Developing Models for a Sustainable Transition to Green Hydrogen in Western Canada

by

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Abstract

This work aims to conduct a techno-economic feasibility analysis of adopting a hybrid approach to hydrogen generation. This includes grey hydrogen sourced from natural gas using Steam Methane Reforming (SMR) and green hydrogen from renewable energy. The key focus is on assessing the environmental impacts of such a transition over the next decade in Western Canada while ensuring a clean and stable supply of hydrogen for various industrial processes. A life cycle assessment (LCA) is performed to ascertain greenhouse gas emissions per kg of hydrogen produced. The system boundaries extend from the set up and generation of renewable electricity at standalone and integrated renewable power plants (solar and wind) to the production of hydrogen using water electrolysis. The viability of a site for hydrogen generation from renewables is based on a study of the photovoltaic (PV) and wind potential of various locations in Western Canada. Additionally, an analysis considering the expected improvements in efficiency and scale of upcoming electrolyzer technologies is incorporated into the model. Most of the life cycle CO_2 emissions of solar and wind sourced hydrogen are from the initial setting up of the power plants. In comparison with SMR sourced hydrogen, total life cycle emissions show a reduction of approximately 90%. As electrolyzer technology is improved, hydrogen produced using dedicated renewable sources will achieve price parity over the longer term with the model proposed. An analysis is performed to ascertain the relative viability and cost of utilizing low-cost electricity for hydrogen generation. This includes the development of models based on various electricity price thresholds. It is expected that up to 15% of the annual hydrogen demand could be met by using this clean electricity, depending on the model adopted. It also helps predict the rate at which a hybrid supply of hydrogen can be converted to a primarily green hydrogen supply. These results will serve as a reliable way to transition from grey hydrogen that is currently being produced to

green hydrogen, without increasing costs exponentially and with no change in availability. The analysis provides a roadmap for a phased decarbonization of various industries, including the oil and gas industry, where hydrogen is used as a feedstock. Further, it acts as a technical guide to effectuating various hydrogen strategies and achieving emission reduction targets that have been envisaged by provinces in Western Canada.

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Chapter 1: Introduction

Under the Paris Climate Agreement of 2015, 196 countries around the world committed to limit global warming to well below 2°C, ideally to 1.5°C above pre-industrial levels. This requires the need to limit global warming to 45% by 2030 and achieve net zero emissions by 2050. The recent pandemic led to a temporary fall in emission levels which have since rebounded to higher levels as before. Achieving global net zero requires high decarbonization in a variety of sectors including industries, transport, and agriculture (SDG Indicators , 2022).

In recent decades, the average temperatures in Canada have risen at twice the average global rate of temperature rise. To mitigate this, Canada has released the 2030 emission reduction plan to limit reductions to 40-45% below 2005 levels by 2030 and achieve net zero by 2050. This includes abating pollution from the oil and gas sector by up to 42% by diversifying the sources of energy and adopting clean technologies. Additionally, heavy industries and the electricity sector will be encouraged to decarbonize through incentives and subsidies to upgrade clean technology and enhance renewables in the power grid. Currently, oil and gas, electricity, and heavy industries contribute almost 45% of the total greenhouse gas emission in Canada. Emission reduction pathways by 2030 for various sectors include abatement of 40% in oil and gas, 65% in electricity and about 30% in heavy industries over the current levels by 2030 (Government of Canada, 2022).

The Province of Alberta has the second highest emissions per capita in Canada with a 55% increase since 1990 and a further 20% increase in the last two decades. Oil and Gas, and the electricity sectors constitute the highest portion of the total emission with 52% and 11% of the total share respectively. Alberta plans to be carbon neutral by 2050 with measures such as carbon pricing and emission trading mechanisms already introduced in the province. Twenty-five Carbon Capture and

Storage (CCS) hubs have been identified to develop facilities for decarbonization of heavy industries, clean hydrogen, and the power industry. The Alberta electricity grid will phase out coal by the end of 2023 and has a target of powering 30% of the grid by renewable energy by 2030. Other measures to decarbonize the power sector includes leveraging CCUS technologies, hydrogen fueled power plants, and upscaling nuclear energy in the form of small modular reactors (Emissions Reduction and Energy Development Plan, 2023).

1.1 Role of Hydrogen in a Net-zero Transition

Hydrogen is slated to play a central role in the various strategies identified to achieve the net zero targets. It has the potential to complement other technologies such as renewables in decarbonizing highly emitting industries. Scaling up hydrogen deployment rapidly can result in an emissions savings of up to 20% of the required level in net zero scenarios by 2050 and can contribute more than a fifth of the total global energy demand. Approximately 75MT of clean hydrogen is required by 2030 and 660MT by 2050 to achieve these targets (Hydrogen Council, 2021). Low carbon hydrogen includes hydrogen from a variety of sources including renewables and fossil fuels-based hydrogen accompanied by Carbon Capture and Storage (CCS). The required renewable energy capacity for emissions reduction targets is 400GW and 5TW by 2030 and 2050 respectively and electrolyzer generation capacity is 200GW and 3TW by 2030 and 2050 respectively (IEA, 2022).

Global hydrogen demand is currently 94MT annually which is approximately 2-3% of the total energy consumed globally. The traditional users such as refining, and agriculture constitute a majority of this demand with new sectors such as transport and heavy industries coming up recently. This demand is forecast to increase to 130MT by the end of this decade with 25% of the demand coming from new applications and replacement of current hydrogen production (highly emitting) by low emission hydrogen (IEA, 2022).

A majority of the current global hydrogen production demand is met by fossil fuels with natural gas accounting for 62% and coal-based sources accounting for 19% of the total production. Low carbon hydrogen accounts for less than 1% of the total hydrogen with almost all this production from fossil fuels with CCS. Electrolysis based hydrogen forms a smaller portion currently but is rapidly expanding by more than 20% per year (IEA, 2022).

Various large scale clean hydrogen production projects including renewables and low carbon hydrogen (>1GW) are in the pipeline all over the world with more than 1000 such projects set to be completed by 2030. Europe constitutes the highest number of projects (35%) followed by North America (15%). The projected capacity addition by 2030 can be up to 24MT hydrogen per year with electrolysis and fossil fuels with CCS contributing equally to the mix (IRENA, 2021).

The hydrogen produced from electrolyzers accounts for about 0.1% of the total production and the total capacity exceeded 1GW in 2022. If the current projects come to fruition, the total capacity is expected to be 130GW by 2030. Alkaline electrolysis technology dominates current electrolysis installations with about 70% followed by Proton Exchange Membrane (PEM) with around a quarter. By 2030, there is a greater expected scale up of PEM electrolyzers resulting in an equal share of both the major electrolysis technologies. The cost reduction for both major electrolysis technologies is expected to be more than 50% by 2025 over current levels and is expected to reach $500/kW per unit of installed capacity. By 2030, further cost reductions will lead to an average cost of $300/kW (IEA, 2022).

Layzell et al. have analyzed the role of hydrogen in a net-zero scenario in Canada by 2050. Hydrogen will contribute up to 27% of the Canadian energy demand and the demand of hydrogen will be approximately 64 kT per day. This demand can be met by a mixture of green and blue hydrogen. Low carbon electricity can be produced through renewables, nuclear, or hydropower for electrolyzers or natural gas with CCS can be leveraged depending on the province. Policies and standards must be developed along with roadmaps to bring down final retail costs of low carbon hydrogen. The end use for hydrogen in a net-zero system will be as an industrial feedstock in agriculture, transport, and chemicals and as fuel in buildings, transport, and power industries. Canada has the capacity and potential to be one of the world's leading producers of low-cost, low-carbon hydrogen due to a diversity of resources including suitability for renewable energy and basins for CO_2 sequestration. Electrolysis based hydrogen can be produced either through low carbon grid electricity or dedicated renewables (Layzell, 2020).

Layzell et. al. have also analysed various strategies to transition the Alberta Industrial Heartland into a hub for hydrogen production. The shift to hydrogen as a replacement fuel can be in the diesel, gasoline, and natural gas markets depending on the end use- transport, non-transport, domestic heating, and storage. If all the currently produced grey hydrogen (SMR) is converted into blue hydrogen (SMR+CCS), the pipeline capacity required will be six times the current CO_2 carrying capacity. Additionally, a network of pipelines connecting sources of various types of hydrogen- green, blue, or byproduct to the end use location including filling station and buildings is required in Alberta. The conversion of hydrogen into liquid for transport on trucks increases the unit (per kg) cost of hydrogen by $3. Natural gas pipelines no longer in use can be repurposed to transport hydrogen to specific end users. A variety of strategies including upscaling green hydrogen are required to make the transition viable and cost effective (Layzell, 2020).

1.2 Problem Statements

1. What are the total emissions and costs associated with producing a unit of green hydrogen in Western Canada?

2. How can green hydrogen production be optimized to contribute a significant percentage of annual hydrogen demand and the rate at which this transition can take place cost effectively?
3. What are the savings in emissions associated with the various proposed models and their contribution to overall emission targets?
4. How can excess and low-cost renewable electricity be harnessed to further decrease unit costs of green hydrogen over the next decade?
5. Can producing hydrogen avoid the issue of curtailment of renewables during periods of overproduction thereby avoiding wastage of low carbon energy?

1.3 Methods

The current forecast for hydrogen production for the next decade predicts a scale up of blue hydrogen with either retrofit of existing hydrogen production facilities or installation of new ones. As outlined previously, blue hydrogen alone may be insufficient to meet emission reduction targets and further decarbonize heavy emission industries. There is a requirement to scale up alternate sources of clean hydrogen such as green hydrogen. A major hindrance to large scale adoption and production of green hydrogen are the costs associated with installation and setup of the production facilities.

This work undertakes a life cycle assessment (LCA) based cradle to gate approach beginning at setup of renewable energy power plants in Western Canada and producing hydrogen in electrolyzers. Various technologies and improvement in electrolyzers are considered to create models for sustainable green hydrogen adoption. The hydrogen production emission trends based on the business-as-usual scenario increase emissions by up to 10 MT CO_2eq over the current emissions. The Hydrogen production models proposed here will lead to significant emission savings and when this clean hydrogen is used in hard to decarbonize industries, it will help further emission reductions. Large scale installation of dedicated renewable energy facilities will also contribute towards net-zero goals of electricity sector since Alberta's Grid emits approximately five times the national average emissions.

Further, this work proposes an alternate method of clean hydrogen production by using low-cost renewable energy in Alberta and Western Canada. This method of hydrogen production will help the province avoid periods of renewable curtailment when electricity supply exceeds demand especially as renewables are scaled up to meet net-zero and emissions goals in the electricity sector. Renewable energy supply is intermittent with supply peaks occurring during the mid-day for solar energy due to maximum insolation and during late evenings and early mornings for wind energy. These periods often do not coincide with peaks in electricity demand and thus may lead to curtailment of low emission electricity. A plan to produce green hydrogen from this electricity is proposed by analyzing hourly production and price trends to identify specific periods during which hydrogen may be generated. These are aligned with the net zero emission pathways proposed by Alberta for the next decade. This hydrogen production scheme will also help scale up the nascent green hydrogen industry and contribute to the province's proposed emission reduction targets to be achieved under the climate plans.

Chapter 2: Life Cycle Assessment of Hybrid and Green Hydrogen Generation Models for Western Canada

2.1 Abstract

The aim of this paper is to conduct a techno-economic feasibility analysis of adopting a hybrid approach to hydrogen generation. This includes grey hydrogen sourced from natural gas using Steam Methane Reforming (SMR) and green hydrogen from renewable energy. The key focus is on assessing the environmental impacts of such a transition over the next decade in Western Canada while ensuring a clean and stable supply of hydrogen for various industrial processes. A life cycle assessment (LCA) is performed to ascertain greenhouse gas emissions per kg of hydrogen produced. The system boundaries extend from the set up and generation of renewable electricity at standalone and integrated renewable power plants (solar and wind) to the production of hydrogen using water electrolysis. The viability of a site for hydrogen generation from renewables is based on a study of the photovoltaic (PV) and wind potential of various locations in Western Canada. Additionally, an analysis considering the expected improvements in efficiency and scale of upcoming electrolyzer technologies is incorporated into the model. Most of the life cycle CO_2 emissions of solar and wind sourced hydrogen are from the initial setting up of the power plants. In comparison with SMR sourced hydrogen, total life cycle emissions show a reduction of approximately 90%. As electrolyzer technology is improved, hydrogen produced using dedicated renewable sources will achieve price parity over the longer term with the model proposed. It also helps predict the rate at which a hybrid supply of hydrogen can be converted to a primarily green hydrogen supply. These results will serve as a reliable way to transition from grey hydrogen that is currently being produced to green hydrogen, without increasing costs exponentially and with no change in availability. The analysis provides a roadmap for a phased decarbonization of various industries, including the oil and gas industry, where hydrogen is used

as a feedstock. Further, it acts as a technical guide to effectuating various hydrogen strategies and achieving emission reduction targets that have been envisaged by provinces in Western Canada.

2.2 Introduction

Hydrogen is seen as a key driver both in meeting climate goals and enhancing energy security. It has the potential to be used extensively in many hard-to-abate sectors for which energy demand is primarily due to fossil fuels such as aviation, transport, heating, and steel making (IEA, 2019). Hydrogen can meet up to 6% of the world's energy needs by 2050 (IRENA 2019) while other aggressive estimates point to almost 20% of the total energy consumption needs being met by hydrogen to achieve net zero targets (Global Hydrogen Council 2021).

There are various pathways for hydrogen production such as production from natural gas and other hydrocarbons (grey or brown), natural gas with Carbon Capture, Utilization and Storage- CCUS (blue), water electrolysis (green), and nuclear-powered sources (yellow). Fossil fuel-based hydrogen production is the dominant production method with more than 90% of the global share, with 2% of the global coal and 6% of the global natural gas consumption being used to produce hydrogen which is accompanied by CO_2 emissions. Steam Methane Reforming (SMR) is the most commonly used method (around 75% of the global production) to produce natural gas-based hydrogen followed by Auto Thermal Reforming (ATR) (Howarth and Jacobson 2021). Combining natural gas based processes with Carbon Capture and Storage (CCS) is the most viable way to reduce hydrogen production emissions in the short term (Tetteh and Salehi 2022). However, even when 90%, which is the current maximum, of the carbon emitted is captured in the process the emissions reduce by 10-20% compared to grey hydrogen as fugitive methane emissions contribute a majority of the remaining Green House Gas (GHG) emissions (Howarth and Jacobson 2021). Additionally, the global energy crisis due to geopolitical factors has increased the prices of natural gas by fourfold in Europe, three times in Asia and double in the USA (BP 2022). Therefore, to achieve decarbonization targets other clean energy sources have to be scaled up.

The hydrogen produced from renewable sources generates almost no emissions during operation and a majority of emissions are in the form of embodied carbon during the initial phases where fossil fuels may be used. Low carbon sources contribute less than 5% to the total hydrogen production (UNECE 2021). To achieve the 1.5 °C climate target, green hydrogen and its derivatives will contribute 12% of global energy usage by 2050 and 5000 GW of electrolyzer capacity has to be added by then (IRENA 2022). Some jurisdictions have developed green hydrogen certification systems to track emissions from such projects while Canada is yet to adopt such a system (IRENA 2022). For the purpose of this study, the European Union's (EU) standard CertifHy will be used which defines green hydrogen as the hydrogen with lifecycle emissions lower than 4.5 Kg CO_2e/kg H_2 or 60% lower emissions than a benchmark based on non-renewable based hydrogen production (CORDIS European Commission 2016).

The aim of this study is to conduct an LCA of the green hydrogen production process and assess the viability of this in terms of emissions and costs involved. There have been studies conducted for green hydrogen production from wind alone for Western Canada, (Ghandehariun and Kumar 2016) this study considers a mix of solar and wind generated on site and fed into the electrolyzers. Two types of commercially available electrolyzers are considered for the study. An additional analysis considers grid electricity as an input for the electrolyzer up to the amount the produced hydrogen can be considered green according to CertifHy standards. A plan for integration of green hydrogen into the overall hydrogen production targets of the province of Alberta is proposed.

2.3 Solar PV System Description

The PV Solar modules are considered to be of the crystalline silicon (C-Si) type and manufactured in China. More than 95% of the solar panels produced around the world are of the C-Si type. China has about 70% of this PV Solar Modules manufacturing capacity and the manufacturing in North America is around 4% of the total PV solar panels produced annually (Fraunhofer 2022).

The typical production efficiency of the silicon panel is as high as 16%, (Singh, Chaudhary, and Karthick 2021) while the panel considered here has an average efficiency of 20-21% due to it being a bifacial module (CSI 2022). The system is ground mounted, with a lifetime of 30 years and around 10% of the system mass is to be replaced every 10 years (Frischknecht 2015) and the PV Modules are installed on an axis tracking system. The balance of system includes the auxiliary equipment including the inverters, an electric installation system, transformers, and the ground mounting system.

Life Cycle Inventory (LCI) data for the system during the upstream phase (raw material, transport), core phase (manufacturing, distribution, installation, use, maintenance) and downstream phase (end of life) is taken from a typical manufacturers setup. The distribution phase involves transport of the manufactured modules from Shanghai Port to the Port of Vancouver, BC on ship and from Vancouver to Alberta using lorries. The LCI data is taken from the ecoinvent version 3.8 LCI database. The electricity emissions during installations, maintenance and operational energy use are assumed to be from the Alberta Grid in 2020 (C.E.R. Government of Canada 2022). The specifications of the solar PV system and the flow process diagram for the system are given in Figure 2.

2.4 Wind Farm Description

An onshore wind power generation facility using high speed geared drive turbines is considered in Alberta. These type of turbines account for around 70% of the world's installed capacity (IRENA 2019). The total energy produced by the turbine would be 8400 MWh if medium wind conditions around the year are assumed. The Annual mean wind speed for South Alberta is 7.8 m/s that comes under the medium rated capacity of the turbine (Government of Canada 2016).

The Technical Specifications of the turbine are given in Table 1. The turbine for this study is assumed to be of 2MW, as the recent turbine size trend is from 1.5-3MW (Lantz, Wiser, and Hand 2012). The operational lifetime of the turbine is taken to be 20 years which is the minimum lifetime according to the International Electrotechnical Commission standard (IEC 2006). The system boundary life cycle stage of the wind farm include the manufacturing of turbines, site components, setting up of the wind plant (transport, installations), the operations phase (source, maintenance, replacement) and the end of the life phase (scrappage, recycling, dismantling) (Garrett and Razdan 2016). The primary energy consumption during the plant set up and operations is assumed to be from the Alberta Electricity grid.

Table 1 Wind Farm Technical Specifications

Technical Specifications		
Description	Unit	Quantity
Lifetime	years	20
Rating per turbine	MW	2
Generator type	-	Induction
Turbines per power plant	pieces	25
Plant size (typical)	MW	50
Hub height	m	80
Rotor diameter	m	100
Wind class	-	Medium (IEC2B)
Tower type	-	Standard steel
Foundation type		Low ground water level (LGWL)

Production @ 8.0 m/s (medium wind)	MWh per year	8401
Grid distance	km	20

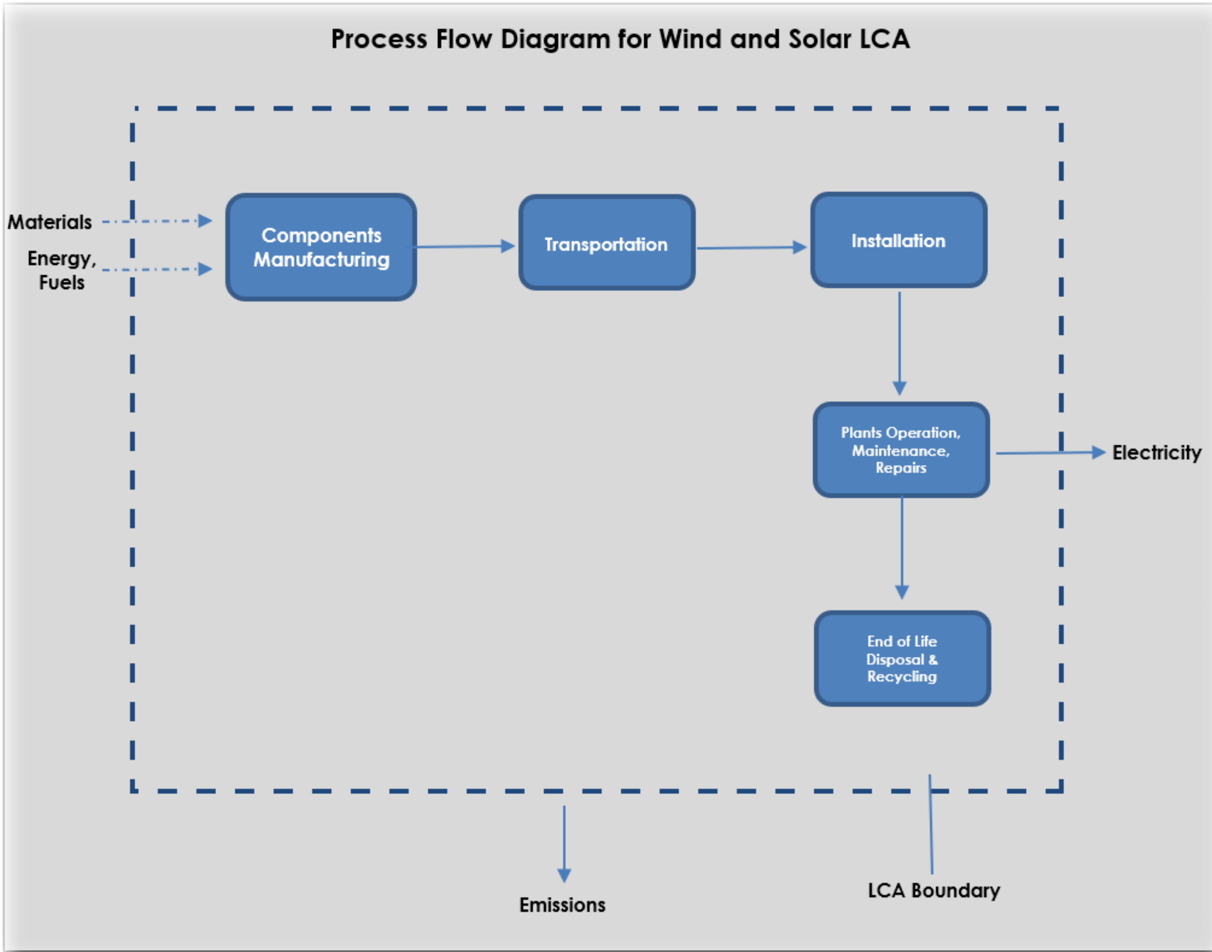

Figure 1: Process Flow Diagram for Wind and Solar LCA

2.5 Modelling Approach

A Life Cycle Assessment is an analysis method to quantify the environmental impacts of various processes based on ISO 14040 standards (Muralikrishna and Manickam 2017). The current study is a cradle to gate based LCA. The system boundary includes the manufacture, installation, operation, and end of life of a renewables-based hydrogen production facility. The system is shown in figure 2. The scope of this study is to present an emission-based study of green hydrogen production. The functional unit for analysis is 1kg of H_2 produced at 20-30 bar and the impact category considered is the GWP in grams CO_2e of different processes. The study also includes a costing analysis to evaluate the current and expected economic performance of the proposed system. The costs are calculated based on current exchange rates. The LCI data was taken and adapted for the analyses from primary sources including research journals, government, international reports, manufacturer specifications, and the ecoinvent 3.8 data base.

