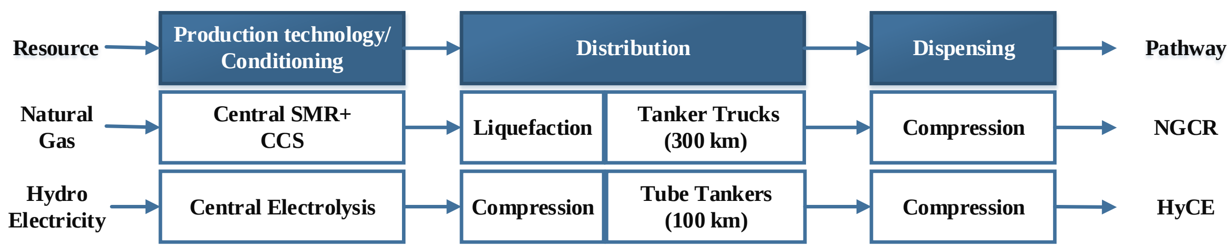

Figure 6.4. Hydrogen production pathways

The effect of electrification on the GHG emissions of road freight transport in 2040 was investigated by substituting the WTW GHG emissions of ICE trucks with the WTT GHG emissions of battery electric and fuel cell trucks in the BAU and CLF scenarios. For the BAU scenario, the fuel efficiency of all-electric trucks was estimated based on the energy efficiency of the powertrains provided by [207], and the average fuel efficiency of ICE trucks in B.C. driven from Table 6.2. For battery electric trucks, the fuel efficiency was estimated at 2.5, 1.3 and 0.6 km/KWh for light-duty, medium-duty and heavy-duty trucks, respectively. The fuel efficiency of fuel cell trucks was estimated at 62, 35 and 16 km/kg H_2 for the aforementioned classes, correspondingly. For the CLF Scenario, some sections of the current legislation which were not dependent on the powertrain were applied to all-electric trucks, e.g., lower rolling resistance tires, aerodynamic drag improvements and speed limiters. These technologies are projected to increase the fuel efficiency by 15% for LDT, 10% for MDT and 20% for HDVs by 2027 [176].

The following assumptions were considered in the WTW GHG emissions calculations of the all-electric freight trucks:

- This study considered the effects of uncertainties associated with the projection of new vehicles and the vehicle use-intensity on the stock of all-electric vehicles, energy requirements and the GHG emissions calculations. The uncertainties associated with vehicle average fuel efficiency, vehicle average lifetime and the technology efficiency for different components of fuel supply chain were not covered in this analysis.

- As the share of hydroelectricity is projected to stay above 86% of total electricity generation in B.C. [10], the GHG intensity of electricity generation was assumed to stay constant for the studied time-frame.

- The charging loss is included in the total fuel efficiency of the battery electric trucks [208].

- The driving range of 120 km was assumed for all classes of battery electric trucks. Based on this assumption, the effect of battery weight on the fuel efficiency of battery electric trucks was not considered in this analysis [188].

- The total electricity required in NGCR and HyCE pathways was assumed to be generated from hydropower.

- The ICE trucks were assumed to deliver hydrogen for both NGCR and HyCE pathways. In the BAU scenario the GHG emissions associated with hydrogen delivery was used from Table 6.4. In the CLF scenario, the fuel efficiency improvement of 35% was considered from fully deployment of federal regulations (Table 6.3).

Table 6.4. WTT energy requirement and GHG emissions for the selected hydrogen pathways [103], [112], [214]–[216], [113]–[115], [209]–[213]

	Feedstock production, conditioning and transportation					
	Natural gas			Hydro power		
GHG emissions	354 gCO_2eq/m^3			11 gCO_2eq/kWh		
	Feedstock transformation to hydrogen					
	Central reforming+ CCS			Central electrolysis		
Energy requirement	NG 4.745 $m^3/kg\ H_2$	Electricity 1.4 $kWh/kg\ H_2$		50.2 $kWh/kg\ H_2$		
GHG emissions	1140 gCO_2eq/kgH_2	11 gCO_2eq/kWh		11 gCO_2eq/kWh		
	Distribution and dispensing					
	Gaseous delivery			Liquefied delivery		
	Compression at dispenser to 87.5 MPa	Delivery (tube trailer)	Compression to 25 MPa	Liquid hydrogen to gas compression to 87.5 MPa	Delivery (tanker truck)	Liquefaction
Energy requirement	2 $kWh/kg\ H_2$		1.5 $kWh/kg\ H_2$	0.6 $kWh/kg\ H_2$		9 $kWh/kg\ H_2$
GHG emissions	11 gCO_2eq/kWh	138 $gCO_2eq/tonne.km$	11 gCO_2eq/kWh	11 gCO_2eq/kWh	138 $gCO_2eq/tonne.km$	11 gCO_2eq/kWh

Figure 6.5 shows the share of all-electric freight trucks required to reduce 64% GHG emissions from road freight transport in 2040 compared to those from 2007. The results suggest that the share of all-electric freight trucks (either battery electric or fuel cell) has to be more than 65% of the freight stock, regardless of the WTT pathway and the considered scenario. As the annual number of new trucks varies between 5% and 7% of the stock during the projection period, the all-electric new trucks are required to reach 100% market share as early as 2025. Figure 6.5 also indicates that less battery electric trucks are required to meet the target compared to fuel cell trucks. However, the market penetration of the battery technology is dependent on the duty cycle of the vehicle, especially, for long-haul HDTs, battery is a challenging technology to adopt. The same amount of GHG emissions could be reduced by 5-6% more heavy-duty fuel cell trucks, if hydrogen is produced via HyCE pathway. It is also observed that the full deployment of current legislation (CLF scenario) in ICE trucks has the same effect in terms of GHG emissions reduction as 7-10% penetration of all-electric freight trucks, in 2040.

