UNIVERSITY OF CALGARY

UTILIZING RENEWABLE HYDROGEN FOR FUEL-CELL MINE HAUL VEHICLES IN CANADA: A TECHNO ECONOMIC ASSESSMENT

by

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Abstract

To reduce emissions from diesel-fuelled mine-haul fleets in Canada, hydrogen has been considered a viable alternative. However, emissions from electrolysis can increase depending on the carbon dioxide (CO_2) intensity of the electrical source. This study found that total emissions can be reduced by 50% with grid-connected electrolysis and up to 90% when connected to a renewable energy source such as a wind turbine. The study results indicate that the current cost of ownership for fuel-cell electric vehicles (FCEVs) and hydrogen production from wind energy is approximately 18%-30% higher than diesel fuel. As technology learnings increase, utilizing hydrogen in mine trucks will be economically viable to diesel-fueled mine-haul fleets as future costs are projected to drop by 2030. This techno-economic prefeasibility study investigates the amount of emissions reduction and cost-savings from diesel-fuelled mine-haul fleets by utilizing electrolysis from either grid-electricity or wind-energy in FCEVs within the Canadian mining industry.

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BEV	Battery Electric Vehicle
CAD	Canadian Dollars
CANWEA	Canadian Wind Energy Association
CO_2e	Carbon Dioxide Equivalent
COSIA	Canada's Oil Sands Innovation Alliance
DOE	Department of Energy
ESG	Environmental Social Governance
FCEV	Fuel-cell Electric Vehicle
GHG	Greenhouse Gas
GHGPPA	Greenhouse Gas Pollution Pricing Act
H_2	Hydrogen
HFTO	Hydrogen and Fuel Cell Technologies Office
ICMM	International Council on Mining and Metals
IEA	International Energy Association
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
IRR	Internal Rate of Return
LAC	Life Cycle Analysis
LCOE	Levelized Cost of Energy
LCOH	Levelized Cost of Hydrogen Production
LHD	Load Haul Dumps
NRCAN	Natural Resources Canada
NREL	National Renewable Energy Laboratory
NPV	Net Present Value
PEM	Proton Exchange Membrane
PPA	Power Purchase Agreement
REC	Renewable Energy Certificate
SAM	System Advisor Model
SDGs	United Nations Sustainable Development Goals
SMR	Steam Methane Reforming

SOEC	Solid Oxide Electrolysis Cell
TOU	Time Of Use
U.S.	United States
VPPA	Virtual Power Purchase Agreement
VRE	Variable Renewable Energy

$CAD	Canadian Dollars
g	Grams
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt Hour
MW	Megawatt
MWh	Megawatt Hour
t	Tonne
Mt	Million tons
MJ	Mega Joule
L	Litres
tCO_2e	Tonne Carbon Dioxide Equivalent

Chapter 1 – Introduction

The mining industry contributes on average 4%-7% of the global greenhouse gas (GHG) emissions annually. Diesel-fuelled mine-haul vehicles, which can consume over one million litres of diesel fuel per year, can contribute between 30%-80% of a mine's total emissions (Delevingne et al., 2020) (International Council on Mining and Metals, 2021). In the global race to net-zero emission by 2050, a conundrum occurs within the mining industry: as demand for minerals required in clean-energy technology increase by 400%-600% in 2050 (Figure 1), the emissions from diesel-fuel mine trucks are expected to increase in tandem (IEA, 2021). Furthermore, as mineral extraction increases, some mines may experience degradation of the ore body, which can increase emissions, as run-time (ore extracted from the pit) can increase by 50%-120% to meet commodity demand (Muralidhharan et al., 2019). In order to reach net-zero emissions targets and develop mineral resources sustainably, alternatives to diesel-fuel, such as hydrogen, must be considered. This research attempts to determine emissions reductions and techno-economic viability of utilizing hydrogen, produced in a Proton Exchange Membrane (PEM) electrolyzer, in a PEM Fuel-Cell Electric Vehicle (FCEV).

Producing hydrogen in a proton exchange membrane (PEM) electrolyzer and utilizing it in a PEM fuel-cell electric vehicle (FCEV) can theoretically produce zero Scope 1 emissions (emissions from fuel). However, as electrolysis requires electricity to produce hydrogen, the emissions are tied to the carbon dioxide (CO_2) intensity of the source of electrical generation (Scope 2 emissions). In Ontario, where 96% of the electrical grid is considered clean energy, the study results indicate that hydrogen produced from electrolysis can reduce approximately 50% of the total emissions compared to a diesel-fuelled base case. To maximize emissions reductions, zero-carbon energy sources, such as wind turbines, can further reduce the emissions to over 90%. However, as wind energy is variable, grid electricity will be required to provide the energy balance for electrolysis (grid-balance). The higher the grid-balance percentage, the higher the Scope 2 emissions produced. The amount of grid-balancing is dependent on the wind capacity of the turbine site, the size of the wind farm and the amount of hydrogen storage available.

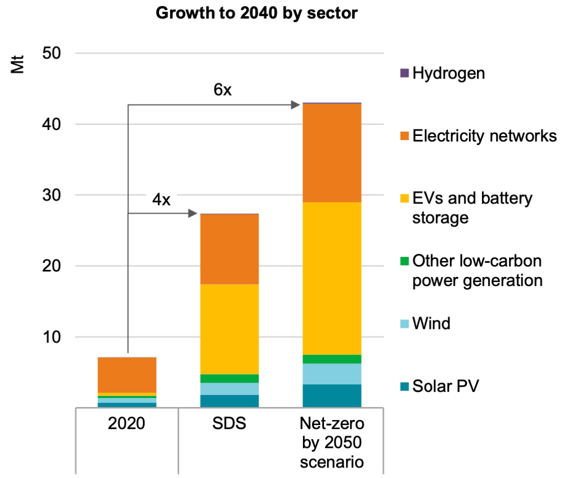
One of the limiting factors to hydrogen fuel-switching is that the cost is significantly higher than the cost for the incumbent diesel fuel (Rivard et al., 2019). This study found that the total costs for a hydrogen fleet are approximately 18% higher than a diesel-fuel fleet. However, increasing diesel-fuel costs, coupled with the Canadian Federal Government carbon tax rising to \$170 per tonne carbon dioxide equivalent (tCO_2e) by 2030, and hydrogen technology costs decreasing with economies of scale, hydrogen could become cost-competitive to diesel by the end of the decade. This study also investigates the investment optionality by comparing the current and future costs to determine when fuel-switching can be economically feasible. The study results indicate that an FCEV mine-haul fleet will be financially viable by 2027, but only if the carbon tax remains high. With an impending federal election in September 2021, and as the opposing political party (Conservatives) have announced a lower carbon tax of \$50 /tCO_2e by 2030, a Conservative Party win could mean that hydrogen-fuel switching is not as financially viable with the lower carbon tax on emissions.

Based on a sensitivity analysis of the data, if the cost for diesel fuel is more than \$CAD 1.50 per litre (\$CAD/litre), the results are favourable for an FCEV wind-hydrogen production project regardless of the carbon tax. Therefore, fuel-switching could also be an economic incentive for remote mining locations, where diesel fuel is seasonably shipped via barge or airplane, thus increasing the fuel cost by 25%-300% higher than mine locations in central Ontario.

This capstone research is a pre-feasibility analysis of the techno-economics of fuel switching from diesel to hydrogen for a 290-ton mine-haul vehicle to reduce CO_2 emissions and maintain an operator's competitive advantage in the Canadian mining sector. This study also looks at the investment optionality by comparing how the financial metrics can change over time with increasing and decreasing future costs of energy, and a high and low carbon tax on emissions. Two sources of electricity procurement were studied, grid-electricity and wind energy, to compare the amount of potential Scope 2 emissions abated from fuel-switching from diesel-fuel. The techno-economic section focused on the cost-savings from three (3) scenarios: (1) electricity is procured from the grid; (2) electricity from a wind virtual power purchase agreement (PPA); (3) electricity from a behind-the-meter direct connect wind farm (Figure 2).

Figure 1

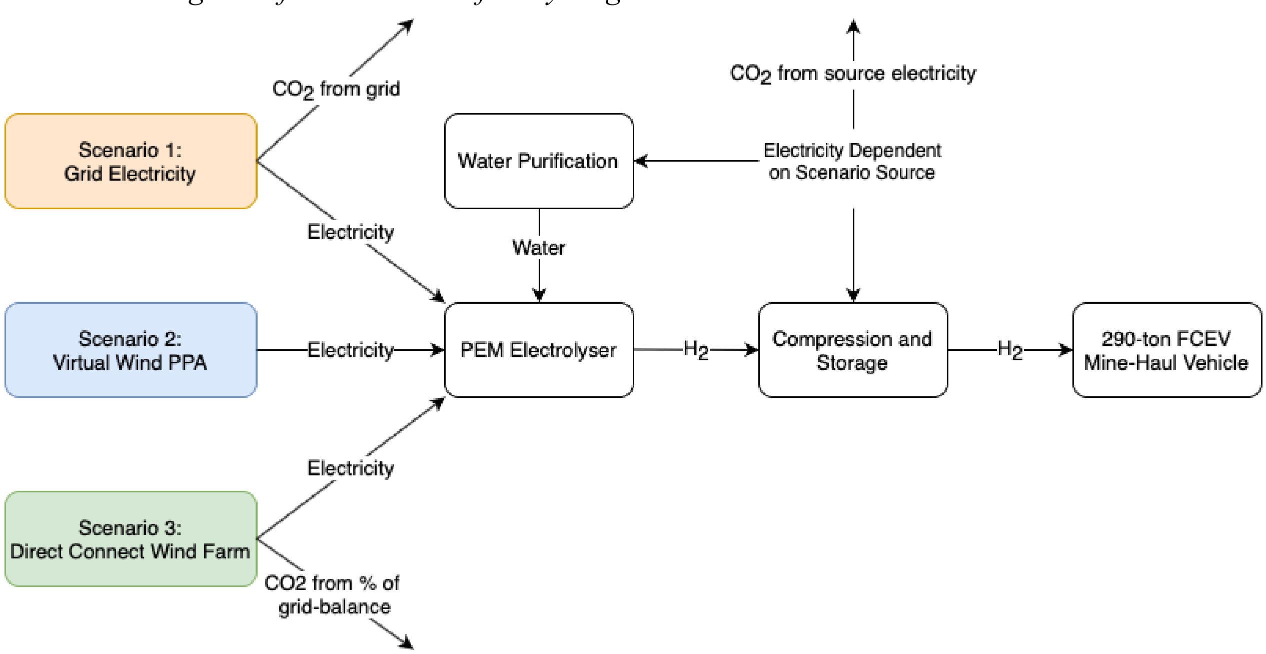
Mineral Demand for Clean Technologies Based on IEA Scenarios.



Note: From EIA, 2021. To reach emissions targets from the EIA's Sustainable Development (SDS) and Net-Zero by 2050 Scenarios, the minerals required for clean energy technologies could increase by 4x-6x current demand. Y-axis is Million Tons (Mt)

Figure 2

Schematic Diagram of the Scenarios for Hydrogen Production Scenarios.



Note: Wallace, 2021

1.1 Novel Approach

This study is unique in that it investigates not only the costs for the technical equipment for fuel-switch from diesel to hydrogen but includes a comparison between electrolysis produced hydrogen from grid-energy and wind-energy to compare CO_2 reductions and economic viability. The study uses historic 10-second wind data from the Canadian Wind Atlas to determine the amount of hydrogen produced from wind energy and the corresponding amount from grid-balancing. The study also compares Canada's carbon tax implications from both political parties to understand how sensitive the financial viability is to the political regimes.

There have been many studies on the techno-economic analysis of hydrogen production from renewables from authors such as Christensen (2020) and Glenk et al. (2019) and industry sources such as Bloomberg New Energy Finance (BNEF), the National Renewable Energy Laboratory (NREL), the International Renewable Energy Association (IRENA), the International Energy Association (IEA). However, only one study found from Vega (2020) (which was only recently released) was a techno-economic feasibility study to compare diesel-fuelled mine-haul vehicles to FCEVs for the Chilean mining industry. Vega (2020) investigated the financial implications for the vehicles and the fuel costs but did not compare different hydrogen-fuel production pathways nor the carbon emission reductions from fuel-switching.

As renewable energy is variable, it becomes challenging for operators to predict the percentage of grid energy required for windfarms of varying sizes and in varying wind capacity factor regions. This can affect the cost of hydrogen production from electrolysis and the financial metrics over the lifetime of a mine. By analyzing the three-year historical 10-minute wind data, the amount of grid-balancing required for different nameplate capacity wind farms, the effect on the cost to produce hydrogen and the emissions reduction was calculated. This allows for a more optimized calculation into the nameplate size required for the wind farm to generate the required amount of hydrogen and predict the cost-savings for fuel-switching.

As Canada has enacted a carbon tax to reduce emissions, this can have a direct bearing on the financial metrics for mine sites due to the amount of CO_2e that is emitted from mine-haul trucks. The current Federal Government's carbon tax is set to reach \$170 /tCO_2e by 2030; however, the Conservative Party of Canada's proposed carbon tax is targeting \$50 /tCO_2e by

2030. Along with emissions reductions, this study investigates how the carbon tax from the two different political platforms can affect the cost-savings for fuel switching.

1.2 Inter-Disciplinary Approach

Sustainable development solutions require a holistic balance between the environment, energy, and economics. This study analyzes how both Scope 1 and Scope 2 emissions can be reduced from switching from diesel-fuel to hydrogen-fuel for large mine-haul trucks. As industrial sectors move towards electrification to decarbonize operations, the amount of energy required from the electrical grid will increase, increasing electricity prices and destabilize the grid if more generation sources are not installed. The economics aspect of this study highlights how utilizing clean energy sources, such as wind turbines, can reduce Scope 2 emissions and be economical by 2030. Utilizing clean-energy wind resources will reduce the grid-electricity required to produce hydrogen and could insulate mining companies from volatile future energy rates.

1.3 UN Sustainable Development Goals

The United Nations Sustainable Development Goals (SDGs) are important call to all countries and industries to take urgent action to achieve a more sustainable future (United Nations, n.d.) This project is anchored in SDG Goal 9, Goal 12, and Goal 13.

- SDG Goal 9 (Industry, Innovation, and Infrastructure): the further testing and technology improvements of hydrogen-fuel-cells and electrolyzers will foster innovation and rapid growth for sustainable industrialization within both the hydrogen and mining industry. Switching to hydrogen fuel can develop local value chains and markets to help increase the gross domestic product and support economic and human development.
- Goal 12 (Responsible Consumption and Production): Goal 12 targets sustainable production and extraction of materials such as minerals by achieving sustainable management and efficient use of natural resources (UN, n.d.). Through transparent emissions reporting for mining companies on Scope 1 and 2 emissions, clean technology procurement companies and investors can better evaluate and choose more sustainable options.

- Goal 13 (Climate Action): as it is expected that global mineral demand for clean energy technologies could increase over 400% by 2050 (EIA, 2020), the emissions from the mining sector are expected to rise in tandem. Climate change threatens global weather patterns and increases in global temperature: decreasing harmful greenhouse gas emissions is essential to preventing a climate crisis. As the extraction and production of diesel fuel contributes 640 grams CO_2 per litre (gCO_2e/litre), and combustion of diesel emits 2660 gCO_2e/litre (Hoekstra, 2020) (NRCAN, 2014), fuel-switching from diesel to hydrogen can drastically reduce fossil-fuel emissions and help achieve net-zero emissions targets by 2050.

Chapter 2 - Literature Reviews and Background Information

This chapter provides literature reviews on previous studies and background information for the mine-haul vehicles and hydrogen production.

2.1 Literature Review

A 2019 paper written by Fúnez Guerra et al. performed a viability analysis on replacing a fleet of 20 diesel-fuelled underground mine vehicles (load haul dump (LHDs)) with hydrogen fuel-cell LHDs. A fuel-cell vehicle is essentially a battery-powered vehicle that uses hydrogen as a fuel to make electricity that is stored in the battery and can extend the range and operating time of the vehicle. The study found that hydrogen could increase the power stored in a battery LHD from 165 kWh to 605 kWh with 30 kgH_2 stored in four tanks (Fúnez Guerra et al., 2019). The authors' techno-economic assessment was developed based on Capital Expenditure (CAPEX) of the hydrogen range extenders (fuel cells, tanks, AC/DC converters), hydrogen production and refuelling station. The study assumed that each diesel LHD would consume 20 litres/hours/vehicle of diesel (approximately 6.3 million litres/year), with a cost of €0.785/L (CAD$1.20/L). Fúnez Guerra et al. (2019) calculated that replacing diesel LHDs would save 21,900 MWh/year and save ~€875,000/year (CAD$1.3 million/year). The results calculated the theoretical net-present value of the hydrogen system was €12,051,391 (CAD$1.84 million) and would have a payback period of 7.8 years. The CO_2 emissions that could be avoided were ~16,537 tonnesCO_2/year.

Another study by Kalantari et al. (2020), focused on how hydrogen could be integrated into a renewable-multi-storage (wind turbine/battery/fuel-cell/thermal storage) system to develop a 100% off-grid power supply for remote underground mining operations with either electric or hydrogen fuel-cell vehicles. Off-grid mines typically rely exclusively on diesel fuel for creating electricity and in mine vehicles as it is reliable and easy to store, however as the fuel must be delivered via barge or airplane, the fuel can be expensive. The parametric feasibility study found that wind speed and mine-life were the most critical parameters and that battery-electric vehicles provided the most significant financial viability over hydrogen fuel-cell vehicles due to the amount of energy lost in the production of hydrogen. However, the study referenced other works for the battery and fuel cell vehicles and was not specific in the size or type of mining vehicle. The results showed that the payback for the most optimal system with battery-electric vehicles was 10.3-10.7 years, where the fuel-cell LHDs was 13.3-18.4 years (Kalantari et al., 2020).

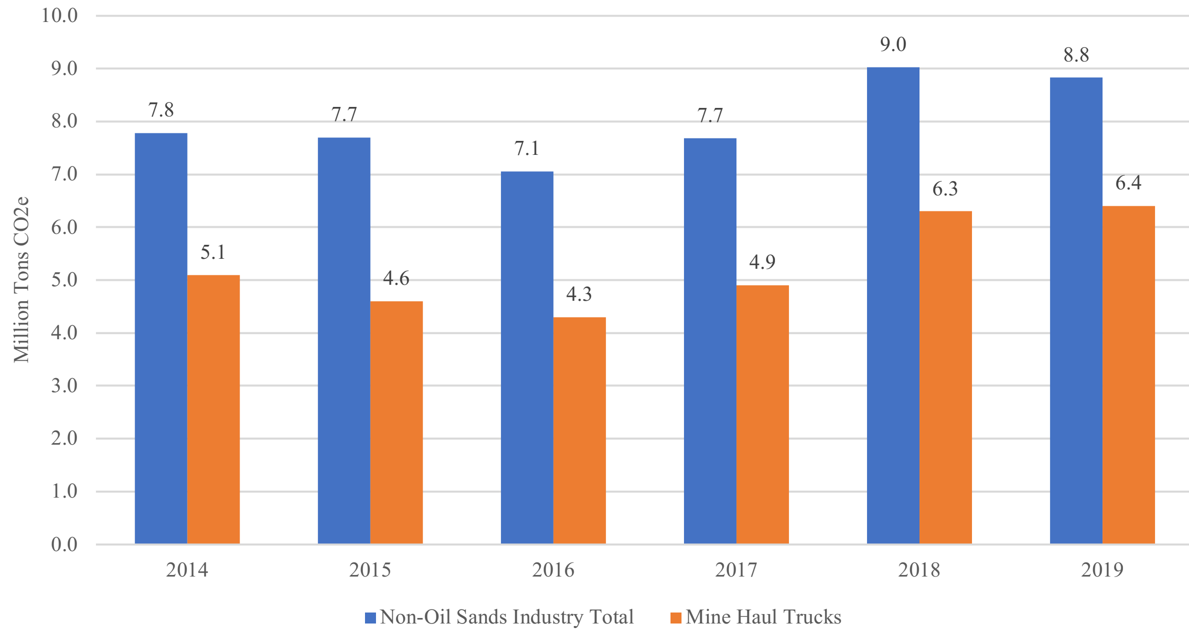
The most recent study on FCEV mine haul vehicles was completed by Vega (2020). The author completed a techno-economic on retrofitting 290-ton diesel-electric mine-haul trucks for hydrogen consumption in Chile. The results indicate that the high cost for producing hydrogen, PEM fuel-cell and battery manufacturing does not make financial sense in 2020 as the costs are 56% higher than the CAPEX for a diesel mine-haul fleet (Vega, 2020). As production costs are expected to decrease towards 2030, the author calculated the net present value for an investment in 2030 and found that the hydrogen retrofitting case was still 8% higher than the convention diesel-case.

2.2 Overview of Mine-Haul Trucks

There are approximately 28,000 large mine-haul vehicles globally, with more than 2000 in Canada (Muralidharan et al., 2019) (Intergroup Consultants, 2017). The average large vehicle (200 tons and greater) uses between 900,000 – 1,400,000 litres of diesel per year and can contribute between 30-80% of a mine's total energy use (Muralidharan et al., 2019). Emissions from mine-haul trucks are estimated to be 68 million tons CO_2e per year (MtCO_2e/year) globally, and in Canada, account for 6.4 MtCO_2e/year (Muralidharan et al., 2019) (Government of Canada, 2020). Since 2016, the emissions from mine-haul vehicles have steadily increased along with the total emissions from the sector (Figure 3).

Figure 3

Carbon Dioxide Emissions from Mine-Haul Vehicles and Non-Oil Sands Mining.

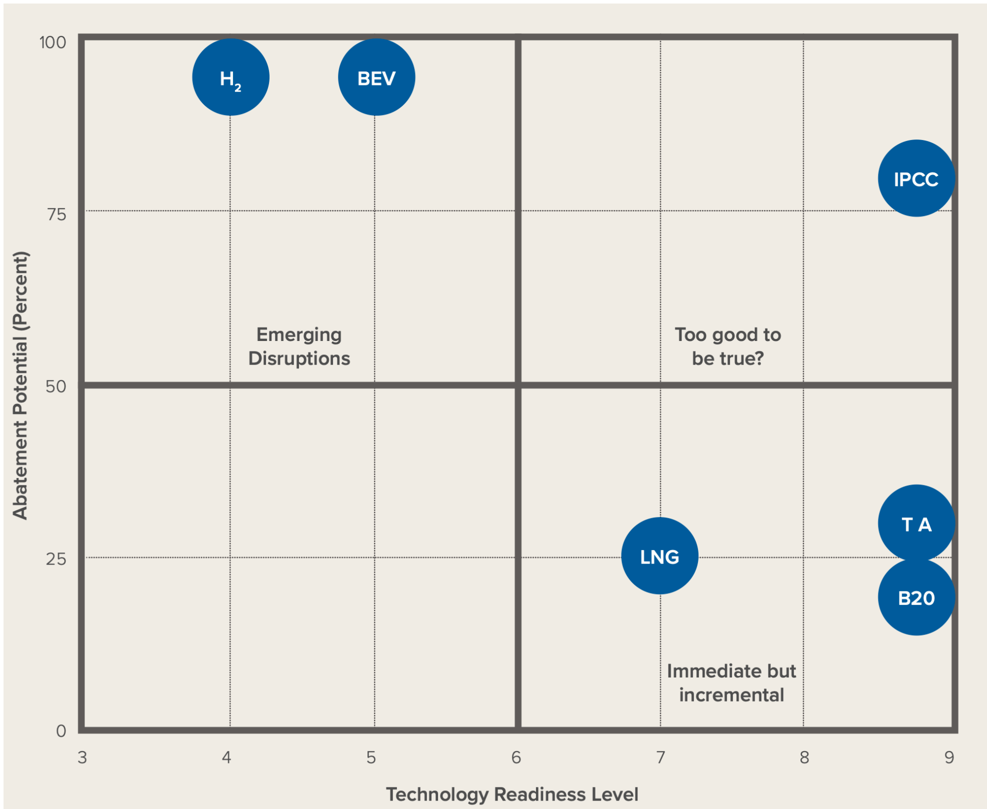


Note: Government of Canada, 2020.