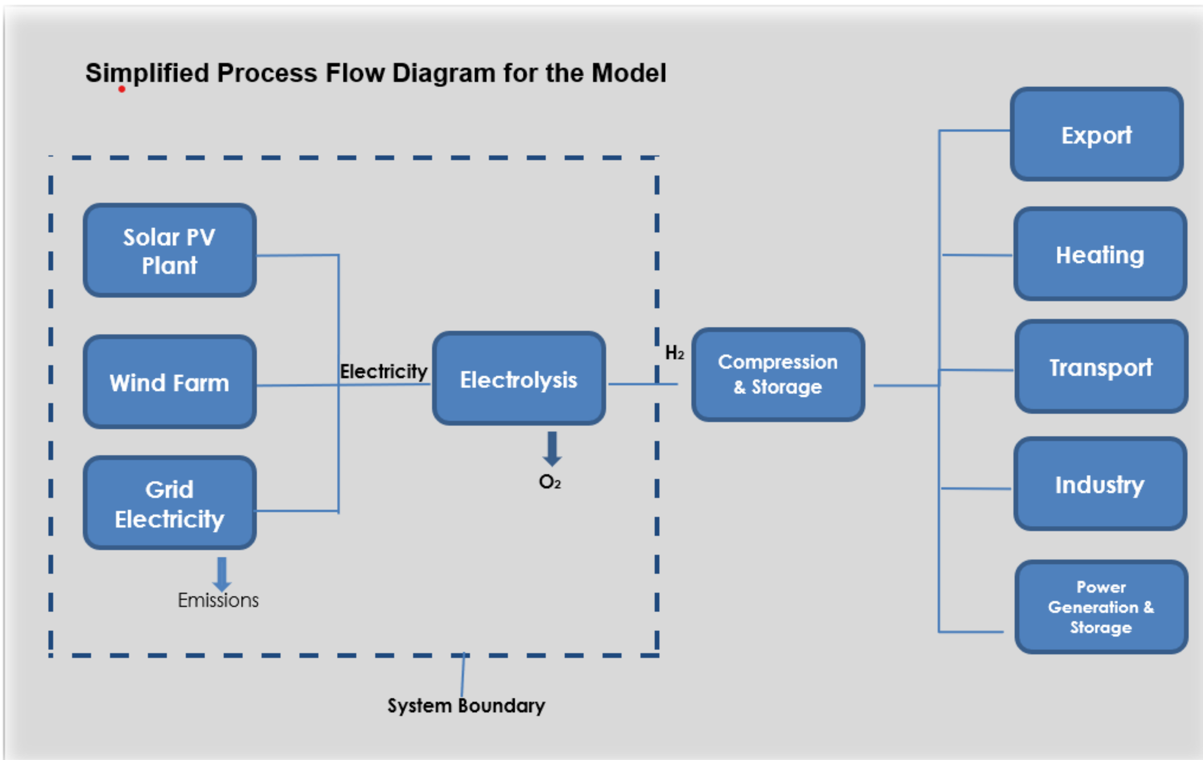

Figure 2 Simplified Process Flow Diagram for the Study Model

2.6 Electrolyzers

The electrolyzer is the critical component in the conversion of electricity to hydrogen. There are three major electrolyzer technologies either at commercial scale or advanced laboratory scale.

1. Alkaline Electrolyzer Cells (AEC): These are the oldest and currently the most widely used electrolyzers for industrial uses with a technology readiness level (TRL) of 9 (IEA 2021). The first AECs were constructed in Germany in the 1920s and by 1980s, they were under

large scale deployment (Smolinka et al. 2022). The materials used in this type of electrolyzers are readily available such as iron, nickel, and steel. Concentrated KOH is used as electrolyte in which the electrodes are dipped (Guillet and Millet 2015). Major drawbacks include limited allowance for variability in supply and operating pressure, low current density, and diffusion of gases through the separating diaphragm especially at low loads. Additionally, the design is bulky and there are large power losses due to the electrolyte and the diaphragm and the hydrogen produced has to be compressed for downstream uses (Carmo et al. 2013), (Lehner et al. 2014). Future developments in these electrolyzers will be due to increasing economies of scale rather than new technological developments (Lehner et al. 2014). Figure 3 shows the setup of an AEC type electrolyzer.

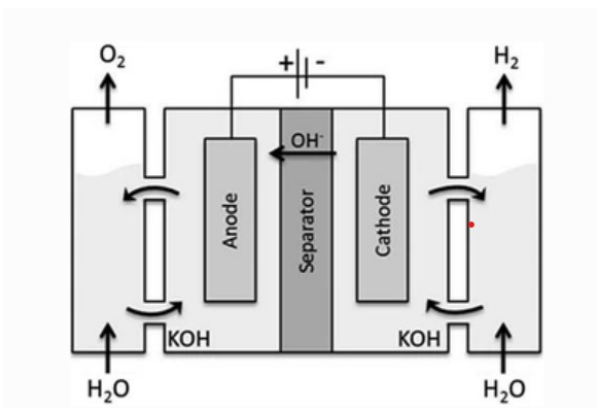

Figure 3 Setup of an Alkaline Electrolyzer, Source (Lehner et al. 2014)

2. Proton Exchange Membrane Electrolyzers (PEM): This is the second commercially available electrolyzer technology after the AEC and has a similar TRL of 9 in terms of potential for hydrogen production but is currently operational at a smaller scale (IEA 2021). These were developed in the 1960s and are based on the concept of solid polymer electrolyte (SPE) water electrolysis. They can be operated at much higher current densities as compared to AEC and have lower losses as the membrane is thinner and low amount of

gases pass through the membrane (Carmo et al. 2013). They can operate better at low loads and have low sensitivity to variation in the electric load. The drawbacks of these type of electrolyzers include high acidity of the membrane and since the current density is high, the materials that can be used are costly and harder to mine such as platinum. Future developments are focused on upscaling the technology stack and developing alternatives to materials as the cost is almost double that of a similar capacity AEC system (Lehner et al. 2014). Figure 4 shows a typical PEM electrolyzer setup.

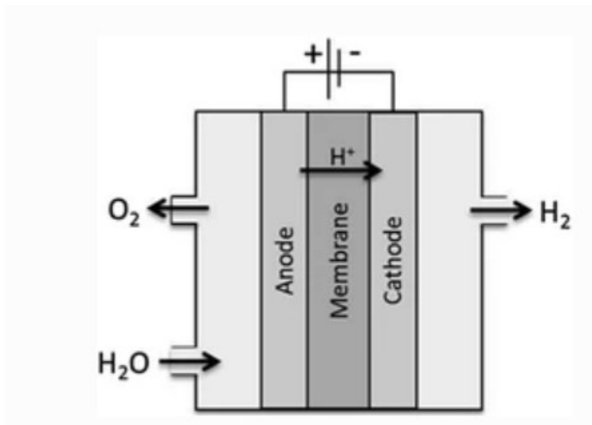

Figure 4 Setup of a Proton Exchange Membrane Electrolyzer, Source (Lehner et al. 2014)

3. Solid Oxide Electrolysis Cells (SOEC): This is the third most mature technology in electrolyzer development with a TRL of 7 and is at the demonstration stage (IEA 2021). World's first megawatt scale (2.6 MW) SOEC is being built in Netherlands to produce green hydrogen (Sunfire 2022). There is no liquid electrolyte, rather it is the solid oxide layer which starts conducting ions at high temperatures above 850 °C. The current densities can theoretically be up to PEM electrolyzers but are operationally kept at AEC range for longevity. The cathode is commonly made up of Ni and the anode is a composite of YSZ with mixed oxides and ceramic materials are used between single cells. One of the major

drawbacks of SOEC electrolyzers is the degradation of the ceramic materials due to elevated temperatures in the system (Laguna-Bercero 2012). Future developments are in the areas of reducing operating temperatures to 500-700 °C and managing degradation of materials (Lehner et al. 2014). Some of the alternate electrolytes developed include the ScSZ type and the gadolinium doped ceria (GDC) type and nickelate based materials (Nechache and Hody 2021). Figure 5 shows a schematic of the SOEC electrolyzer.

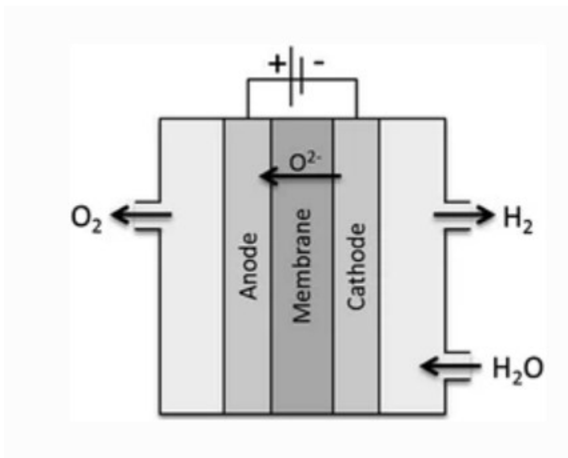

Figure 5 Setup of a Solid Oxide Electrolyzer, Source (Lehner et al. 2014)

2.7 Status of Global Electrolyzer Capacity

Globally, by the end of 2021 electrolyzer capacity accounted for only 0.1% of total hydrogen production. This was a 70% increase form 2020 with the total electrolyzer capacity crossing 500 MW for the first time (IEA 2022). The world's largest electrolyzer producing green hydrogen is a 150 MW system operating in China that went into operation in 2021 (FuelCellsWorks 2021) and this will be followed by a 260 MW AEC electrolyzer that will run on a mix of dedicated solar and wind energy which is to be operational in 2023 (Reuters 2021).

The global capacity is expected to cross 1GW by the end of 2022 and reach 134 GW by the end of this decade (IEA 2022). Recently, there have been various governmental incentives to scale up electrolyzer capacity such as the Inflation Reduction Act in USA which incentivises hydrogen technology development. The EU has approved its first hydrogen linked Important Project of Common European Interest (IPCEI) which will focus on hydrogen technologies (European Commission 2022). The Government of Spain has proposed a plan to include at least 25% green hydrogen to the total hydrogen consumed by industries by 2030 (IRENA 2020). The average installed size of electrolyzers was just 0.65 MW by 2019 (IEA 2022) but this has improved to 5MW in 2021 and expected to increase to 260 MW and Gigawatt scale by 2025 and 2030 respectively (IEA 2022).

Emissions due to hydrogen production were almost 900 million tonnes of CO_2e in 2021 and that trend has increased year-on-year. To achieve net zero targets, 95 million tonnes of hydrogen are needed with 61.7 million tonnes coming from electrolyzers and require 3-4 TW of additional electrolyzer capacity. This scale of electrolyzer capacity will require 4.5-6.5 TW of dedicated renewable energy capacity which is double the currently installed global renewable energy generation. China, Europe, and North America are predicted to be the largest users of clean hydrogen (IEA 2021).

2.8 Scenarios Considered

The baseline scenario considers the current Government of Alberta plan to meet its hydrogen production targets using a mixture of grey hydrogen and blue hydrogen (SMR with CCS) (AER 2022). A majority of the capacity addition will be from blue hydrogen, with almost 40% of the production needs to be met by blue hydrogen in 2031. Figures 6 and 7 show the production in million tonnes with source and share in the total production respectively.

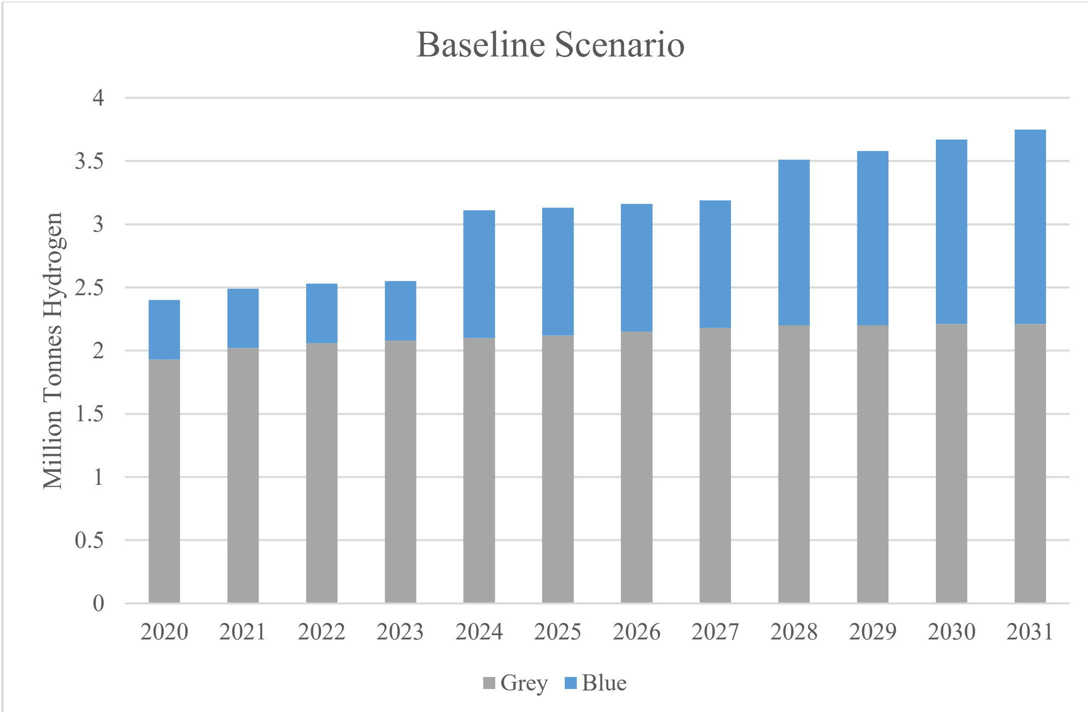

Figure 6 Total Hydrogen Production by Source- Baseline Scenario

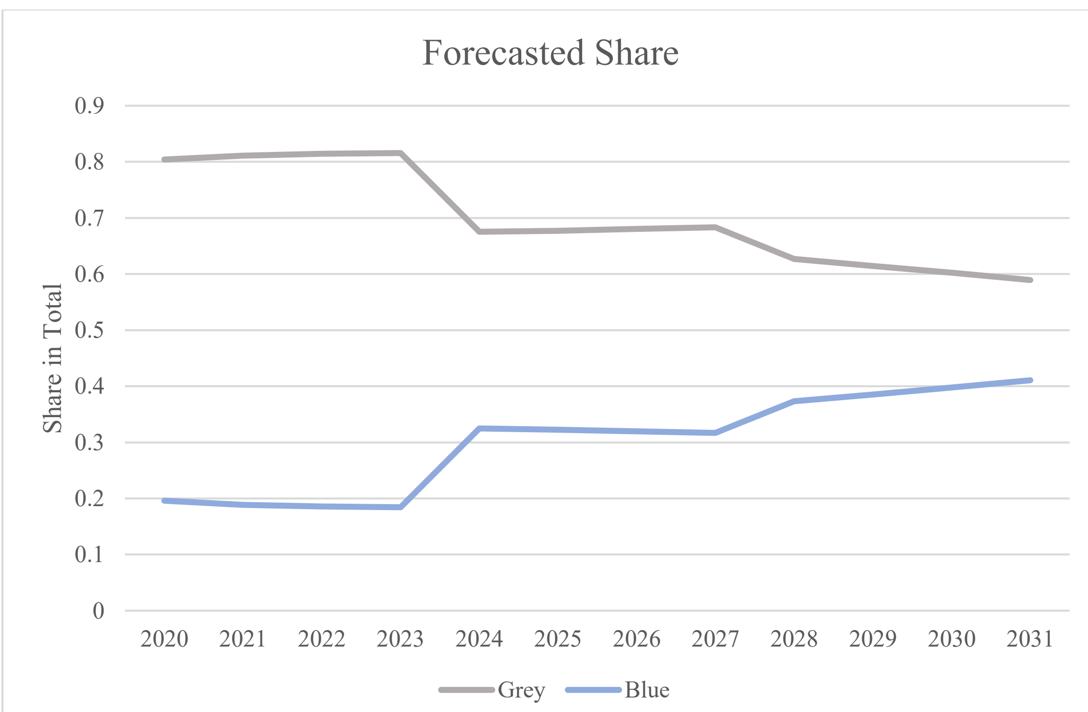

Figure 7 Share in Hydrogen Production- Baseline Scenario

An analysis is done considering the business-as-usual case in which all the forecasted wind and solar energy production is used to produce green hydrogen. No extra capacity addition of renewables is done. The results in figures 8 and 9 show that in this case the green hydrogen will contribute less than 6% of the total hydrogen production by the end of this decade and around 0.2 million tonnes green hydrogen will be produced.

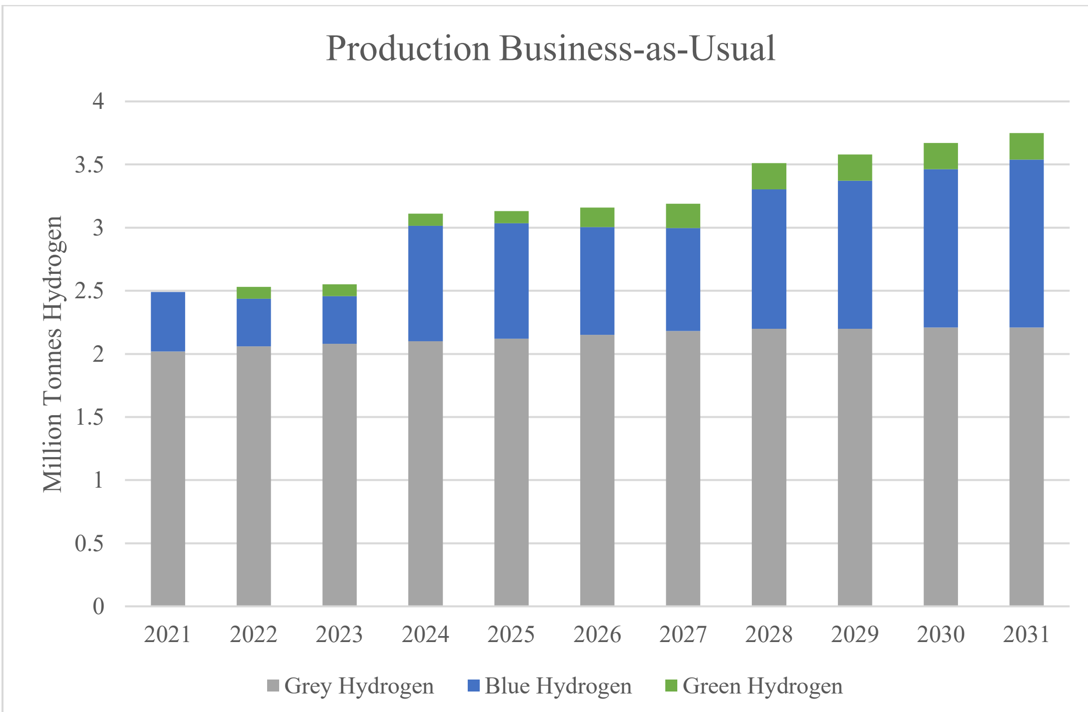

Figure 8 Business-as-usual Total Production by Source

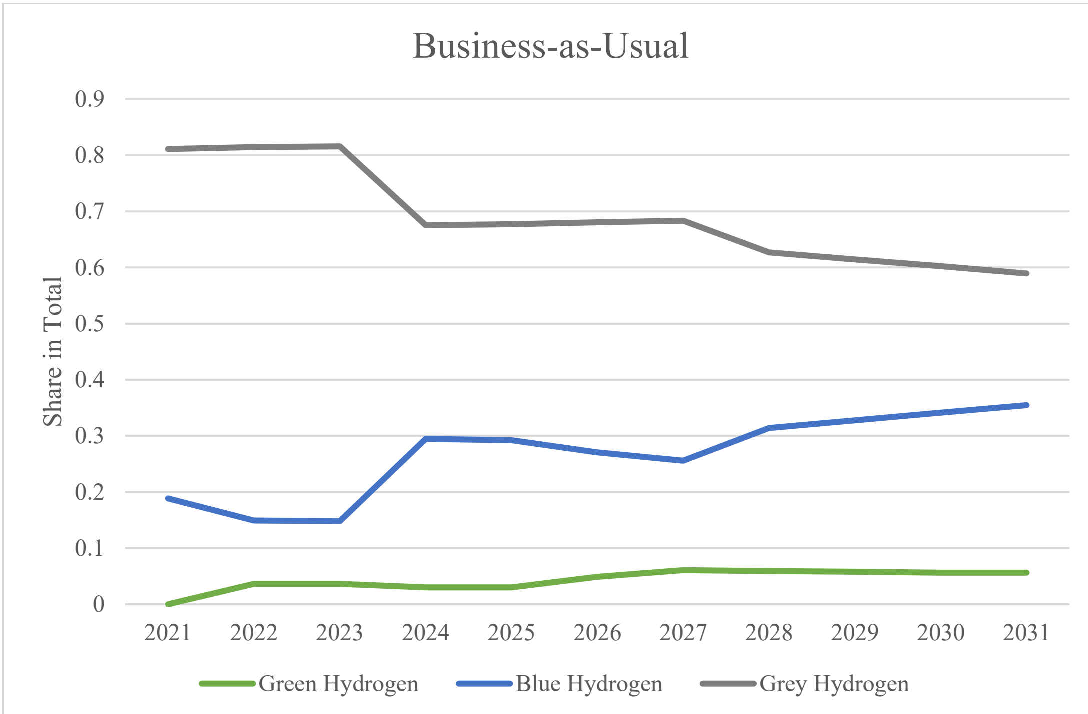

Figure 9 Business-as-Usual Share in Hydrogen Production

The first scenario for this study will consider half the capacity addition of hydrogen production in Alberta being met by green hydrogen in the next decade. The other model would consider an aggressive scenario where all the new hydrogen capacity going forward is from green hydrogen. The production of grey and blue hydrogen is assumed to be the same over the next decade as it was at the end of 2021. The figures 10, 11, 12 & 13 show the total production and share of future production for the scenarios modelled.