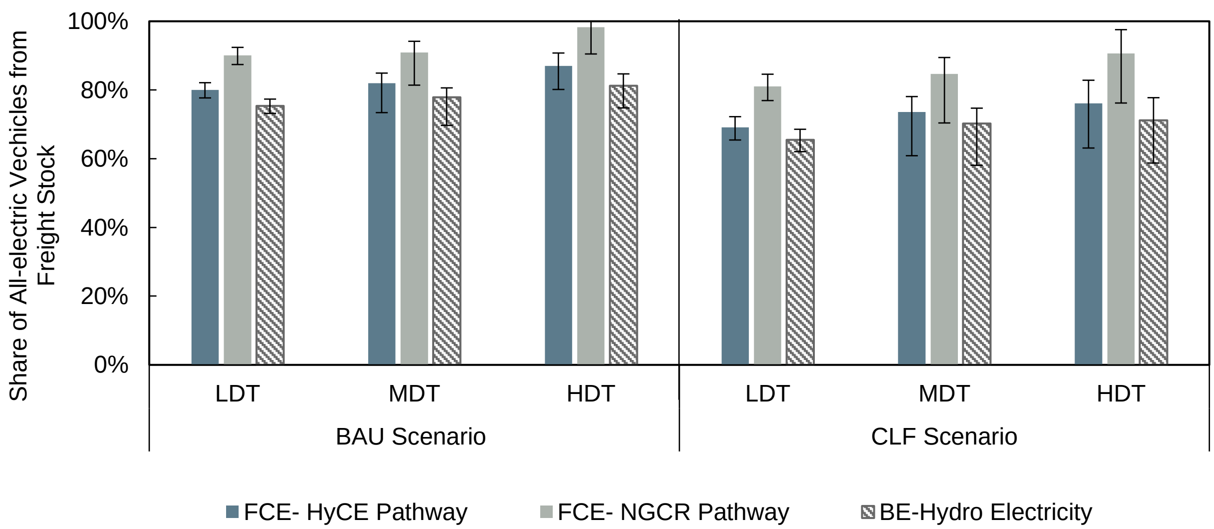

Figure 6.5. Share of all-electric freight trucks (FCE: fuel cell electric, BE: battery electric) for 64% GHG emissions reduction from road freight transport in 2040 (from 2007 level): business as usual (BAU) and current legislation fulfillment (CLF) scenario

6.2.4 B.C. resource assessment to support all-electric trucking

Figure 6.6 compares the electricity requirement to support the 2040 all-electric trucking, described in Figure 6.5, for BAU and CLF scenarios. The National energy Board projections [10] stated that the total electricity generation in B.C. will be around 81.1 TWh in 2040, of which 86% will be generated from large-scale hydroelectric dams. These projections also stated that the hydroelectricity production in B.C. will surpass the demand by 12% in 2040. Figure 6.6 shows that the extra electricity generation in B.C. can support up to 33% of the fuel cell trucks (with HyCE pathway) and up to 72% of the battery electric trucks in BAU scenario, regardless of associated uncertainties. These percentages can increase up to 42% and 93%, respectively in CLF scenario. The NGCR pathway also requires electricity in different stages of hydrogen production, transportation and distribution. The total electricity requirement for meeting 2040 targets via this pathway is 69% and 55% of 2040 extra electricity generation in BAU and CLF scenarios, respectively. For illustrative purposes, the total electricity demand of all-electric trucks was compared to the projected capacity of Site C dam, which will be the 4th largest producer of hydroelectricity in B.C. The government of B.C. recently decided to proceed with the Site C project despite opposition from indigenous communities and the mounting construction costs [217]. As shown in Figure 6.6, the required hydroelectric energy for FC HyCE pathway in BAU scenario is around 6.5 times the total electricity generation of Site C [218]. Even supporting the battery electric trucks in the CLF scenario requires around 2.5 times the total electricity generation of Site C.