Many of the top mining companies, such as Anglo-American and Fortescue Metals Group, have made net-zero commitments for 2040, and BHP Group, Rio Tinto, and Vale have committed to net-zero by 2050 (Kuykendall et al., 2020). While many have varied approaches to their individual pathways toward net-zero, many companies are looking to alternative fuels and technologies to replace the CO_2-intensive diesel-fuel vehicles that dominate the global mining fleets. For instance, liquified natural gas, biodiesel and trolly assist are further along the in-technology readiness but can only reduce between 15%-30% CO_2 emissions. At the other end of the spectrum, both battery-electric vehicles (BEVs) and hydrogen-fuel-cell vehicles (FCEVs) produce zero CO_2 emissions during their operation but are limited in that fact that they are still in demonstration phases (Figure 4). While this technology is improving, hydrogen is an alternative that needs to be explored deeper.

Figure 4

Mine-Haul Vehicle Decarbonizing Options and Technology Readiness Level.



Note: Muralidharan et al (2019). Hydrogen (H_2), Battery Electric Vehicle (BEV), Liquified Natural Gas (LNG), In-Pit-Crushing-and-Conveying (IPCC), Trolly Assist (TA), Biodiesel 20% (B_{20}).

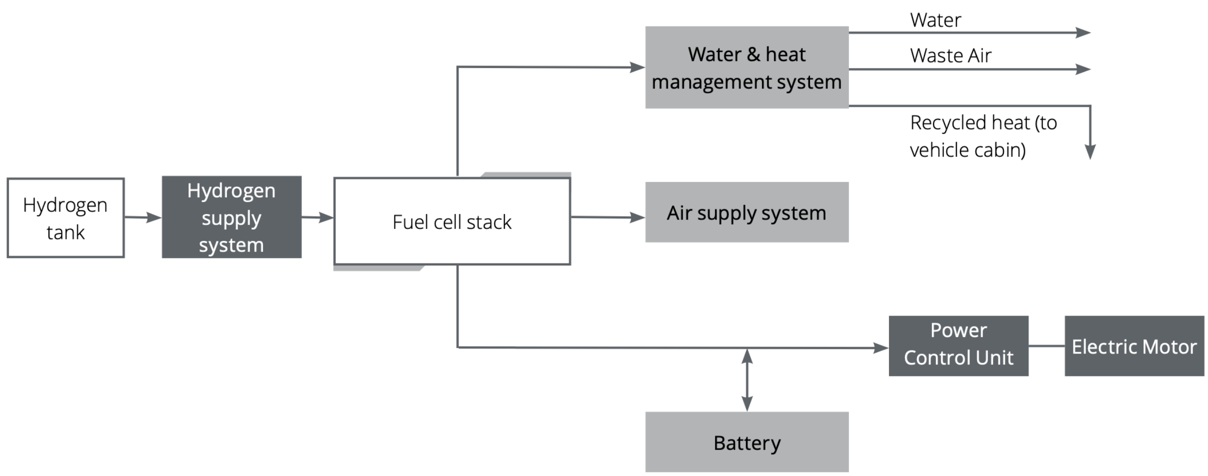
Many underground mine sites are transitioning to BEVs to decarbonize operations and improve worker health and safety. However, as battery storage devices have less energy per mass than hydrogen systems, 150Wh/kg versus 550Wh/kg for hydrogen, they can add more weight to a vehicle and reduce the gross-weight of haulage capabilities (Rivard et al., 2019). This weight difference is the main advantage that hydrogen has in the heavy haul category.

2.2.1 FCEV Mine-haul Demonstration Project

One of the top global mining companies, Anglo-American, has begun a viability study of an FCEV Ultra-Class 290-ton mine vehicle that will run on hydrogen produced from renewable solar energy via electrolysis to lower emissions from their fleet (Anglo American, 2020). It is expected that this vehicle will be in operation by the end of 2021, and if successful, Anglo-American hopes to have 40 of these trucks in operation by 2024. The current demonstration vehicle utilizes eight 100kW Ballard FCmove PEM fuel-cell and a 1.1 MW lithium-ion battery (Moore, 2021). A diagram of the operating principle for an FCEV is depicted in Figure 5.

Figure 5

Diagram of the Operational Principle in a FCEV for Mobility.



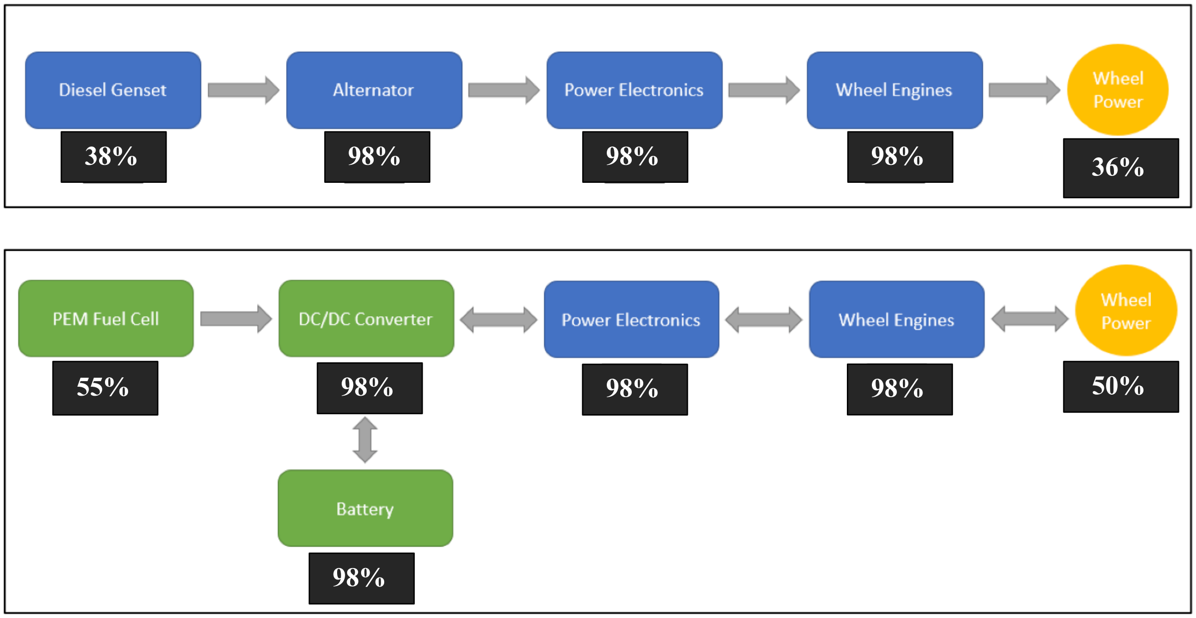
Note: Deloite, 2020

2.2.2 Hydrogen Fuel-Cell Efficiencies

Figure 6 is a comparative diagram of the overall efficiencies of the Komatsu 930E diesel-electric and FCEV mine-haul vehicle. The diesel-electric vehicle has an efficiency of 36%, where the FCEV is 50% (Vega, 2020). The Power Electronics in the diagram refer to the converter, inverter and onboard charger that is responsible for controlling the electric power in the vehicle.

Figure 6

Efficiency Comparison for Diesel-Electric and FCEV Mine Truck Powertrains.



Note: Vega, 2020. Efficiencies are for a Komatsu 290-Ton mine-haul vehicle. Power Electronics refer to the converter, inverter and onboard charger that is responsible for controlling the electric power in the vehicle.

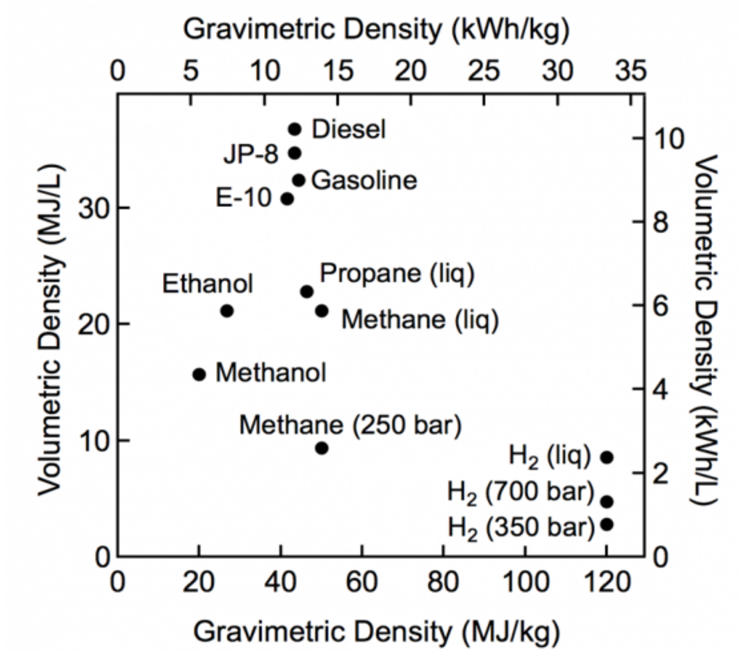
2.3 Hydrogen as a Fuel Overview

Comparatively, hydrogen is the most abundant and lightest element on the periodic table. As a gas in its natural state, it is invisible, odourless, tasteless, non-toxic. As an energy carrier, hydrogen has the highest specific energy (energy per mass) but the lowest volumetric density than any other fuel-based on lower heating values (Figure 7). For example, hydrogen has nearly 3x the energy content of diesel on a mass basis: 120 Mega Joules per kilogram (MJ/kg) versus 44 MJ/kg. However, on a volumetric basis, hydrogen is 4.75x less than diesel: 8 MJ/litre versus 38 MJ/litre (Office of Energy Efficiency and Renewable Energy, n.d). On a kilowatt-hour basis, diesel has a value of 10.22 kWh/litre, where hydrogen has 33.6 kWh/kg.

In comparison to battery storage devices, hydrogen energy systems contain more energy per mass, 550 Wh/kg versus 150 Wh/kg for batteries (Rivard et al., 2019). This weight difference is the main advantage that hydrogen has in the heavy transport sector.

Figure 7

Comparison of Fuel Sources Based on Lower Heating Value.



Note: Office of Energy Efficiency and Renewable Energy, n.d. Comparison of volumetric energy density (energy per volume) and specific energy (energy per mass) for different fuel sources based on lower heating value.

2.4 Hydrogen Production from Electrolysis Overview

An electrolyzer uses electricity to split water into hydrogen and oxygen. According to Saulnier et al. (2020) current commercially available PEM electrolyzers require between 10-11 litres of water for every kilogram of hydrogen produced (Saulnier et al., 2020). Theoretically, if an electrolyzer operated at 100% efficiency, it would require 39 kWh to produce one kilogram of hydrogen (Christensen, 2020). Current PEM electrolyzers are approximately 60%-70% efficient and are expected to increase to 75% (Mallapragada et al., 2020) (Christensen, 2020). An electrolyzer with 67% efficiency requires 58.4 kWh to produce 1 kg of hydrogen.

The low volumetric density for hydrogen makes storing this fuel a challenge. Hydrogen is typically stored in its natural state as a gas; however it can also be stored as a liquid or in materials-based storage technologies, with the latter still in development testing. Gaseous storage is typically done at low pressure (~100 bar) in pressurized tubes that can be bundled together. At high pressure (<300bar), hydrogen can embrittle and fatigue metals, so storage vessels must be designed with specialized materials to resist this challenge (Mallapragada et al., 2020). High-pressure storage vessels are typically more expensive than low pressure for this reason. As PEM fuel-cells typically run at 700 bar pressure, onboard storage tanks must be designed to handle this pressure. Some electrolyzers can output hydrogen at high pressure, but for those that do not, compressors are required to pressurize up the storage tanks to the required pressure.

The cost to produce the hydrogen is directly linked to the efficiency of the electrolyzer and the cost for the electricity. To determine production cost, the amount of electricity required is multiplied by the cost for the electricity. It should be noted that this is not the same as the Levelized Cost of Hydrogen Production (LCOH). The production cost is for the input energy and does not include the CAPEX and OPEX for the electrolyzer, compressor, storage, and water purification system.

The cost to produce hydrogen from a Variable Renewable Energy (VRE), such as wind, is linked to the CAPEX and OPEX for the wind farm and the wind capacity factor for the site: the higher the capacity, the lower the cost and vice versa. The Levelized Cost of Electricity (LCOE) can be calculated from the total costs for the wind farm and divide by the total amount of energy produced. The capital cost for new onshore wind installations has decreased by 71% over the past decade and is expected to drop another 35% by 2030 (Lazard, 2020) (CER, 2020) (IRENA, 2019). As wind energy is variable, a direct connect wind farm would require a certain amount of grid-balancing, which is linked to the size of the wind farm, the amount of hydrogen storage and the wind capacity factor. Excess hydrogen is stored and utilized when wind energy is insufficient to produce the require amount of hydrogen. Grid energy is required when the storage has been depleted.

2.4.1 Ontario Electricity Rates and Grid Overview

Electricity for Ontario is managed by the Independent Electricity System Operator (IESO). Commercial customers are charged a fixed-rate rather than time-of-use (TOU) pricing, and are subject to the global adjustment fee, which covers the cost of new energy infrastructure and conservation programs to ensure that enough electricity supply will be available in the long-term. The annual 2020 electricity price for a large industrial customer was between $9.90/kWh and $12.81/kWh, with an average rate of $112.90/MWh (IESO, 2021). According to the IESO (2021a), a portion of the electricity rate is subsidized by the Ontario Provincial Government, which means the actual rate is likely much higher.

As the actual electricity rate is based on two estimates depending on hourly demand, large consumers are unable to accurately forecast electricity costs (IESO, 2021a). In the IESO's 2020 Annual Planning Outlook report, the operator discusses how over 21 GW of existing contracts/commitments will have reached expiry by mid-decade and there will be a gap emerging in the market that will require new options (IESO, 2021). If capacity has not been filled, the short-term needs of the market will require capacity auctions that will increase the cost of electricity (IESO, 2021). The author assumes that this capacity gap will likely be filled with natural gas generation facilities (until new clean sources can be built), which will not only increase the carbon emissions intensity of the grid, but in turn increase electricity prices.

The assumptions used in the IEA G20 Hydrogen Report, which was used to create the IEA Future of Hydrogen Report, expected the electricity rate for the United States (U.S.) to increase by 3% per year to 2030 and then 0.5% into the future (IEA, 2020). Another report by the Goldman School of Public Policy from the University of Berkley, California assumes that as the U.S. electrical grid approaches 80% clean energy generation, the cost for electricity could increase by 0.6%/year to 2030 (Abhyanker et al., 2021) (Phadke et al., (2020).

2.4.2 Power Purchase Agreement Overview

Power purchase agreements (PPAs) are becoming increasingly popular for corporations as they provide opportunities to hedge against rising electricity prices and as a means to deliver on sustainability goals (such as reducing emissions). A PPA is defined as a contract to purchase power/electricity from an energy generator. Typically, PPAs are for renewable energy, but they could in theory, be for any energy generation type. Contracts are for a set-price over an agreed length of time, and all risks that stem from owning and operating the asset are assumed by the third-party seller. The renewable energy asset can be co-located on the customers' site (behind-the-meter) and directly connected to their equipment, or off-site where electricity flows from the grid to location (in-front-of-the-meter). Off-site scenarios are typically called a virtual power purchase agreement (VPPA). In both cases, the electricity generates a renewable energy certificate (REC) to validate sustainability goals, or for carbon offset programs to either use sell to other companies. For this study, the cost of RECs was not included as Ontario is not participating in a carbon offset program at the moment.

As costs for wind energy continue to decline, the cost of electricity generated by wind has also followed this trend. In regions of Canada with high wind capacities, such as Alberta, PPAs for wind energy have regularly been below $50/MWh (Barron, 2020). According to the Canadian Wind Energy Association (CANWEA), Ontario's most competitive wind energy procurement was in 2014 for $84.50/MWh for 20 years (CANWEA, n.d.).

Chapter 3 - Study Outline and Methodology

3.1 Objective

The primary objective of this study is to determine the number of emissions that can be reduced from switching from diesel-fuel to hydrogen-fuel and develop a prefeasibility techno-economic model to understand the potential cost savings for an open-pit mine-haul fleet in Canada. As it is difficult to predict the future costs and technology learnings, literature reviews of current public information and data sources were investigated to determine the Capital Expenditure (CAPEX), Operational Expenditure (OPEX) and assumptions for this techno-economic model. This study also includes the policy implications of the current and future carbon tax that the Federal Government mandates on emissions in Canada. While there are many new and disruptive technologies in the hydrogen space, only readily available and proven were considered for this study. All currency values are in Canadian Dollars ($CAD).

One major challenge for this study is that, as of August 2021, there is only one 290-ton FCEV demonstration vehicle, which is expected to be operational by the end of 2021. Therefore, costs have been assumed based on the diesel equivalent and the additional equipment required to convert the vehicle to hydrogen-fuel. As it is predicted that FCEV Ultra-Class 290-ton or greater mine-haul vehicles will not enter commercial production until 2025 or later, it allows the mining industry to prepare and evaluate how switching to hydrogen-fuel can affect their business and Environmental Social Governance (ESG) metrics.

The assumptions and costs are outlined in Chapter 4 and Chapter 5, and the results and conclusions in Chapter 6 and Chapter 7.

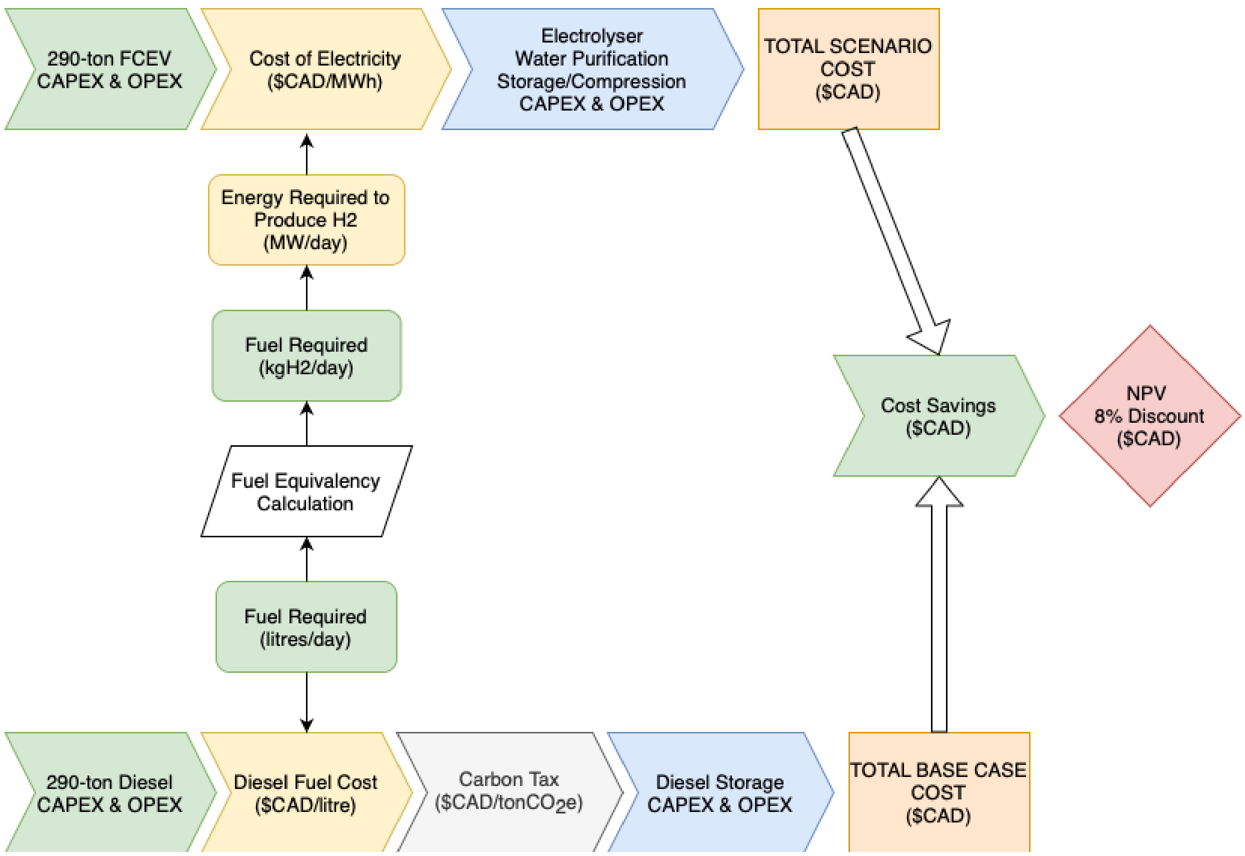
The main objective of this study is the following:

- Develop a techno-economic prefeasibility evaluation for a 290-ton FCEV Ultra-Class mine-haul vehicle, fuelled with hydrogen produced from the electrolysis of water, in a grid-connected Canadian open-pit mining location, with a mine life of twenty (20) years.
- Determine the overall Scope 1 and Scope 2 CO_2 emissions reduction from fuel-switching from diesel to hydrogen and compare the additional reductions from producing hydrogen from grid electricity and wind energy.

- Calculate the LCOH for hydrogen production based on the three (3) different electricity procurement scenarios.
- Determine the cost savings (Figure 8) over a 20-year mine, with investment dates between 2020 and 2030, to show how investment optionality can affect the financial metrics due to technology learnings and future cost increases/decreases.

Figure 8

Flow Diagram of Techno-Economic Model.



Note: Wallace, 2021.

3.2 Fictitious Mine Scenario

A fictitious mine was used for the case study and is assumed to operate for 20 years. As it is assumed that capital and operating expenditures (CAPEX and OPEX) for the diesel-fuel base case and the hydrogen scenarios will increase and decrease over time, this study analyzes the investment optionality to determine when fuel-switch will be financially viable. For instance, the financial metrics were calculated based on a 20-year mine life, with an investment start date between 2020 and 2030. With an investment in 2020, financial metrics are calculated to 2040, while investment in 2030 would run until 2050. The total investment costs (CAPEX and OPEX) for each scenario and each investment start date are calculated, and then the cost savings were calculated based on the Net-Present-Value (NPV) with an 8% discount factor. All monetary values in this paper are in Canadian Dollars ($CAD).

Any shortage of fuel or extended downtime for trucks can have financial implications for the mine site. For this study, it is assumed that the tonnage of ore hauled, kilometres driven, and fuel usage will remain constant for the lifetime of the mine.

3.3 Mine-Haul Vehicle

The size of the mine-haul vehicle for both the diesel-fuel base-case and the FCEV scenarios was chosen based on the recent announcement by Anglo American and ENGIE regarding a demonstration project converting a Komatsu 930E 290-ton Ultra-Class vehicle to an FCEV, with 800 kW PEM fuel-cell and 1.1 MW lithium-ion battery (Anglo American, 2020). There are no official reports published on the CAPEX and OPEX for the FCEV mine-haul vehicle. Interviews with anonymous industry professionals and one paper by Vega (2020) have agreed that the CAPEX for the FCEV vehicle would be approximately 30% more than that of the diesel equivalent ($8.58 million versus $6.6 million for the diesel-fuel truck). This includes the cost of the PEM fuel cell, onboard hydrogen storage, and the lithium-ion battery pack.

The OPEX for an Ultra-Class mine-haul vehicle can be upwards of 60% of the CAPEX per year (Stantec, 2019). This includes parts, lube, tires, maintenance labour and operator labour. While these are important parameters to consider, it becomes problematic when comparing the cost to that of a FCEV that currently has no data on OPEX. It could be assumed that tires, maintenance labour, and operator labour would be similar for both the diesel-fuel and FCEV cases, and only the drive train replacement costs (diesel engine, PEM fuel cell and lithium-ion battery) would differ. With this in mind, an OPEX value of 2% of CAPEX was considered for both cases.

3.3.1 Hydrogen Fuel and Energy Requirements

The amount of hydrogen-fuel required is based on an energy equivalency from the amount of diesel required for the conventional 290-ton vehicle. As diesel has 10.22 kilowatt hours per litre (kWh/litre) and hydrogen has 33.6 kilowatt hours per kilogram (kWh/kg); thus, the fuel-cell would require 0.304 kgH_2 for every litre of diesel required. Intergroup Consultant (2017) report estimated the 290-ton truck would require 187 litres of diesel-fuel per hour (litre/hour). Thus the equivalent amount of fuel is 56.9 kgH_2/hour.