In both the scenarios a varying mix of electricity supply to the electrolyzers will be considered including fully renewable and grid integration. Additionally, the AEC and PEM electrolyzers will be considered for the study as the SOEC technology is still under development (IEA 2022).

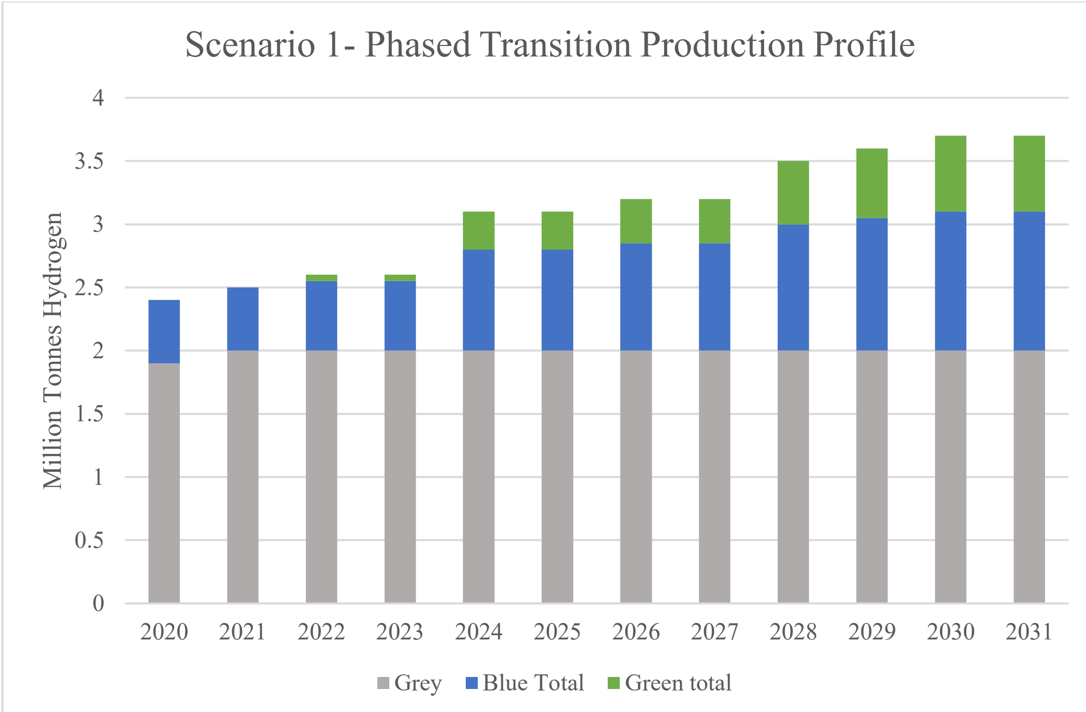

Figure 10 Scenario 1 Total Production by Source

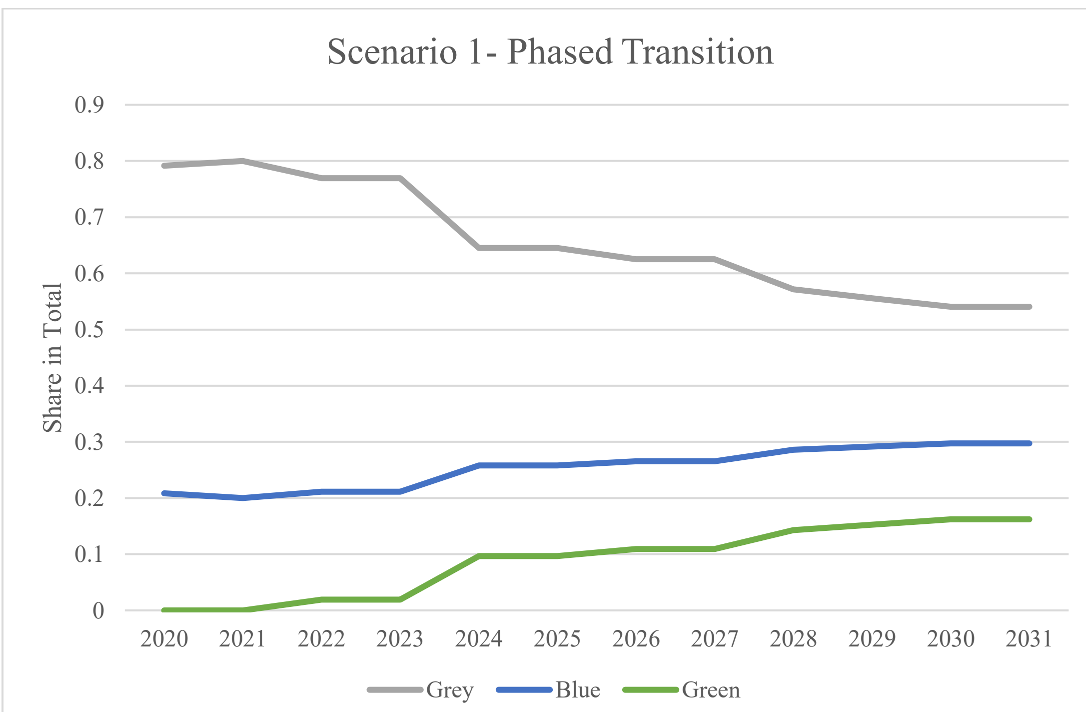

Figure 11 Scenario 1 Share in Hydrogen Production

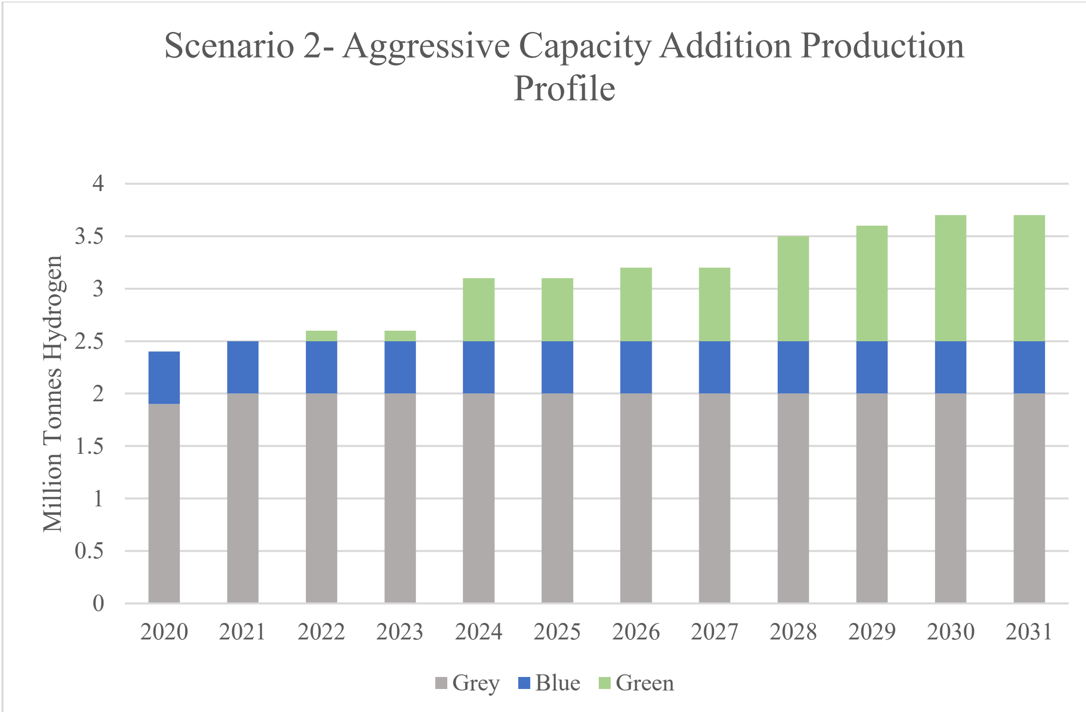

Figure 12 Scenario 2 Total Production by Source

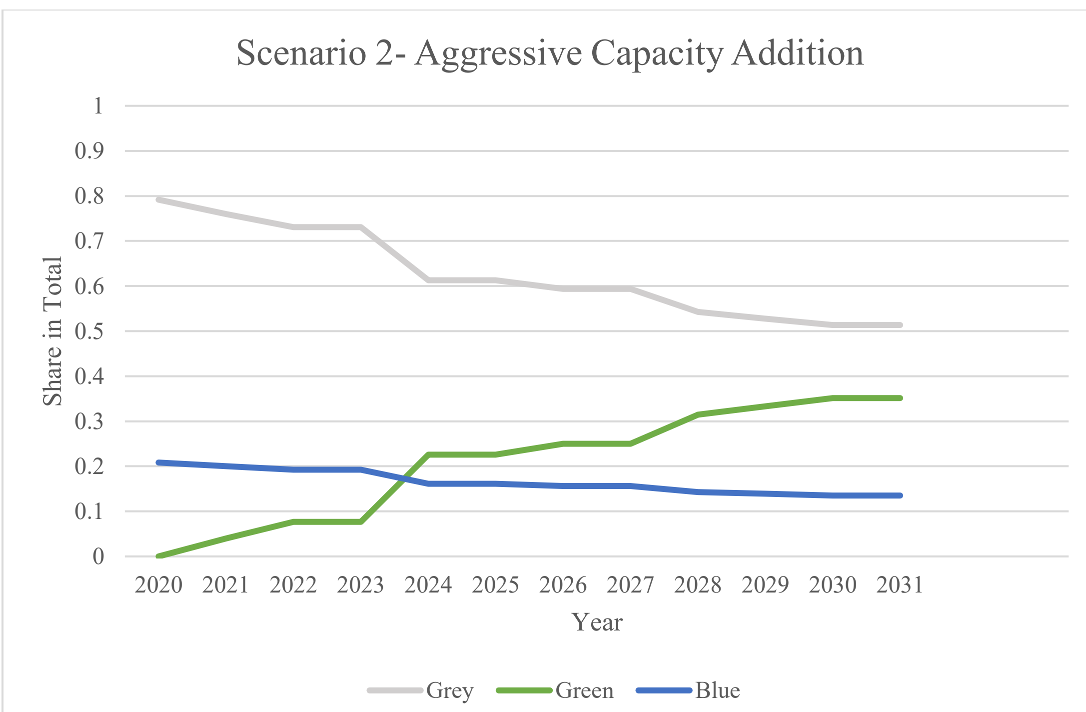

Figure 13 Scenario 2 Share in Hydrogen Production

2.9 Results and Discussions

2.9.1 Solar PV Farm

The LCA modelling for the various processes involved in solar power plant electricity production give a total GHG emission rate of 45 g CO_2/kWh of solar energy generated. This is in line with the harmonization study conducted by NREL which predicts an average GHG emissions rate of 40 g CO_2e/kWh (NREL 2012) and a study for integrating utility scale solar in the Albertan grid (Mehedi, Gemechu, and Kumar 2022). This is due to the Alberta electricity grid producing emissions of almost 590 g CO_2e/kWh which is more than five times the average Canadian grid emissions (110 g CO_2e/kWh in 2020) due to high share of fossil fuels in the grid and use of this grid electricity in installation and maintenance phase (C.E.R. Government of Canada 2022). The lifecycle stage wise emissions are distributed as approximately 65%, 25% and 10% for the upstream phase (module manufacturing, transport, and assembly), operational phase and end-of-life respectively. The monthly production profile of the plant is shown in the figure 14 which shows that the solar energy produced almost doubles during the summer months because Alberta has low sunlight hours during the winters.

The scale and cost analysis were conducted by taking into account the major solar projects installed in the last 3 years and the proposed projects in the next 5 years in Alberta (Government of Alberta 2022). The average installed capacity is more than 100 MW with a few large projects having an installed capacity of more than 350 MW. The average cost to install is $1750/kW with economies of scale bringing it to less than $1000 for the bigger installations.

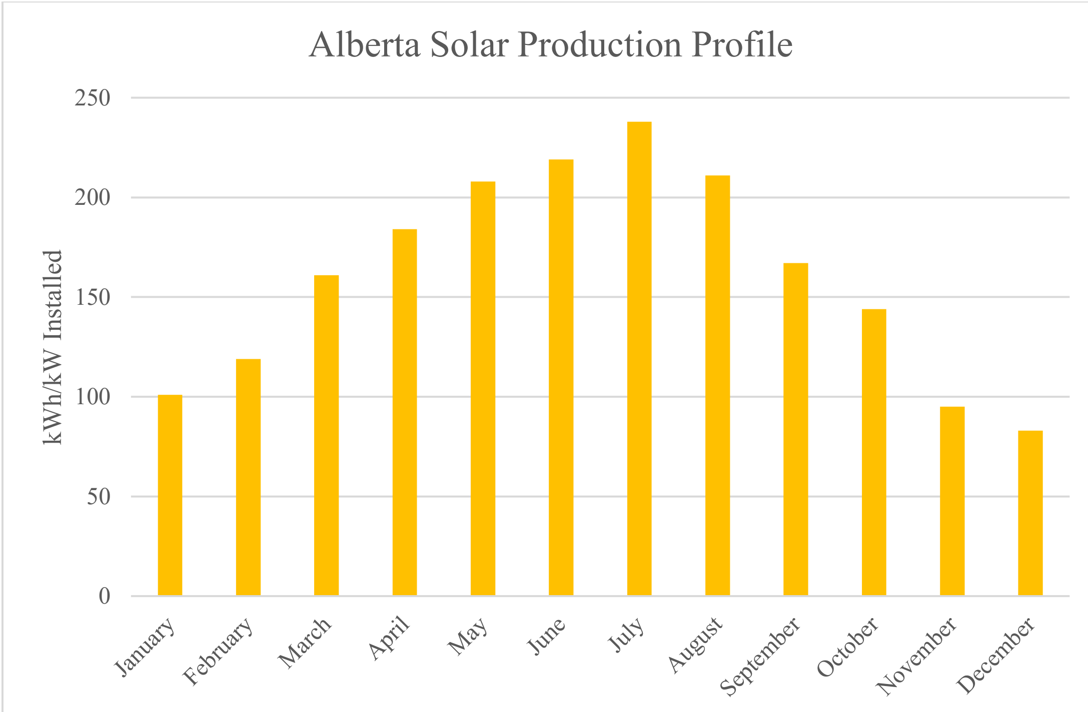

Figure 14 Alberta Monthly Solar Potential

2.9.2 Wind Farm

The net lifecycle GHG emissions for the wind farm in Alberta were 6.2 g CO_2e/kWh with the manufacturing stage contributing the most- almost 90% of the total emissions. The end-of-life phase included recycling of some of the dismantled materials which were added in the form of credit to the total emissions (8 g CO_2e/kWh) (Garrett and Razdan 2016). The plant setup and operation accounted for less than 15% of the emissions put together and CO_2 was the main gas emitted (91%) during all the lifecycle stages. The results from the NREL Harmonization study (NREL 2012) showed a range of 8g CO_2e/kWh to 20 gCO_2e/kWh with an average value of 10 g CO_2e/kWh. The difference in emissions is due to the increase in scale of wind turbines and plant capacities. The monthly production profile of the wind plant based on real time forecasts shows a variation in production (AESO 2021). Wind power follows a profile which contrasts with the solar energy profile shown in Figure 15. The winter months account for some of the highest production rates with performance ratios reaching almost 50% while the summer months have a lower performance of almost 32% of the installed capacity. The average (annual) performance ratio is almost 41%.

Alberta has a well developed infrastructure for onshore wind energy production with an installed capacity of more than 3000 MW (AESO 2022). Alberta has more than 2000 MW of large scale wind farm projects in the pipeline in the next few years (Government of Alberta 2022) with an average capacity of each wind farm being 200 MW and the cost of production per kW of wind power is $1650 with $1400/kW being the lower value for larger projects.

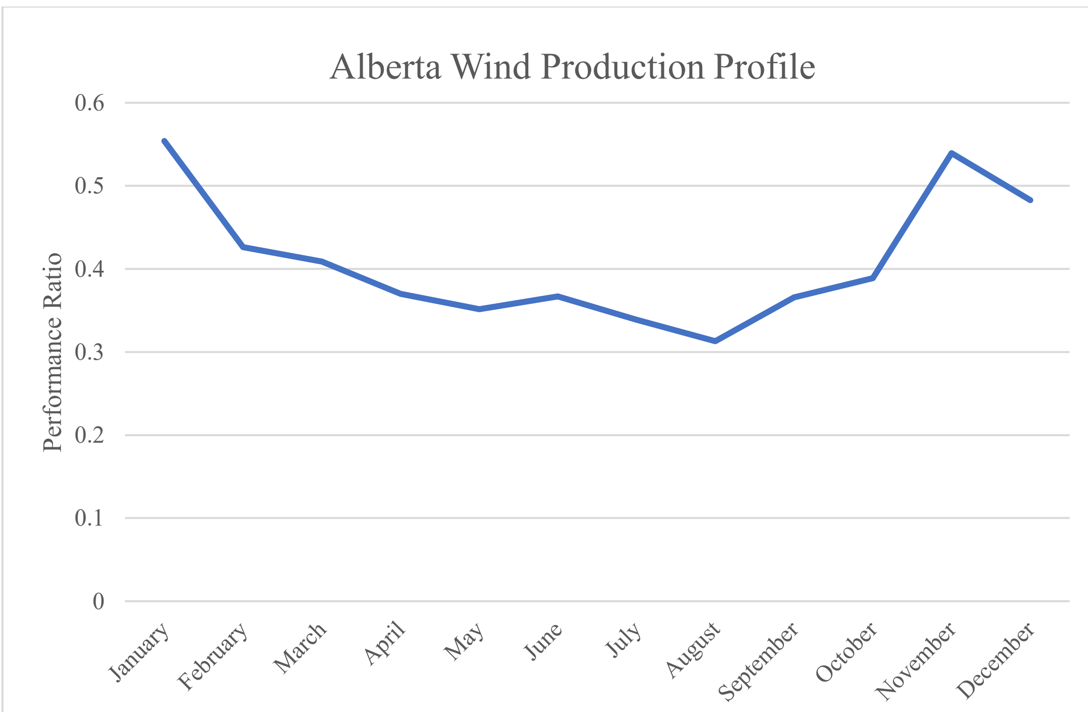

Figure 15 Alberta Monthly Wind Performance

2.9.3 Electrolyzers:

The emissions and capacity data for the electrolyzers considered was taken from primary sources and available research data. The additional installations of electrolyzers will see a shift towards PEM from AEC in the next decade (Schmidt et al. 2017). The emissions from setting up of the electrolyzer set up are very low as compared to the solar and wind farms with GHG impact of 43g $CO_2e/Kg\ H_2$ (Mann and Spath 2004).

The AEC electrolyzers can generate hydrogen from 6 bar to 30 bar and the electricity required for producing 1 N-m^3 (0.084 Kg H_2 at STP) of H_2 varies from 4.1-6 kWh depending on the output pressure (Smolinka, Ojong, and Garche 2015). The efficiency varies from 78% to 85% for atmospheric electrolyzer and high pressure electrolyzer respectively (Bhandari, Trudewind, and Zapp 2014) and the operational lifetime is 30 years. The production capacity varies from 0.084 Kg H_2/hour to 63 Kg H_2/hour and the purity of hydrogen produced is more than 99% (Zeng and Zhang 2010). The costs of production are calculated by taking the higher limit of stack operation as 90000 hours over the lifetime and a commercial electrolyzer of 500 kW which produces 8.4 Kg H_2/hour (Thomas 2019). The calculated cost of produced hydrogen is \$0.92/Kg H_2 today and expected to reduce to \$0.36/Kg and further to \$0.29/Kg if all the proposed AEC electrolyzer projects come into operation.

A similar analysis as above was done for PEM electrolyzers. The PEM electrolyzers require 6-8 kWh of energy to produce 1 N-m^3 of hydrogen and the production capacity less than 3.4 Kg/hour depending on the electrolyzer size (Lehner et al. 2014). The efficiencies range from 67-82% and the hydrogen production pressure is up to 30 bar (Bhandari, Trudewind, and Zapp 2014). For calculations, a typical 1 MW PEM electrolyzer is considered producing 14.3 Kg H_2/hour having a stack lifetime of 60000 hours (Mayyas et al. 2019). The calculated cost of hydrogen is \$2.1/Kg H_2 today, \$0.75/Kg H_2 in 2025 and \$0.60/Kg H_2 in 2030 if all the announced projects become operational.