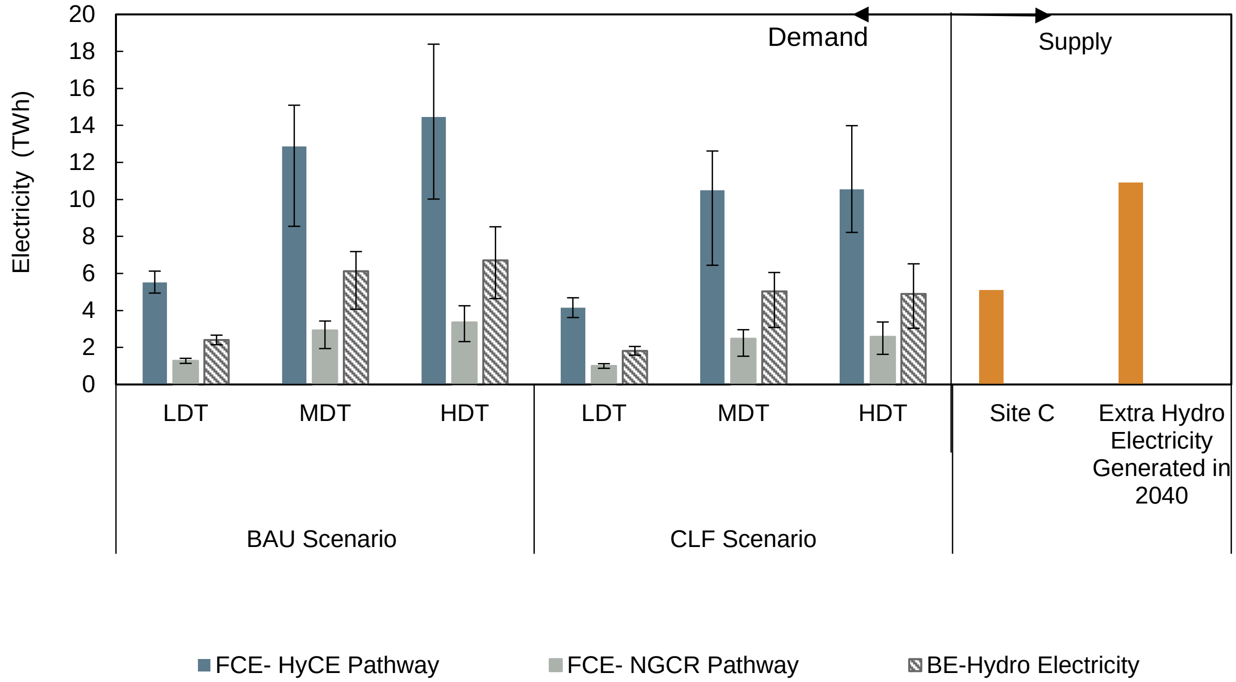

Figure 6.6. Electricity requirement for 64% GHG emissions reduction from road freight transport in 2040 (from 2007 level) - FCE: fuel cell electric and BE: battery electric trucks- business as usual (BAU) and current legislation fulfillment (CLF) scenario

The total electricity generation (e.g., in TWh), may not give a comprehensive picture of the electricity availability to support the mass electrification in the road freight sector. In B.C, the installed generation capacity and the peak load of electricity is projected to be 21000 MW and 16900 MW in 2040, respectively [10]. Assuming that sufficient battery electric trucks penetrate the market to meet the 2040 GHG emissions reduction target in the BAU scenario (Figure 6.5). Even with the total extra generation capacity, up to 10% of all battery electric trucks could use DC fast chargers (50 kW), or up to 25% could use Level 2 AC chargers (19.2 kW) during peak hours. And if all battery electric trucks use off-peak hours for charging using Level 2 AC chargers (between 5 to 8 hours), a 16300 MW load will be added to the system. This means peak hours may extend to midnight and early morning.

The projections on the total electricity generation show that the hydroelectric power can hardly satisfy the large electrification of road freight transport in B.C. Moreover, the projected installed electricity capacity is not ready to support the large percentage of battery electric trucks on the roads. It should also be noted that B.C. can no longer rely on any imported power to meet the forecast requirement. The BC Clean Energy Act called on BC Hydro to become self-sufficient in electricity production and a net exporter of clean electricity starting in 2016. Moreover, the Clean Energy Act banned the future development of large-scale hydro-electric storage dam projects on all rivers in B.C., except for site C. Thus, the diversification of the renewable supply mix seems to be inevitable to support large-scale electrification. As discussed in Chapter 3 (section 3.1) 44 TWh of the wind resource potential and around 6 TWh of the geothermal resource potential in B.C. can be harvested for less than $200 per MWh. Moreover, the wood-based biomass resources available for bioenergy production has the technical electricity production potential of 4.5 TWh, generated mostly below $200 per MWh.

It is evident that there is a huge wind electricity potential in B.C. to support the electricity demand from the transportation sector. However, the intermittency associated with wind-generated electricity poses a challenge with regards to load leveling at large capacities [219]. The power-to-hydrogen pathway is a promising option to mitigate the intermittency of wind energy in a form of stored hydrogen. Hydrogen could be produced via electrolysis during off-peak demand hours at lower price and stored as an electricity back-up or directly used for transportation needs. In the short term, as the transportation is predominantly reliant on fossil fuels, the electrolytic hydrogen can be used in oil refineries to reduce the carbon intensity of the petroleum fuels [220]. Moreover, electrolytic hydrogen can be injected to the natural gas system and used in hydrogen enriched natural gas (HCNG) engines [186]. Thus, the power-to-hydrogen is helpful to increase the flexibility of the power system and enables the high contribution of wind electricity in a short and long-term perspective [221], [222].

The NGCR pathway opens up the opportunity to partially unburden the renewable electricity generation to reduce GHG emissions from the road freight transport. The natural gas requirement for NGCR pathway is approximately 3×10^{9} m^{3} and 2.4×10^{9} m^{3} for BAU and CLF scenarios which is 3% of projected production for 2040 in B.C. [10]. However, the GHG emissions reduction of the NGCR pathway is dependent on the deployment of large-scale carbon capture and sequestration (CCS) facilities. It should be mentioned that CCS technology is yet to be widely deployed. The economic feasibility and potential environmental impacts of CCS may limit its application [223]. Figure 6.7 shows that the NGCR pathway without CCS falls short of meeting the GHG emissions target in road freight transport, even with 100% of truck stock running on hydrogen.