The amount of energy required for electrolysis is dependent on the efficiency of the electrolyzer. For this study, a Cummins HyLYZER-1000 was modelled for the electrolyzer, requiring 5 MW input power and producing 2,055 kgH_2/day (Cummins, 2021). With an efficiency of 67%, the input energy required will be 58.4 kWh/kgH_2. Thus, if the FCEV requires 56.9 kgH_2/hour, the electrolyzer will require 3.2 MW.

As technology learnings increase, the efficiency of the fuel-cell and the electrolyzer will increase: requiring less hydrogen and less energy, which will, in turn, reduce costs.

3.4 Carbon Tax on Diesel

For this study, it is assumed that the carbon tax will be incurred on the Scope 1 emissions (sources directly controlled or owned by mining company) from combusting the diesel in the mine-haul trucks. According to Natural Resources Canada, diesel-fuel emits 2.66 kilograms CO_2e/litre (NRCAN, 2014).

In December 2020, the Canadian federal government announced increasing federal Carbon Tax from \$30/tCO_2e by \$10/tCO_2e until 2022, and then \$15/tCO_2e to \$170/tCO_2e in 2030 (Government of Canada, 2020c). The carbon tax is part of the federal Greenhouse Gas Pollution Pricing Act (GHGPPA).

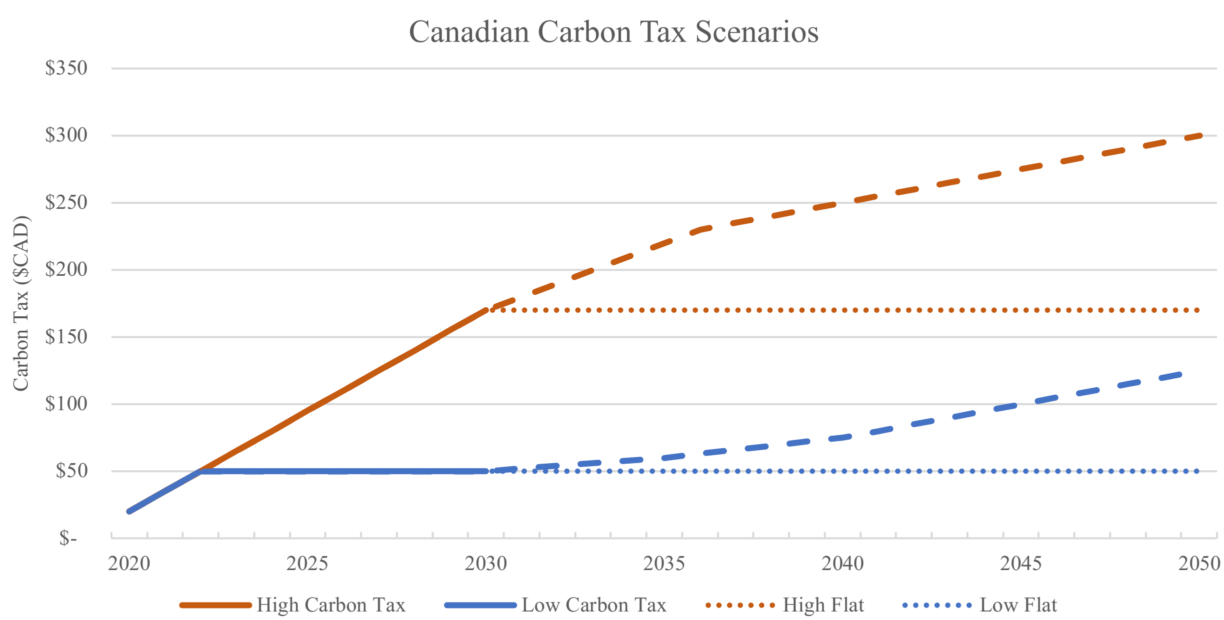
The carbon tax is split into two scenarios for this study: high carbon tax and low carbon tax. The high carbon tax is based on the current Federal/Liberal Government's carbon policy, increasing to \$170/tCO_2e in 2030. The low carbon tax scenario is based on the Conservative Party carbon platform, which will hold the carbon tax at \$50/tCO_2e to 2030 (Conservative Party of Canada, 2021).

As the economic model for this study is calculated to 2050. As neither party have released forward looking statements regarding the carbon tax past 2030, it has been assumed that the carbon tax will continue to rise or stay flat at the 2030 rate. The Canada Energy Regulator (CER) has projected that the carbon tax will likely continue to rise to 2050 for the country to meet its net-zero emissions target (CER, 2020). For this study, it has been assumed that each of the political platforms would continue to increase carbon taxes toward 2050. A sensitivity was performed to analyze how the carbon tax holding flat between 2030-2050 would affect the results.

Figure 9 is a graph of the high and low carbon tax scenarios and the extrapolations to 2050.

Figure 9

High and Low Carbon Tax Scenarios and Extrapolations to 2050.



Note: Government of Canada, 2020c; Conservative Party of Canada, 2021. Author assumes that the carbon tax will increase to 2050 for both cases. A sensitivity was completed to analysis how no increase (holding flat) affects results.

3.5 Hydrogen Production Scenarios

As there are many pathways and technologies to produce hydrogen, this study focuses only on production from the electrolysis of water in a PEM electrolyzer as this technology is commercially available and proven. The CAPEX and OPEX for water purification of the feedstock (reverse osmosis water filtration unit) and 700-bar pressurize storage and compression is also included.

For each of the three (3) scenarios below, the cost for the FCEV, electrolyzer, water purification, compression and storage are identical. Only the cost of electricity for the electrolyzer varies. Electrolysis requires an ample supply of electricity to split water molecules into hydrogen and oxygen. Three (3) scenarios were considered for the procurement of electricity to determine which scenario would lead to the greatest emissions reductions and cost-savings: (1) grid-connected, (2) virtual wind Power Purchase Agreement (PPA), (3) direct connect wind farm (Figure 10)

- *Scenario 1 - Grid Rate*: electricity is procured directly from Ontario electrical grid at $115 per megawatt hour (MWh), which is based on the annual 2020 average electricity price for a large industrial electricity customer on the Ontario electrical grid (IESO, 2021). This price includes the transmission, distribution, and grid charges. The CO_2 emissions (Scope 2) from the Ontario grid are estimated to be 77 grams CO_2e per kWh (gCO_2e/kWh) (CER, 2021).

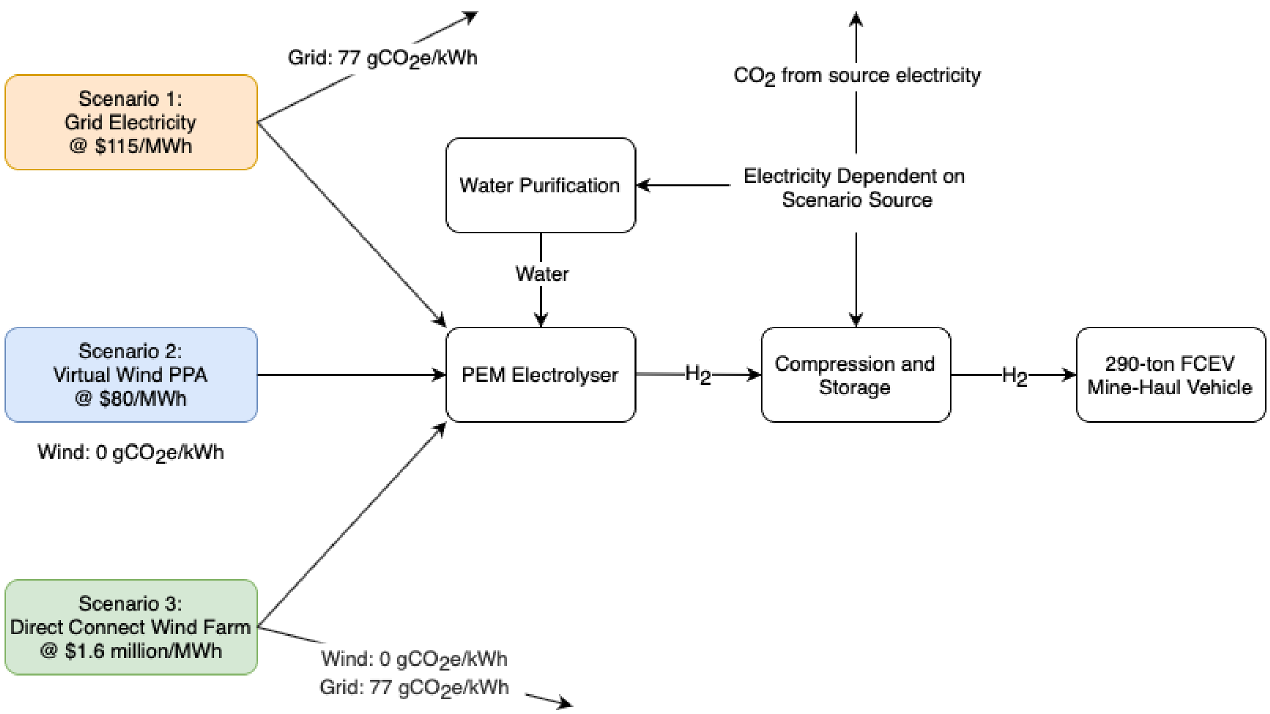
- *Scenario 2- Wind Virtual Power Purchase Agreement (VPPA)*: electricity is procured from a co-located or near located wind farm through a 20-year PPA at $80/MWh. As this is an in-front-of-the-meter wind farm, this price includes the transmission, distribution, and the global adjustment fee. The Scope 2 CO_2 emissions from the production of electricity from wind power are zero. It is assumed that the developer has designed the renewable energy facility to meet or exceed the demand for the mining company.

- *Scenario 3 - Direct Connect Wind Farm*: electricity is produced from a wind farm that is directly connected to the electrolyzer and owned and operated by the mining company (behind-the-meter) with a CAPEX of $1.6 million/MW. According to the Wind Atlas for

Canada, the wind capacity factor in the Sudbury region is estimated to be approximately 28% (Government of Canada, 2021). As wind energy is variable, grid-balancing would be required with electricity procured at the same rate as *Scenario 1* of $115/MWh. Emissions are calculated based on the percentage of wind energy and grid-balancing required. Scope 2 CO_2 emissions from the electricity required from the grid is calculated at 77 gCO_2e/kWh as in *Scenario 1*.

Figure 10

Schematic Diagram of Hydrogen Scenarios.



Note: Wallace, 2021. Grid-electricity carbon intensity from (Government of Canada, 2021).

3.6 Grid-Balance Calculation

Grid-balancing refers to the amount of electricity from grid-energy to offset variable renewable energy (VRE) generation sources (wind turbines). For hydrogen production via electrolysis, the amount of grid-balancing required is related to the wind capacity factor, the size of the wind farm, and the amount of hydrogen storage on-site. The average wind capacity for

Ontario is approximately 30% (CANWEA, 2016) and it is assumed that there would be two (2) days of hydrogen storage on-site for one FCEV. The size of the windfarm required was determined by modelling the percentage of grid-balance, CO_2 emissions from grid-energy and the LCOH. Using historic 10-second wind data from the Canadian Wind Atlas, the amount of hydrogen produced from wind energy each day was calculated, and any excess hydrogen was stored in high-pressure storage tank to be used for times when wind energy was lacking. When storage was depleted, the electricity would be pulled from the grid.

Overview of methods for grid-balance calculation:

1) Historical 10-minute wind speed data, extrapolated to 80m hub height, from 2008-2010 was downloaded from the Government of Canada Canadian Wind Atlas site for a location close to the industrial mining area of Sudbury. Figure 11 shows the 2008 average hourly wind speed data with a 100-point moving average to show season variation.
2) The power curve for a 5MW onshore wind turbine was used to calculate the turbine output (kW) depending on wind speed (meters per second (m/s)). A Bard 5.0 wind turbine was chosen as the reference turbine from the System Advisor Model (SAM) software (NREL, 2021) (Figure 12). The maximum output of this turbine is 5000 kW at 12.5 m/s wind speed. The total amount of power produced (kW) was calculated by comparing the wind speed (m/s) to the power output of the turbine (kW) and multiplying by the number of wind turbines in the wind farm. This was
3) The amount of hydrogen produced per hour was calculated by multiplying the output power of the wind turbine (kW) by the energy required by the electrolyzer (kWh/kg). The amount of hydrogen produced per day was the sum of all hydrogen produced in 24 hours.
4) The amount of hydrogen required per day was found based on the fuel equivalency calculation for the FCEV truck.
    a. Excess-produced hydrogen is stored to be used when the wind power is insufficient for the required hydrogen production. It is assumed that there would be two (2) days of on-site hydrogen storage in pressurized tanks.

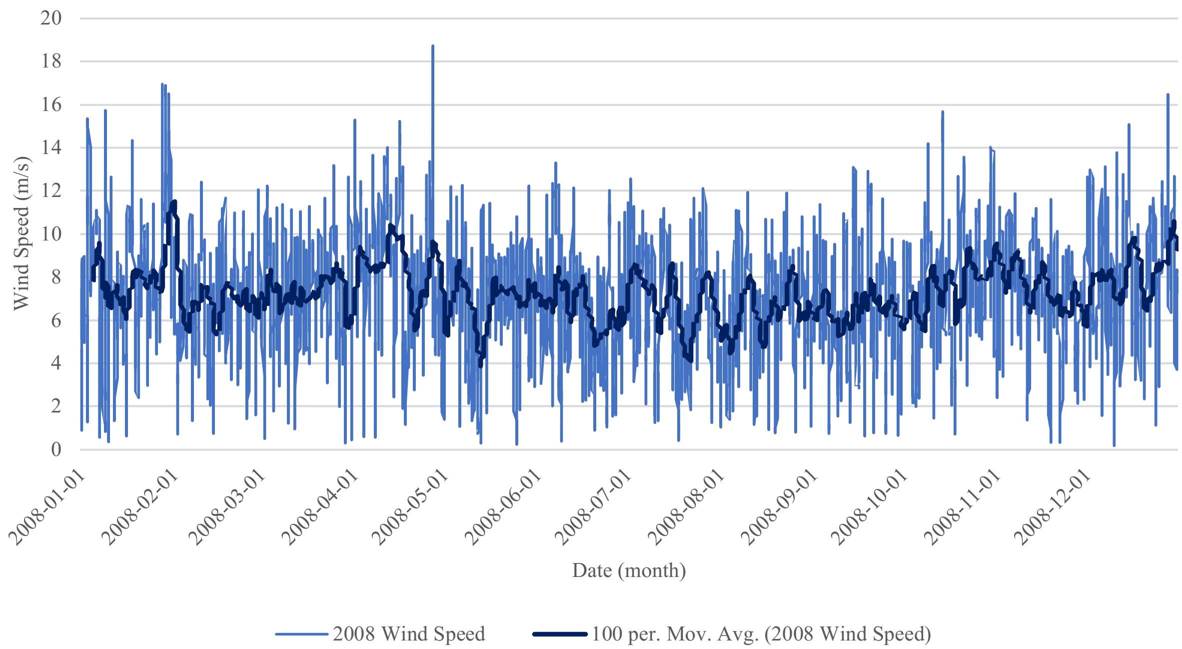
b. If the wind farm did not produce the required amount of hydrogen, the amount available in storage would be used until depleted.

c. The balance of the required hydrogen would be produced from grid electricity.

5) The percentage of grid-balancing was calculated by dividing the total amount of grid-produced hydrogen by the amount of hydrogen produced from wind-energy.

Figure 11

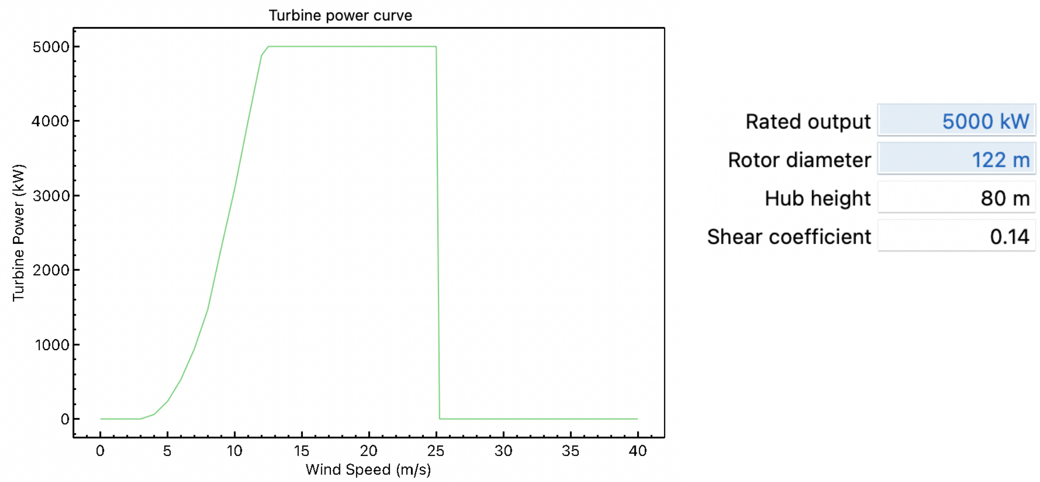
2008 Average Hourly Wind Speed Data for Sudbury Region.



Note: Government of Canada (2021). 2008 historical wind speed data from Canadian Wind Atlas for Sudbury, Ontario Region. Dark blue trendline shows seasonal variation in wind speed.

Figure 12

Power Curve for BARD 5.0 Wind Turbine.



Note: NREL, 2021

Chapter 4 –Diesel-Fuel Base Case

This chapter summarizes the parameters used in the model for the Diesel-Fuel Base Case. The primary sources of data and assumptions to create the economic model are referenced in the tables below. Appendix A includes a tabulated overview of the cost for a 20-year mine with an investment start date in 2020. This calculation was repeated for investment years 2021 to 2030.

4.1 Diesel-Fuel Base Case

For the Diesel-Fuel Base Case, the following parameters were analyzed:

- Diesel Mine-haul Truck CAPEX costs, lifetime, and technology learnings
- Diesel mine-haul truck OPEX costs and lifetime of replacement components (engine)
- Diesel-fuel costs and future costs of diesel
- Storage cost of diesel
- Carbon Tax on diesel-fuel emissions

4.1.1 Diesel-Fuel Base Case Parameters and Cost Assumptions

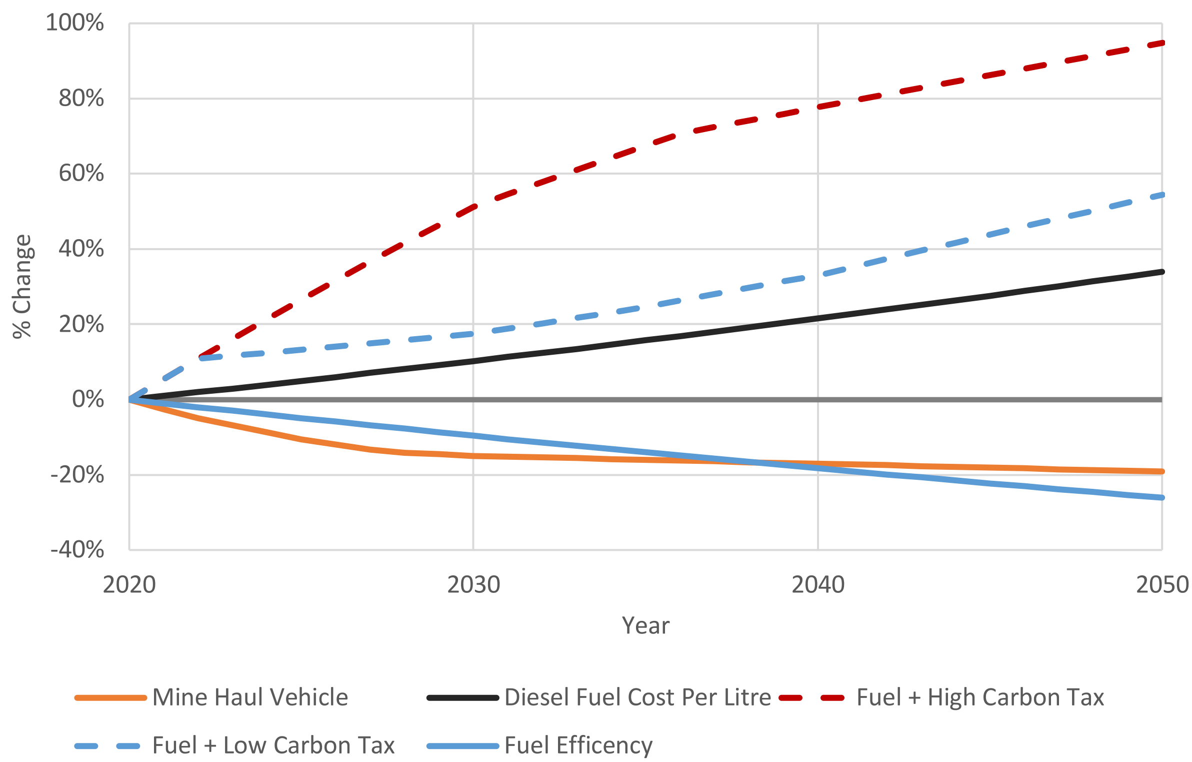
The CAPEX, OPEX, lifetime of equipment and assumptions are outlined in Table 4.1. Figure 13 is a graphical representation of the change in normalized costs from 2020 to 2050 based on assumptions in Table 4.1.

The CAPEX for the diesel-fuelled 290-ton vehicle is \$6.6 million and is based on an industry white paper by Stantec (2019). The lifetime of the diesel engine is approximately 27,000 hours, and replacement costs are 10% of the vehicle CAPEX (Vega, 2020). As previously mentioned, the OPEX is set at 2% as the significant items such as tires, maintenance and labour would be similar for both cases. It is assumed that manufacturing and technology learnings will allow for the capital costs to decrease by 2% per year and fuel-efficiencies to increase by 1% per year. Thus, there will be a decrease in the amount of fuel used and the amount of CO_2 emitted for every engine replacement. The industrial fuel-rate of \$0.80 /litre is based on the Government of Ontario (2021b) website on motor fuel prices. It is assumed that diesel-fuel costs will increase by 2% per year.

It is assumed that there will be two days of diesel storage onsite (which is identical timeframe for the hydrogen scenarios). The CAPEX is $52 per litre stored, and OPEX is approximately 10% of CAPEX, including electricity and maintenance costs. There was no decrease in costs associated with storage CAPEX as this is a mature technology.

Figure 13

Change in Normalized Cost Parameters for Diesel Base Case.



Note: Wallace, 2021.

Table 4.1:

Parameters and Costs for Diesel-Fuelled Base Case.

Parameter	Unit	2020 Value	2030 Value	2050 Value	Reference
Diesel Truck Size	Tonnes	290	290	290	(*)
Fuel Usage	Litres/hour	187	169	138	(1)
% Utilization	Percentage	75%	75%	75%	(1)
Diesel Truck Lifetime	Hours	80,000	80,000	80,000	(2)
Engine Lifetime	Hours	27,000	27,000	27,000	(3)
Mine Truck CAPEX	$CAD/truck	$6,600,000	$5,615,458	$5,341,255	(2)
Engine Replacement Cost	$CAD/truck	$660,000	$561,546	$534,125	(3)
Diesel Mine Truck OPEX	% of CAPEX	2%	2%	2%	(2) (*)
Fuel Cost	$CAD/Litre	$0.80	*$0.98	*$1.45	(4) (*)
Days of Diesel Storage	Days	2	2	2	(*)
Storage Tank Lifetime	Years	30	30	30	(5)
Install Storage CAPEX	$CAD/litre stored	$52	$52	$52	(5)
Diesel Storage OPEX	% of CAPEX	10%	10%	10%	(5)
Diesel Emissions Intensity	gCO_2e/litre	2,660	2,660	2,660	(6)
Low Carbon Tax	CAD/tCO_2$e	$30	$50	$125	(7) (8)
High Carbon Tax	CAD/tCO_2$e	$30	$170	*$300	(9) (*)
Mine Lifetime	Years	20	20	20	(*)
NPV Discount Value	Percentage	8%	8%	8%	(*)

Note: Wallace 2021. This table summarizes the parameters used in calculating the financial metrics for one (1) diesel-fuelled mine-haul truck in the base case. References for the parameters in the table: (*) Author Assumption; (1) Intergroup Consultants (2017); (2) Stantec (2019); (3) Vega (2020); (4) Government of Ontario (2021b); (5) Robert and Company (2017); (6) NRCAN (2014); (7) Conservative Party of Canada (2021); (8) CER (2020); (9) Government of Canada (2020c).