2.10 Hydrogen Generation in Net-zero Emissions Pathways

The Alberta Electric Systems Operator (AESO) modeled 3 scenarios for achieving net-zero emissions from the electricity sector by 2035 (AESO 2022). The rate of adoption of renewable electricity, thermal electricity, and battery storage varies in each modeled scenario. The scenarios are described briefly below.

1. Dispatchable Dominant Scenario: This involves thermal sources constituting a majority portion of the electricity supply as is the case in Alberta currently. The high emissions will be abated by deploying innovative technologies such as carbon capture at a large scale either by retrofitting existing facilities or installing new electricity plants with these technologies. Of the three scenarios, the renewable energy added is least here.

2. First-mover Advantage Scenario: This involves scaling up of wind and solar energy while thermal sources act as base load to account for the fluctuation in the electricity supply due to renewables. Solar and wind energy are upscaled at a higher rate than the current trend and lithium-ion battery storage is developed at a moderate rate.

3. Renewables and Storage Rush Scenario: There is aggressive adoption of wind and solar energy over the next decade along with limited deployment of thermal energy. There is increased adoption of battery storage to account for intermittent supply from renewable sources.

For this analysis, each of three scenarios is considered till 2031. The renewable energy and energy stored in batteries is used to produce hydrogen from the Alkaline Electrolyzer, as Proton Exchange

Membrane Electrolyzers are predicted to be operationally viable at a large by the end of this decade. Figures 16, 17 and 18 show the production of hydrogen in each scenario along with the capacity added from wind, solar, and battery storage respectively. The hydrogen generation from wind energy varies from 0.3 million tonnes in the Dispatchable Dominant Scenario to 0.5 million tonnes in the most aggressive case. The hydrogen generated from battery storage is moderate as the larger share of upscaling in battery storage is after 2031 in the scenarios modeled.

Figure 19 shows the share of the total demand of hydrogen met through each of the scenarios along with the total projected demand in the next ten years. Approximately one-fifth of the total hydrogen generated will be green in the third scenario while the share is around a tenth in the first scenario. Further increase of clean hydrogen supply is required to decrease total emissions from the hydrogen production industry and achieve reduction in emissions in the industries where hydrogen is used as a feedstock. This can be achieved by scaling up the hydrogen supply from green electricity as shown in results in the following sections.

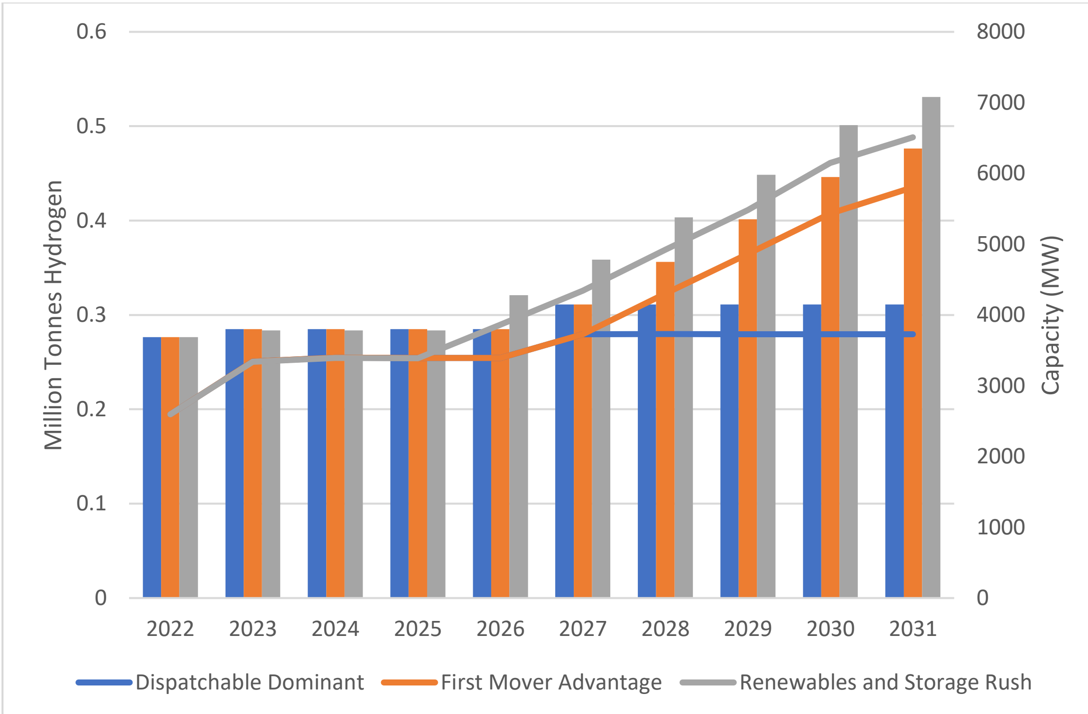

Figure 16 Hydrogen Production from Wind Energy in the Net-zero Emissions Pathways

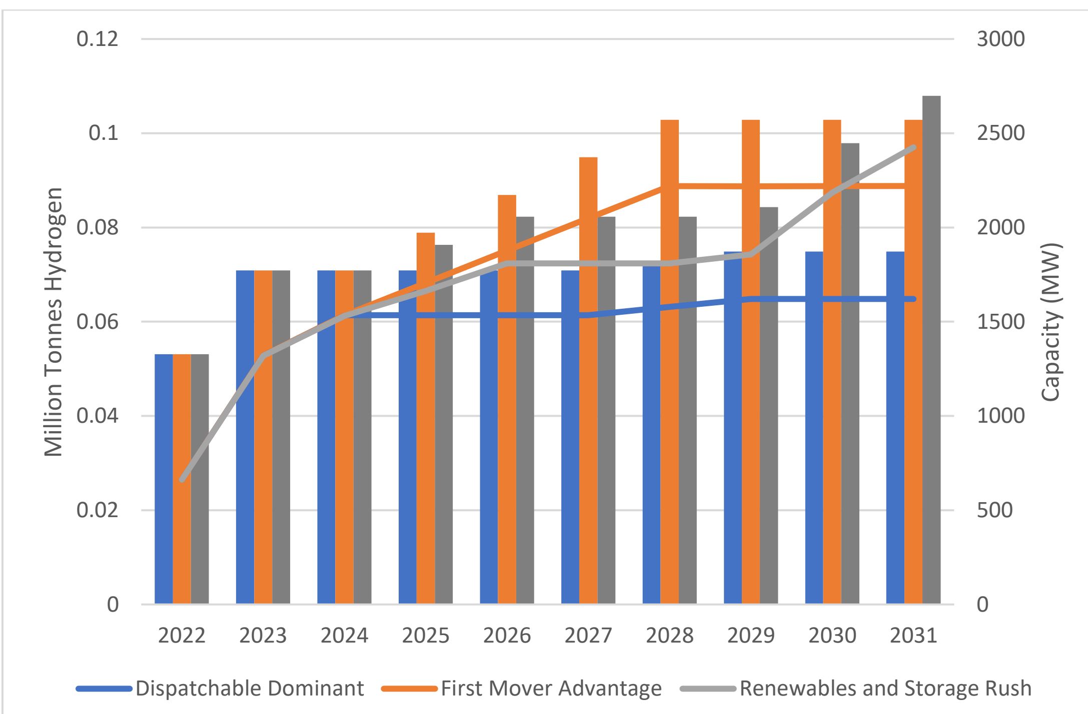

Figure 17 Hydrogen Production from Solar Energy in the Net-zero Emissions Pathways

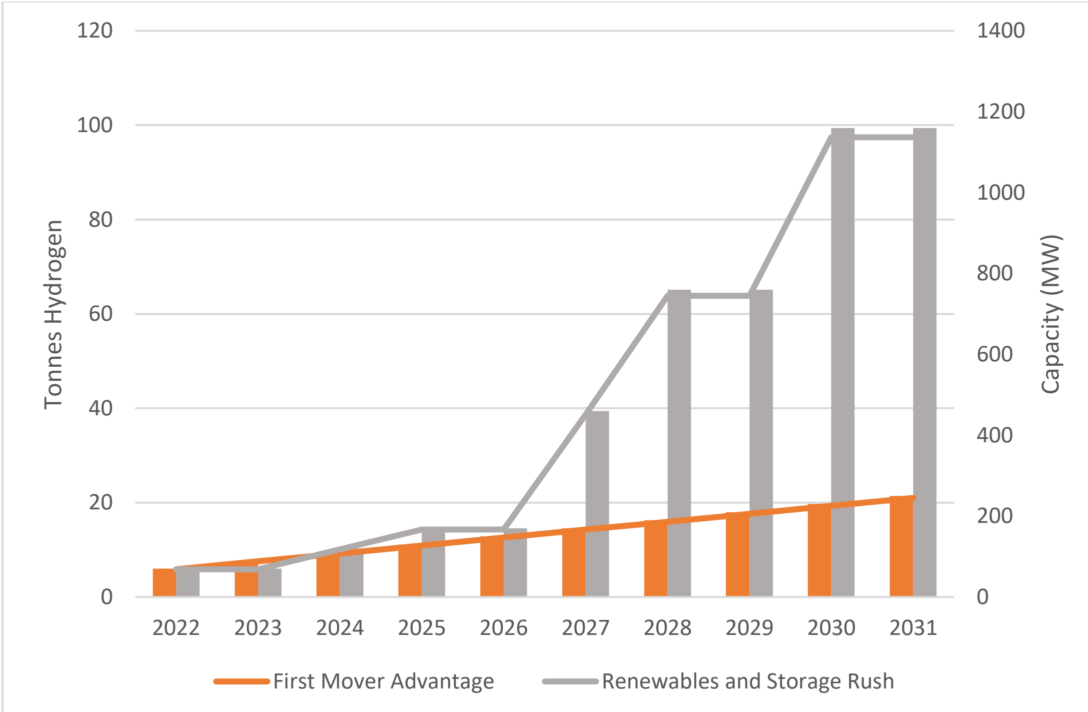

Figure 18 Hydrogen Production from Battery Storage in the Net-zero Emissions Pathways

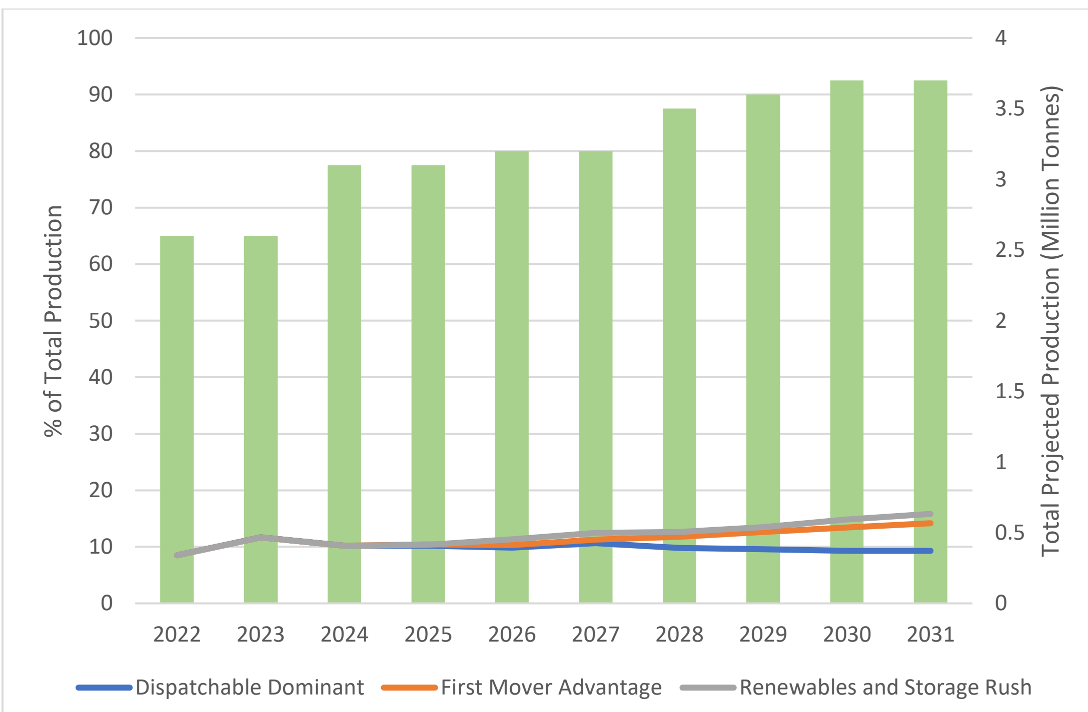

Figure 19 Share in Production vs Total Projected Production of Hydrogen

2.11 Scenario 1- Phased Transition Scenario

Here, the amount of green hydrogen generated was half of Alberta's forecasted hydrogen production. Two green electricity mixes were considered- first, when wind power provided double the electricity to the electrolyzer compared to solar and second when there was an equal amount of wind and solar supply to the electrolyzer.

The reference case in the curve refers to the Alberta Electricity System Operators (AESO) predicted rise in renewable energy generation based on past trends and current regulations (AESO 2021). This is the least aggressive forecast of renewable energy generation and will not meet the Government of Alberta's 30 by 30 target under which 30% of the grid electricity will be generated by renewable sources by 2030 (Government of Alberta 2020).

For the first mix, the results show that the dedicated wind energy supply would have to almost double to meet the hydrogen production targets and the solar capacity would have to increase by 3 times to meet green hydrogen demand. The cost of producing 1 Kg of hydrogen when the capital costs of building the dedicated renewable supply are considered are $1.80 in 2022 and $1.45 and $1.20 in 2026 and 2031 based on expected decrease in solar and wind installation costs 2021). The results are shown in Figure 20.

When the wind and solar energy are supplied in equal numbers, the wind capacity would have to increase by 30% and solar capacity would have to be five times the current capacity. Solar microgeneration can be one of the ways to meet this solar demand where a large number of decentralised grid connected solar plants supply this electricity. Here the costs for producing one kg of hydrogen are $2 in 2022, $1.66 in 2026 and $1.34 in 2031. The results are shown in Figure 21.

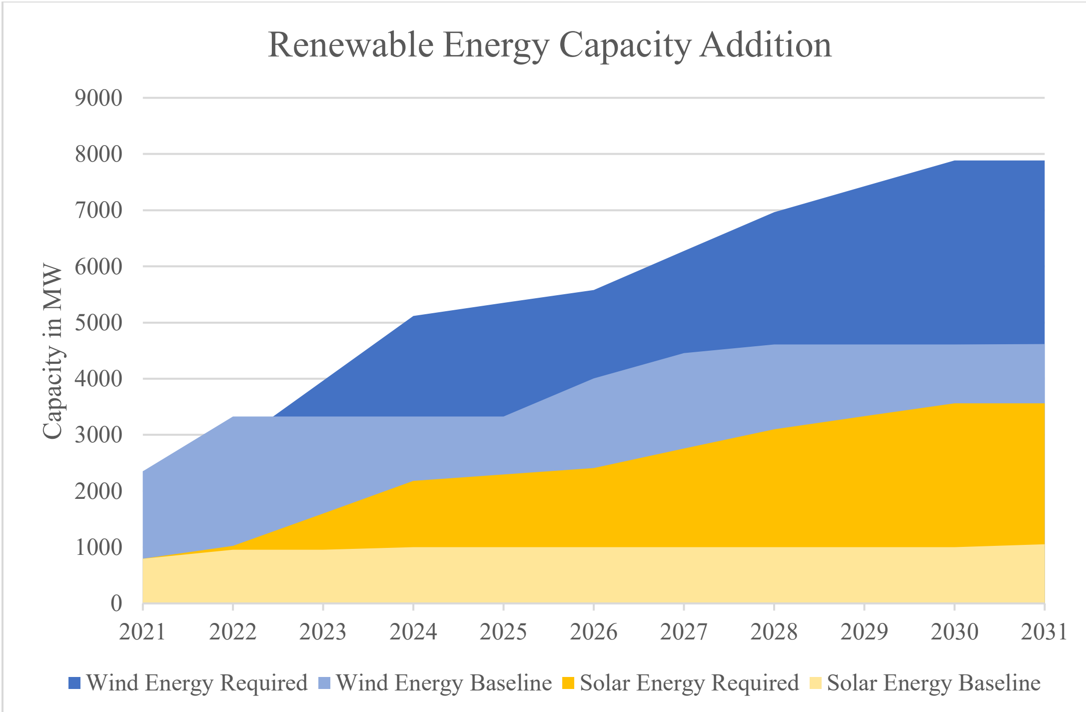

Figure 20 Mix 1- Renewable Capacity Addition

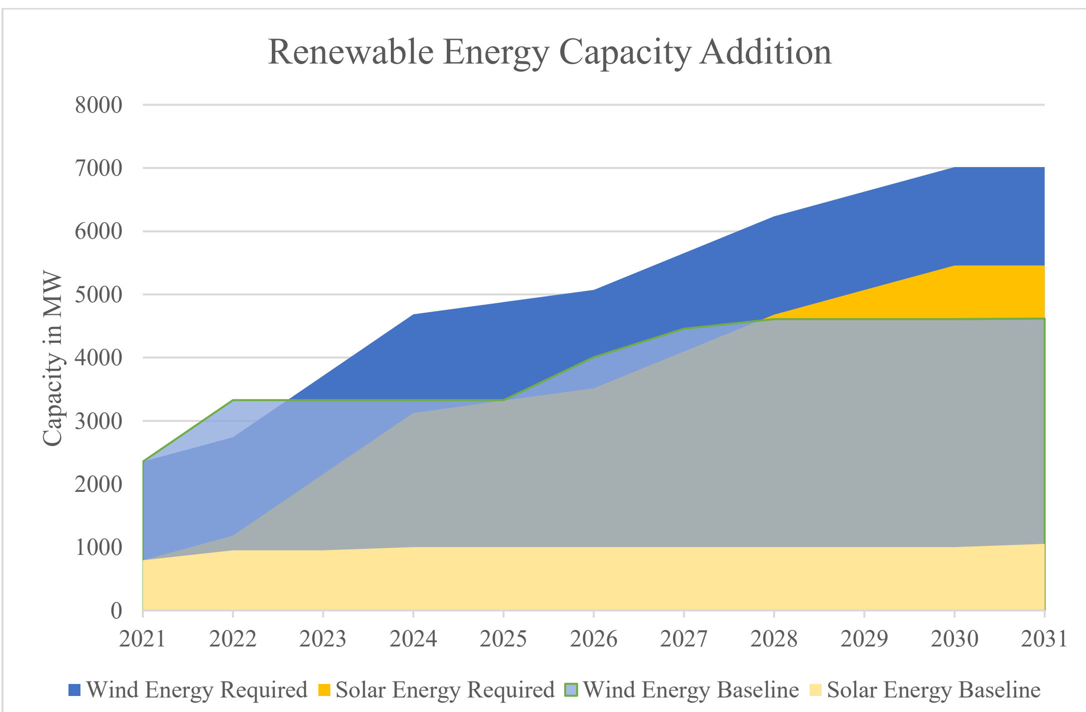

Figure 21 Mix 2- Renewable Capacity Addition

2.12 Scenario 2- Aggressive Capacity Addition Scenario

This is the aggressive scenario where green hydrogen generated all of Alberta's forecasted hydrogen production. Two green electricity mixes were considered- same as Scenario 1. The results are shown in the figures 22 & 23. The reference case here is the same as Scenario 1 mentioned above.

For the first mix, the results show that the dedicated wind energy supply would have to become fourfold to meet the hydrogen production targets and the solar capacity would have to increase by a factor of five to six times to meet green hydrogen demand. The cost of producing 1 Kg of hydrogen when the capital costs of building the dedicated renewable supply are considered are $1.80 in 2022 and $1.45 and $1.20 in 2026 and 2031 based on expected decrease in solar and wind installation costs (AESO 2021).

When the wind and solar energy are supplied in equal numbers, the wind capacity would have to increase by three times and solar capacity would have to be ten times the current capacity. This scenario is unviable, as such an increase in solar capacity is infeasible. This is possible in the next decade once a strong technology pipeline and scale has been built to take advantage of newer technologies and falling prices. Here the costs for producing one kg of hydrogen are $2 in 2022, $1.66 in 2026 and $1.34 in 2031.