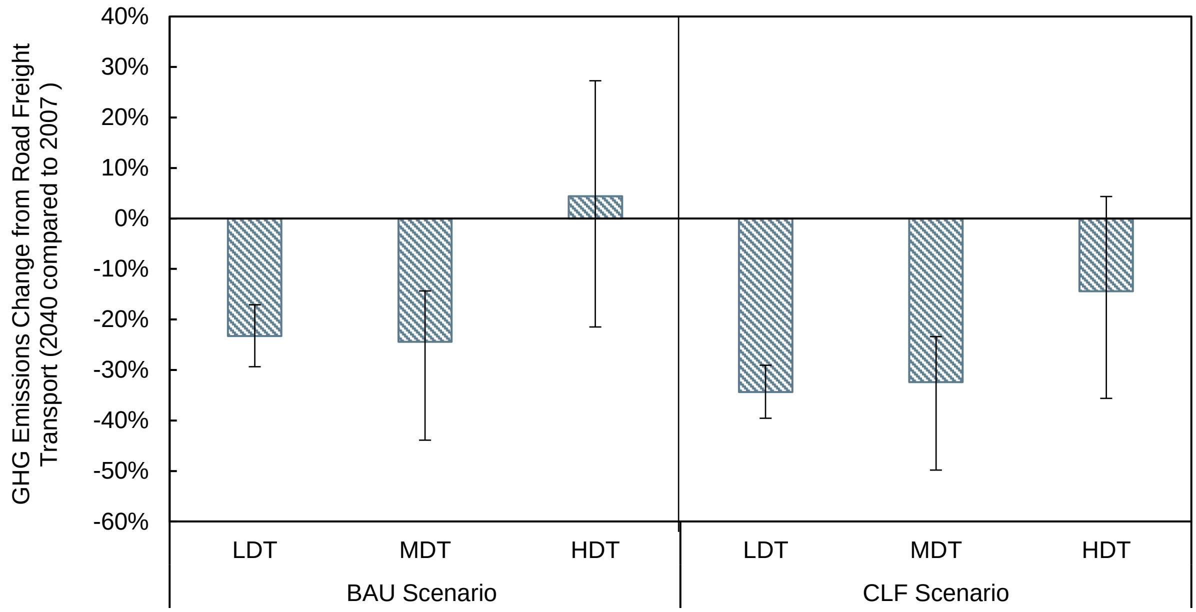

Figure 6.7. GHG emissions change in 2040 road freight transport compared with 2007 - 100% of freight trucks running on hydrogen produced from central natural gas reforming (NGCR) pathway without carbon capture and sequestration (CCS)- business as usual (BAU) and current legislation fulfillment (CLF) scenario

6.2.5 Comparative analysis of emission reductions and energy requirements across scenarios

Converting more than 65% of all freight trucks to electric powertrain by 2040 may be challenging. Currently, there is uncertainty over the cost and lifetime of these vehicles. Moreover, the availability of charging stations and hydrogen refueling infrastructure in neighboring provinces and the United States can affect the all-electric long-haul transportation in B.C. Hence, we consider the penetration requirements for every 1% GHG emissions reduction from the trucking sector in 2040.

According to Figure 6.8, 11,000 to 14,000 all-electric freight trucks are required for every 1% GHG reduction from B.C.'s road freight transport in 2040. As the contribution of HDTs to the

GHG emissions is higher, a smaller number of all-electric HDTs is necessary to reduce the same amount of GHG emissions compared to the all-electric LDTs or MDTs. It is also observed that a larger number of all-electric trucks is required for every 1% GHG emissions reduction in CLF scenario than BAU scenario. As the energy efficiency of ICE technology in CLF scenario is higher than the BAU scenario, the CLF scenario is more resilient to emissions reduction. In other words, the ICE technology in CLF scenario is competing with all-electric powertrains in GHG emissions reduction.

In terms of well-to-wheels energy requirements (Table 6.4), the hydrogen dependent pathways require more than twice as much energy as the battery electric dependent pathway (i.e., 2.2 for the HyCE and 2.5 for the NGCR pathway). Amongst, the NGCR is the most energy intensive pathway for all-electric trucking. The hydroelectricity requirement for every 1% GHG emissions reduction from road freight transport is 1.5% to 1.8% of the B.C.'s 2040 total extra hydroelectricity generation for battery electric trucks and 3.3% to 3.8% for fuel cell trucks with HyCE pathway, depending on the scenario.