4.1.2 Results of Diesel-Fuel Base Case Analysis

Based on the parameters in Table 4.1, the amount of fuel required by one (1) 290-ton diesel-fuelled vehicle was estimated to be 187 litres/hour and 3,336 litres/day with 75% operational hours. Over a 20-year mine life, with increases in fuel-efficiency of the diesel engine during every 4-year replacement, the amount of fuel required is 22.5 million litres, and for an investment start date of 2030, this amount decreases by 10% to 20.3 million litres. At 2660 grams of CO_2e/litres, the daily CO_2 emissions are 9 tCO_2e/day. For a 20-year mine with an investment start date in 2020, the total CO_2e emissions are 60,196 tCO_2e and 54,440 tCO_2e by 2030 (Figure 14). This is a 10% reduction in Scope 1 emissions with fuel efficiency increases.

Based on the CAPEX, OPEX and assumptions in Table 4.1, the analysis details are outlined below and are calculated on the low carbon tax and the high carbon tax scenarios. A discount factor of 8% was used for the net present value (NPV) to determine the time value of money for the cost comparisons.

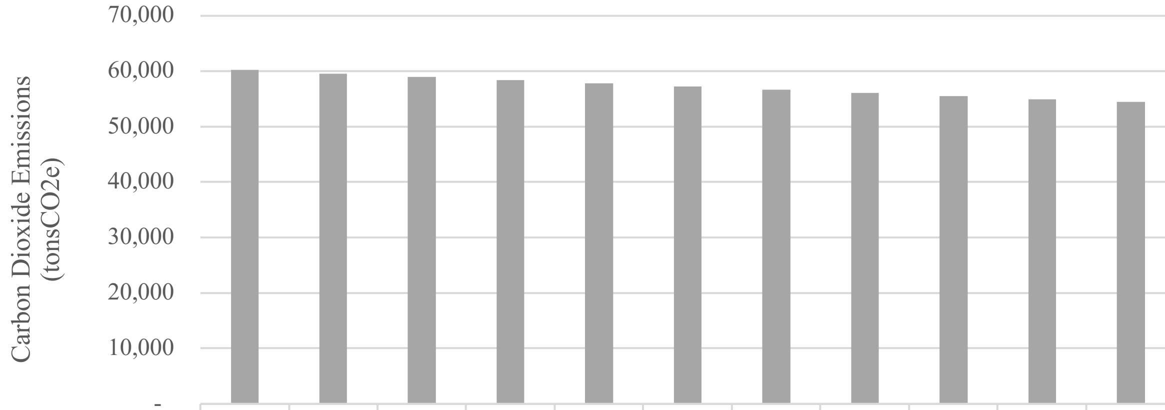
Figure 15 depicts the total undiscounted costs for the Low-Carbon Tax Scenario for a 20-year mine and investment start date between 2020-2030. In 2020, the low-carbon tax contributes \$3.3 million to the total undiscounted cost of \$42.4 million. In 2030, the carbon tax increases to \$4.5 million with a total undiscounted cost of \$44.5 million. This is an increase of 5% in the total undiscounted cost from 2020 to 2030. The NPV, with an 8% discount rate, is \$21.8 million in 2020 and \$10.2 million in 2030 (Figure 16).

Figure 17 depict the total undiscounted costs for the High-Carbon Tax Scenario for a 20-year mine life and investment start date between 2020-2030. In 2020, the carbon tax contributes \$9.6 million to the total undiscounted cost of \$48.6 million. In 2030, the carbon tax increases to \$13.5 million to the total undiscounted cost of \$53.5 million. This is a 10% increase in costs from 2020 to 2030. The NPV, with an 8% discount rate, is \$24 million in 2020 and \$12.1 million in 2030 (Figure 17).

Appendix A is a tabulated overview of the cost summarys for a 20-year mine with an investment start date in 2020.

Figure 14

Total Amount of Carbon Dioxide Emissions from Diesel-Fuelled Mine-Haul Vehicle.

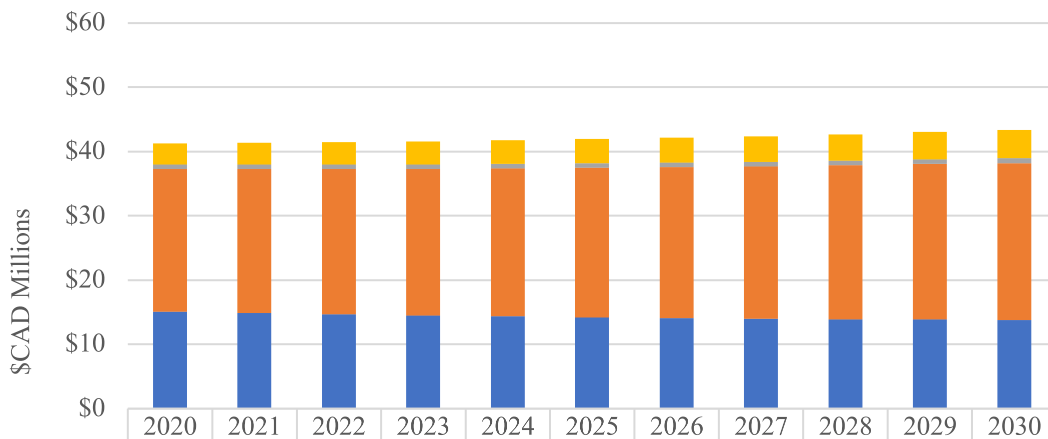


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Diesel Base Case	60,196	59,594	58,998	58,408	57,824	57,246	56,673	56,107	55,546	54,990	54,440

Note: Wallace, 2021. The graph depicts the amount of Scope 1 emissions from combusting diesel-fuel in one mine-haul truck for each 20-year mine lifetime with an investment start date between 2020 and 2030.

Figure 15

Undiscounted Total Costs for Low Carbon Tax Base Case.

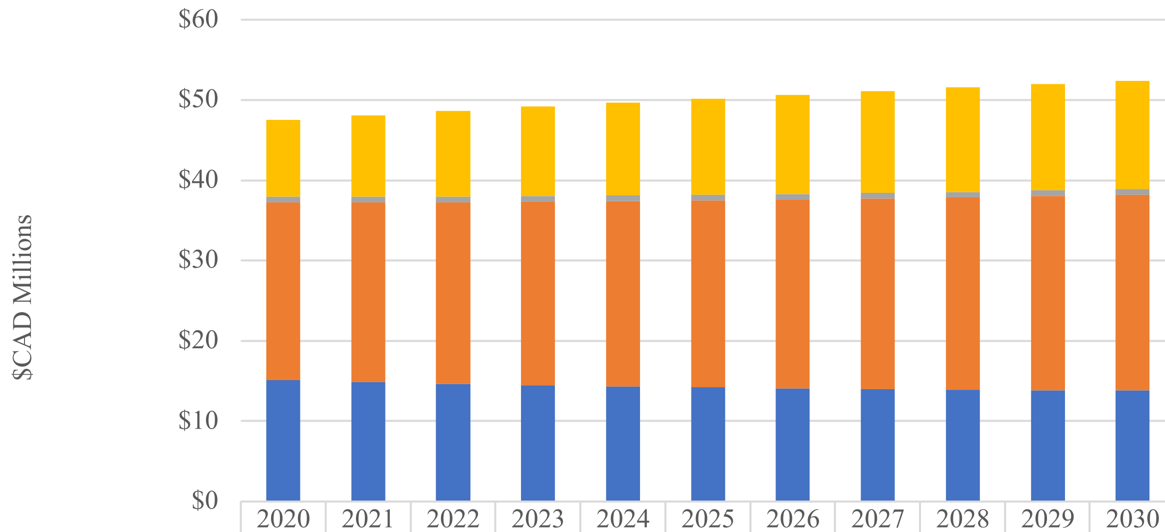


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Carbon Tax (Low)	$3.3	$3.4	$3.5	$3.6	$3.7	$3.8	$3.9	$4.0	$4.1	$4.3	$4.5
Storage	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7
Diesel Fuel	$22.2	$22.4	$22.6	$22.8	$23.0	$23.3	$23.5	$23.7	$24.0	$24.2	$24.4
Diesel Mine Truck	$15.1	$14.9	$14.7	$14.5	$14.4	$14.2	$14.1	$14.0	$13.9	$13.9	$13.8

Note: Wallace, 2021.The graph above depicts the undiscounted total cost for one diesel-fuelled mine truck within the low-carbon tax base-case scenario for each 20-year mine lifetime with an investment start date between 2020 and 2030.

Figure 16

Undiscounted Total Cost for High Carbon Tax Base Case.

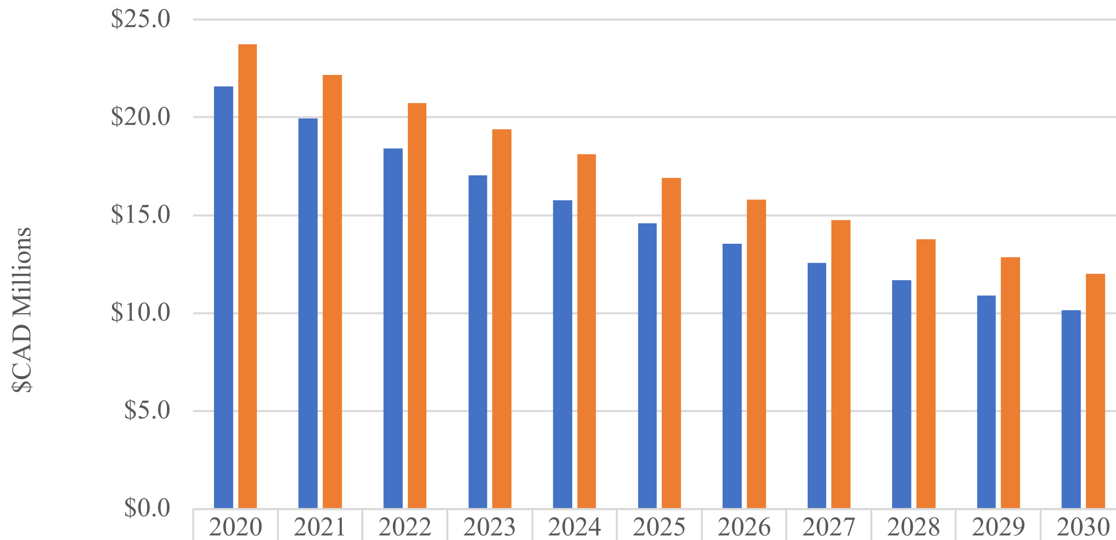


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Carbon Tax (High)	$9.6	$10.1	$10.7	$11.1	$11.6	$12.0	$12.4	$12.7	$13.0	$13.3	$13.5
Storage	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7	$0.7
Diesel Fuel	$22.2	$22.4	$22.6	$22.8	$23.0	$23.3	$23.5	$23.7	$24.0	$24.2	$24.4
Mine Truck	$15.1	$14.9	$14.7	$14.5	$14.4	$14.2	$14.1	$14.0	$13.9	$13.9	$13.8

Note: Wallace, 2021. The graph above depicts the undiscounted total cost for one diesel-fuelled mine truck within the high-carbon tax base-case scenario for each 20-year mine lifetime with an investment start date between 2020 and 2030.

Figure 17

NPV of Low and High-Carbon Tax Base Case Scenarios.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Low Carbon Tax NPV	$21.6	$20.0	$18.4	$17.0	$15.8	$14.6	$13.6	$12.6	$11.7	$10.9	$10.1
High Carbon Tax NPV	$23.7	$22.2	$20.7	$19.4	$18.1	$16.9	$15.8	$14.8	$13.8	$12.9	$12.0

Note: Wallace, 2021. The graph above depicts a comparison of the Net Present Value (NPV), with an 8% discount rate, for the total cost for one diesel-fuelled mine truck within both the low and high carbon tax base-case scenario for each 20-year mine with an investment start date between 2020 and 2030.

Chapter 5 – Hydrogen Scenarios

The following section analyzes the three (3) hydrogen scenarios and the parameters used in the techno-economic model. As mentioned in the methodology section, the FCEV, electrolysis, water purification, and storage and compression costs are identical for all three hydrogen production scenarios: only the cost to produce the hydrogen (LCOH) is different. Appendix A includes a tabulated summary of the cost for a 20-year mine with an investment start date in 2020. This calculation was repeated for investment years 2021 to 2030.

5.1 Hydrogen FCEV Mine-Haul Vehicle Analysis

This section is a summary of the data and assumptions for the hydrogen FCEV 290-ton Ultra-Class mine-haul vehicle. As stated previously, this is a converted Komatsu 930E 290-ton chassis outfitted with eight 100kW fuel cells, 1.1 MWh lithium-ion battery, and 840kgH_2 of onboard storage. As technology learnings increase and PEM fuel-cells increase in efficiency, the amount of fuel required for the same power out-put will decrease.

The CAPEX, OPEX, lifetime of equipment and assumptions are outlined in Table 5.1 and the results of the analysis are in Figure 18.

The following parameters were analyzed:

- FCEV mine truck CAPEX and OPEX costs
- FCEV future costs (2030 through to 2050)
- FCEV mine truck and equipment lifetime (fuel-cell, battery, onboard storage)
- FCEV hydrogen-fuel requirements

Vega (2020) reported that diesel engine cost for a Komatsu 930E was approximately 10% of the CAPEX of the vehicle ($660,000). Thus, the truck without a drivetrain would be $5.94 million. Vega (2020) reported that converting the Komatsu 290-ton diesel mine-haul vehicle to hydrogen would add approximately $2.6 million to the CAPEX, which includes the cost of the PEM fuel cell at $2250/kW, onboard hydrogen storage at $660/kg, and the lithium-ion battery pack at $180/kW (Vega, 2020). This confirms anonymous industry professions estimates as the difference in CAPEX calculated in Vega (2020) are also 30% ($6.6 million for diesel truck and $8.58 million for FCEV).

The lifetime of the truck chassis has been assumed to be identical to the base case of 80,000 hrs and an annual operational hour of 75%. The lifetime for onboard hydrogen storage has an expected lifetime of 11,000 cycles (one cycle equals one fill and deplete) (Adams, 2020). As the onboard storage capacity is 840 kg and the average daily fuel usage is 1,024 tonsH2/day/truck, the truck would be refuelled 1.2x per day; thus the onboard storage tanks would have a lifetime of 25 years.

According to Ballard Power, the PEM fuel-cell has a lifetime of 30,000 hours and is expected to increase to 50,000 hours by 2025 (Colbrow, 2020). While it could be expected that technology learnings could extend this lifetime by 2050, the 50,000 hours lifetime was used for 2050. Based on the DOE Hydrogen Program Record 2021 report, the replace cost for a fuel-cell is USD$76/kW (CAD$100/kW) (Kleen & Padgett, 2021). As stated above, the replacement cost for fuel-cells is expected to drop by 50% by 2050. The lithium-ion battery pack is expected to have a lifetime of 13,000 hours (Vega, 2020). As stated above, the costs for lithium-ion battery packs are expected to drop by 50% in 2030 and 70% in 2050.

Multiple other sources, such as IRENA and Hydrogen Council, predict that fuel-cell costs will likely drop by 50-60% in 2050 (IRENA, 2019) (Hydrogen Council, 2020). For this study it is assumed that by 2050, PEM fuel-cell costs will drop by 50%. According to BloombergNEF, the cost of lithium-ion battery packs is expected to decrease by 58% (BloombergNEF, 2020). A report by Cole and Frazier (2019) from the NREL, amalgamated ten industry reports and projected that by 2030 that lithium-ion battery packs could drop by 45-65% and 60-80% by 2050 (Cole & Frazier, 2019). This study assumes that lithium-ion battery packs will drop by 50% in 2030 and 70% in 2050. The DOE H2 Heavy Duty Trucks Targets report from 2020 estimates that the cost for onboard hydrogen storage tanks to drop by 40% in 2030 and 47% in 2050 (Adams, 2020).

Table 5.1

Parameters and Costs for Hydrogen FCEV Truck

Parameter	Unit	2020 Value	2030 Value	2050 Value	Reference
FCEV Truck Size	Tonnes	290	290	290	(10)
H_2 Fuel Usage	kgH_2/day	1,024	973	922	**
% Utilization	Percentage	75%	75%	75%	*
PEM Fuel-Cell Efficiency	Percentage	60%	65%	70%	(14)
PEM Fuel-Cell Size	kWh	800	800	800	(10)
Lithium-Ion Battery Size	kW	1,100	1,100	1,100	(10)
Onboard H_2 Storage Capacity	kgH_2	840	840	840	(3)
FCEV Truck Lifetime	Hours	80,000	80,000	80,000	*
PEM Fuel Cell Lifetime	Hours	30,000	50,000	50,000	(11)
Lithium-Ion Battery Lifetime	Hours	13,000	13,000	13,000	(12)
Onboard H_2 Storage Lifetime	Cycles	11,000	11,000	11,000	(13)
FCEV Truck CAPEX	$CAD/truck	$8,580,000	$5,577,000	$4,290,000	(***) (3) (15) (16)
FCEV OPEX	% of CAPEX	2%	2%	2%	(*)
Fuel Cell Replacement	$CAD/kWh	$100	$52	$40	(15) (16)
Lithium-Ion Battery Replacement	$CAD/kWh	$180	$76	$53	(12) (16)
Onboard H_2 Storage	$CAD/kg	$660	$396	$350	(13)
Ore Haulage Cycle	Cycles/day/truck	18	18	18	(*)
Amount of Ore Hauled	Tons/day/truck	5.22	5.22	5.22	(*)
Mine Lifetime	Years	20	20	20	(*)
NPV Discount Value	Percentage	8%	8%	8%	(*)

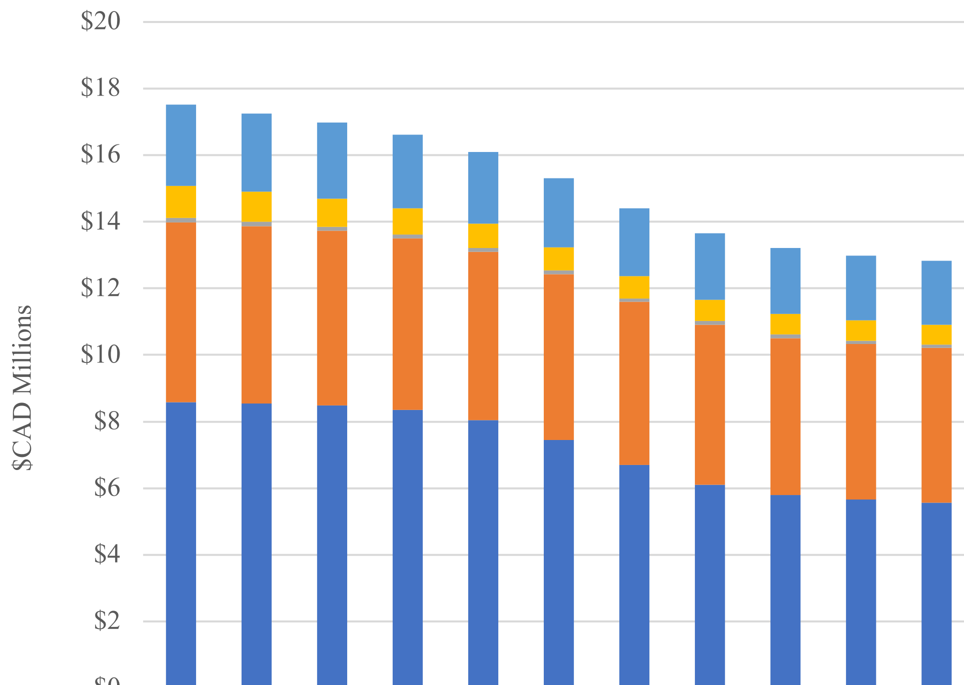
Note: Wallace, 2021. This table summarizes the parameters used in calculating the financial metrics for one (1) hydrogen-fuelled FCEV mine-haul truck for the hydrogen scenarios. References for the parameters in the table: (*) Author Assumption; (**) Author Calculated; (***) Anonymous Industry Interviews; (3) Vega (2020); (10) Anglo American (2020); (11) Colbrow (2020); (12) Cole & Frazier (2019); (13) Adams, 2020; (14) IEA (2020); (15) IRENA (2019); (16) Hydrogen Council (2020); (17) BloombergNEF (2020).

5.1.1 Analysis of FCEV Total Costs

Based on the assumptions and parameters in Table 5.1, the total undiscounted total costs for the FCEV, including chassis, onboard hydrogen storage, replacement of PEM fuel-cells, and lithium-ion battery replacements is $17.5 million in 2020 with a 20-year mine and decreases by 27% in 2030 to $12.8 million (Figure 18). Appendix A is a tabulated overview of the cost summary for the FCEV over a 20-year mine with an investment start date in 2020.

Figure 18

Undiscounted FCEV Total Costs Based on Investment Start Date.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
FCEV OPEX	$2.4	$2.4	$2.3	$2.2	$2.1	$2.1	$2.0	$2.0	$2.0	$1.9	$1.9
Lithium-Ion CAPEX	$1.0	$0.9	$0.8	$0.8	$0.7	$0.7	$0.7	$0.6	$0.6	$0.6	$0.6
PEM CAPEX	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
FCEV Replacement CAPEX	$5.4	$5.3	$5.2	$5.1	$5.1	$5.0	$4.9	$4.8	$4.7	$4.7	$4.6
FCEV CAPEX	$8.6	$8.6	$8.5	$8.4	$8.0	$7.5	$6.7	$6.1	$5.8	$5.7	$5.6

Note: Wallace, 2021. The graph above depicts the undiscounted total cost for one hydrogen-fuelled FCEV mine truck for a 20-year mine with an investment start date between 2020 and 2030.

5.2 Hydrogen Production

In this section, the CAPEX, OPEX and parameters for the electrolyzer, water consumption, and storage and compression are detailed in Table 5.2.

The following parameters were analyzed:

- Electrolyzer CAPEX / OPEX costs and technology learnings
- Electrolyzer stack replacement OPEX costs and lifetime
- Storage and compression CAPEX and OPEX costs
- Water CAPEX and OPEX costs (for hydrogen production)

For this study, the electrolyzer was modelled after the Cummins HyLYZER-1000, which can produce 2,055 kgH2/day with an input power of 5 MW and an efficiency of 67% (Cummins, 2021). Based on the efficiency and hydrogen output, the electrolyzer will require 58.4 kWh/kgH2. It is assumed that the electrolyzer would be operational for 90% of the year due to maintenance and stack replacements. CAPEX is based on work by Christensen (2020) of $1625 /kW, which includes $66 /kW for other system costs (piping, electrical, etc.) and a technology learning improvement of 2% per year (Christensen, 2020). OPEX is set at 3.3% based on Glenk et al. (2019).

The PEM electrolyzer requires to be replaced over time due to degradation of the membrane and stacks. Based on Christensen (2020), the average lifetime for a stack is 60,000 hours. The IEA estimates that as technology learnings increase, the stack lifetime would increase linearly to 125,000 hours in 2050 (IEA, 2019). Replacement costs are estimated to be 35% of CAPEX (IRENA, 2019). It can be expected that the 2030 and 2050 replacement costs for the stacks would follow the same pathway as the electrolyzer of 50% and 60%, respectively. A salvage cost of 20% was included on the CAPEX for the stack replacement cost.

CAPEX costs for storage are identical to the DOE H2 Heavy Duty Trucks Targets report at $660/kg with a cost decrease of 40% in 2030 and 47% in 2050 (Adams, 2020). According to Christensen (2020), the OPEX for compression is estimated to be $0.66/kg and would decrease in cost by identical rates as the storage of 40% in 2030 and 47% in 2050 (Christensen, 2020).

Table 5.2

Hydrogen Production Equipment Costs and Parameters.