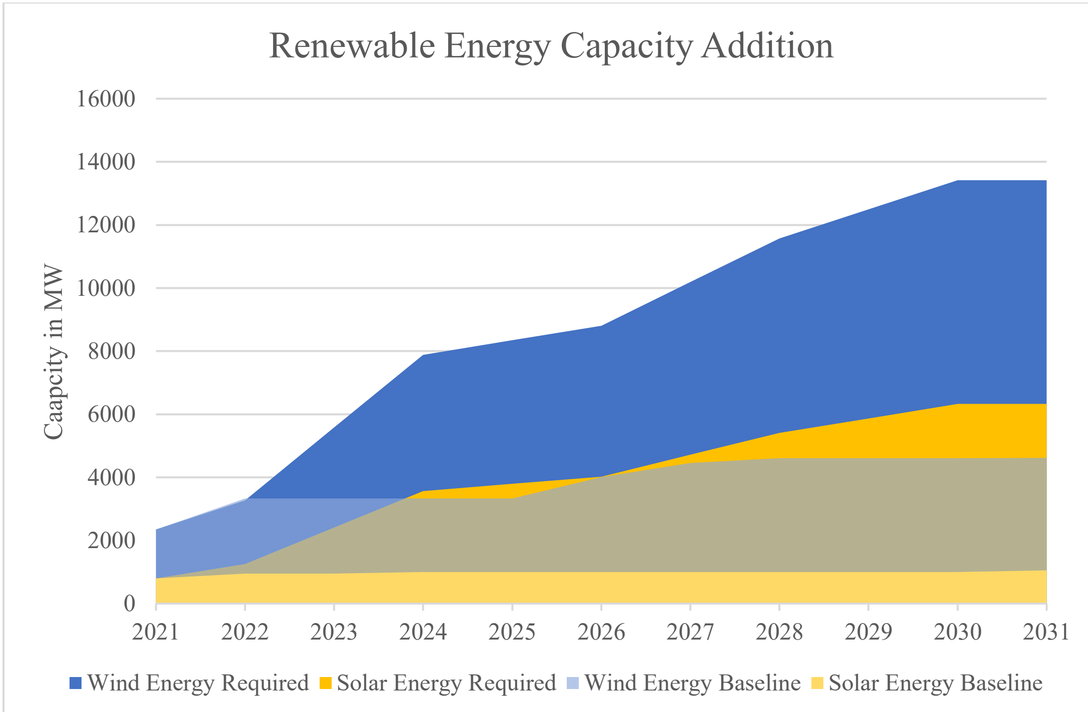

Figure 22 Mix 1- Renewable Capacity Addition

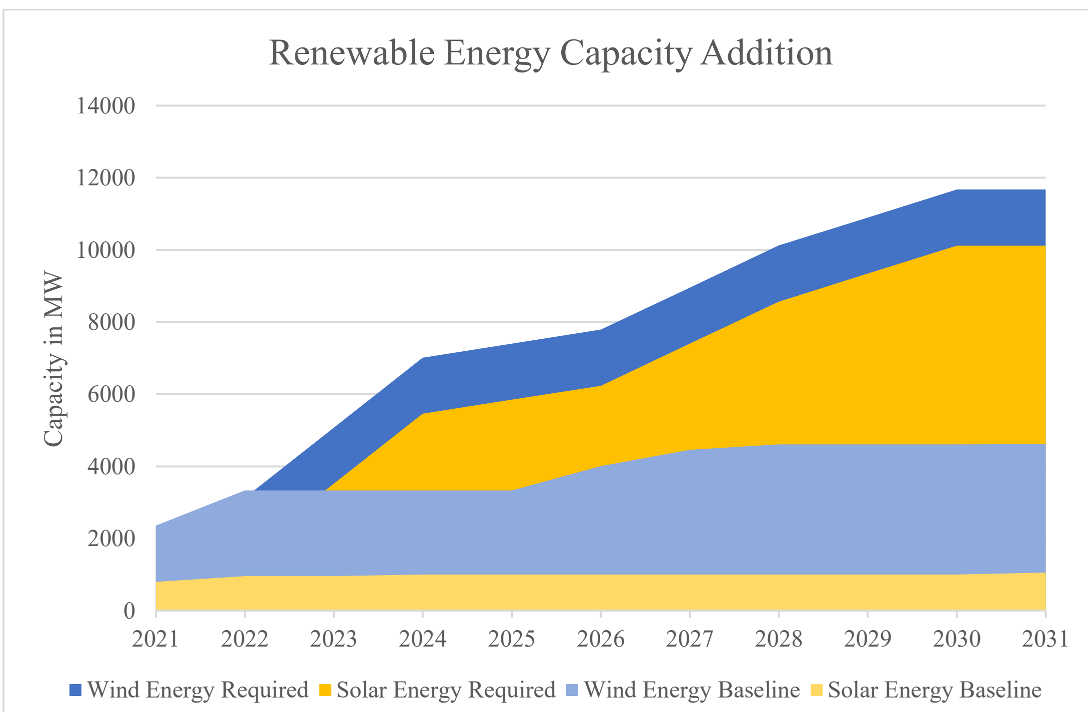

Figure 23 Mix 2- Renewable Capacity Addition

2.13 Cost Analysis

An analysis of the total system costs was done considering the two renewable energy mixes and two electrolyzers- Alkaline Electrolyzer and Proton Exchange Membrane Electrolyzer. While analysing the costs of renewable energy, an accelerated depreciation costing model was taken in which the initial years have a higher contribution towards the total costs spread over 25 years. The unit cost of wind and solar production for the current costs was based on the average costs of recent projects and the future costs were based on the Government of Alberta forecasts. These costs were added with electrolyzer costs calculated in the previous section. The forecasts for the next decade are shown in Figures 24, 25, 26 & 27.

Figure 24 Energy Mix 1 with Hydrogen Produced in Alkaline Electrolyzer

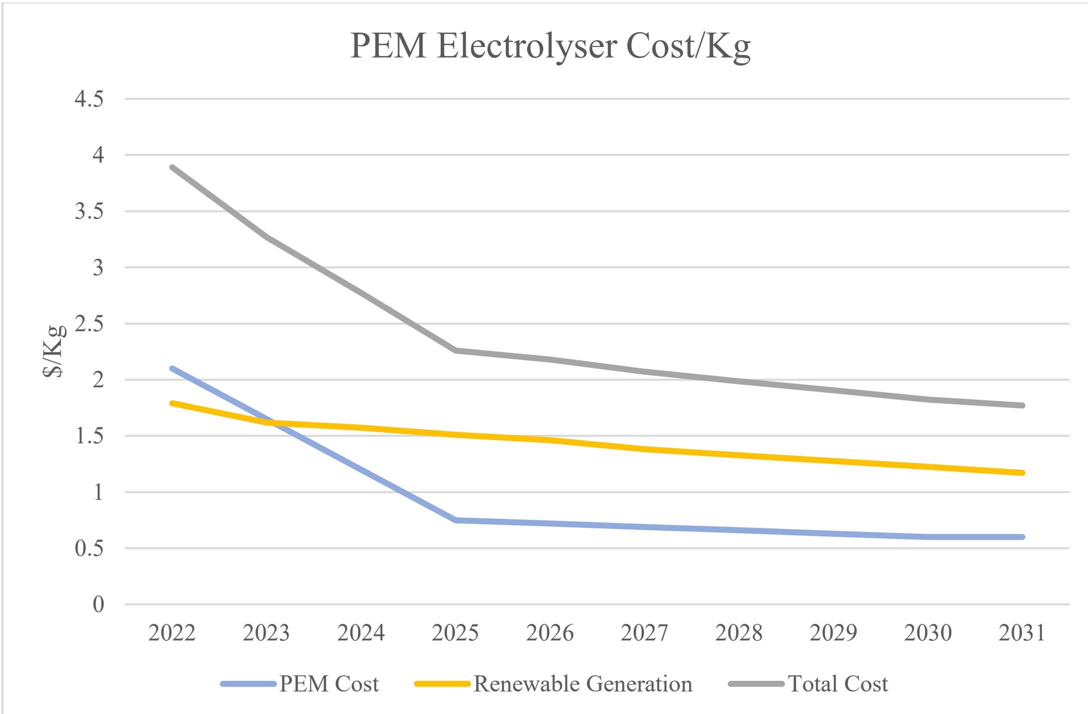

Figure 25 Energy Mix 1 with Proton Exchange Membrane Electrolyzer

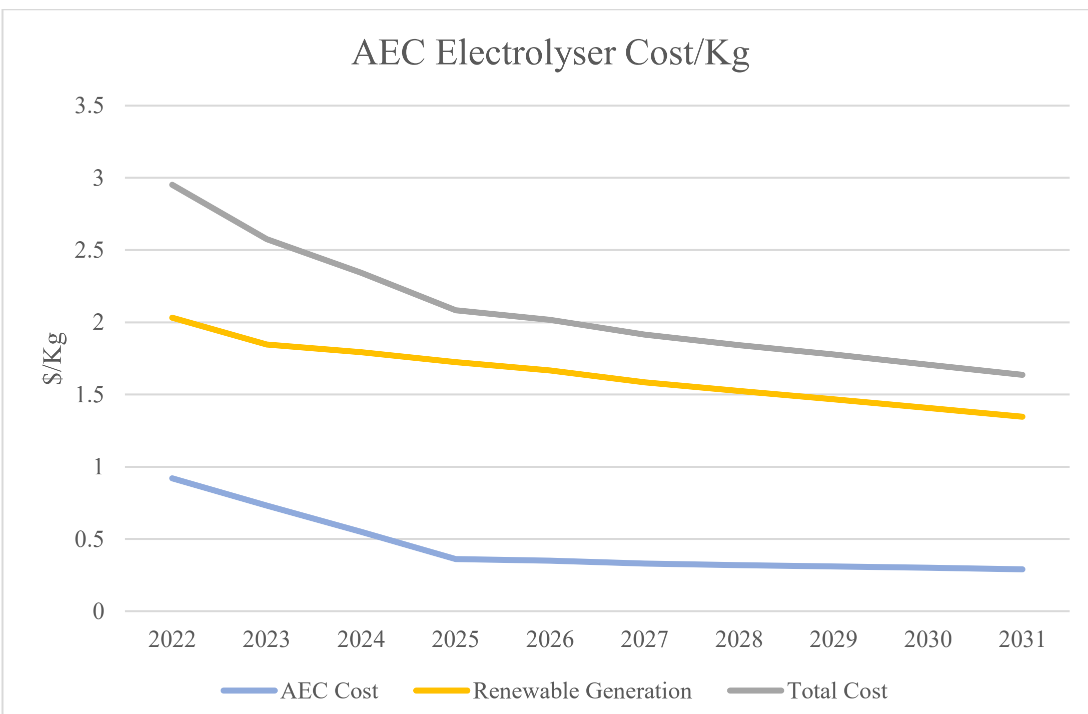

Figure 26 Energy Mix 2 with Hydrogen Produced in Alkaline Electrolyzer

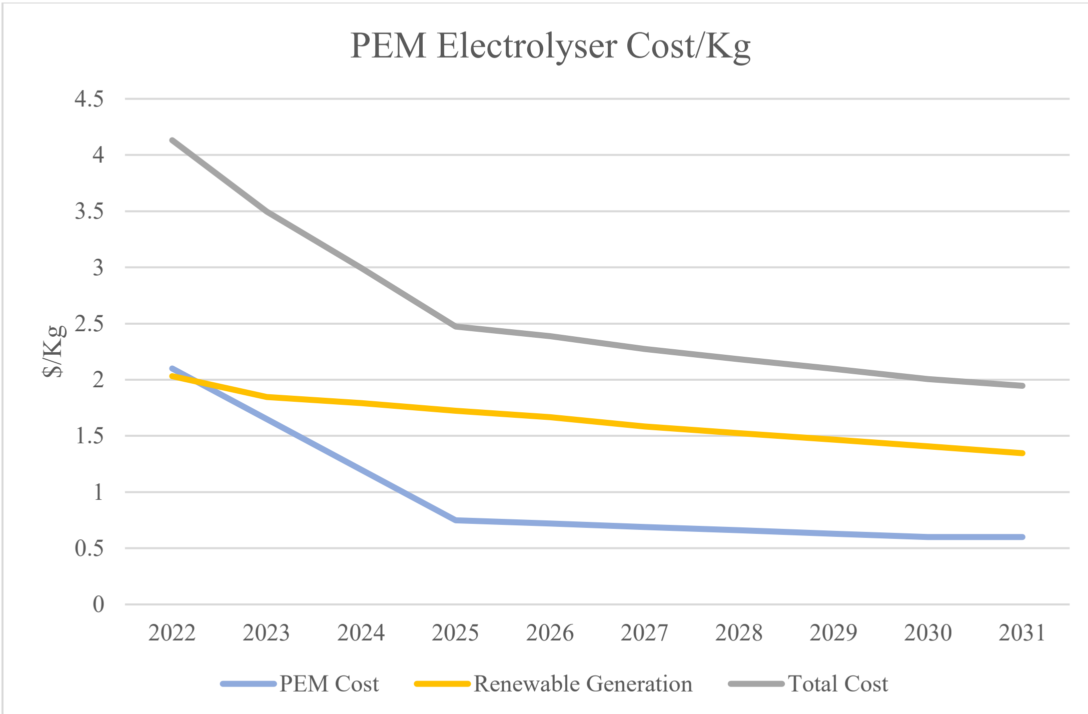

Figure 27 Energy Mix 2 with Proton Exchange Membrane Electrolyzer

Additionally, the cost of green hydrogen for both renewable mixes was compared with the current and expected costs of blue hydrogen (SMR and CCS). The results show that presently, electrolyzer produced hydrogen costs 1.5-2 times the hydrogen produced from SMR and CCS. However, by the end of this decade AEC produced hydrogen can be competitive with blue hydrogen in terms of costs. The hydrogen produced from PEM Electrolyzers will continue being costlier than the other two production methods due to higher per unit costs and lower operational life of PEM under the current technology development. The results are shown in Figures 28 & 29.

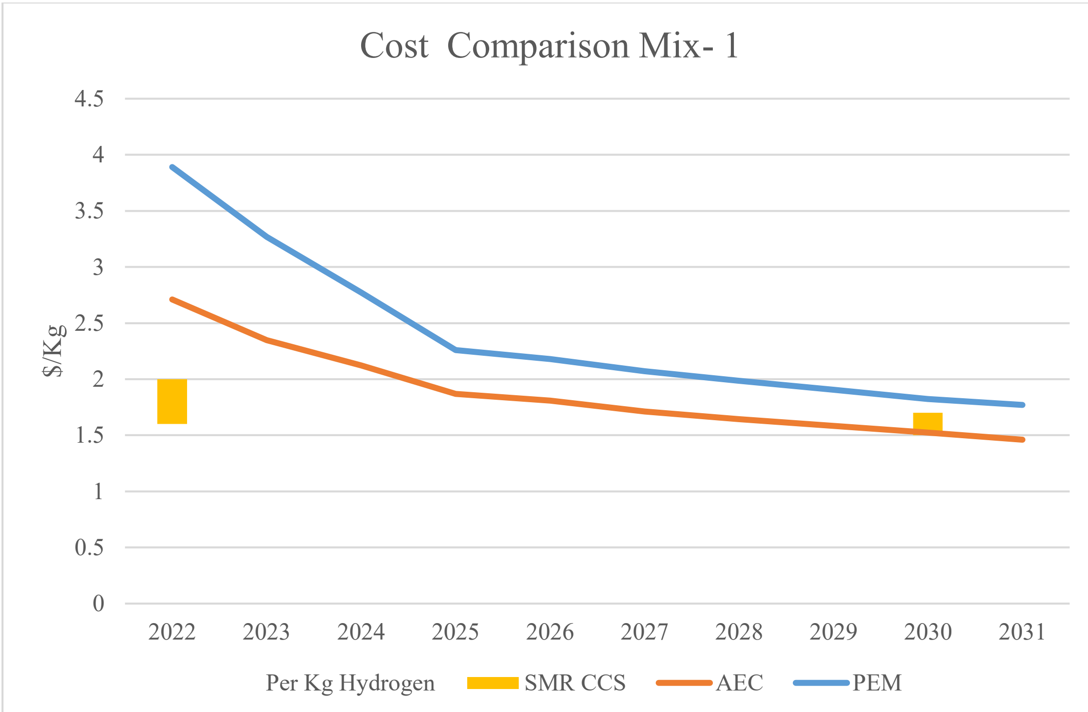

Figure 28 Mix 1: Cost Comparison Forecast

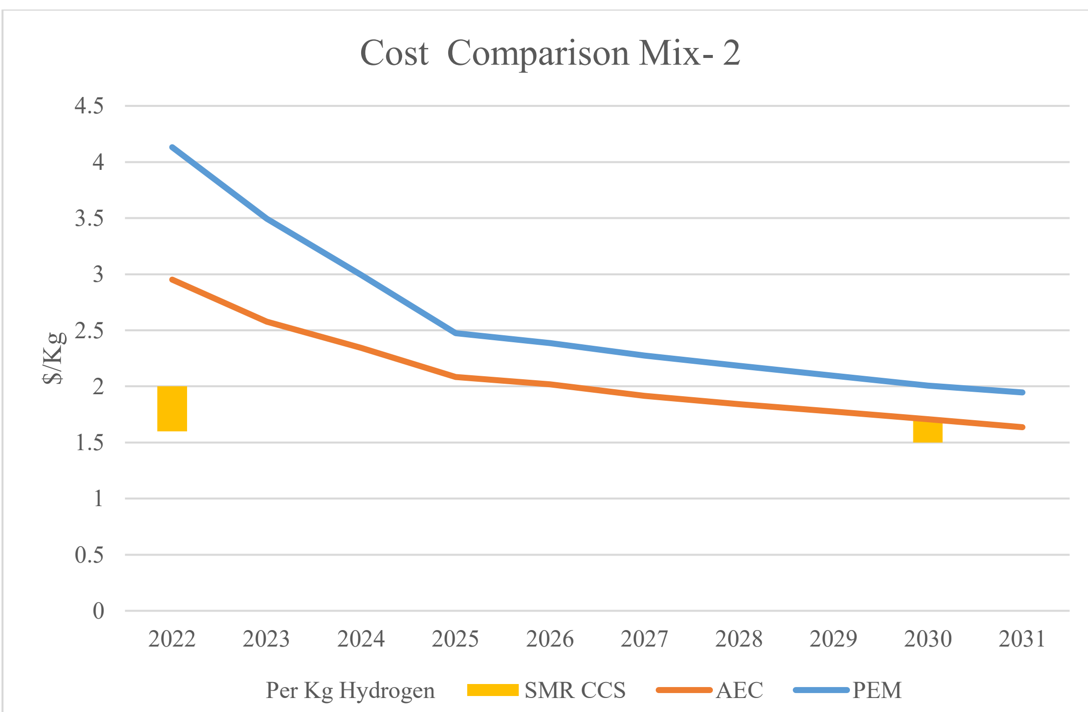

Figure 29 Mix 2: Cost Comparison Forecast

Total costs for the two scenarios and the corresponding mixes based on the per unit hydrogen costs shown above are assessed. Of the two electricity input mixes, a higher proportion of wind energy in comparison to solar energy results in lower costs both in the present production and over the next decade as well. This is due to already established wind power industry and the ensuing economies of scale on increasing production capacity into the future. While large scale solar energy adoption in Alberta is still in the early stages, it has picked up rapidly in the last couple of years and associated costs are expected to decrease over the medium term. Additionally, due to the decreasing costs of electrolyzers, as shown in the previous section, the total project costs will decrease by about 5% per year per unit of H_2 produced by the end of this decade.

Figures 30 and 31 show the total costs for the proposed capacities and the total green hydrogen produced in the corresponding year. The figures illustrate the costs and capacity for the Phased Transition Scenario. For the Aggressive Capacity Addition Scenario, the graphs follow a similar trend with the total costs and capacity being twice of those in the first case.

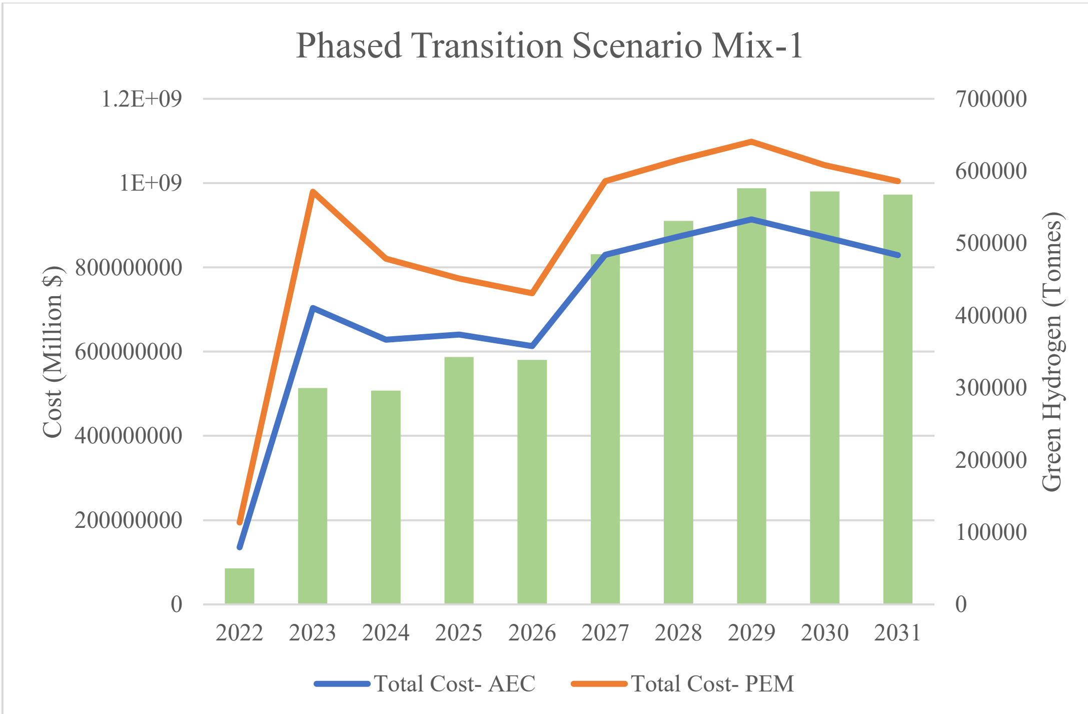

Figure 30 Total Costs vs Capacity Addition- Phased Transition Scenario Mix-1

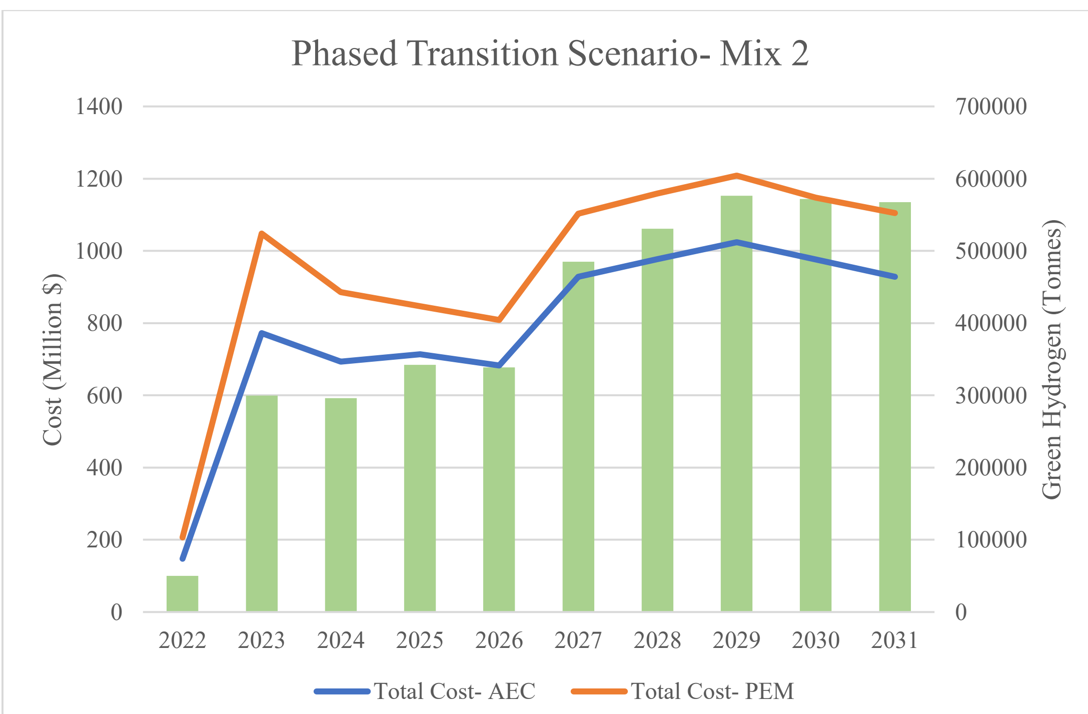

Figure 31 Total Costs vs Capacity Addition- Phased Transition Scenario Mix-2

An analysis of the cost contribution to the unit cost of produced hydrogen is performed. The results show that currently for AEC electrolyzer, wind and solar energy contribute equally to the costs. However, over the next decade electrolyzer costs decrease with increasing economies of scale and contribute about 20% to the total by 2030. After 2030, as alkaline electrolyzer costs stabilize, most of the decrease would come from renewable costs reduction.