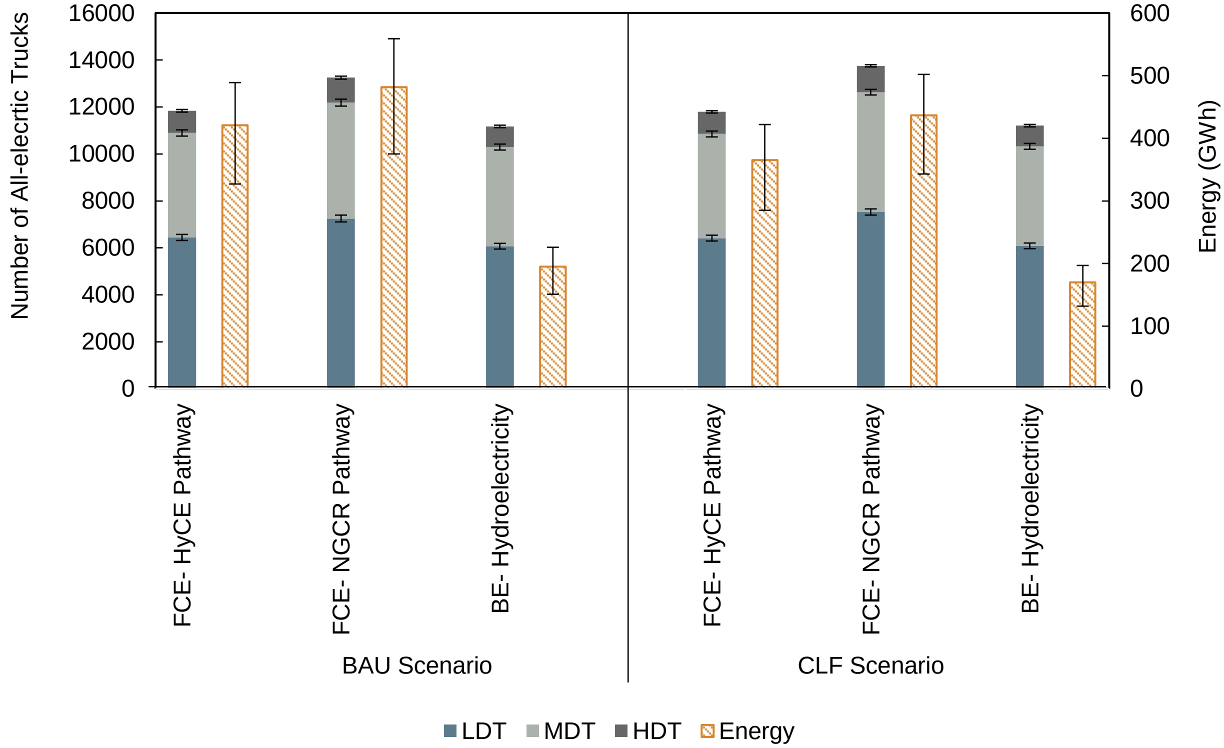

Figure 6.8. 2040 projections on the number of all-electric trucks (FCE: fuel cell electric and BE: battery electric) and total energy required for 1% GHG emissions reduction from road freight transport in B.C.

Chapter 7: Conclusion and Future Work

The optimization-based framework (H2SCOT) was developed for the long-term planning of hydrogen fuel supply chains (HFSC) at low demand. The model considered various capacity options for all components of the supply chain, covered the on-site production and capacity expansion options as well as minimum storage requirement for fueling stations. The model also included a range of environmental policies in the formulation of the objective function. The H2SCOT was applied to a case study of light duty passenger in British Columbia, considering three demand scenarios and a 30-year time frame.

Freight road transport has a similar contribution to GHG emissions as the light duty passenger vehicles in B.C. However, there exists no government plans to support zero-emission freight transport. In this study, the WTW energy requirement and GHG emissions reduction potential of the battery electric and fuel cell electric trucks were measured to meet the provincial emissions reduction targets. The results can be used to develop a plan to support the purchase of these vehicles and the infrastructure development.

7.1 Light duty passenger vehicles (current provincial policies)

H2SCOT was applied to the case study of light duty passenger vehicles in B.C. The optimization was performed for the case in which no environmental policy was included, as well as for the cases in which carbon tax, low carbon fuel standard (LCFS) and a mix of both policies were included.

- SMR was found to be the dominant hydrogen production technology even with the current carbon control policies in place. While the inclusion of carbon tax and LCFS boosted the adoption of on-site electrolysis, the tax rates and carbon credits were not sufficient to pay off the central electrolysis nor the carbon capture and sequestration (CCS) without significant cost reductions in the relevant technologies.
- The configuration of transportation networks and fueling stations switched gradually from low- to high-capacity units, as the demand grew over time. High-capacity gas delivery delayed the adoption of liquid delivery, so that liquid hydrogen was restricted to the optimistic scenario and to the policy-included cases in the moderate scenario.

- A post-optimization economic analysis was conducted to compare hydrogen with the gasoline supply chain based on the potential revenues and the monetary value of GHG emissions avoidance. The results showed that even in the pessimistic scenario, the monetary benefit of emissions reduction was 4 times the extra costs incurred by the HFSC. For moderate and optimistic scenarios, the HFSC was both economically and environmentally cost competitive.

- The effectiveness of environmental policies was found to depend on the demand and decreased from the pessimistic to the optimistic scenario. The inclusion of carbon tax improved the emission reduction contributions; however, the hydrogen price increase became a restriction as the demand increased. The inclusion of LCFS decreased the hydrogen price compared to the base case, while a negligible effect was observed on emissions reduction.

- Coupling the carbon tax with the LCFS was found to work best for the pessimistic scenario in which the emissions reduction was achieved at a lower hydrogen price, compared to the base case. For moderate and optimistic scenarios, the policy coupling reduced the GHG emissions at the expense of hydrogen price increase; yet it is the most suitable policy option when hydrogen price and GHG emissions are weighted equally.