Parameter	Unit	2020 Value	2030 Value	2050 Value	Reference
Electrolyzer Input Power	MW	5	5	5	(18)
Electrolyzer Operating Time	Percentage	90%	90%	90%	(18)
Electrolyzer Efficiency	Percentage	66.8%	73%	75%	(18)
Hydrogen Output	kg/day	2,055	2,055	2,055	(18)
Electrolyzer Stack Lifetime	hours	60,000	91,667	125,000	(14) (19)
Electrolyzer CAPEX	$/kW	$1,625	$813	$650	(19) (20) (21)
Electrolyzer Stack Replacement	$/kW	$500	$250	$200	(15)
Electrolyzer OPEX	% of CAPEX	3.3%	3.3%	3.3%	(19) (20)
Salvage Cost on Replacement Stack	% of CAPEX	20%	20%	20%	(*)
Water Required	kgH_2O/kgH_2	11.1	11.1	11.1	(22)
Water Facility CAPEX	$CAD/m3/day	$12,200	$11,033	$9,024	(23)
Water Facility OPEX	CAD/kgH_2$	$0.10	$0.09	$0.07	(19) (20)
H_2 Storage Required	Days	2	2	2	(*)
H_2 Storage Capacity	kg/H_2	2,048	1,947	1,844	(13)
700-bar Storage CAPEX	$CAD/kg	$660	$396	$350	(13)
Compressor OPEX	% of CAPEX	10%	10%	10%	(19)
Mine Lifetime	Years	20	20	20	(*)
NPV Discount Value	Percentage	8%	8%	8%	(*)

Note: Wallace, 2021. This table summarizes the parameters used in calculating the financial metrics for hydrogen production equipment (electrolyzer, storage, compression, and water treatment) for the hydrogen scenarios. References for the parameters in the table: (*) Author Assumption; (13) Adams, 2020; (14) IEA (2020); (15) IRENA (2019) ; (18) Cummins (2021); (19) Christensen (2020); (20) Glenk et al. (2019); (21) Government of Canada (2020b); (22) Saulnier et al. (2020); (23) Cosins (2019).

5.2.1 Hydrogen Production Equipment Analysis

The amount of energy required per day to produce hydrogen-fuel for one truck (1024 kgH_2/day) is 3.2 MW and requires 69.12 MWh/day and 25.2 Gigawatts per year (GW/year). The electrolysers' total undiscounted CAPEX and OPEX, including PEM stack replacements, is $8.3 million. By 2030, this total decrease by 40% to $5.0 million for a 20-year operation (Figure 19).

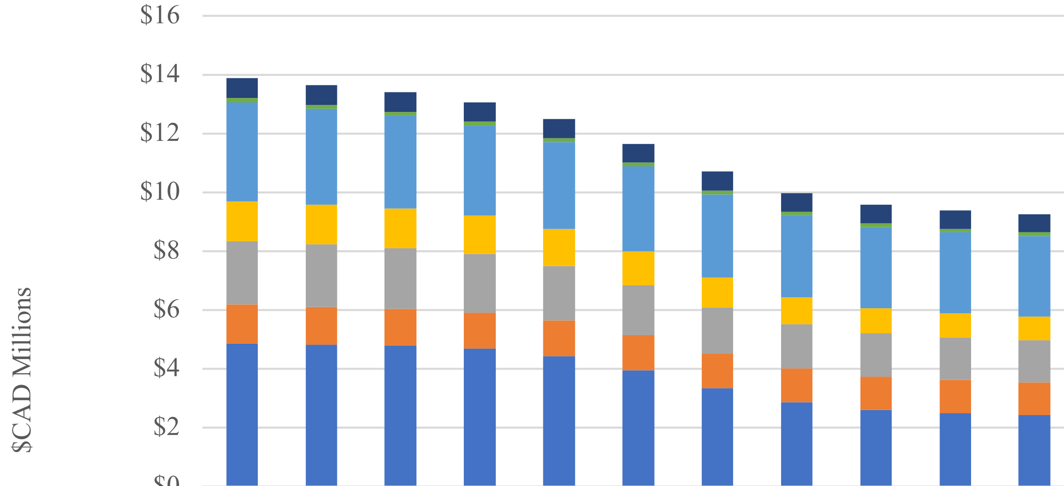
Storage for two (2) days of hydrogen-fuel requires 2048 kgH_2 to be compressed and stored. The total 2020 CAPEX for high-pressure 700-bar storage is $1.4 million and the OPEX is $3.4 million. By 2030, this has decreased by 36% (Figure 19) to $0.8 million for storage CAPEX and $2.7 million for OPEX.

Water CAPEX and OPEX costs for a 2020 investment start date are $0.14 million and $0.68 million over a 20-year lifetime. These costs decrease by 10% in 2030 (Figure 19). For the required hydrogen-fuel, the amount of water required per day is 11.4 cubic meters per day (m^3/day). To put this into perspective, a standard bathtub holds 300 litres of water. Therefore, the amount of water required for hydrogen production for one 290-ton FCEV truck is equivalent to 2 bathtubs per day.

Appendix A is a tabulated overview of the cost summary for a 20-year mine with an investment start date in 2020. This calculation was repeated for investment years 2021 to 2030.

Figure 19

Undiscounted Total Cost of Hydrogen Production Equipment.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Water OPEX	$0.7	$0.7	$0.7	$0.7	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6
Water CAPEX	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
H2 Storage OPEX	$3.4	$3.3	$3.2	$3.1	$3.0	$2.9	$2.8	$2.8	$2.8	$2.8	$2.7
H2 Storage CAPEX	$1.4	$1.3	$1.3	$1.3	$1.3	$1.1	$1.0	$0.9	$0.8	$0.8	$0.8
Electrolyzer OPEX	$2.2	$2.1	$2.1	$2.0	$1.9	$1.7	$1.6	$1.5	$1.5	$1.4	$1.4
PEM Stack Replacement	$1.3	$1.3	$1.3	$1.2	$1.2	$1.2	$1.2	$1.2	$1.1	$1.1	$1.1
Electrolyzer CAPEX	$4.9	$4.8	$4.8	$4.7	$4.4	$3.9	$3.3	$2.9	$2.6	$2.5	$2.4

Note: Wallace, 2021. The graph above depicts the undiscounted total cost for hydrogen production equipment (electrolyzer, storage, compression, and water treatment) for a 20-year mine with an investment start date between 2020 and 2030.

5.3 Hydrogen Production Scenarios

This section is dedicated to the three production scenarios for this research project to determine the levelized cost of hydrogen production (LCOH). The cost for electricity has a direct bearing on the LCOH as the electrolyzer requires electricity to produce hydrogen. Appendix A is a tabulated overview of the cost summary for a 20-year mine with an investment start date in 2020.

The scenarios and parameters analyzed are:

- Scenario 1 – grid-connected: grid electricity rate and future cost of electricity, Scope 2 emissions from grid electricity.

- Scenario 2 - virtual wind PPA electricity rate
- Scenario 3 - direct connect wind farm: CAPEX and OPEX for a windfarm, cost of electricity for grid-balancing and Scope 2 emissions associated

5.3.1 Scenario 1 – Grid Connect

For Scenario 1, the cost for electricity is assumed to be $115 MWh. This cost is based on a 2% increase from the annual 2020 average electricity price of $112.90/MWh for a large industrial electricity customer on the Ontario electrical grid (IESO, 2021). This price includes the transmission, distribution, and the global adjustment fee, which covers the cost of new energy infrastructure and conservation programs by the grid operator. The future cost of electricity is assumed to increase by 2% per year to 2030, and then 0.5% per year between 2030 and 2040. The author speculates that past 2040, as renewable energy and energy storage costs decrease, coupled with new disruptive energy generation technology, such as small modular nuclear reactors, the cost of electricity could potentially drop by 0.5% per year to 2050. Table 5.3 details the price for electricity and future rates assumed for the results.

5.3.2 Scenario 2 – Wind Virtual Power Purchase Agreement (PPA)

In this scenario, the windfarm is owned and operated by a third party with no investment risk or operational expenses to the mining company. The renewable wind energy is purchased though a 20-year PPA at a fixed rate. In this study, the PPA rate is set at $80/MWh for 20 years (lifetime of the mine operation). This is assumed to be in-front-of-the-meter wind farm and the rate includes the transmission, distribution, and global adjustment fee. It can be assumed that as wind installation and CAPEX prices drop by 35% between 2020 and 2030, the price of the PPA would also drop. For this study, the PPA rate is assumed to decrease by 2% per year to $65/MWh by 2030. Table 5.3 details the electricity rate and future costs.

5.3.3 Scenario 3 - Direct Connect Wind Farm

In this scenario, electricity is produced from a behind-the-meter wind farm directly connected to the electrolyzer and owned by the mining company. The percentage of grid-balancing required is based on the wind energy and capacity factor, the size of the wind farm, and the amount of hydrogen storage on-site. As the cost of electricity is a critical parameter in the LCOH, optimizing the amount of grid-balancing required is a crucial factor. The cost of grid-electricity is calculated at \$115/MWh (identical to Scenario 1). Minimizing the percentage of grid-energy also reduces the Scope 2 emissions which are calculated at 77 gCO_2e/kWh as in Scenario 1.

As previously mentioned, the average wind capacity of Ontario is 28% and is used as the basis for the calculation to determine wind farm size and grid-balance. Based on the amount of hydrogen (1024 kgH_2/day) and energy (3.2 MW) required, the optimal number of 5 MW turbines is two (2).

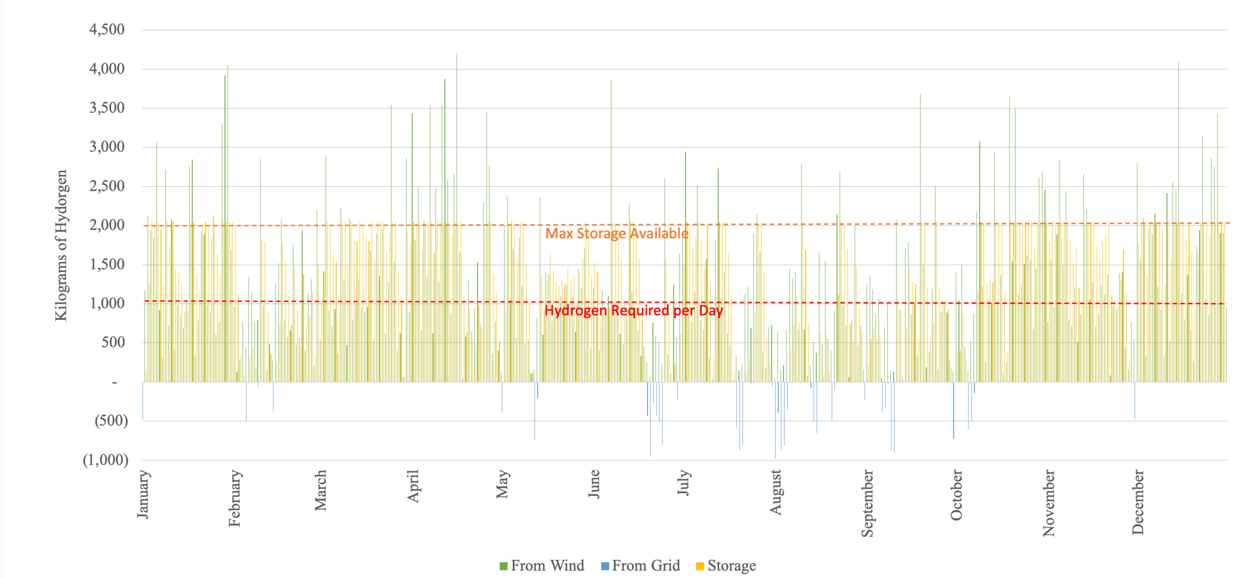
The CAPEX, OPEX, lifetime of equipment and assumptions are detailed in Table 5.3.

5.3.3.1 Results of Grid-Balance Analysis

Based on a 10 MW wind farm in a wind capacity region of 28%, the average annual energy produced between 2008 and 2010 was 24.3 GW per year and could produce 331.6 $tonsH_2$/year. As the required amount of hydrogen for one truck is 373.8 $tonsH_2$/year, the amount of hydrogen from grid energy is 42.3 $tonsH_2$/year. Thus, the percentage of grid-balancing is 11.3%. Figure 20 shows the amount of hydrogen produced per day in 2008 from a 10 MW wind farm (in green), the amount of hydrogen in storage (in yellow), and the amount produced from grid-energy (in blue). Figure 21 is a graphical model in the determination of the optimal wind farm size by plotting the amount of grid-balancing required, the Scope 2 abetment (based on diesel-fuel switching) and the LCOH.

Figure 20

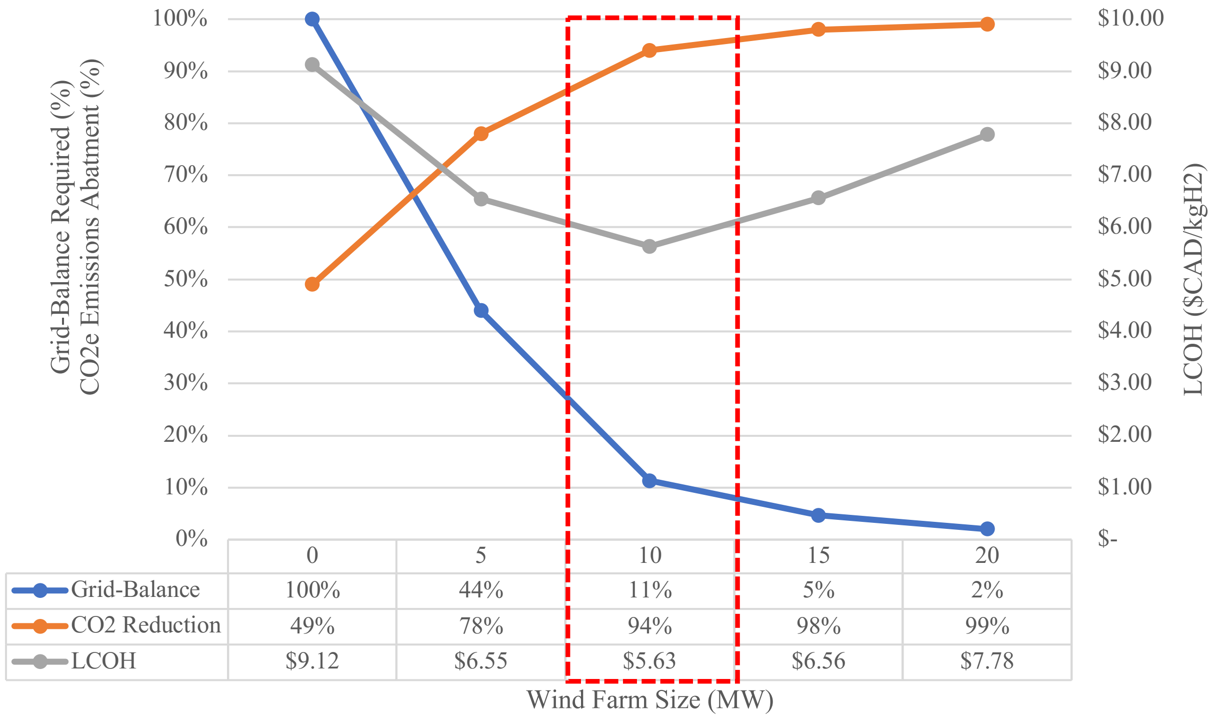
Annual Hydrogen Production from 10MW Wind Farm with 28% Wind Capacity Factor.



Note: Wallace, 2021. Graphical representation the amount of hydrogen production from a 10 MW wind farm based on the historical 10 second wind data for a location with 28% wind capacity factor. Green bars represent hydrogen production from wind energy, orange depicts amount of hydrogen in storage, blue bars depict amount of hydrogen produced from grid-energy. Results indicate that 11% grid-balance is required for a 10 MW wind farm and two days of hydrogen storage.

Figure 21

Graphical Display to Determine Optimal Wind Farm Size.



Note: Wallace, 2021. Graphical representation to determine the optimal wind farm size for the required amount of hydrogen production based on grid-balance percentage, CO_2 emissions abatement and LCOH. The results indicate that a 10 MW wind farm is the optimal choice as the LCOH is the lowest and the CO_2 reductions are over 90%.

Table 5.3

Parameters and Costs for Hydrogen Production Scenarios.

Parameter	Unit	2020	2030	2050	Reference
Grid Electricity Rate	$CAD/MWh	$115	*$137	*$137	(*) (24)
Wind PPA Rate	$CAD/MWh	$80.00	$65.00	$65.00	(25)
Turbine CAPEX	$CAD/MWh	$1,600,000	$1,045,545	$885,545	(8) (15)
Turbine OPEX	% of CAPEX	2%	2%	2%	(26)
Turbine Salvage Cost	% of Capex	3%	3%	3%	(*)
Turbine Size	MW	5	5	5	(*)
Turbine Operating Time	% of year	90%	90%	90%	(*)
Wind Capacity Factor	Percentage	28%	28%	28%	(27)
Ontario Grid CO_2 Intensity	grams/kWh	77	77	77	(28)
Wind Turbine Lifetime	Years	30	30	30	(*)
Mine Lifetime	Years	20	20	20	(*)
NPV Discount Value	Percentage	8%	8%	8%	(*)

Note: Wallace, 2021. This table summarizes the parameters used in calculating the financial metrics for hydrogen production equipment (electrolyzer, storage, compression, and water treatment) for the hydrogen scenarios. References for the parameters in the table: (*) Author Assumption; (8) CER (2020); (15) IRENA (2019); (24) IESO (2021); (25) CANWEA (n.d.); (26) IRENA (2018); (27) Government of Canada (2021); (28) CER (2021a).

5.4 Results of LCOH for Hydrogen Production Scenarios

The LCOH for each scenario was calculated from the undiscounted total costs for production equipment (electrolyzer, storage and compression, and water) that was calculated previously, plus the energy cost, and then divided by the total amount of hydrogen produced. Figure 22 shows the average LCOH for a 20-year mine life for each of the scenarios and the change between 2020 and 2030 investment start dates.

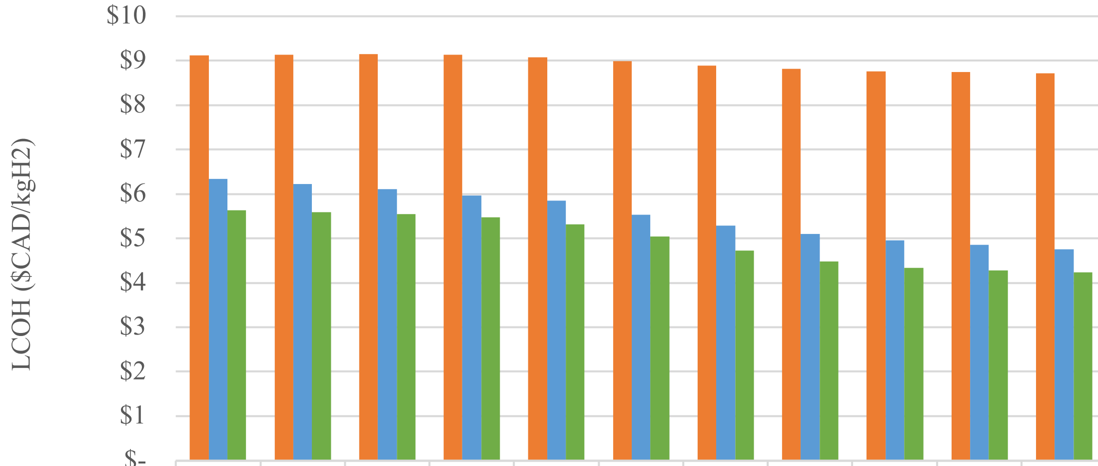
- Scenario 1 – Grid Rate: this scenario has the highest cost for electricity and thus has the highest cost to produce hydrogen at $9.12 /kg$H_2$. As the electricity rate is increasing by 2% per year, the cost of electricity has a significant influence on the total cost even as production equipment decreases. The average cost for an investment date in 2030 is still relatively high at \$8.71 /kgH_2. This is a 4% decrease between 2020 and 2030.

- Scenario 2 – Wind PPA: the LCOH for a mine investment start date in 2020 is \$6.35 /kgH_2, and in 2030 it drops by 25% to \$4.76 /kgH_2. This is a 25% decrease between 2020 and 2030.
- Scenario 3 – Direct Connect Wind Farm:
    - LCOE: based on the \$16 million CAPEX and \$4.6 million OPEX for the 10 MW wind farm, the LCOE is \$50.60 /MWh in 2020 and decreases to \$38.80 /MWh in 2030. This is a decrease of 25%.
    - LCOH: this scenario requires 11.3% grid-balancing, the cost for electricity used from the grid is identical to Scenario 1 (\$115 /MWh), resulting in an LCOH of \$5.63 /kgH_2 for a 2020 investment date, and in 2030 is \$4.28 /kgH_2. This is a 25% decrease between 2020 and 2030.

Many studies and industry reports have calculated the levelized cost of producing hydrogen (LCOH) from electrolysis via grid and wind energy. Current reports from the *Hydrogen Strategy of Canada* show that LCOH for renewable-hydrogen production are approximately \$3.20-\$5.90/kgH_2 and \$4.20-\$8.30/kgH_2 for grid-only electrolysis (Government of Canada, 2020b). Lazard's current estimates for LCOE produced from a new build wind installation are between USD\$26-54/MWh (CAD\$34-71/MWh) (Lazard, 2020). The results from this study fall within the other studies and validate the results.

Figure 22

Summary of Levelized Cost of Hydrogen Production (LCOH) for Scenarios.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Scenario 1 - Grid Rate	$9.12	$9.14	$9.15	$9.13	$9.08	$8.99	$8.89	$8.81	$8.77	$8.74	$8.71
Scenario 2 - Wind PPA	$6.35	$6.23	$6.11	$5.97	$5.86	$5.54	$5.29	$5.10	$4.96	$4.86	$4.76
Scenario 3 - Wind Farm	$5.63	$5.60	$5.56	$5.47	$5.31	$5.05	$4.73	$4.48	$4.34	$4.28	$4.24

Note: Wallace, 2021. The graph above depicts the LCOH for hydrogen production for a 20-year mine with an investment start date between 2020 and 2030. LCOH for Scenario 1 is 30% higher due to high price for electricity.

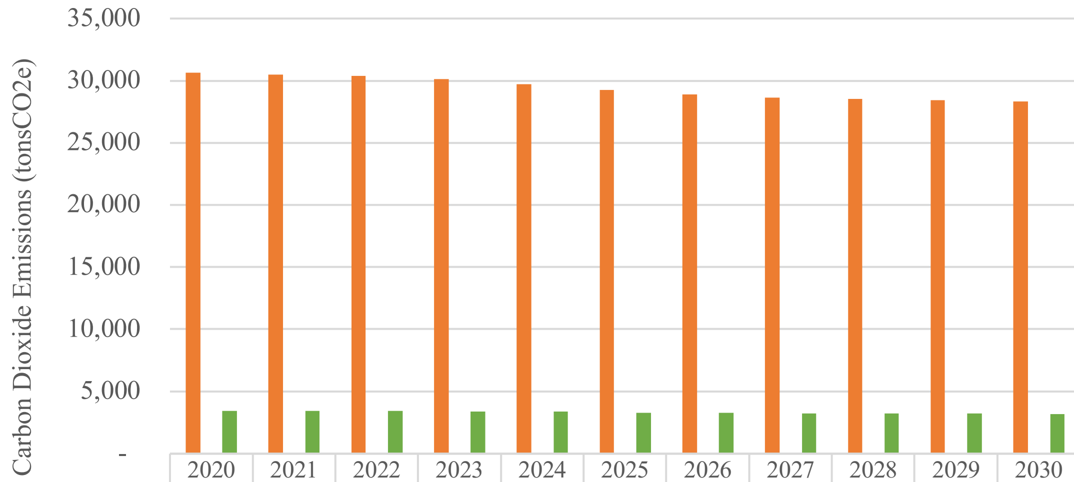
5.5 Results for Carbon Dioxide Emissions of Hydrogen Scenarios

The amount of Scope 2 emissions produced from hydrogen production is directly related to the carbon intensity of the electricity source. The results of the Scope 2 emissions for each 20-year mine based on an investment start date between 2020 and 2030 are shown in Figure 23.