For PEM electrolyzers, the cost reduction due to technology improvements would be seen after 2030 as well. Currently, more than 50% of the costs of hydrogen production are from the electrolyzer which is reduced to about 30% by the end of this decade. To bring them in line with blue hydrogen and alkaline electrolyzer produced hydrogen, renewable energy costs will have to be further brought down. Figures 32 & 33 show the results.

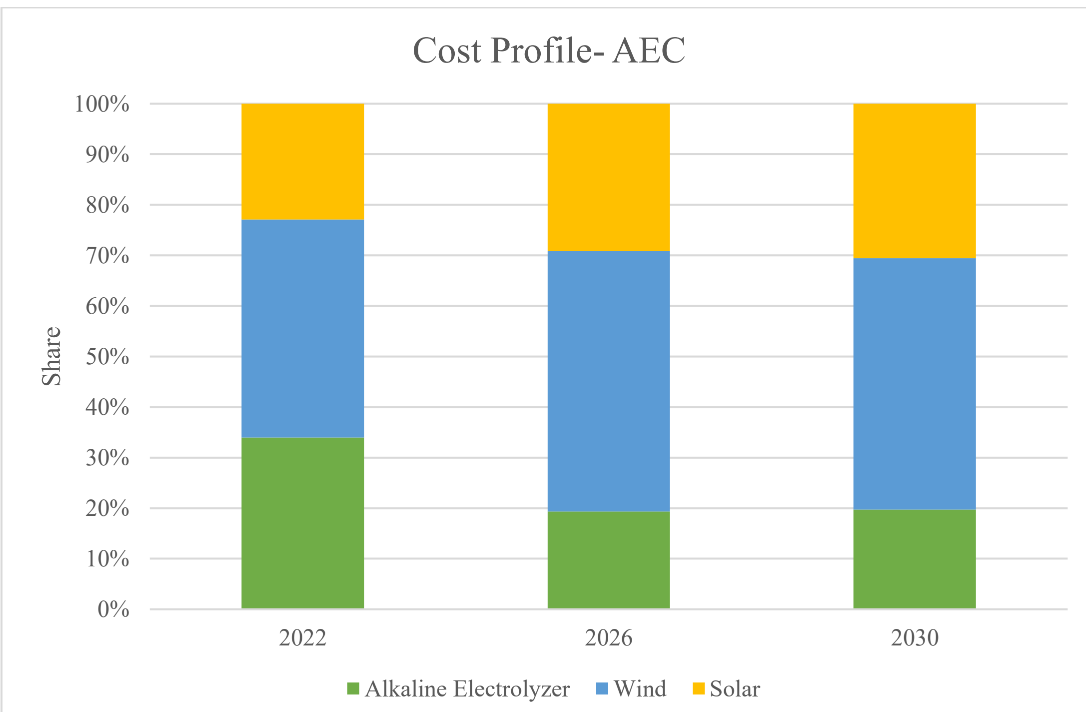

Figure 32 Cost Profile Alkaline Electrolyzer

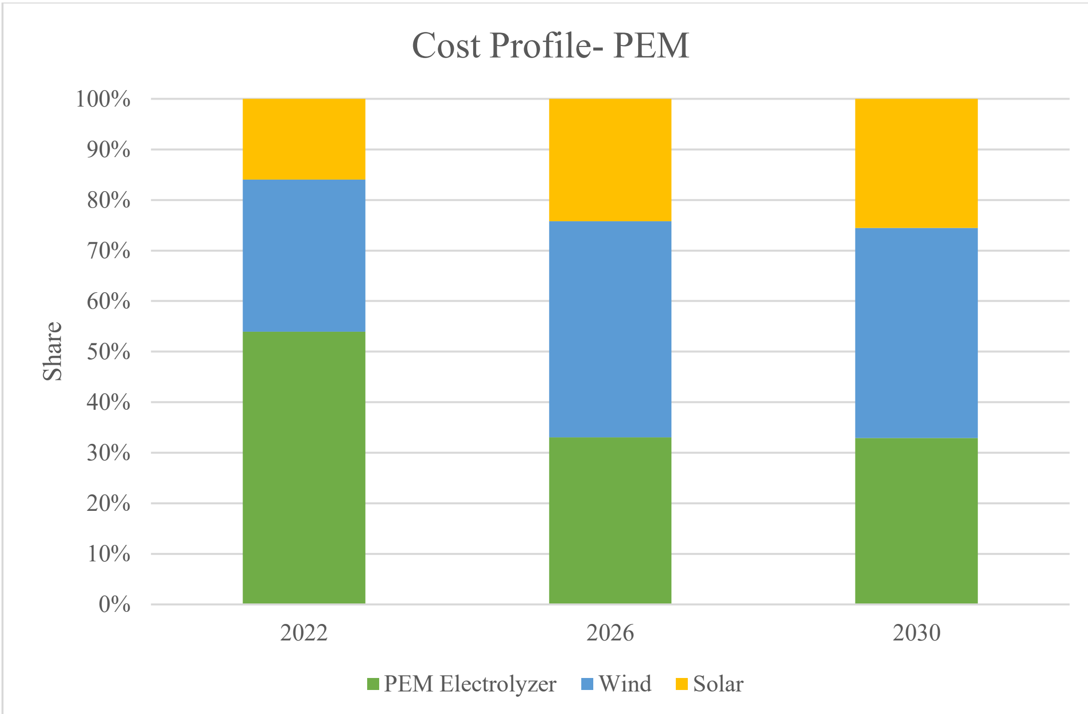

Figure 33 Cost Profile PEM Electrolyzer

2.14 Emissions

The figure 34 below shows the emission profile of the two renewable mixes considered above. The results show that a greater contribution of wind to the feed lowers the overall emissions because of lower embodied emissions in wind electricity. Each of these cases produces hydrogen with significantly lower emissions than both the grey hydrogen processes- SMR and ATR. The emissions are less than half of those permitted under the CertifHy program.

The total yearly emissions trend is shown in the Figure 35. The current emissions are around 25 million tonnes CO_2 because of a large share of natural gas-based hydrogen in Alberta. If the current profile is followed with no addition of green hydrogen, CO_2e emissions would increase by more than 10 million Tonnes per year by 2030. When the total emissions from the green hydrogen production scenarios modelled here are considered, there is gradual decrease in total emissions by 2030 depending on the scenario adopted. The aggressive green hydrogen only strategy (Scenario

2) can bring down the total yearly emissions by almost 8 million tonnes a year for both the renewable mixes.

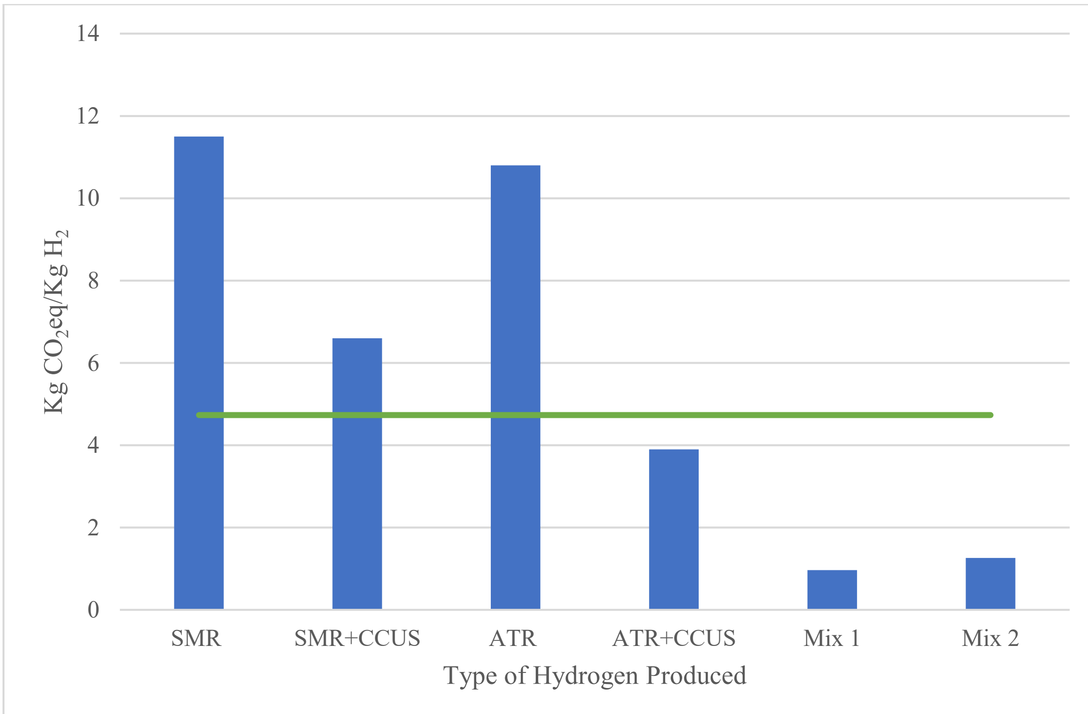

Figure 34 Per unit Emissions by Source of Hydrogen; Green Line represents the CertifHy Certification

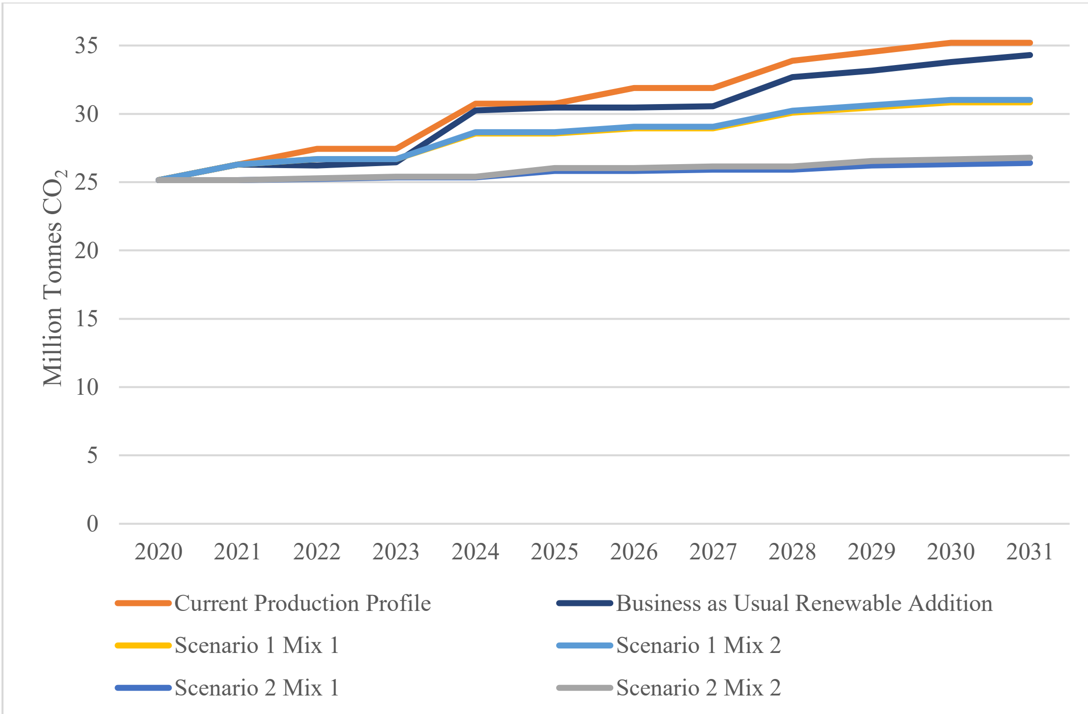

Figure 35 Total Yearly Emissions based on Various Scenarios

2.15 Electricity Grid Integration

Both the scenarios discussed above show a high price for green hydrogen derived from dedicated renewables. To decrease the price of hydrogen, the Alberta electricity grid was considered to provide a part of the electrolyzer energy input. An analysis was done for both renewable mixes and the results are shown in the figures 36 & 37. The results show that, since the Alberta electricity grid has high per unit emissions, only 10-15% of the electricity feed can be from the grid before the emissions cross the CertifHy green hydrogen threshold. The cost for producing hydrogen from the grid in Alberta is approximately 75-80% of the cost of producing it from dedicated renewable feed, based on wholesale electricity rates (EPCOR 2022). This grid based hydrogen production cost is higher than other Canadian provinces such as Quebec, Manitoba, and Newfoundland and Labrador where wholesale electricity prices are almost 50% less than that of Alberta (Nguyen et al. 2019).

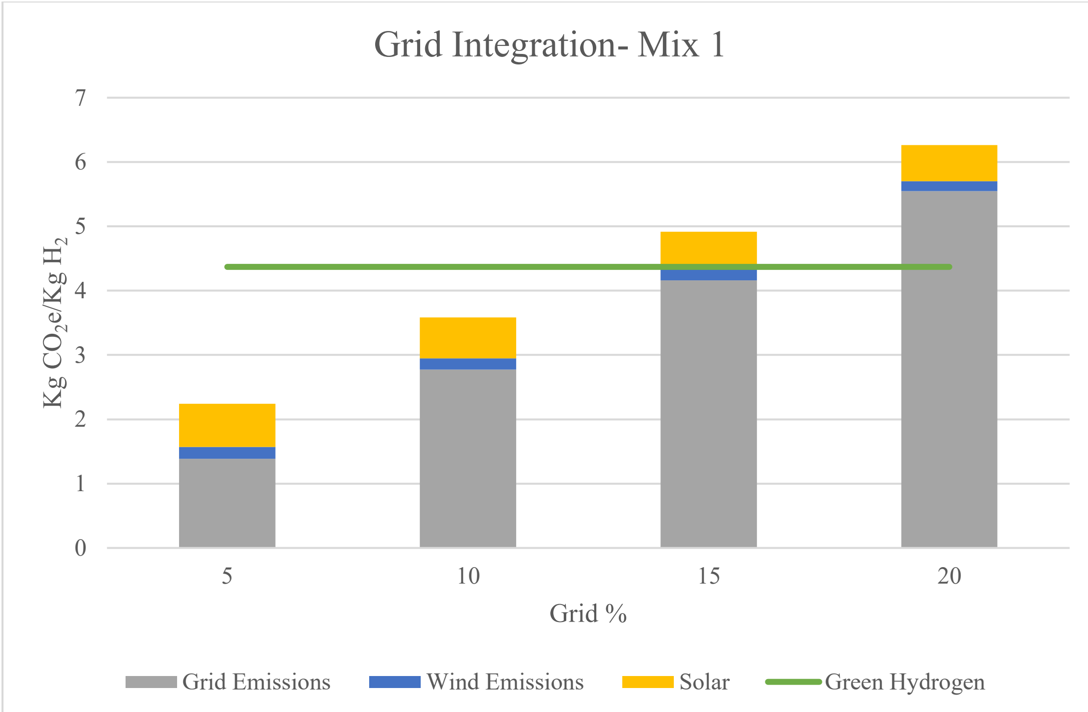

Figure 36 Per Unit Emissions with Different Ratios of Grid Integration for Mix 1

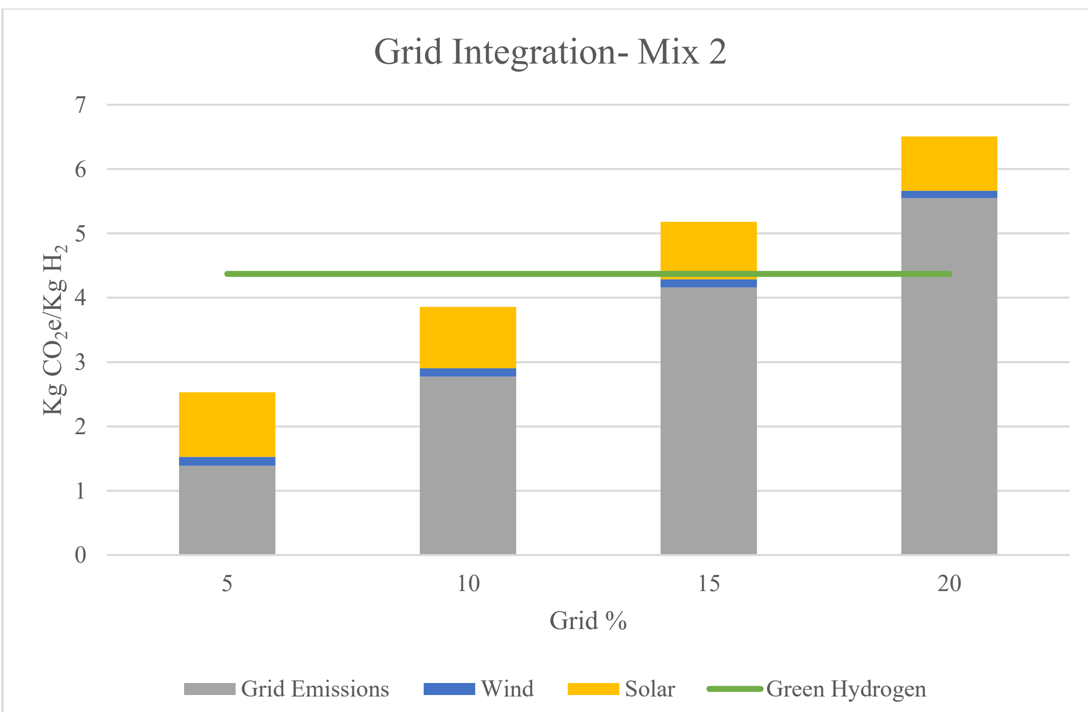

Figure 37 Per Unit Emissions with Different Ratios of Grid Integration for Mix 2

2.16 Resource and Material Requirements

Setting up integrated renewable energy and electrolyzer plants at such large scales require use of other essential and critical materials. These essential resources such as land and water may need to be diverted from social development uses and may cause additional land degradation due to the mining required for critical materials.

2.16.1 Water Use

Water supply is a concern in setting up of solar, wind energy plants and in electrolyzer units as water is the primary input for electrolyzers. During the lifetime of a solar power plant installation, approximately 0.5 liters of freshwater is used per kWh of electricity produced with the maximum being used in raw materials extraction (0.4 liters) for solar module manufacturing followed by installation (0.03 liters) (CSI 2022). The net freshwater use over the lifecycle of setting up the wind farm is 0.06 per kWh with the manufacturing phase contributing highest to the water use. Of the total water use during the hydrogen production, about 45% is in the electrolyzer stage with about 12 litres of water consumption per kg of H_2 followed by the renewable energy generation with 8.1 liters per kg of H_2. An alternative to freshwater use in electrolyzers is the use of seawater directly or desalination of sea water before being fed to the electrolyzers. However, installation of a solar powered desalination plant can increase the hydrogen production costs as it costs \$2.90 per 1000 liters of water (Hoffmann 2019). Direct seawater splitting in an electrolyzer is not viable in terms of energy and costs as compared to desalination followed by hydrogen production (Niklas Hausmann et al. 2021).

2.16.2 Land Use

With the increase in population, land availability is a concern especially in urban areas where the hydrogen demand is expected to increase in the future while installing the hydrogen production plants farther away would increase the transportation costs. The average area of land required for setting up a solar power plant is 20 m^2 per kW (Palmer et al. 2021) and for the onshore wind farm is 4 m^2/kW (Denholm et al. 2009).

2.16.3 Critical Materials

Supply and demand of critical materials is an important consideration for the various pathways associated with the achievement of the climate targets. Solar PV and wind power generation will be the major drivers of demand of critical materials in the coming years. An exponential increase in solar PV needs would increase the demands for metals such as silver, germanium and telluride substantially with annual demand forecasted to be three to four times the current demand (IRENA 2021). For wind energy production, the highest need would be of copper, zinc and rare earth elements (IEA 2021). Clean hydrogen production would require large amounts of nickel, zirconium and platinum group metals for use in electrolyzers which may come with significant supply risks especially for PEM electrolyzers (Kiemel et al. 2021).

2.17 Summary

The need to upscale the clean hydrogen production capacity is essential as hydrogen is a critical component of the clean energy pathways that are key to achieving the climate and decarbonisation targets. Currently, a majority of the hydrogen is produced from fossil fuel-based sources, but cleaner hydrogen is expected to be economically viable in the medium and long term.