7.2 Light duty passenger vehicles (complementary policies)

The effectiveness of complementary policies was assessed on the economic viability of low-carbon hydrogen production. The policies were integrated in the formulation of H2SCOT. Stepwise deployment strategies of each policy were adopted in addition to the current policies in B.C. (i.e., the carbon tax and LCFS) for light duty passenger FCEVs.

-Production subsidies and electricity incentives were found to be more effective in GHG emissions reduction than grant subsidies, bans on SMR-production or adoption of higher carbon tax rates.

-Every unit of production subsidies and electricity incentives were more effective in hydrogen price decrease as the demand grew from pessimistic to optimistic scenarios. However, the reverse effect was observed when grant subsidies were applied to the supply chain.

-The addition of a production tax credit (PTC) to the current policies in B.C., was found to be an effective strategy to boost the low-carbon hydrogen production and decrease the hydrogen price. A PTC can be considered a market subsidy to decouple the financial support systems from government budgets by obtaining the required subsidies from undesirable technologies. Thus, higher tax rates can be imposed on conventional fuels and a share of revenues can be directed as a tax incentive for low-carbon hydrogen production.

-The size of the hydrogen supply chain (e.g., hydrogen demand) restricts the potential contribution of subsidies in the technology shift (GHG emissions reduction). Thus, the deployment strategy of policies over time was found to be more effective in GHG emissions reduction than the total subsidies allocated in each demand scenario.

-Higher rates of carbon tax reduced the cost of GHG emissions reduction from the hydrogen supply chain. This effect was more pronounced at lower demand levels.

-Pathways relying on SMR production with carbon capture and sequestration (CCS) were found to be less economically and environmentally favorable compared to the electrolytic hydrogen production. Low demand and long-distance hydrogen transport from Northeast B.C. diminish the financial and environmental benefit of CCS integration into the SMR facility.

- Large subsidies were required to shift from SMR production to electrolytic hydrogen. However, subsidies are essential to avoid locking into SMR technology with a lower environmental benefit and long investment cycle. The subsidy schemes in this study were developed for a 30-year time frame, which made them susceptible to government changes and budget volatility.

7.3 Fright road transport

7.3.1 GHG emissions reduction potential in B.C.

The analysis was built based on two scenarios: the business as usual (BAU) with no technology improvement in ICE trucks and the current legislation fulfillment (CLF), which considered the full deployment of current legislation targeting freight transportation.

- The analysis showed that the continuity of the current ICE technology (BAU scenario) by 2040 results in 39%, 53% and 84% GHG emissions increase from 2007 levels for LDTs, MDTs and HDTs, respectively. Moreover, the CLF scenario fail to set the GHG emissions on a downward trajectory.

- The projection results showed that all-electric trucking can help B.C. reduce 64% of the emissions from road freight transport by 2040. The WTW energy and GHG emissions analyses indicated that the share of all-electric freight trucks would have to be more than 65% of the stock, regardless of the WTW pathway and the considered scenario. Therefore, the government must enforce strict fleet emission regulations and allocate early-market subsidies for manufacturers, customers and the infrastructure developers to promote all-electric vehicles. Moreover, the partnerships between public authorities to mass-purchase electric vehicles for the public fleets, can provide reliable demand for vehicle manufacturers (Lambert, 2017c).

7.3.2 Energy requirement and resource availability

- As the WTW energy efficiency of battery electric trucks is more than two times higher than fuel cell trucks, less battery electric trucks are required to meet the 2040 GHG emissions target. However, the adaptiveness of the battery technology is dependent on the duty cycle of the vehicle. Battery electric trucks could cover urban delivery with short and well-defined routes. This duty cycle is suited for light-duty and medium-duty classes. The heavy-duty class is suitable for long-haul application which can be satisfied by fuel cell trucks. It is recommended that policy strategies support both fuel cell and battery electric powertrains, as they are complementary solutions to decarbonize road freight transport.
- The analysis showed that every 1% GHG emissions reduction from road freight transport requires between 1.5% and 3.8% of 2040 extra hydroelectric generation in B.C. Thus, the B.C. hydroelectricity will fall short of generating sufficient energy to support all-electric trucking required to fulfill the 2040 emissions reduction target. Therefore, B.C. has to undertake policies to incentivize electricity generation from diversified renewable energy resources. Wind energy provides reliability, wide scale resource availability and economic competitiveness with hydro power. The current B.C.'s policies such as 10-year exemption from participation rents for new wind projects has laid the ground for wind energy development. However, more policies may be required to address the economic challenges of wind project developments in the private sector. Along with expanding energy resources, transmission capacity needs to be increased to meet the on-peak demand created by mass adoption of electric vehicles.
- Natural gas may provide a pathway for low-carbon hydrogen production in B.C., but it would require CCS technology development and deployment. This pathway can help B.C. decrease the electricity requirements for all-electric trucking.