- Scenario 1 - Grid Rate: with a grid CO_2 intensity of 77 gCO_2e/kWh, the daily amount of CO_2 produced from electrolysis is 4.6 tCO_2e/day. The total amount of Scope 2 emissions for a 20-year investment start date of 2020 is 30.6 thousand tCO_2e and decreases by 8% to 28.3 thousand tCO_2e in 2030.
- Scenario 2 – Wind PPA: as 100% of the energy required for electrolysis is from wind energy, the amount of carbon emissions is zero.
- Scenario 3 – Wind Farm: with a grid-balance percentage of 11.3%, the total amount of Scope 2 emissions for a 20-year investment start date of 2020 is 3,469 tCO_2e in 2020 and drops by 8% to 3,207 tCO_2e in 2030.

Figure 23

Scope 2 CO_2 Emissions for Hydrogen Scenarios Based on Investment Start Date.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Scenario 1 - Grid Rate	30,632	30,499	30,366	30,122	29,735	29,266	28,893	28,663	28,524	28,425	28,319
Scenario 2 - Wind PPA	-	-	-	-	-	-	-	-	-	-	-
Scenario 3 - Wind Farm	3,469	3,454	3,439	3,411	3,367	3,314	3,272	3,246	3,230	3,219	3,207

Note: Wallace, 2021. The graph above depicts the total Scope 2 emissions for each hydrogen scenarios for a 20-year mine with an investment start date between 2020 and 2030.

5.6 Results of Total Cost for each Hydrogen Scenarios

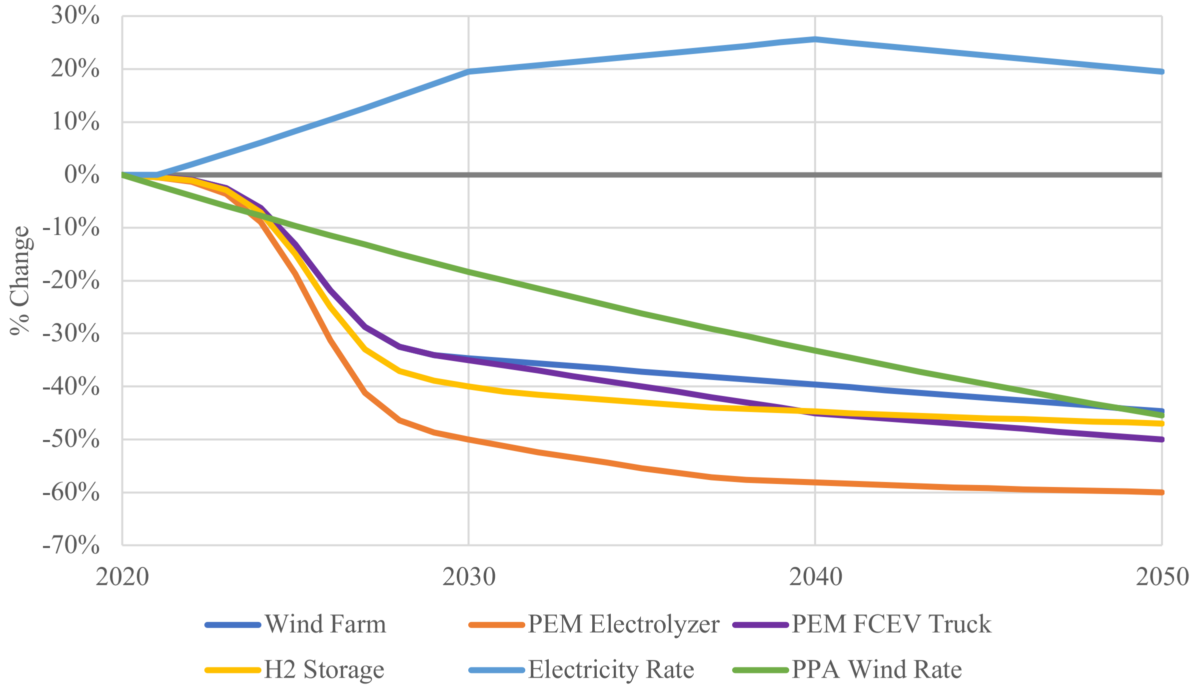
The results for the total cost of each scenario are based on the total costs for the FCEV, hydrogen production equipment, and cost for hydrogen production. Figure 24 outlines the change in normalized cost assumptions from 2020 to 2050. As expected, this scenario also has the highest total cost due to the high cost of electricity for Scenario 1.

- Scenario 1 – Grid Rate (Figure 25): as this scenario has the highest cost for energy; the total cost is also the highest. For a 20-year mine starting in 2020, the total undiscounted cost is \$83.1 million and decreases by 12% in 2030 to \$73.3 million.
- Scenario 2 – Wind PPA: the total cost for a 20-year mine life starting in 2020 is \$63.2 million and decreases by 28% in 2030 to \$45.9 million.
- Scenario 3 – Direct Connect Wind Farm: the total cost for a 20-year mine life starting in 2020 is \$58.05 million and decreases by 28% in 2030 to \$42.3 million.

Figure 28 and Figure 29 are a summary of the undiscounted total costs and 8% discounted NPV total costs for each scenario.

Figure 24

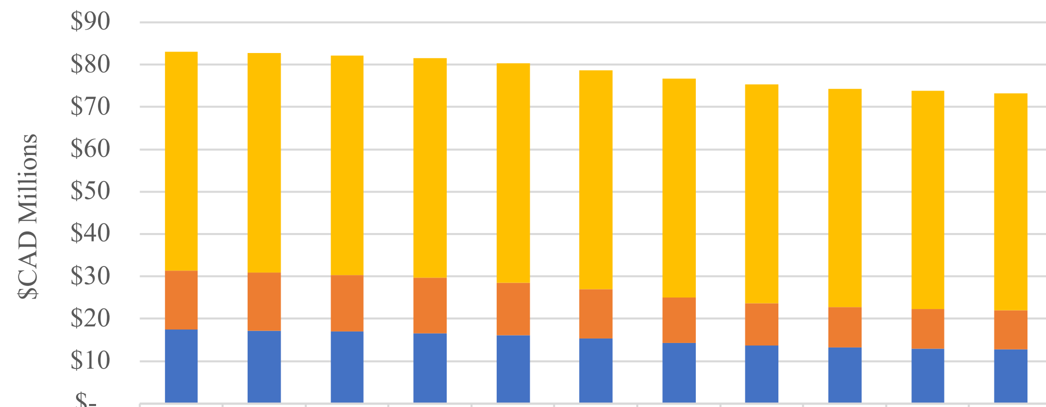
Summary of Normalized Cost Changes for Hydrogen Scenarios.



Note: Wallace, 2021. Normalized changes in costs for hydrogen production scenarios between 2020 and 2050 is based on literature reviews and industry reports. Positive change is an increase in costs, where negative change is a decrease in costs.

Figure 25

Scenario 1 - Undiscounted Total Cost for each Investment Start Date.

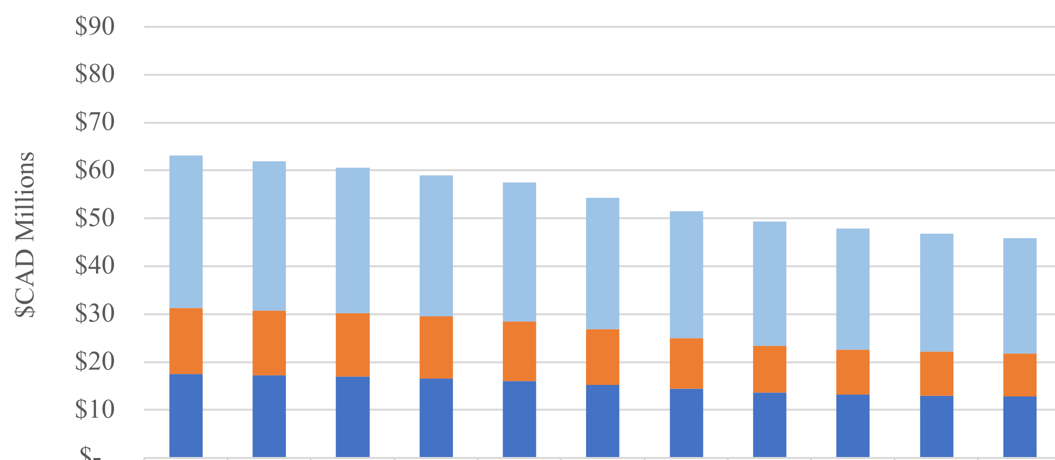


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Grid-H2 Production	$52	$52	$52	$52	$52	$52	$52	$52	$52	$51	$51
H2 Production Equipment	$14	$14	$13	$13	$12	$12	$11	$10	$10	$9	$9
Fuel-Cell Mine Truck	$18	$17	$17	$17	$16	$15	$14	$14	$13	$13	$13

Note: Wallace, 2021. The graph above depicts the total undiscounted cost for Scenario 1 for a 20-year mine with an investment start date between 2020 and 2030.

Figure 26

Scenario 2 - Undiscounted Total Cost for each Investment Start Date.

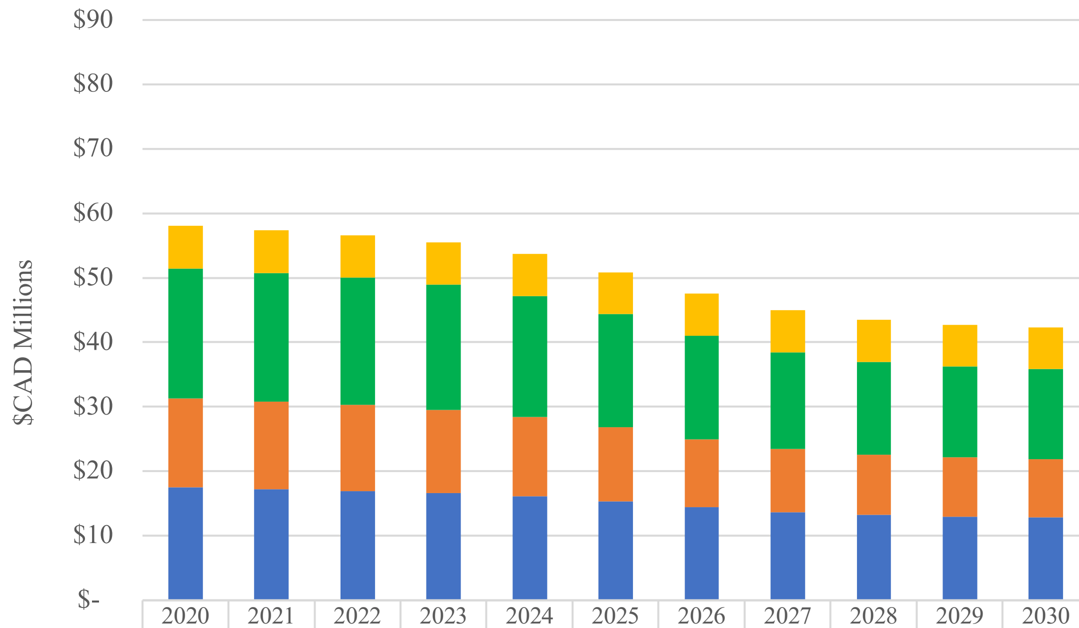


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind PPA-H2 Production	$32	$31	$30	$29	$29	$27	$27	$26	$25	$25	$24
Electrolyzer	$14	$14	$13	$13	$12	$12	$11	$10	$9	$9	$9
Fuel-Cell Mine Truck	$18	$17	$17	$17	$16	$15	$14	$14	$13	$13	$13

Note: Wallace, 2021. The graph above depicts the total undiscounted cost for Scenario 2 for a 20-year mine with an investment start date between 2020 and 2030.

Figure 27

Scenario 3 - Undiscounted Total Cost for each Investment Start Date.

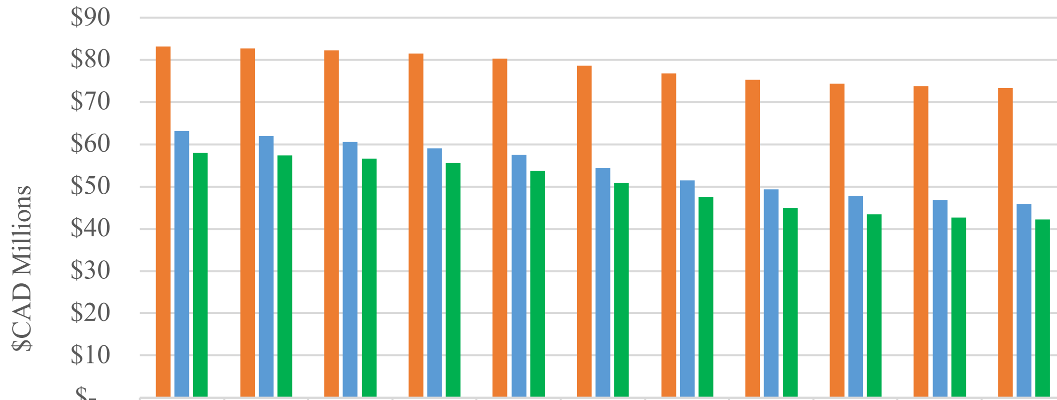


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Grid-H2 Production	$7	$7	$7	$7	$7	$7	$7	$7	$6	$6	$6
Wind Farm Investment	$20	$20	$20	$19	$19	$18	$16	$15	$14	$14	$14
Electrolyzer	$14	$14	$13	$13	$12	$12	$11	$10	$9	$9	$9
Fuel-Cell Mine Truck	$18	$17	$17	$17	$16	$15	$14	$14	$13	$13	$13

Note: Wallace, 2021. The graph above depicts the total undiscounted cost for Scenario 3 for a 20-year mine with an investment start date between 2020 and 2030.

Figure 28

Scenario Comparison Summary of Undiscounted Total Cost.

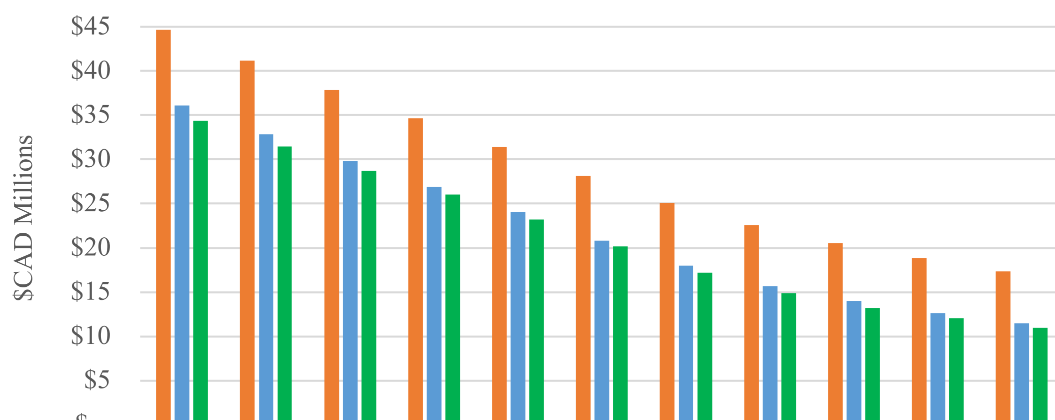


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Scenario 1 - Grid Rate	$83	$83	$82	$82	$80	$79	$77	$75	$74	$74	$73
Scenario 2 - Wind PPA	$63	$62	$61	$59	$58	$54	$52	$49	$48	$47	$46
Scenario 3 - Wind Farm	$58	$57	$57	$56	$54	$51	$48	$45	$43	$43	$42

Note: Wallace, 2021. The graph above depicts the total undiscounted cost for each hydrogen scenario for a 20-year mine with an investment start date between 2020 and 2030.

Figure 29

Scenario Comparison Summary of NPV Total Cost.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Scenario 1 - Grid Rate	$45	$41	$38	$35	$31	$28	$25	$23	$21	$19	$17
Scenario 2 - Wind PPA	$36	$33	$30	$27	$24	$21	$18	$16	$14	$13	$12
Scenario 3 - Wind Farm	$34	$31	$29	$26	$23	$20	$17	$15	$13	$12	$11

Note: Wallace, 2021. Graph depicts the total NPV with an 8% discount factor for each hydrogen scenario over a 20-year mine with an investment start date between 2020 and 2030.

Chapter 6 –Results and Discussion

This chapter is the results of the comparison between the Diesel-Fuel Base Case and the three hydrogen production scenarios.

The comparisons analyzed are:

- Carbon Dioxide emissions and reductions from the base case
- Incremental cost from base-case
- Undiscounted total investment cost for each scenario
- NPV (8% discounted) total investment cost for each scenario
- NPV (8% discounted) avoided cost between the base case and hydrogen production scenario
- Pay-back period

6.1 Carbon Dioxide Emissions Reduction of Hydrogen Production Scenarios

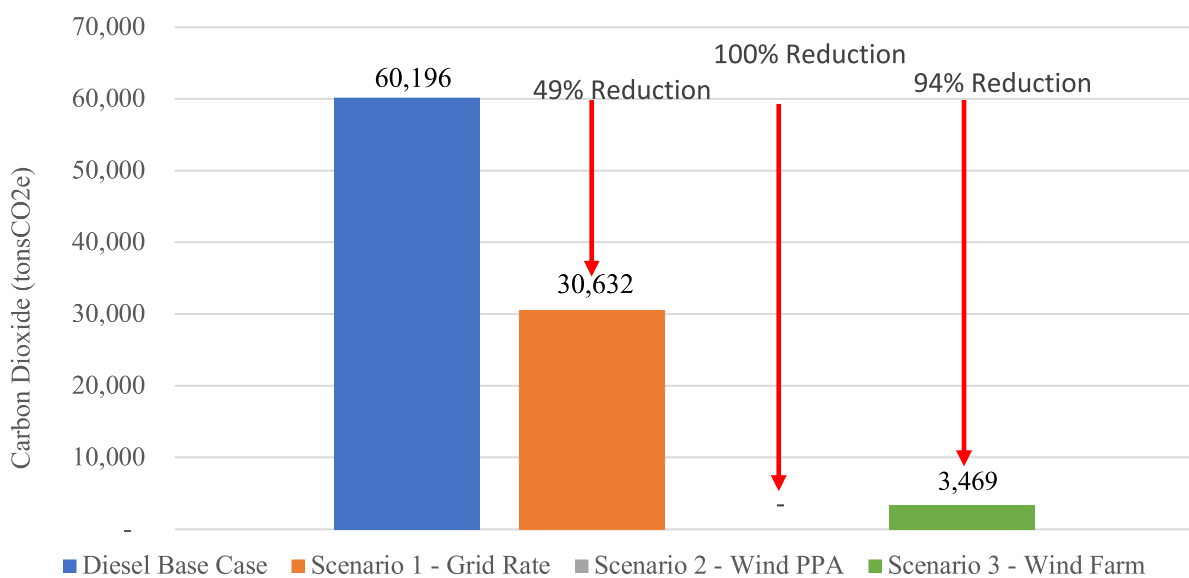
The CO_2 emissions for the diesel base case are determined by the amount of diesel-fuel combusted in the mine truck (Scope 1 emissions), while the CO_2 emissions from hydrogen production are determined by the carbon intensity of the electricity generation source (Scope 2). As mentioned previously, diesel contains 2660 gCO_2e/litre (260 gCO_2e/kWh) (EPA, n.d.), while the Ontario electrical grid has a CO_2 intensity of 77 gCO_2e/kWh and electricity generated from wind energy is considered to have zero-emissions for this study. As the fuel-efficiency of the diesel mine truck increases, the amount of fuel required decreases, and thus the CO_2 emissions also decrease by 10% between 2020 investment date and a 2030 investment date. For the hydrogen production scenarios, as the efficiency of the PEM electrolyzer increases to 75% by 2050, and the amount of hydrogen required for the PEM fuel-cell decreases, the CO_2 emissions from hydrogen production will also decrease by 8%. The total amount of Scope 2 emissions is dependent on how much grid-electricity is required.

For comparison between the diesel-fuel base-case and the hydrogen scenarios, the ratio between the amount of CO_2 avoided will remain relatively the same for each investment start date as the amount of hydrogen required is based on the equivalency of diesel-fuel. Figure 30 shows the total emissions for 20-year mine with an investment start date in 2030 and the percentage of emissions reduction from fuel-switching to hydrogen. The results indicate that producing hydrogen with grid-electricity can avoid up to 50% of diesel emissions, but wind energy can avoid 90% or more emissions.

To truly determine the amount of Scope 2 emissions that could be avoided, a Lifecycle Analysis (LCA) approach should be included. However, as mentioned previously, it was beyond the scope of this project to fully analysis this data, and thus, only the emissions intensity published for the grid was used. Nevertheless, for the purpose of comparison, one could use the LCA emissions for wind turbines at 11 gCO_2e/kWh to estimate the amount of potential CO_2 from wind power (NREL, 2013). If the LCA was used, the total emissions abatement for Scenario 2 would be 93% and for Scenario 3 would be 88%. This is not a negligible amount but does highlight that wind energy is still considerably more effective at reducing emissions than grid electricity.

Figure 30

Comparison of CO_2 Emissions and Percentage of Reduction.



Note: As emissions are based on hydrogen production requirements, which are calculated from diesel-fuel equivalency, the reduction percentage will remain relatively the same between 2020 and 2030.

6.2 Results of Economic Evaluation of Diesel Base Case and Hydrogen Production Scenarios

The techno-economic evaluation completed for each case made a comparison between the three (3) hydrogen production scenarios and the diesel-fuel base case to determine the most optimal scenario.

The incremental cost from the diesel-fuel base case (overnight CAPEX) is displayed in Figure 30. Scenario 1 and Scenario 2 are identical in costs as the FCEV and hydrogen production equipment are identical, where Scenario 3 is nearly double the investment cost due to the CAPEX of the wind farm.

The total investment cost for each investment start date was calculated (Figure 31) and discounted by 8% to show the NPV of each of the scenarios (Figure 32). A cash flow analysis on the NPV (Figure 33) was then completed to compare the cost of the low and high carbon tax base cases to the three different hydrogen production scenarios.

The discussion on the results below are based on the NPV cash flow analysis for each scenario:

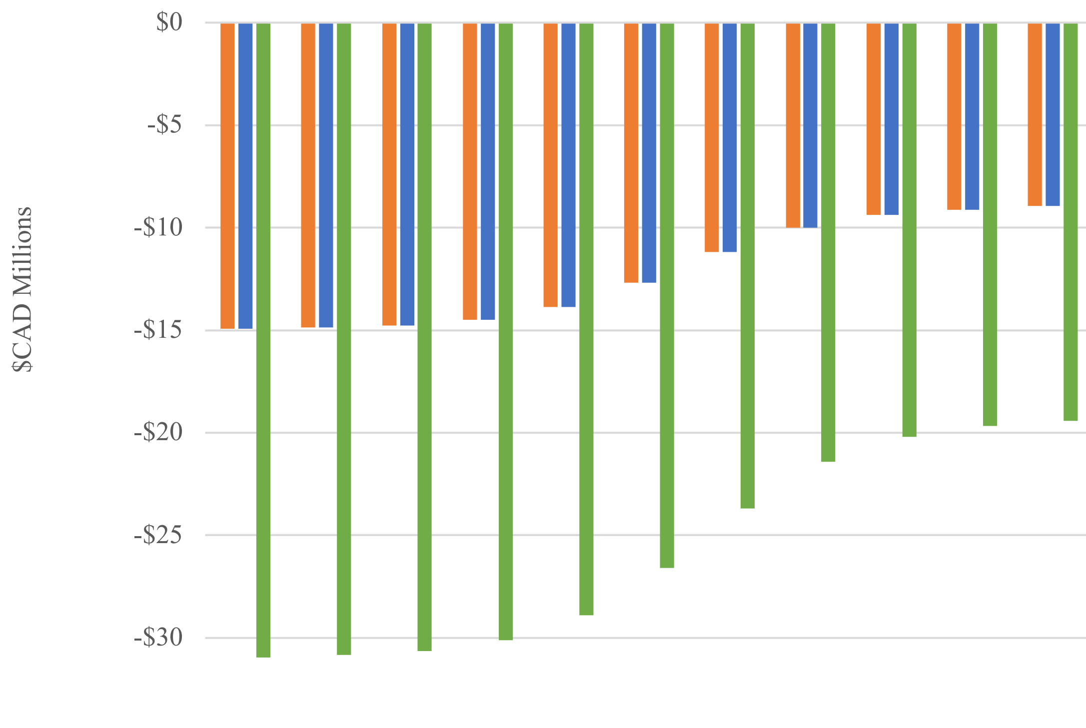
- Scenario 1 – Grid Rate: this scenario is not considered an economically viable option regardless of the carbon tax due to the high LCOH for this scenario.
- Scenario 2 – Wind PPA: in the high carbon tax regime, the scenario becomes economically viable with a 20-year investment start dates of 2029 and 2030. Compared to the High Carbon Tax Base Case, the results indicate that this scenario is approximately 2.3% higher in 2029 and 5% greater 2030. In the low carbon tax regime, this scenario is 12% lower than the Base Case in 2030 and not considered economically viable with the current parameters.
- Scenario 3 – Direct Connect Wind Farm (10 MW): the high carbon tax regime results are economically favourable, with a 20-year investment start date in 2027. Compared to the High Carbon Tax Base Case, the scenario is 0.1% greater in 2027, 4.6% in 2028, 7.2% in 2029 and 9% in 2030. In the low carbon tax regime, this scenario is 8% lower than the Base Case in 2030 and not considered economically viable with the current parameters.