This study conducted a techno-economic analysis of green hydrogen production in Western Canada. A lifecycle approach is adopted to ascertain the global warming potential in terms of carbon dioxide emitted over the whole lifecycle and per unit of hydrogen produced. Various scenarios and green electricity mixes are considered to forecast the capacity required to gradually transition Western Canada to green hydrogen over the next decade. The results are compared with the business-as-usual scenario both in terms of emissions and costs and a need for aggressively scaling up the renewable energy is concluded. The unit costs for producing green hydrogen are higher than the traditional methods such as SMR and SMR with CCS in the short term but the costs start equalising by the next decade although the reduction in emissions is high in the near term if green hydrogen capacity is scaled up. A further avenue for cost reduction could be higher integration of grid electricity into the mix if the emissions associated with the grid are reduced over time.

This study does not consider other downstream processes such as hydrogen compression as various end uses require hydrogen at different pressures. Hydrogen transport costs and emissions through pipelines, trucks and ships are not analysed and would further increase the life cycle costs associated with green hydrogen. Further work is required on Solid Oxide Electrolyzers which are at technology demonstration stage and have the potential to produce greater volumes of hydrogen with lower emissions.

Chapter 3: Utilization of low-cost and low carbon emitting electricity for hydrogen generation in a Dynamic electricity market in Western Canada

3.1 Abstract

The aim of this paper is to conduct a techno-economic feasibility analysis of hydrogen generation from excess electricity during periods of curtailment from renewable sources. The key focus is on assessing the environmental impacts of such a transition to cleaner hydrogen over the next decade in Western Canada while ensuring a clean and stable supply of hydrogen for various industrial processes. An analysis is performed to ascertain the relative viability and cost of utilizing low-cost electricity for hydrogen generation. This includes the development of models based on various electricity price thresholds. The viability of a site for hydrogen generation from renewables is based on a study of the photovoltaic and wind potential of various regions in Western Canada. Green hydrogen is produced by integrating renewable energy into the grid in line with net-zero electricity pathways for Alberta. Additionally, an analysis considering the relative emissions from hydrogen generated in the models and hydrogen generated from fossil fuels is conducted. The price of green hydrogen currently stands at approximately \$8.5-10/Kg of H_2. Results from our earlier models and analyses have shown that green hydrogen production would be more viable in the medium term with an average price of \$3-4/Kg of H_2. These rates are comparable to the current rates of natural gas derived hydrogen with Carbon Capture and Storage (CCS), which is approximately \$2-2.50/Kg of H_2. Assuming the results from this initial assessment, it is expected that up to 15% of the annual hydrogen demand could be met by using this clean electricity, depending on the model adopted. As electrolyzer technology is improved, hydrogen produced using dedicated renewable sources will achieve price parity over the longer term with the model proposed and become cheaper than fossil fuel based hydrogen if subsidies are introduced. It also

helps predict the rate at which a hybrid supply of hydrogen can be converted to a primarily green hydrogen supply. These results will serve as a reliable way to transition from grey hydrogen that is currently being produced to green hydrogen, without increasing costs exponentially and with minimal change in availability and help minimize curtailment of low cost, emission free renewable energy. The analysis provides a roadmap for a phased decarbonisation of various industries, including the oil and gas industry, where hydrogen is used as a feedstock.

3.2 Introduction

Renewable energy expansion is seen as an integral component of achieving the net zero targets by 2050. The share of renewables in the worldwide electricity sector is forecasted to be 60% by 2030 and 90% by 2050 in the net zero energy scenario (IEA 2021). Wind and solar energy will be the major drivers of this push towards renewables with annual capacity additions in the future predicted to be five times higher than the recent trends. Renewable energy contributed 40% to the global energy mix in 2022 with 83% of the new capacity added in the electricity sector being renewables (IRENA 2023). Alberta will phase out coal fired power plants by 2023 and aims to have 30% of the total electricity to be produced from renewables by 2030 (Government of Alberta 2020). About 80% of Canada's new renewables addition in 2022 (solar and wind) was in Alberta (Government of Alberta 2023).

Variable Renewable Energy (VRE) such as solar PV and wind will constitute 70% of the total renewable supply by 2050. The renewable energy scaling needs to be accompanied by management of transmission and distribution facilities along with storage and smart electrification to minimize periods of curtailment and accommodate flexibility in supply and demand. Interconnection or intertie enhancement- both within countries and between different countries will help countries with unique renewable energy mixes to supplement each other requirements. A recent study concluded that increasing interconnections by 15% reduces the volume of curtailment by 86% in 2030 (IRENA 2020).

The global hydrogen demand is expected to increase from 90 Mt currently to about 200 Mt in 2030 and 530 Mt by 2050. Renewable energy based hydrogen produced in electrolyzers is expected to make up 60% of the total hydrogen production mix (IEA 2021). This renewable energy may be from the electricity grid if the grid produces low emissions or from dedicated renewable energy plants for hydrogen production. The Alberta Hydrogen Roadmap envisions two scenarios for future hydrogen development in the province- an incremental future and a transformative future. In both, clean hydrogen plays a key role in reducing emissions, decarbonizing industries such as power and transport, and leveraging existing infrastructure to export hydrogen (Government of Alberta 2021).

In our earlier paper, we analysed the viability of manufacturing hydrogen from dedicated renewable energy plants in Wester Canada by conducting a Life Cycle Assessment (LCA). The aim of this study is to propose a model of producing hydrogen from low-cost grid based renewable energy in Alberta. This will have major benefits which include- minimizing curtailment of renewables and establishing Alberta as a hub for green hydrogen production in Canada. The hydrogen produced will be green i.e. having a total emission lower than 4.5 kg CO_2e/Kg H_2 as defined by the European emission CertifHY standards (European Commission, 2021). An emission analysis is done to ascertain the contribution of this low emission hydrogen to Alberta's net zero targets and a cost comparison of produced hydrogen is done with the current methods of hydrogen production.

3.3 Jurisdiction and Literature Review

California: The California Independent System Operator (CAISO) manages surplus renewable generated in the state by curtailing and reducing the production during specific hours. This is done either automatically or manually by the CAISO. Over the last three years, the levels of renewable curtailment has increased progressively with the maximum curtailment being about 600-700,000 MWh in March and April of each year (CAISO 2023). The curtailments are done either at the local level or the system level and are grouped into economic, self-schedules, and exceptional dispatch categories. The state has set a target of net zero grid and zero carbon electricity by 2035 and 100% renewable energy by 2045 (EIA 2023).

Various options including storage, time of use rates, and flexible resources are being examined to reduce the level of curtailment and further reduce emissions form the electricity grid (CAISO, 2023). The current strategies including use of the Automatic Generation Tool (AGS) to dynamically adjust the volume in real time, negative pricing with progressively falling floor of up to $200/MWh, and storage. Smart charging of electric vehicles during periods of higher renewables production and low prices is another solution proposed to decrease curtailment in the state (Energy Policy 2020). Figure 38 shows the solar and wind curtailment in California from 2014 to 2023.

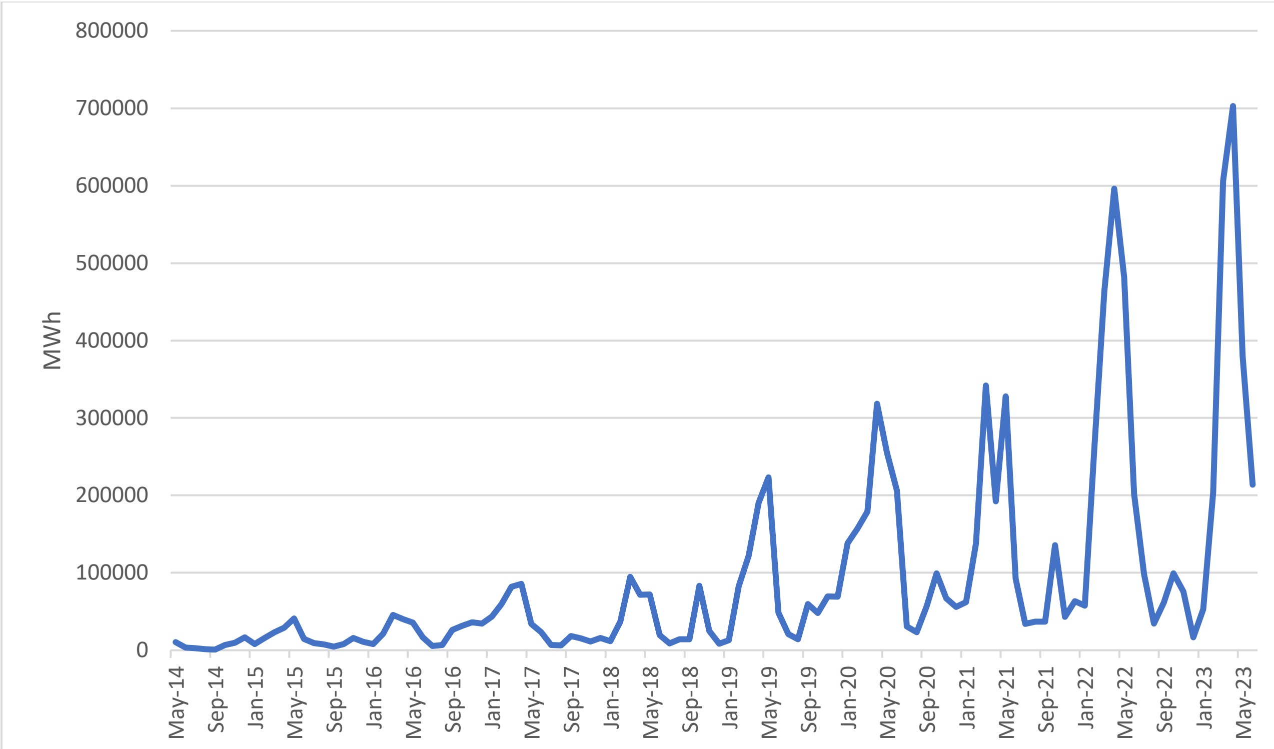

Figure 38 Wind and Solar Curtailment in California, Data from CAISO

Germany: Wind and solar energy are the dominant sources of renewable power in the country with the goal of 80% renewable energy based electricity grid by 2030. The level of curtailment has become stable over the last 5-7 years with an average curtailment of 5000-6000 GWh per year. This amounts to almost 4% of the total renewable energy produced in the country (IEA 2023). Challenges to the grid include low exports due to limited intergeneration and the electricity grid reliant on conventional generation facilities.

Potential solutions include storing the excess electricity in the form of thermal energy in power-to-heat plants with government incentives to finance such facilities (Largue 2023). Policy initiatives include retrofitting conventional coal fired plants to be flexible and planned wind energy sites to be located by the government to account for regional congestion in the grid. The rule to control production from solar PV, which limited the production to 70% of the rated power for solar plants has been removed from 2023 (Rated Power 2023). This may result in increased curtailment especially during periods of high solar energy production. The electricity sector is undergoing reforms to increase flexibility in the electricity grid including managing the demand and using solutions such as smart grids, cross-border exchanges and linking power and end use sectors (IRENA 2015).

Texas: The Electric Reliability Council of Texas (ERCOT) manages the curtailment policy of the state. A majority of the curtailed electricity is concentrated in the western part of the state since it has the highest generation of wind and solar energy (ERCOT 2022). The volume of curtailment in 2022 was 9% for the solar energy generated and 5% for the total wind generation in the state. By 2035, around 19% of the total renewable energy would have to be curtailed if all the proposed generation plants are realised. This is due to limited transmission capacity and greater generation during certain periods. The addition of battery storage can reduce the potential levels of curtailment from 26% to 19% for solar and 16% to 13% for wind energy (EIA, 2023).

New York: The State aims to have a 70% share of renewables in the electricity grid by 2030 and 100% clean and carbon free electricity by 2040 (SUNY 2020). New York in its long-term electricity outlook has identified zones or pockets in its electricity grid system where renewable energy may have to be curtailed due to transmission constraints. The grid is currently facing renewable curtailment and further there are 3 pockets where the level of curtailment will potentially be more than 10% and 5 pockets where it may be between 5-10% out of a total of 13 pockets. A majority of the curtailment will be of offshore wind energy and the spring season has the highest volume of curtailment. The solutions identified include exporting excess wind energy and strengthening the state’s transmission system to account for the added renewables load (NYISO 2022).

United Kingdom (UK): Renewable electricity has overtaken fossil fuel based electricity as the major source of UK's energy demand since 2020. The volume of curtailment in 2020 was 3.5 TWh and 2.3 TWh in 2021 which is about 6% of the total wind energy produced in the country (Drax LCP 2022). The National Grid manages UK's electricity system, and the current policy is to pay renewable energy generators to stop producing electricity for specific periods when the supply is saturated, and the costs are borne by the consumers. The turned off renewables supply is then compensated by fossil fuel based supply during periods of excess demand thus raising the emission levels from the grid. The level of curtailment is expected to increase fourfold by the end of this decade and cost $2.5 B in lost renewable energy annually. The National Grid electric system operator aims to increase interconnections, smart EV charging, energy storage, and electrolyzer capacity by 2050 to minimize curtailment. The annual curtailment in the three future electricity grid scenarios is expected to peak at about 60 TWh. (National Grid ESO 2023).

Spain: Spain plans to install 50 GW of wind energy and 39 GW of solar PV by 2030 and have a 74% supply of renewable energy in its grid (European Commission 2020). The country has been curtailing wind and solar energy since 2015 and 2020 respectively. During periods of oversupply, the electricity grid operator mandated producers to disconnect their systems from the grid or reduce output. To minimize potential curtailment, Spain plans to increase interconnections internationally such as with France and Portugal, generate hydrogen and increase blending into the natural gas network, demand management, and storage mechanisms such as battery depending on whether the requirement is for short term or long term storage (Gómez-Calvet et. al. 2023).

3.4 Alberta Grid

The current annual production trends for wind and solar energy including the seasonal variation are shown in figures 39, 40, and 41. An analysis of the hourly trends shows that wind and solar complement each other in terms of production reliability. During the winter months fewer hours of insolation results in lower production from solar farms while wind energy capacity factor can be around 55-60%. The trend reverses in summer and there is much higher solar production (per unit of installed plant capacity) as compared to wind energy where the capacity factor comes down to 30-35%. The hourly variation during particular months in figures 42 and 43 shows the difference in capacity factor of wind and solar during the summer and winter months respectively. The capacity factor of solar energy is noticeably higher in July and wind is higher in November and the hours of solar energy generation in the winter are lower relative to the hours in July.