7.4 Study limitations

- The optimization results were calculated using hydrogen fuel cell penetration in the passenger light duty sector for three demand scenarios. Hydrogen demand from other transportation sectors, industry, energy storage, or for export would modify the optimal HFSC and could lower the total cost of hydrogen.
- The LCFS credit price and carbon tax assumptions are subject to uncertainty. This study aimed to show the links between policy measures to the configuration of the HFSC, the price of hydrogen, and the WTW GHG emissions. A detailed analysis is needed to assess the sensitivity of an HFSC to various levels of revenues and fees generated through those policy measures.
- The subsidy schemes in this study were developed for a 30-year time frame, which made them susceptible to government changes and budget volatility.
- The policy effectiveness was measured for a limited number of scenarios. Moreover, the assessment is sensitive to the assumptions on energy price, discount rate, the rate of technology development and the technological breakthrough. Moreover, there are transaction and program costs and policy implementation challenges that were not considered in this study. Thus, it is recommended to interpret the results of this study as directional estimates rather than exact quantifications.

7.5 Future work

7.5.1 Extending the frontiers of H2SCOT

The current optimization model can be expanded to include hydrogen demand from B.C. road freight transport as well as the road transport sector in other provinces in Canada. Moreover, the model can include hydrogen export to other jurisdictions, as well as the possibility of blending hydrogen to the natural gas network.

The model expansion requires a comprehensive techno-economic analysis on the configuration of potential hydrogen supply chain in each province based on resource availability, vehicle stock projections, GHG emissions targets and current environmental policies. Based on the level of hydrogen penetration to the market and the current and planned energy profile in each region, it may be required to include seasonal hydrogen storage facilities and hydrogen pipeline transport to the model.

H2SCOT was developed based on the commercially available technologies. Emerging technologies can be added to the model as they enter into the commercial stage.

7.5.2 Multi criteria decision making

H2SCOT was developed based on a mono-objective framework. The aim was to minimize the total cost of the supply chain. The model also dealt with the environmental impact by assigning monetary value to the GHG emissions from the HFSC. A future analysis can include an expansion of the model to a multi-objective setting, with environmental impacts and safety as separate objective functions. As there is not a unique optimal solution to this class of problems, the concept of optimality is replaced with Pareto optimality[224]. A set of Pareto optimal solutions is generated and the sorting and arranging methods (e.g., ELECTRE, TOPSIS and M-TOPSIS) are used to determine the best alternative among the available options [225].

7.5.3 Parametric study on economic factors

The configuration of a cost optimal HFSC is dependent on several economic factors such as the projection of electricity and natural gas price, the rate of technology cost reduction over time (technology learning rate) and the favorable interest rates for different investors. HFSC can be optimized for different realization of economic factors as well as their interactions. Accordingly, the sensitivity of HFSC to each economic factor can be measured with respect to the variations in hydrogen price and the emissions reduction benefits.

7.5.4 Introducing non-linearity and uncertainty to the model

As fuel cell powertrains penetrate to the trucking sector, a portion of the hydrogen transport fleet may also run on hydrogen. This introduces non-linearity to the model, as the demand is also a function of the number of trucks and transportation distance. A future study can deal with the non-linearity using non-linear solvers like MINOS.

In this work, the optimization was performed for three demand scenarios. Scenario development is a post-optimization technique to introduce uncertainty to the model. This technique does not provide a single overall optimal solution for all scenarios. Stochastic programming can overcome this issue by incorporating uncertainty in the optimization model during the decision-making process. This method optimizes the expected value of the objective function over all scenarios, while finding solutions that are feasible for all realization of uncertain parameters. The technique is based on capturing the uncertainty in terms of a number of likely scenarios with known probability distributions that are possible to materialize during the lifetime of the supply chain [31], [32]. The future work can be an extension of H2SCOT from the deterministic framework into a multi-stage stochastic model to optimize HFSC planning with respect to hydrogen demand uncertainty.

7.5.5 Expansion on policy scenarios and integration mechanisms

A limited number of environmental policies was studied in this work. Future analyses can expand on the number of policies, policy integration strategy and the policy switch over time.

Because hydrogen may be penetrated from transportation to the wider energy market, different sets of policies are required to be implemented in each sector. The interaction between policies can be studied to help the sustainable development in all hydrogen markets.

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Appendix A

A.1 Hydrogen demand projection

Table A.1 Hydrogen demand (kg/day) distribution among municipalities in the final year of each time step for different demand scenarios:

time	2025			2030			2035			2040			2045			2050		
Scenario/Municipality	Pes	Mod	Opt	Pes	Mod	Opt	Pes	Mod	Opt	Pes	Mod	Opt	Pes	Mod	Opt	Pes	Mod	Opt
Surrey	17	52	86	97	290	483	388	1165	1942	994	2981	4969	1723	5169	8615	2272	6817	11361
Vancouver	51	152	253	271	814	1356	1049	3148	5246	2594	7781	12968	4357	13071	21786	5581	16744	27906
Burnaby	28	85	141	156	467	778	615	1846	3076	1548	4643	7738	2637	7911	13185	3416	10248	17080
Coquitlam	20	59	99	110	331	551	436	1309	2181	1089	3268	5447	1828	5484	9140	2314	6943	11572
Langley	20	61	101	114	342	571	460	1379	2298	1174	3523	5871	2027	6081	10134	2655	7965	13274
Delta	15	46	77	83	248	414	318	954	1591	777	2330	3884	1283	3848	6414	1620	4859	8098
Maple Ridge	15	42	70	77	231	385	299	898	1497	730	2191	3652	1200	3601	6002	1505	4515	7525
North Vancouver	21	62	103	111	333	554	432	1297	2162	1078	3233	5388	1827	5480	9134	2362	7086	11811
Richmond	35	80	133	145	436	726	574	1723	2872	1450	4351	7252	2488	7465	12442	3255	9765	16276
West Vancouver	0	24	41	44	132	221	172	515	858	424	1271	2119	707	2122	3536	897	2690	4483
Kelowna	39	118	197	216	647	1079	847	2542	4236	2117	6352	10587	3585	10756	17926	4621	13863	23105
Kamloops	24	71	118	129	388	647	508	1525	2542	1270	3811	6352	2151	6454	10756	2773	8318	13863
Prince George	24	71	118	129	388	647	508	1525	2542	1270	3811	6352	2151	6454	10756	2773	8318	13863
Victoria	67	201	335	367	1100	1834	1440	4321	7202	3600	10799	17998	6095	18285	30475	7856	23567	39278
Abbotsford	0	18	30	33	98	164	129	386	643	321	964	1607	544	1632	2720	701	2104	3506
Hope	0	0	15	15	41	68	54	161	268	134	402	669	227	680	1134	292	877	1461
Whistler	0	0	0	0	30	50	39	118	196	98	295	491	166	499	831	214	643	1071
Williams Lake	0	0	0	0	33	55	43	130	217	108	325	542	184	551	918	237	710	1183