The payback period is calculated on the cumulative avoided cash flow for each scenario. Only the two wind scenarios showed a positive payback period if the carbon tax remains high.

The low carbon tax had no payback regardless of the scenario. The results are tabulated in Table 6.2 below.

Figure 30

Incremental Cost for each Scenario Compared to Diesel-Fuel Base Case.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Scenario 1- Grid Rate	-$14.9	-$14.9	-$14.8	-$14.5	-$13.9	-$12.7	-$11.2	-$10.0	-$9.4	-$9.1	-$8.9
Scenario 2 - Wind PPA	-$14.9	-$14.9	-$14.8	-$14.5	-$13.9	-$12.7	-$11.2	-$10.0	-$9.4	-$9.1	-$8.9
Sceanio 3 - Wind Farm	-$30.9	-$30.8	-$30.6	-$30.1	-$28.9	-$26.6	-$23.7	-$21.4	-$20.2	-$19.7	-$19.4

Scenario 1- Grid Rate   Scenario 2 - Wind PPA   Sceanio 3 - Wind Farm

Note: the graph above depicts the total incremental costs from the base-case for each hydrogen scenario for a 20-year mine with an investment start date between 2020 and 2030.

Figure 31

Undiscounted Economic Comparison of Scenarios.

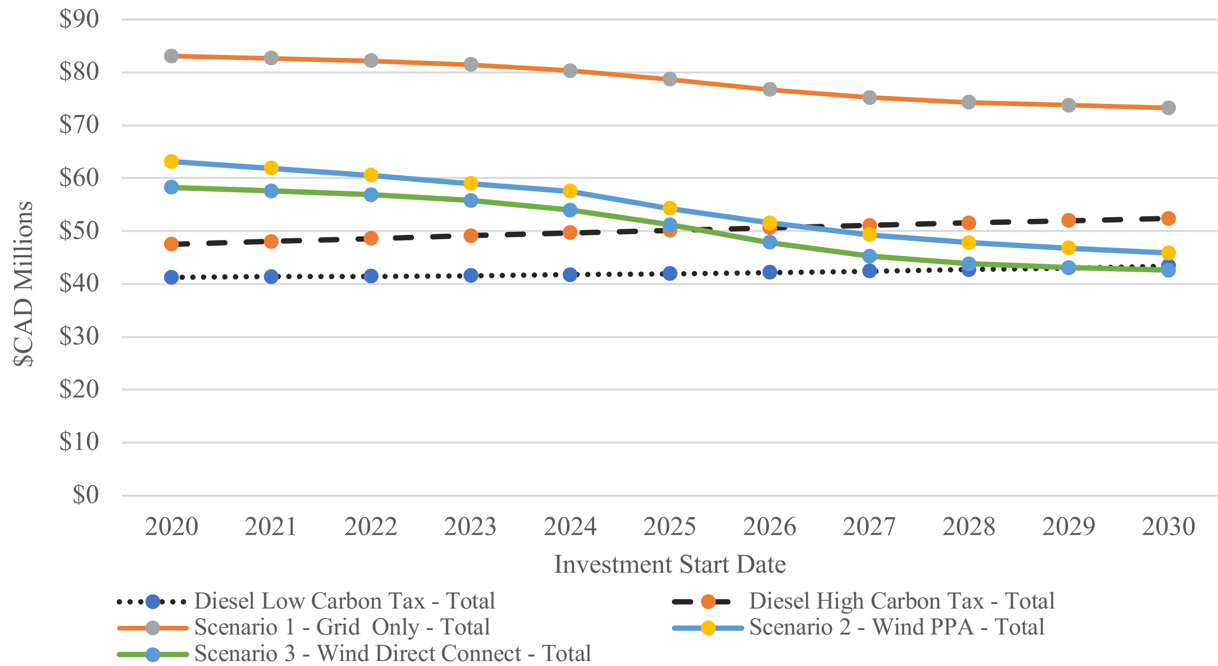


Figure 32

NPV Economic Comparison of Scenarios.

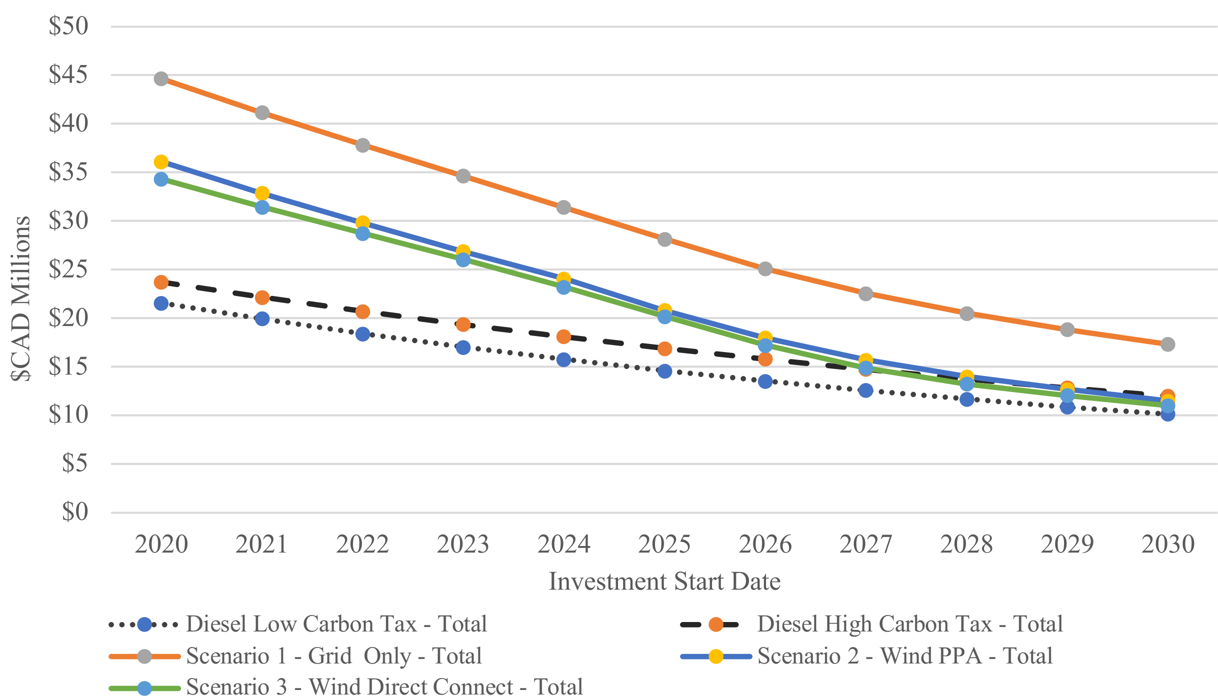
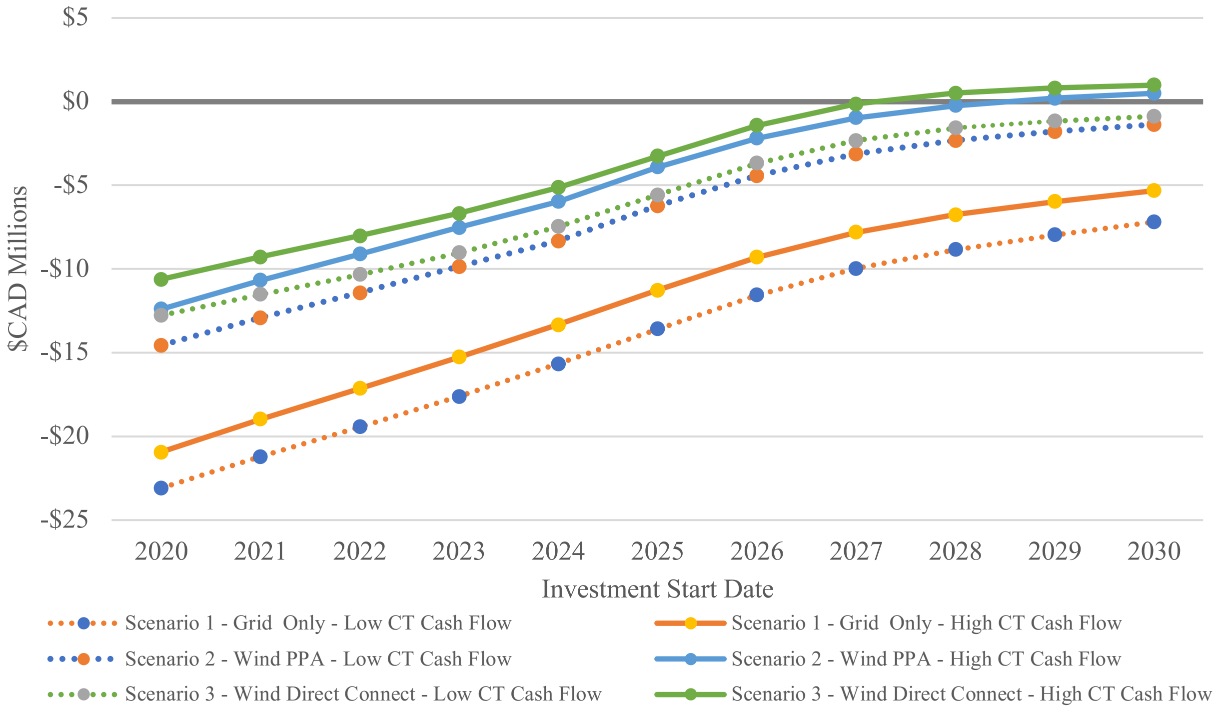


Figure 33

NPV Avoided Cost Comparison.



Note: CT refers to Carbon Tax. Results are based on a 20-year mine for each investment start date between 2020 and 2030.

Table 6.2

Net-Payback Based on Avoided Cost NPV (8% Discount Factor).

High-Carbon Tax Rate	Scenario 1	Scenario 2	Scenario 3
Investment Start Date	**Payback Years**	**Payback Years**	**Payback Years**
2020	-	-	-
2021	-	-	-
2022	-	-	-
2023	-	-	-
2024	-	-	-
2025	-	-	-
2026	-	-	-
2027	-	-	-
2028	-	-	14
2029	-	15	12
2030	-	12	11

Note: "-" denotes No-Payback. Only the high carbon tax results are shown as the low carbon tax regime had no payback in each of the scenarios. Results are based on a 20-year mine for each investment start date between 2020 and 2030.

6.3 Sensitivity Analysis

The results of the scenarios in this project assumed that the carbon tax would continue to rise to 2050 for both the High-Carbon Tax (($300/t$CO_2$e) and Low-Carbon Tax ($125/tCO_2e) Base Case Scenarios. To understand the carbon tax holding flat between 2030 and 2050 for each case (High = $170/t$CO_2$e, Low = $50/t$CO_2$e), a sensitivity was analyzed to compare how the results would be affected. Figure 34 shows the NPV cash flows between the scenarios with an 8% discount factor. If the carbon tax remained low, none of the scenarios are viable. However, if the carbon tax remains high at $170/t$CO_2$e, Scenario 3 becomes cost-competitive to the diesel-fuel base case in 2029 and in 2030 is 2.3% higher.

The results show that the carbon tax has a direct bearing on the financial viability of fuel-switching to hydrogen.

Figure 34

Sensitivity Analysis on NPV to Carbon Tax Not Increasing to 2050.

Note: Low Carbon Tax holds at $50/t$CO_2$e and high carbon tax hold at $170/t$CO_2$e to compare economic feasibility for each 20-year investment start date between 2020 and 2030.

A sensitivity analysis was also completed on the diesel-fuel prices, electricity rate, hydrogen technology learnings and wind technology learnings to determine how each parameter affected the results. Essentially, the learnings are linked to the CAPEX for equipment. A 10% increase in technology learning results in a 10% decrease in costs. As this study analyzes the investment optionality, the sensitivity was completed on an investment start date in 2030. The results can be found in Appendix C.

The annual change in diesel price was analyzed from -2% to 3% with an initial base case of $0.80 /litre, increasing 2% per year. As the cost for diesel-fuel decreases, the total avoided costs increase. The results indicate that with a fuel-cost increase of 0.5%/year, the windfarm scenario will be cost-competitive to the base case in 2030. With an increase of 1.5%, the wind PPA scenario will be financially viable in 2030.

A sensitivity analysis was completed to determine that optimal fuel price where the low-carbon tax scenario would become economically favourable for fuel-switching to hydrogen. The cost of fuel in this analysis remains flat and does not increase to 2050. Based on a sensitivity analysis of the data, if diesel-fuel is contracted for more than $1.50 per litre ($CAD/litre), the results are favourable for a FCEV wind-hydrogen production project regardless of the carbon tax (Figure 35). Fuel-switching could be an economic incentive for remote mining locations, where diesel-fuel is shipped via barge or airplane, the cost for diesel can be 25%-300% more expensive than mine locations in central Ontario.

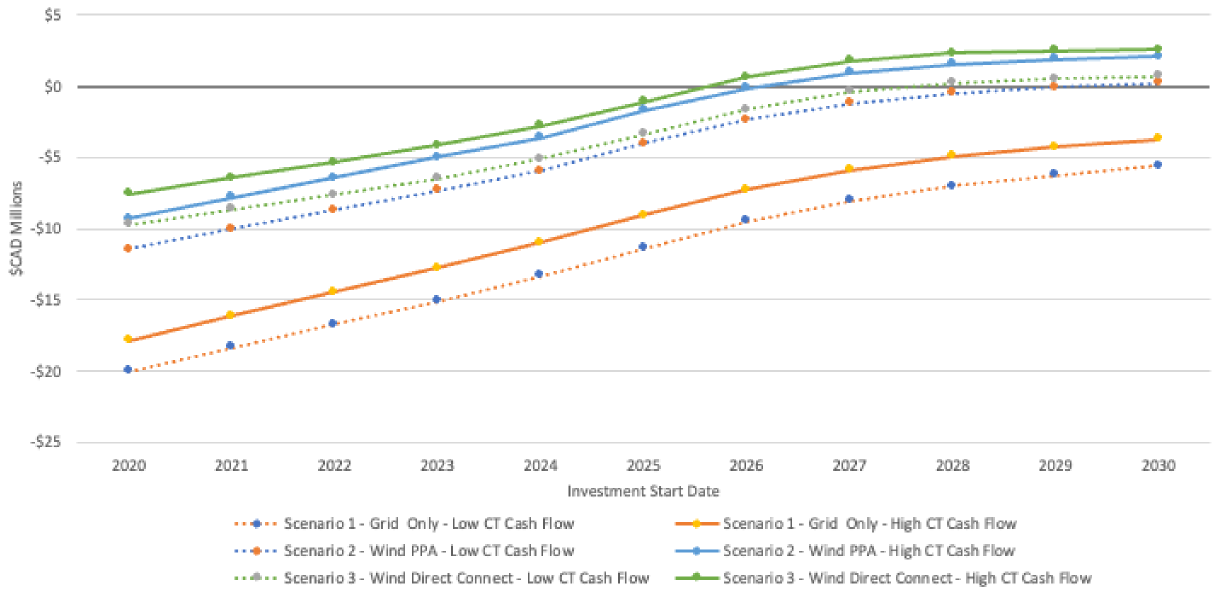
As expected, Scenario 1 showed the most significant sensitivity to electricity price. At $60/kWh in 2030 (7% /year decrease), the scenario is financially viable in the high carbon tax regime and $45 /MWh (10%/year decrease) in the low carbon tax regime.

Hydrogen technology learnings substantially affect the results as the costs are directly tied to the increases in learnings due to economies of scale and efficiencies. Scenario 3 is viable above 20% learnings, while Scenario 2 is viable above 30%. As the high LCOH constrains the financial metrics of Scenario 1, hydrogen technology learnings do not provide a viable financial option.

Wind technology learning has a substantial effect on the results for Scenario 3. The results indicate that 15% or greater technology learnings will positively incentivize a renewable-hydrogen project.

Figure 35

Sensitivity Analysis on NPV to Diesel-Fuel Price at $1.50/litre.



Note: Diesel-fuel-price at $1.50/litre in 2020 and holding constant to 2050.

Chapter 7- Conclusion, Limitations and Future Work

This study evaluated the feasibility of fuel-switching from diesel to hydrogen through a holistic analysis of the environment, energy, and economics. The results indicate that switching from a diesel-fuel mine-haul fleet to an FCEV fleet can reduce total emissions by over 90% if the electrolyzer is connected to a renewable energy source and be economically feasible by 2027 with a carbon tax of \$125 /tCO_2e. If the electrolyzer is connected to an electrical grid with a low carbon intensity, such as Ontario (77 gCO_2e/kWh), the emissions can be reduced by 50%, however, the high levelized cost of hydrogen production results in uneconomic viability regardless of the carbon tax rate. While the up-front costs are nearly 50% higher than grid-electrolysis, there are considerably more significant environmental and economic benefits over the lifetime of a renewable-hydrogen.

With a federal government parliamentary vote in September 2021, the election results could have a financial bearing on the financial viability of a hydrogen-fuel switching project. For example, if the carbon tax remains high and rises to \$170 /tCO_2e by 2030, an investment in hydrogen would make financial sense. However, suppose the carbon tax holds flat at \$50 /tCO_2e (low carbon tax). In that case, the financial potential may not be achieved unless the Conservative Party of Canada enacts other emissions control measures that have financial implications on CO_2 emissions from diesel.

7.1 Future Research and Recommendations

It is recommended that future studies investigate emissions reduction and economics of hydrogen production from other renewable energies, such as solar, nuclear, and hydro energy, and within other jurisdictions within Canada. As water is the feedstock for electrolysis, a water scarcity study is recommended to be completed to determine the additional water stress on the environment. Further investigations of government incentives and policies for fuel-switching to hydrogen, such as Clean Fuel Standard (Government of Canada, 2021b), is necessary to identify financial incentives to ensure economic success.

While many of the assumptions made in this study are based on current 2020 cost estimates, predicting the future energy and equipment cost is difficult. The assumptions used in this study have been supported by predictions from sources such as IRENA, the IEA, and the

Government of Canada. However, as recent events with COVID-19 have shown, costs can increase for materials essential to the energy transition if there are massive global disruptions to supply chains. In addition, there is currently only one publicly announced 290-ton FCEV Ultra-Class demonstration project that has yet to begin operation. Therefore, this study should be revisited once more information on the equipment parameters becomes readily available.

7.1 Final Thoughts

In the pathway towards net-zero mining, alternatives to diesel must be implemented to reduce emissions, especially as global mineral demand is expected to increase with the clean energy transition. With a nearly limitless feedstock of water across the globe, hydrogen produced via renewable energy sources can be a crucial fuel to decarbonizing the mining sector. As industrial mining companies move towards sustainable development and analyzing decarbonization pathways for their operations, hydrogen should be considered one of the top-tier options.

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Appendix A: Tables for Diesel-Base Case and Hydrogen Scenarios in 2020

Table A1

Yearly Costs for Diesel Base Case with an Investment Start Date in 2020.

Year	Litres of Fuel	Fuel Price	Diesel Fuel Cost	Diesel Mine Truck Cost	Diesel Mine Truck OPEX	Storage Cost	Total Cost
	Total	$CAD/Litre	$CAD/Litre	$CAD	$CAD	$CAD	$CAD
2020	-	$0.80	-	$6,600,000	-	$349,267	$6,949,267
2021	1,216,304	$0.82	$992,504		$128,700	$17,463	$1,138,668
2022	1,216,304	$0.83	$1,012,354		$125,483	$17,463	$1,155,300
2023	1,216,304	$0.85	$1,032,601		$122,973	$17,463	$1,173,038
2024	1,180,179	$0.87	$1,021,971	$602,567	$120,513	$17,463	$1,762,514
2025	1,180,179	$0.88	$1,042,410		$118,103	$17,463	$1,177,977
2026	1,180,179	$0.90	$1,063,258		$116,332	$17,463	$1,197,053
2027	1,180,179	$0.92	$1,084,523		$114,587	$17,463	$1,216,573
2028	1,133,675	$0.94	$1,062,625	$567,204	$113,441	$17,463	$1,760,732
2029	1,133,675	$0.96	$1,083,877		$112,874	$17,463	$1,214,214
2030	1,133,675	$0.98	$1,105,555		$112,309	$17,463	$1,235,327
2031	1,133,675	$0.99	$1,127,666		$112,028	$17,463	$1,257,158
2032	1,089,004	$1.01	$1,104,896	$5,587,416	$111,748	$17,463	$6,821,524
2033	1,089,004	$1.03	$1,126,994		$111,469	$17,463	$1,255,926
2034	1,089,004	$1.06	$1,149,534		$111,190	$17,463	$1,278,187
2035	1,089,004	$1.08	$1,172,524		$110,912	$17,463	$1,300,900
2036	1,046,093	$1.10	$1,148,849	$553,175	$110,635	$17,463	$1,830,122
2037	1,046,093	$1.12	$1,171,826		$110,358	$17,463	$1,299,647
2038	1,046,093	$1.14	$1,195,262		$110,083	$17,463	$1,322,808
2039	1,046,093	$1.17	$1,219,167		$109,807	$17,463	$1,346,438
2040	1,046,093	$1.19	$1,243,551		$109,533	$17,463	$1,370,547
Total	**22,490,803**		**$22,161,947**	**$13,910,362**	**$2,293,078**	**$698,534**	**$39,063,921**
NPV (8% discount)			**$9,811,805**	**$11,561,379**	**$1,148,113**	**$482,153**	**$20,365,963**

Note: Wallace, 2021.

Table A2

Low Carbon Tax Yearly Costs for Diesel Base Case with an Investment Start Date in 2020.

Year	CO2 Emissions	Low Carbon Tax Rate	Low Carbon Tax Cost	Total Cost
	tCO2	$CAD	$CAD	$CAD
2020	-	-	-	$6,949,267
2021	3,235	$35	$113,238	$1,251,905
2022	3,203	$50	$160,151	$1,315,451
2023	3,171	$50	$158,549	$1,331,587
2024	3,139	$50	$156,964	$1,919,478
2025	3,108	$50	$155,394	$1,333,371
2026	3,077	$50	$153,840	$1,350,893
2027	3,046	$50	$152,302	$1,368,875
2028	3,016	$50	$150,779	$1,911,511
2029	2,985	$50	$149,271	$1,363,485
2030	2,956	$50	$147,778	$1,383,105
2031	2,926	$52	$152,153	$1,409,310
2032	2,926	$54	$158,005	$6,979,528
2033	2,926	$56	$163,857	$1,419,783
2034	2,926	$58	$169,709	$1,447,896
2035	2,926	$60	$175,561	$1,476,461
2036	2,926	$63	$184,339	$2,014,461
2037	2,926	$66	$193,117	$1,492,764
2038	2,926	$69	$201,895	$1,524,703
2039	2,926	$72	$210,673	$1,557,111
2040	2,926	$75	$219,451	$1,589,998
Total	**60,196**		**$3,327,022**	**$42,390,943**
NPV (8% discount)			**$1,553,339**	**$21,804,240**

Note: Wallace, 2021.

Table A3

High Carbon Tax Yearly Costs for Diesel Base Case with an Investment Start Date in 2020.