A.2 Distances between supply and demand regions

Google Maps was used to estimate distance in km, based on the zip code of the regions.

Table A.2 Distances between potential production and storage locations (1-14) and distances between potential storage locations and the entrance to Metro Vancouver municipalities (Langley Township).

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	LT
1: Fort Nelson	0	381	809	1048	1572	1526	1333	1360	1487	1712	1471	1439	1680	1593	1541
2: Fort St John		0	437	676	1193	1154	961	988	1115	1334	1093	1067	1308	1221	1169
3: Prince George			0	239	870	718	524	552	679	976	864	631	872	784	733
4: Williams Lake				0	637	952	290	318	445	743	881	397	638	551	499
5: Mica Creek					0	1583	351	436	336	389	524	552	793	705	653
6: Prince Rupert						0	1236	1264	1391	1689	1582	1343	1584	1497	1445
7: Kamloops							0	87	167	457	595	203	444	356	307
8: Merritt								0	127	456	680	120	361	273	220
9: Kelowna									0	346	558	239	479	392	339
10: Nelson										0	259	510	750	662	609
11: Kimberley											0	721	961	874	822
12: Hope												0	242	154	103
13: Victoria													0	126	N/A
14: North Vancouver														0	N/A

Table A.3 Distances between Langley Township (LT) and different municipalities in Metro Vancouver and distances between storage facilities in North Vancouver (NV) and different municipalities in the Metro Vancouver

	1: Surrey	2: Vancouver	3: Burnaby	4: Coquitlam	5: Langley	6: Delta	7: Maple Ridge	8: North Vancouver	9: Richmond	10: West Vancouver
LT	30	62	44	9	55	27	37	44	60	70
NV	32	18	12	45	27	43	30	48	6	15

Table A.4 Distances between potential storage locations and the demand regions (except Metro Vancouver)

	Major Municipalities				Connecting municipalities			
	1: Kelowna	2: Kamloops	3: Prince George	4: Victoria	1: Abbotsford	2: Hope	3: Whistler	4: Williams Lake
1: Fort Nelson	1487	1330	810	1711	1522	1439	1440	1048
2: Fort St John	1115	958	1154	1341	1151	1067	1068	676
3: Prince George	687	522	10	900	715	631	632	240
4: Williams Lake	453	288	240	670	481	397	398	10
5: Mica Creek	336	350	871	825	635	553	648	637
6: Prince Rupert	1391	1234	718	1616	1426	1343	1344	952
7: Kamloops	167	10	525	467	289	204	302	290
8: Merritt	127	87	552	400	202	120	291	318
9: Kelowna	10	167	687	511	321	239	417	445
10: Nelson	346	551	1020	781	591	509	754	743
11: Kimberley	580	595	846	1070	879	797	893	881
12: Hope	239	204	631	275	85	10	272	397
13: Victoria	N/A	N/A	N/A	111	N/A	N/A	N/A	N/A
14: North Vancouver	388	352	781	100	70	150	124	547

A.3 Other parameters used in the model

$Pcap\_max\_prin_c$	100 ,50, 10 (tonnes/day)
$Scap\_max\_prin_{\bar{c}}$	100 ,50, 10 (tonnes/day)
$Dcap\_max_s$	1500, 1000, 500, 150 (kg/day)
α_LR_S	0.07
α_LR_C	0.07
α_LR_O	0.106
α_LR_D	0.106
$Lifetime\_C$	40 years
$Lifetime\_S$	20 years
$Lifetime\_O$	10 years
$Lifetime\_D$	10 years
$Lifetime\_TR$	20 years
Truck parameters	
α	25 C$/hour
γ	0.3 litre/km
β	1.4 C$ /litre
VH	70 km/hour
VG	40 km/hour
$CAPL\_TR$	3800 kg
$CAPG\_TR_a$	100,500, 900 kg
$Loadingtime_d$	d=2: 1.5 hour d=3: 3 hour
$unLoadingtime_d$	d=2: 1.5 hour d=3: 3.5 hour
$H2\_D$	120 MJ/kg
Gas_CI	79.33 g/MJ
EER_t	2.5
r	10%
N	30 years
Tr	27%
timestep	5