Year	CO2 Emissions	High Carbon Tax Rate	High Carbon Tax Cost	Total Cost
	tCO2	$CAD	$CAD	$CAD
2020	-	-	-	$6,949,267
2021	3,235	$35	$113,238	$1,251,905
2022	3,203	$50	$160,151	$1,315,451
2023	3,171	$65	$206,114	$1,379,152
2024	3,139	$80	$251,142	$2,013,656
2025	3,108	$95	$295,249	$1,473,225
2026	3,077	$110	$338,448	$1,535,502
2027	3,046	$125	$380,754	$1,597,328
2028	3,016	$140	$422,181	$2,182,913
2029	2,985	$155	$462,740	$1,676,954
2030	2,956	$170	$502,446	$1,737,773
2031	2,926	$180	$526,682	$1,783,839
2032	2,926	$190	$555,942	$7,377,466
2033	2,926	$200	$585,202	$1,841,128
2034	2,926	$210	$614,462	$1,892,649
2035	2,926	$220	$643,722	$1,944,622
2036	2,926	$230	$672,982	$2,503,104
2037	2,926	$235	$687,612	$1,987,260
2038	2,926	$240	$702,242	$2,025,050
2039	2,926	$245	$716,872	$2,063,310
2040	2,926	$250	$731,502	$2,102,049
Total	**60,196**		**$9,569,684**	**$48,633,605**
NPV (8% discount)			**$3,874,090**	**$23,953,084**

Note: Wallace, 2021.

Table A4

Yearly Costs for Hydrogen FCEV with an Investment Start Date in 2020.

Year	Hydrogen Req.	Fuel-Cell Truck	PEM Fuel-Cell	Lithium-Ion Battery	Truck OPEX	Total Cost
	tons H2 / year	$CAD	$CAD	$CAD	$CAD	$CAD
2020	-	$8,580,000	-	-	-	$8,580,000
2021	374	-	-	-	$171,005	$171,005
2022	374	-	-	$195,320	$169,974	$365,294
2023	374	-	-	-	$167,284	$167,284
2024	374	-	-	$180,452	$160,954	$341,406
2025	367	-	$65,008	-	$149,090	$214,098
2026	367	-	-	$136,105	$134,050	$270,155
2027	367	-	-	-	$122,186	$122,186
2028	367	-	-	$106,114	$115,856	$221,970
2029	356	-	$41,083	-	$113,166	$154,249
2030	356	-	-	$99,000	$111,540	$210,540
2031	356	-	-	-	$109,824	$109,824
2032	353	$5,405,400	-	-	$108,108	$5,513,508
2033	353	-	-	-	$106,392	$106,392
2034	353	-	-	$87,120	$104,676	$191,796
2035	353	-	-	-	$102,960	$102,960
2036	353	-	-	$81,180	$101,244	$182,424
2037	353	-	-	-	$99,528	$99,528
2038	348	-	$33,920	-	$97,812	$131,732
2039	348	-	-	$73,260	$96,096	$169,356
2040	348	-	-	-	$94,380	$94,380
Total	**7,192**	**$13,985,400**	**$140,011**	**$958,551**	**$2,436,125**	**$17,520,087**
NPV (8% discount)		**$12,578,704**	**$122,341**	**$730,828**	**$1,303,964**	**$11,725,172**

Note: Wallace, 2021.

Table A5

Yearly Costs for Hydrogen Production Equipment with an Investment Start Date in 2020.

Year	Electrolyzer CAPEX	Electrolyzer OPEX	H2 Storage	Water	Total Cost
	$CAD	$CAD	$CAD	$CAD	$CAD
2020	$4,858,620	-	$1,351,743	$138,677	$6,349,039
2021	-	$159,541	$245,716	$37,004	$442,261
2022	-	$159,541	$244,022	$36,634	$440,196
2023	-	$159,541	$239,602	$36,268	$435,410
2024	-	$159,541	$229,202	$35,905	$424,648
2025	-	$159,541	$209,709	$35,546	$404,796
2026	-	$159,541	$185,000	$35,190	$379,731
2027	-	$159,541	$165,507	$34,838	$359,886
2028	$801,196	$85,928	$155,107	$34,490	$1,076,721
2029	-	$85,928	$150,687	$34,145	$270,761
2030	-	$85,928	$148,016	$33,804	$267,748
2031	-	$85,928	$145,549	$33,466	$264,943
2032	-	$85,928	$144,315	$33,131	$263,375
2033	-	$85,928	$143,082	$32,800	$261,810
2034	-	$85,928	$141,849	$32,472	$260,249
2035	-	$85,928	$140,615	$32,147	$258,690
2036	$653,298	$70,066	$139,382	$31,826	$894,571
2037	-	$70,066	$138,148	$31,507	$239,722
2038	-	$70,066	$137,531	$31,192	$238,790
2039	-	$70,066	$136,915	$30,880	$237,861
2040	-$130,660	$70,066	$136,298	$30,572	$106,276
Total	**$6,182,454**	**$2,154,542**	**$4,727,994**	**$812,493**	**$13,877,483**
NPV (8% discount)	**$5,608,188**	**$1,206,945**	**$2,934,380**	**$442,298**	**$9,544,349**

Note: Wallace, 2021.

Table A6

Scenario 1 (Grid Rate) Energy Required, CO2 Emissions from Grid-Energy, Yearly Costs and Cash-Flow Totals from Avoided Cost of Diesel with an Investment Start Date in 2020.

Year	Grid Energy Cost	Energy Req.	CO2 from Grid	H2 Production	Scenario Total	Low Carbon Tax Cash Flow	High Carbon Tax Cash Flow
	$CAD/kWh	MWh/year	tonsCO2	$CAD	$CAD	$CAD	$CAD
2020	$0.115	-	-	-	$14,929,039	-$7,979,772	-$7,979,772
2021	$0.115	21,795	1,678	$2,506,380	$3,119,646	-$1,867,741	-$1,867,741
2022	$0.117	21,795	1,674	$2,550,054	$3,355,544	-$2,040,094	-$2,040,094
2023	$0.120	21,795	1,663	$2,583,988	$3,186,682	-$1,855,095	-$1,807,531
2024	$0.122	21,795	1,637	$2,595,293	$3,361,347	-$1,441,869	-$1,347,690
2025	$0.124	21,795	1,591	$2,572,205	$3,191,098	-$1,857,727	-$1,717,873
2026	$0.127	21,795	1,535	$2,530,671	$3,180,557	-$1,829,664	-$1,645,056
2027	$0.130	21,795	1,492	$2,509,486	$2,991,558	-$1,622,683	-$1,394,231
2028	$0.132	19,089	1,470	$2,521,661	$3,820,353	-$1,908,841	-$1,637,440
2029	$0.135	19,089	1,461	$2,555,836	$2,980,845	-$1,617,360	-$1,303,891
2030	$0.137	19,089	1,457	$2,600,630	$3,078,917	-$1,695,812	-$1,341,144
2031	$0.138	19,089	1,452	$2,605,297	$2,980,064	-$1,570,754	-$1,196,224
2032	$0.139	19,089	1,448	$2,610,888	$8,387,770	-$1,408,242	-$1,010,305
2033	$0.140	19,089	1,442	$2,613,438	$2,981,640	-$1,561,857	-$1,140,512
2034	$0.140	19,089	1,437	$2,615,977	$3,068,021	-$1,620,125	-$1,175,372
2035	$0.141	19,089	1,431	$2,618,504	$2,980,155	-$1,503,694	-$1,035,533
2036	$0.142	18,509	1,425	$2,621,021	$3,698,016	-$1,683,555	-$1,194,911
2037	$0.142	18,509	1,419	$2,623,526	$2,962,775	-$1,470,011	-$975,516
2038	$0.143	18,509	1,414	$2,626,019	$2,996,541	-$1,471,838	-$971,491
2039	$0.144	18,509	1,408	$2,628,501	$3,035,718	-$1,478,607	-$972,407
2040	$0.144	18,509	1,402	$2,630,970	$2,831,626	-$1,241,629	-$729,577
Total		**397,819**	**29,937**	**$51,720,343**	**$83,117,913**	**-$40,726,971**	**-$34,484,308**
NPV (8% discount)				**$25,257,025**	**$44,655,655**	**-$22,851,415**	**-$20,702,571**

Note: Wallace, 2021. Cash flows are based on avoided cost of diesel.

Table A7

Scenario 2 (Wind PPA) Energy Required, CO2 Emissions from Grid-Energy, Yearly Costs and Cash-Flow Totals from Avoided Cost of Diesel with an Investment Start Date in 2020.

Year	PPA Rate	Energy Req.	CO2 from Grid	H2 Production	Scenario Total	Low Carbon Tax Cash Flow	High Carbon Tax Cash Flow
	$CAD/kWh	MWh/year	tonsCO2	$CAD	$CAD	$CAD	$CAD
2020	$0.08	-	-	-	$14,929,039	-$7,979,772	-$7,979,772
2021	$0.08	21,795	-	$1,743,569	$2,356,835	-$1,104,929	-$1,104,929
2022	$0.08	21,795	-	$1,743,569	$2,549,059	-$1,233,608	-$1,233,608
2023	$0.08	21,795	-	$1,743,569	$2,346,263	-$1,014,676	-$967,111
2024	$0.08	21,795	-	$1,743,569	$2,509,622	-$590,144	-$495,966
2025	$0.08	21,795	-	$1,743,569	$2,362,462	-$1,029,091	-$889,237
2026	$0.08	21,795	-	$1,743,569	$2,393,455	-$1,042,562	-$857,954
2027	$0.08	21,795	-	$1,743,569	$2,225,641	-$856,766	-$628,313
2028	$0.08	19,089	-	$1,527,136	$2,825,827	-$914,316	-$642,914
2029	$0.08	19,089	-	$1,527,136	$1,952,145	-$588,660	-$275,191
2030	$0.08	19,089	-	$1,527,136	$2,005,424	-$622,318	-$267,650
2031	$0.08	19,089	-	$1,527,136	$1,901,903	-$492,593	-$118,063
2032	$0.08	19,089	-	$1,527,136	$7,304,019	-$324,490	$73,447
2033	$0.08	19,089	-	$1,527,136	$1,895,338	-$475,555	-$54,210
2034	$0.08	19,089	-	$1,527,136	$1,979,180	-$531,285	-$86,531
2035	$0.08	19,089	-	$1,527,136	$1,888,786	-$412,326	$55,836
2036	$0.08	18,509	-	$1,480,692	$2,557,687	-$543,226	-$54,582
2037	$0.08	18,509	-	$1,480,692	$1,819,941	-$327,177	$167,318
2038	$0.08	18,509	-	$1,480,692	$1,851,214	-$326,511	$173,837
2039	$0.08	18,509	-	$1,480,692	$1,887,909	-$330,798	$175,401
2040	$0.08	18,509	-	$1,480,692	$1,681,348	-$91,350	$420,701
Total		**435,892**	-	**$31,825,528**	**$63,223,098**	**-$20,832,155**	**-$14,589,493**
NPV (8% discount)		**213,983**		**$16,062,018**	**$36,141,760**	**-$14,337,520**	**-$12,188,676**

Note: Wallace, 2021. Cash flows are based on avoided cost of diesel.

Table A7

Scenario 3 (Wind Farm) Energy Required, CO2 Emissions from Grid-Energy, Yearly Costs and Cash-Flow Totals from Avoided Cost of Diesel with an Investment Start Date in 2020.

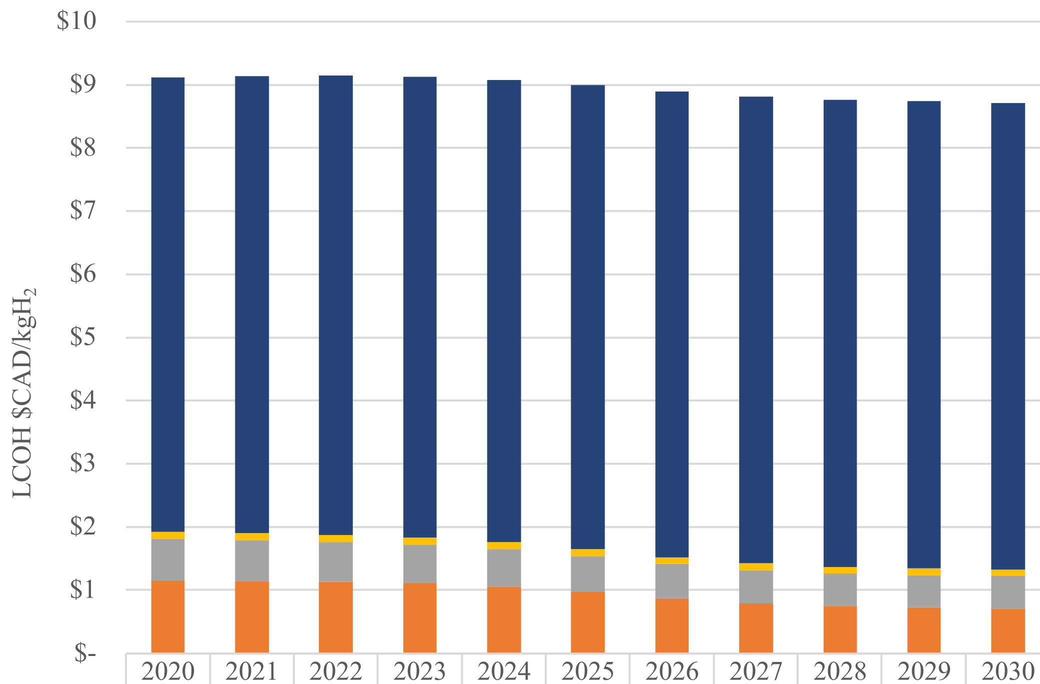
Year	Grid Energy	Wind Energy	CO2 from Grid	Wind Farm	Wind Production Cost	Grid Production	Scenario Total	Low Carbon Tax Cash Flow	High Carbon Tax Cash Flow
	MWh/year	MWh/year	tonsCO2	$CAD	$CAD	$CAD	$CAD	$CAD	$CAD
2020	-	-	-	$16,000,000	-	-	$30,929,039	-$23,979,772	-$23,979,772
2021	2468	19326	190	$320,000	$38,653	$283,838	$1,255,757	-$3,852	-$3,852
2022	2468	19326	190	$316,968	$38,653	$288,784	$1,449,895	-$134,444	-$134,444
2023	2468	19326	188	$311,951	$38,653	$292,627	$1,245,926	$85,661	$133,226
2024	2468	19326	185	$300,147	$38,653	$293,907	$1,398,761	$520,717	$614,895
2025	2468	19326	180	$278,023	$38,653	$291,293	$1,226,861	$106,509	$246,364
2026	2468	19326	174	$249,977	$38,653	$286,589	$1,225,106	$125,787	$310,396
2027	2468	19326	169	$227,853	$38,653	$284,190	$1,032,768	$336,108	$564,560
2028	2162	16927	166	$216,049	$33,855	$285,569	$1,834,164	$77,347	$348,749
2029	2162	16927	165	$211,032	$33,855	$289,439	$959,336	$404,149	$717,619
2030	2162	16927	165	$209,109	$33,855	$294,512	$1,015,763	$367,342	$722,010
2031	2162	16927	164	$207,509	$33,855	$295,040	$911,171	$498,139	$872,668
2032	2162	16927	164	$205,909	$33,855	$295,673	$6,312,320	$667,208	$1,065,146
2033	2162	16927	163	$204,309	$33,855	$295,962	$902,328	$517,455	$938,800
2034	2162	16927	163	$202,709	$33,855	$296,250	$984,858	$463,038	$907,791
2035	2162	16927	162	$201,109	$33,855	$296,536	$893,150	$583,310	$1,051,472
2036	2096	16413	161	$199,509	$32,825	$296,821	$1,606,150	$408,311	$896,954
2037	2096	16413	161	$197,909	$32,825	$297,105	$867,088	$625,676	$1,120,171
2038	2096	16413	160	$196,309	$32,825	$297,387	$897,043	$627,660	$1,128,007
2039	2096	16413	159	$194,709	$32,825	$297,668	$932,419	$624,691	$1,130,891
2040	2096	16413	159	-$306,891	$32,825	$297,948	$224,538	$1,365,460	$1,877,511
Total	**45,052**	**352,768**	**3,390**	**$20,144,198**	**$705,535**	**$5,857,140**	**$58,104,443**	**-$15,713,500**	**-$9,470,838**
NPV (8% discount)				**$16,994,048**	**$356,076**	**$2,860,266**	**$41,241,664**	**-$19,437,424**	**-$17,288,580**

Note: Wallace, 2021. Cash flows are based on avoided cost of diesel.

Appendix B: Levelized Cost of Hydrogen Production for Scenarios

Figure B1

Scenario 1: LCOH for 20-year Mine based on Investment Start Date.

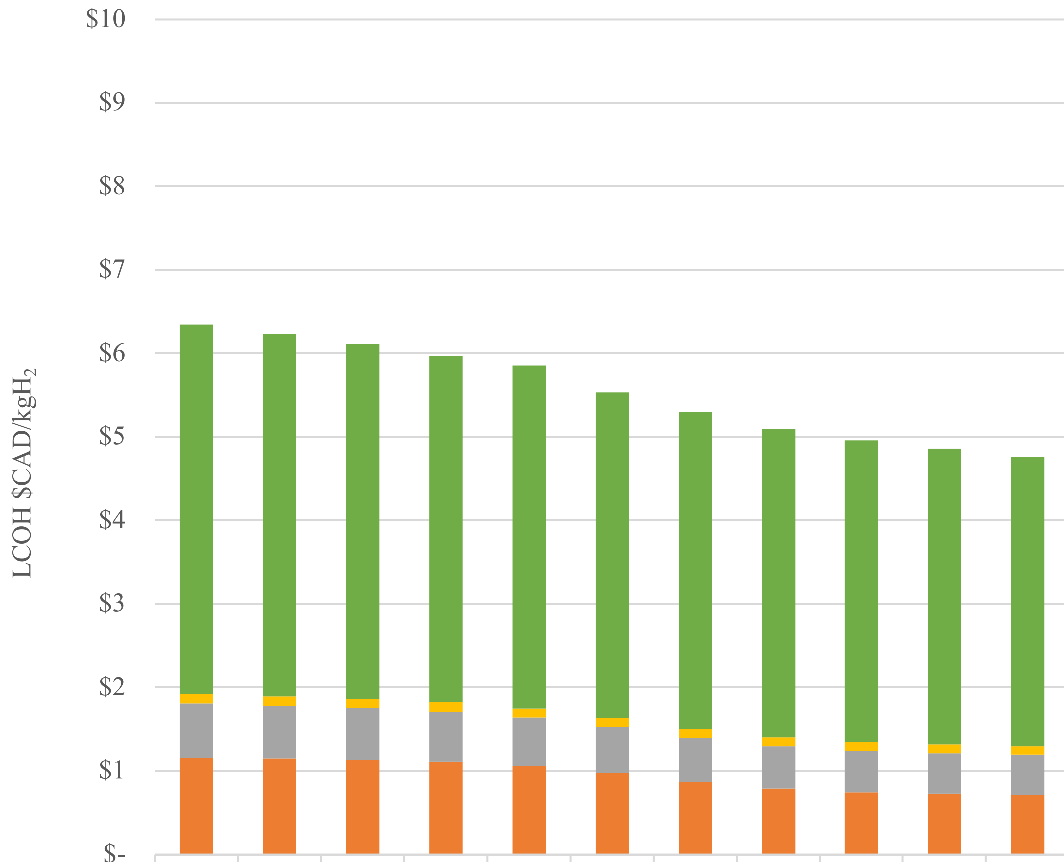


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Grid-H2 Production	$7.19	$7.23	$7.27	$7.29	$7.32	$7.34	$7.37	$7.38	$7.39	$7.39	$7.38
Water	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11
Storage	$0.66	$0.64	$0.63	$0.61	$0.60	$0.57	$0.55	$0.53	$0.52	$0.51	$0.51
Electrolyzer	$1.16	$1.15	$1.14	$1.11	$1.06	$0.97	$0.87	$0.79	$0.75	$0.73	$0.72

Note: Wallace, 2021. The graph above depicts Scenario 1-Grid Rate LCOH for hydrogen production for a 20-year mine with an investment start date between 2020 and 2030.

Figure B2

Scenario 2: LCOH for 20-Year Mine Based on Investment Start Date.

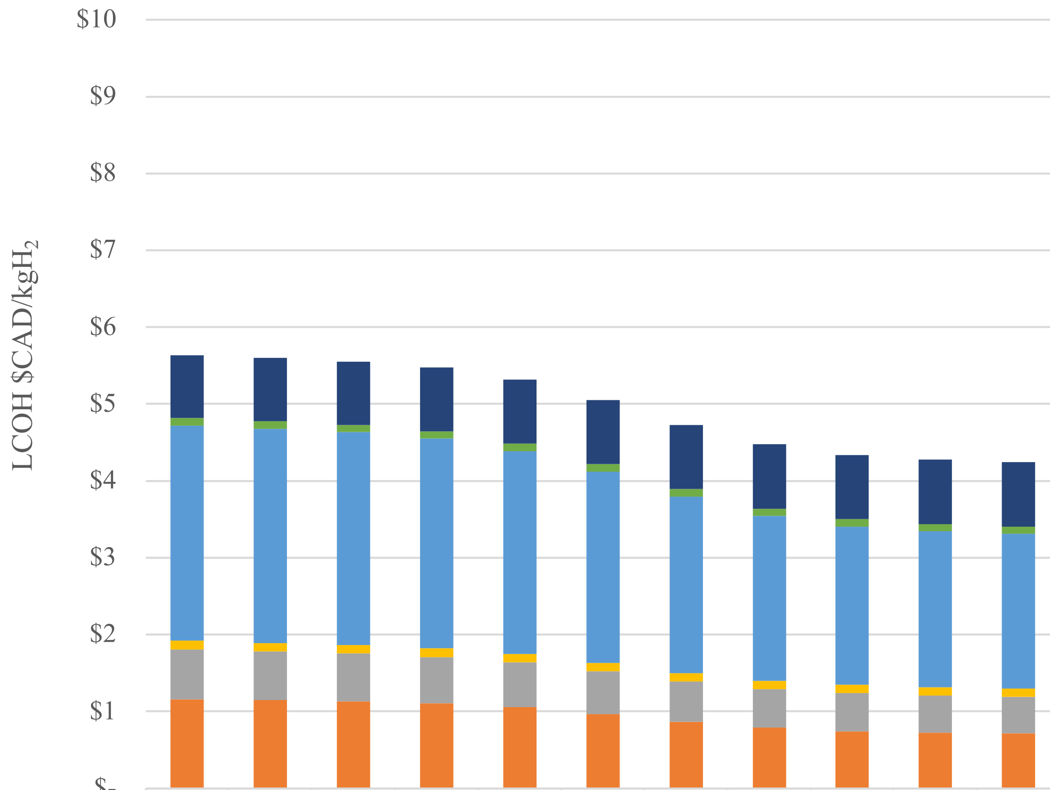


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind-H2 Production	$4.43	$4.34	$4.25	$4.14	$4.11	$3.90	$3.79	$3.70	$3.61	$3.54	$3.46
Water	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11
Storage	$0.65	$0.63	$0.62	$0.60	$0.58	$0.55	$0.53	$0.51	$0.49	$0.48	$0.48
Electrolyzer	$1.16	$1.15	$1.14	$1.11	$1.06	$0.97	$0.87	$0.79	$0.75	$0.73	$0.72

Note: Wallace, 2021. The graph above depicts Scenario 2-Grid Wind PPA LCOH for hydrogen production for a 20-year mine with an investment start date between 2020 and 2030.

Figure B3

Scenario 3: LCOH for 20-Year Mine Based on Investment Start Date.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Grid-H2 Production	$0.81	$0.82	$0.82	$0.83	$0.83	$0.83	$0.83	$0.84	$0.84	$0.84	$0.84
Wind-H2 Production	$0.10	$0.10	$0.10	$0.10	$0.10	$0.10	$0.09	$0.09	$0.09	$0.09	$0.09
Wind Farm CAPEX	$2.80	$2.79	$2.77	$2.73	$2.64	$2.49	$2.29	$2.14	$2.06	$2.03	$2.01
Water	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11	$0.11
Storage	$0.65	$0.63	$0.62	$0.60	$0.58	$0.55	$0.53	$0.51	$0.49	$0.48	$0.48
Electrolyzer	$1.16	$1.15	$1.14	$1.11	$1.06	$0.97	$0.87	$0.79	$0.75	$0.73	$0.72

Note: Wallace, 2021. The graph above depicts Scenario 3-Wind Farm LCOH for hydrogen production for a 20-year mine with an investment start date between 2020 and 2030.