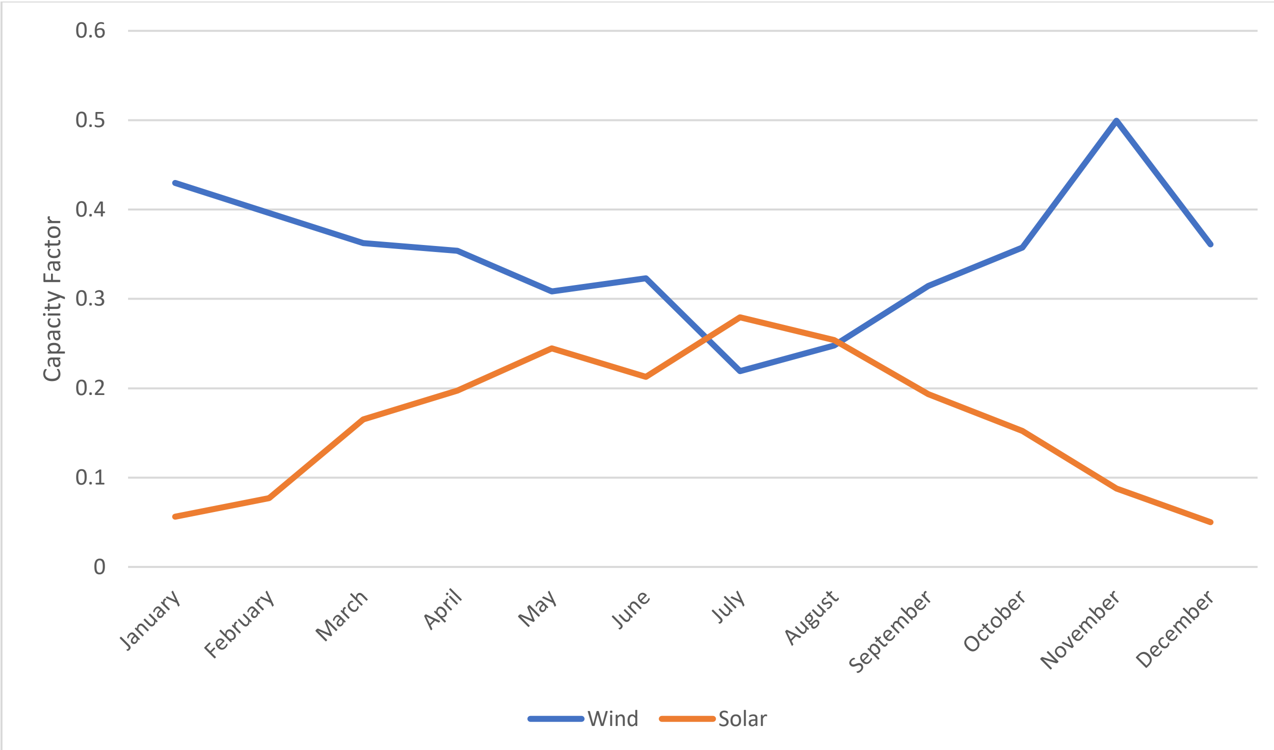

Figure 39 Monthly Capacity Factors for Wind and Solar Energy in Alberta

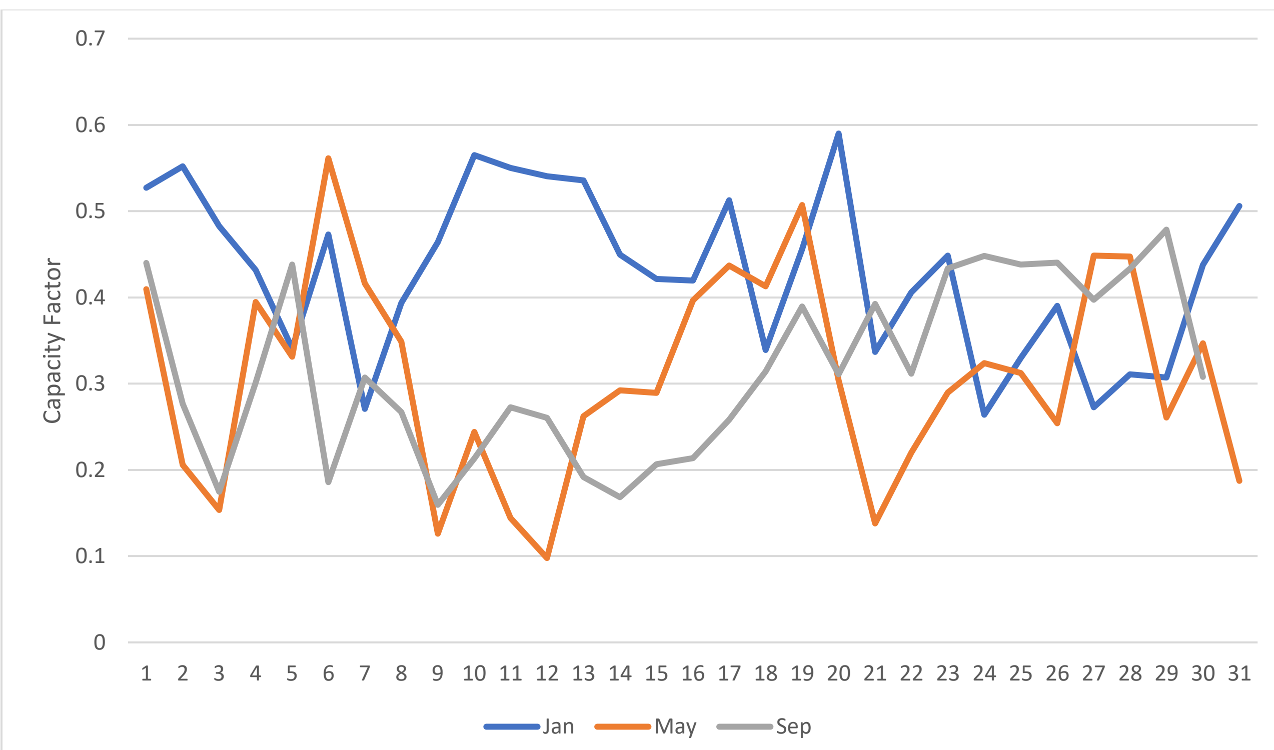

Figure 40 Seasonal Variation- Wind Energy Production

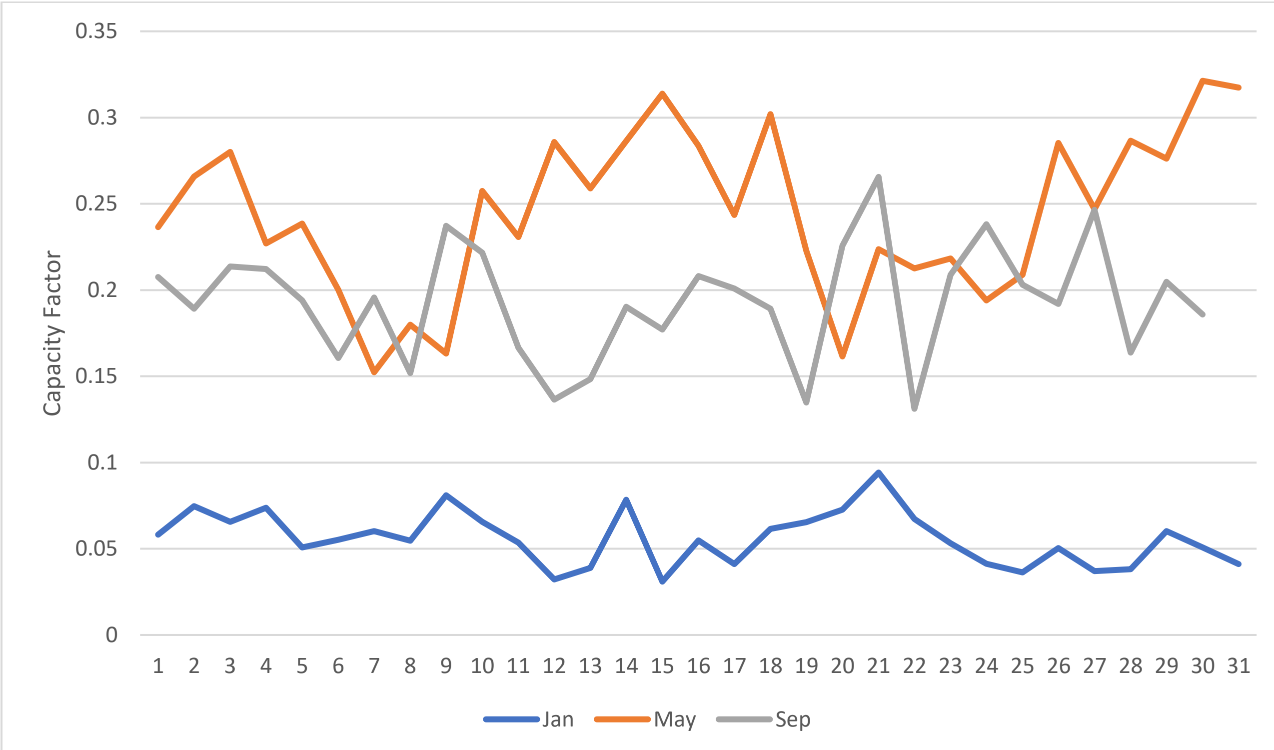

Figure 41 Seasonal Variation- Solar Energy Production

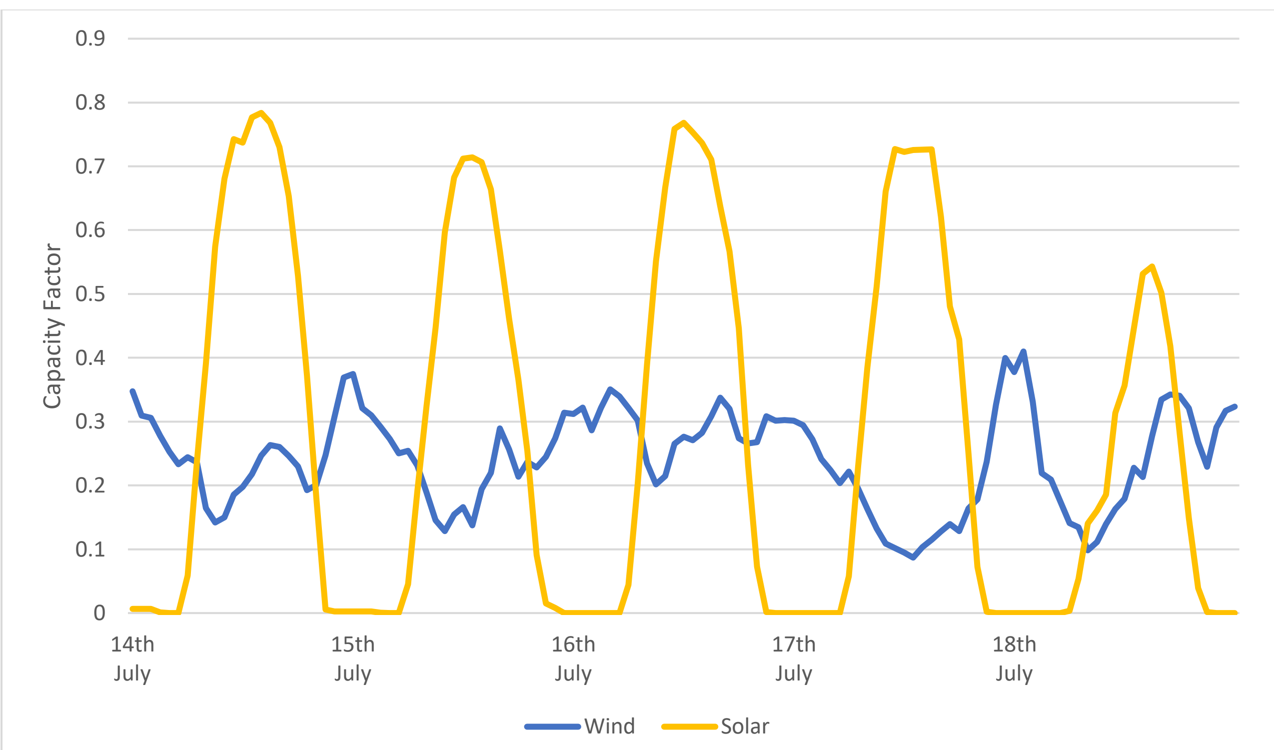

Figure 42 Hourly Variation of Renewable Energy in the Summer

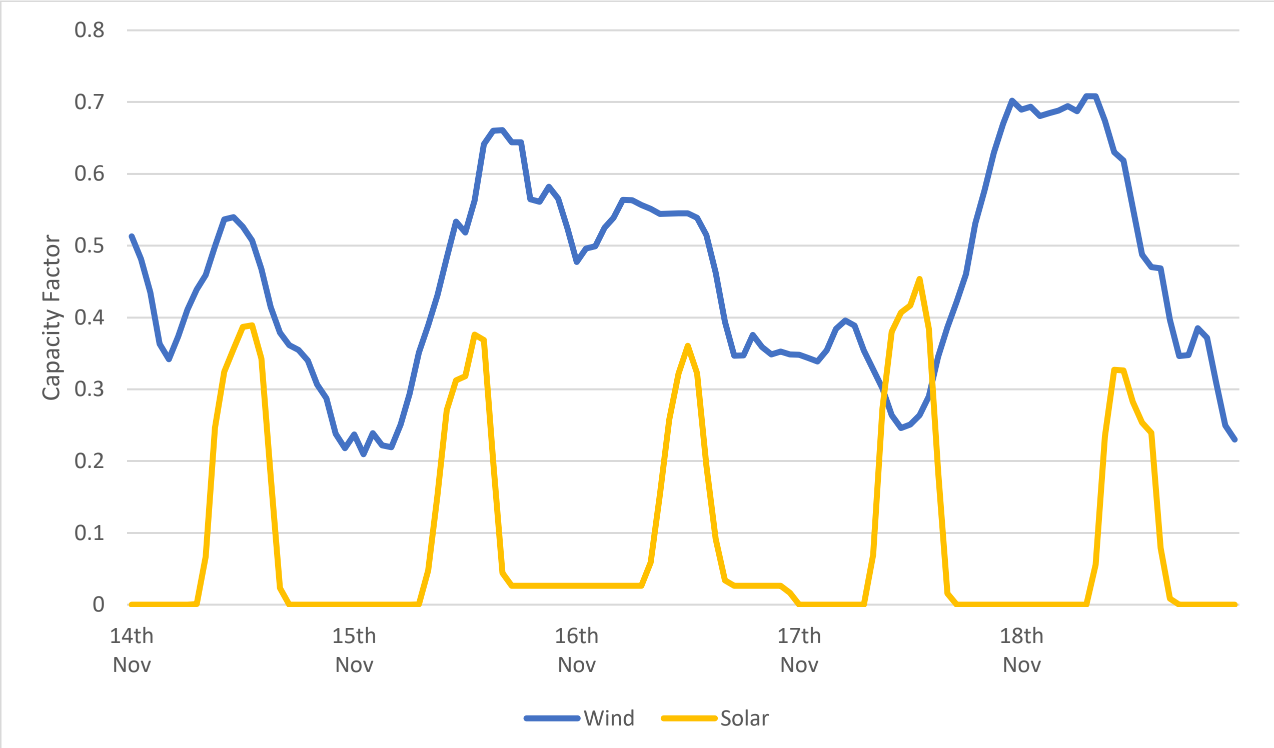

Figure 43 Hourly Variation of Renewable Energy in the Winter

The electricity grid of Alberta follows a competitive pricing model where the Alberta Electric Systems Operator (AESO) ensures matching of supply and demand every hour. Electricity producers submit bids and buyers place demand bids on a day ahead basis for every hour of the day. A merit order is prepared by the AESO depending on the highest offers from the market and the pool price is determined hourly (AESO 2023).

The hourly pool price in the electricity market depends on several factors including the hourly demand and the natural gas price. The demand depends on the season- it is higher in the winter and lower in the summer as shown in the figure 44. Additionally, the daily demand varies with peaks in the early morning and early evening with lower demand during the night. The weekly trend shows a higher demand on the weekdays compared to the weekends. These trends are shown in figures 45 and 46.

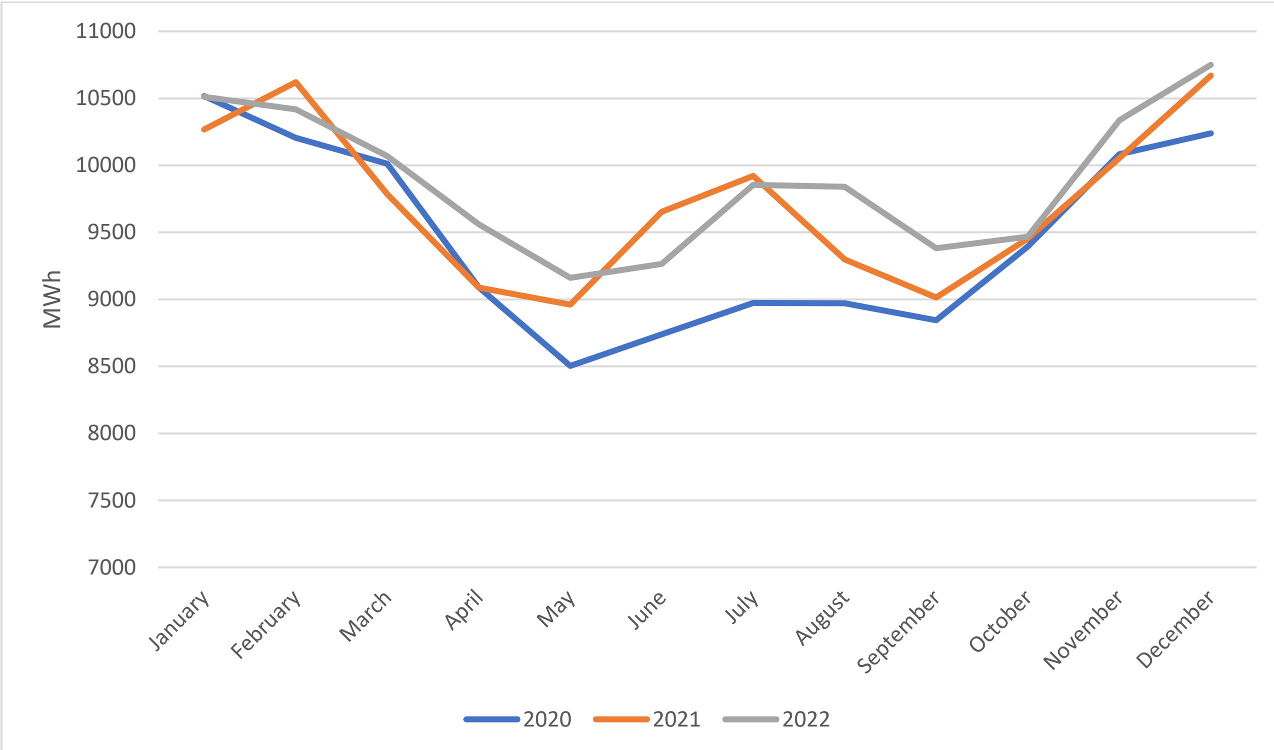

Figure 44 Seasonal Demand Variation of Electricity

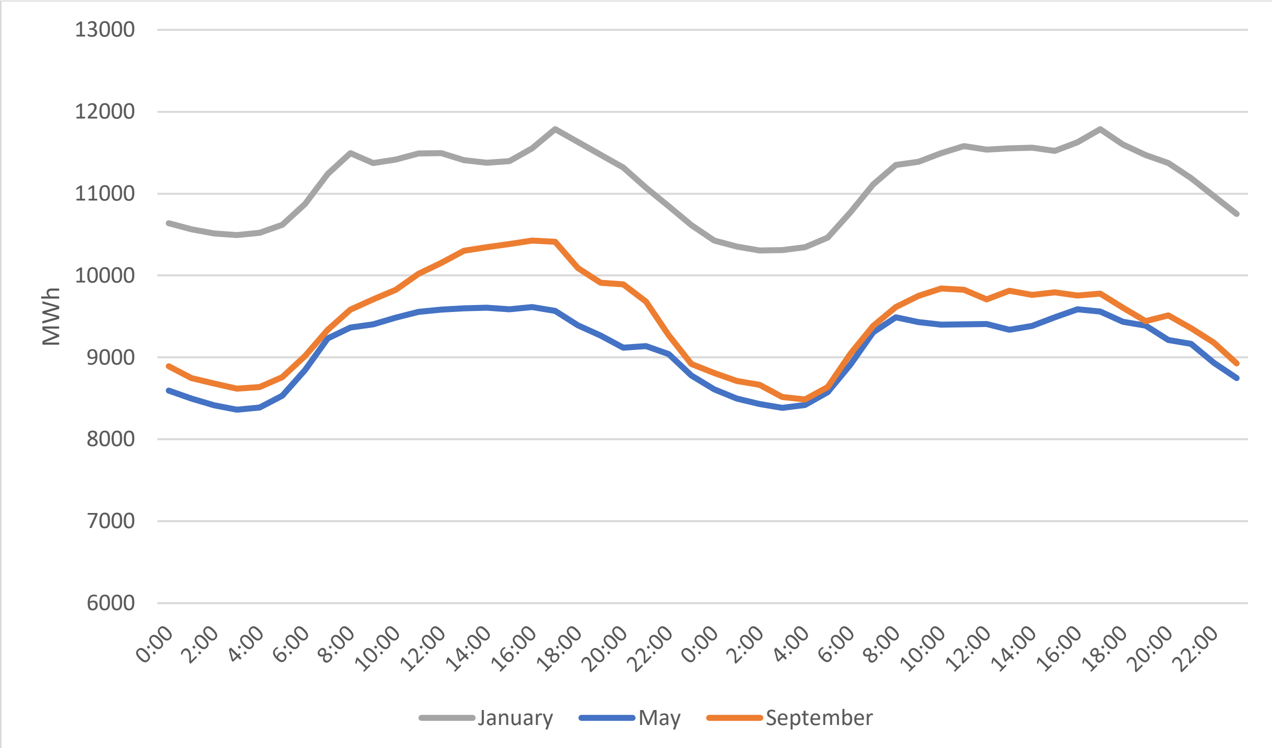

Figure 45 Hourly Variation of Electricity Demand

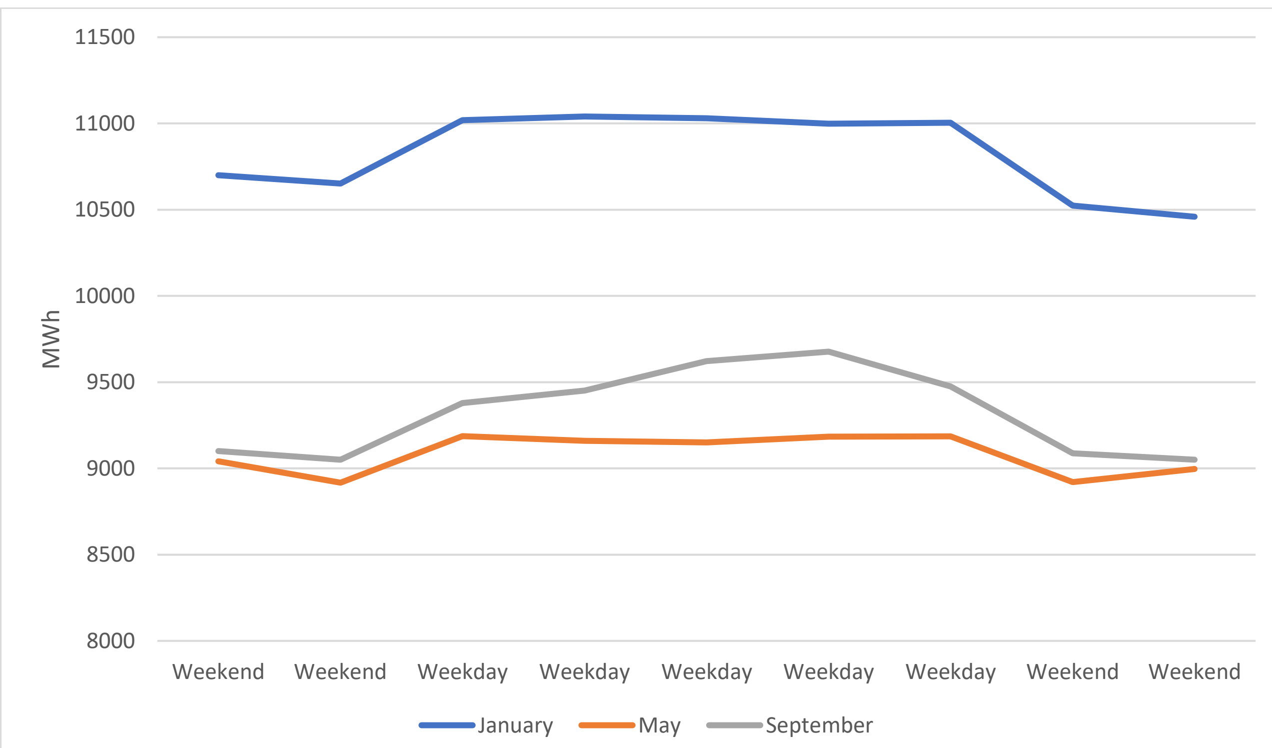

Figure 46 Weekly Variation in Electricity Demand

The Alberta electricity grid is largely dependent on natural gas, around 65 to 70%, and this trend has recently increased with the decrease in share of coal-based power plants due to the government policy of phasing them out by 2030. Natural gas price thus has a prominent effect on the pool price in the Alberta electricity market as shown in the figure 47. For the three preceding years, the level of demand changed by 5-10%, while the average pool price per month increased by 4-5 times in these years.

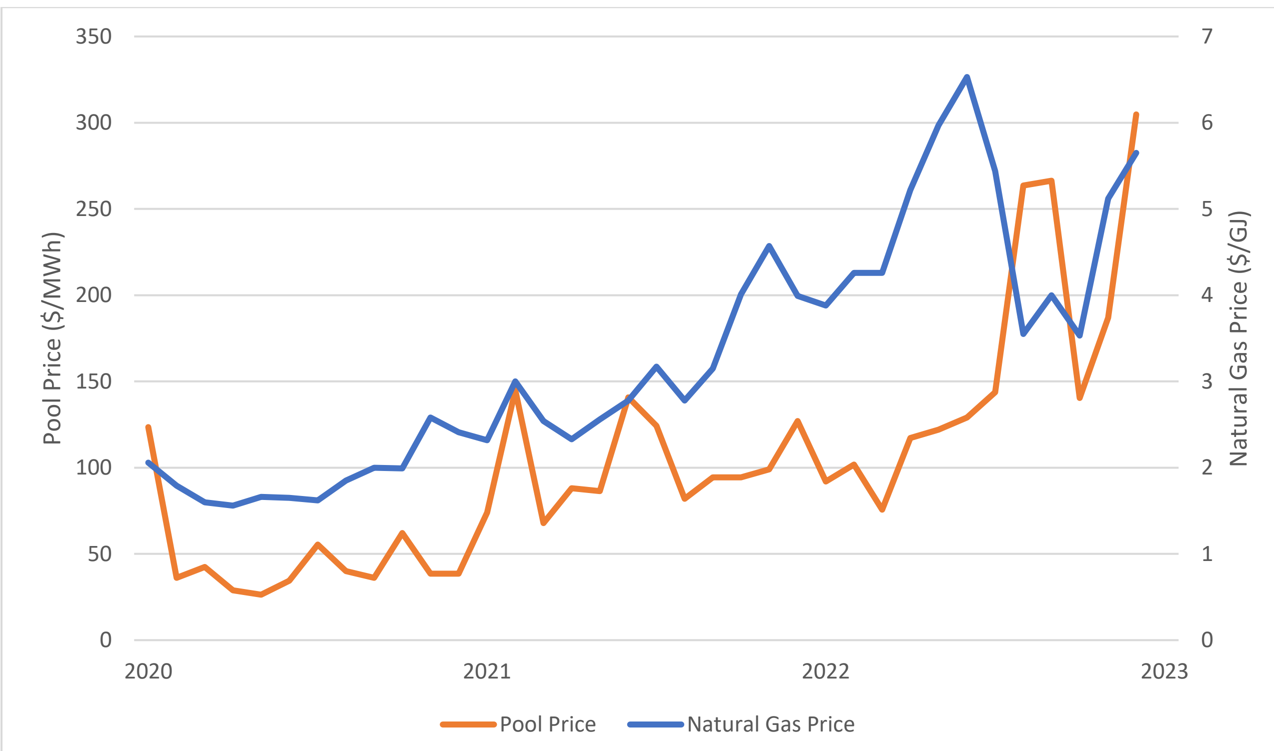

Figure 47 Pool Price vs Natural Gas Price in Alberta

3.5 Net-Zero Scenarios for the Alberta Electricity Grid

The Alberta Electric Systems Operator (AESO) modeled 3 scenarios for achieving net-zero emissions from the electricity sector by 2035 (AESO 2022). The rate of adoption of renewable electricity, thermal electricity, and battery storage varies in each modeled scenario. The scenarios are described briefly below, and the wind and solar energy trends are shown in the figures 48 and 49 below.

1. Dispatchable Dominant Scenario: This involves thermal sources constituting a majority portion of the electricity supply as is the case in Alberta currently. The high emissions will be abated by deploying innovative technologies such as carbon capture at a large scale either by retrofitting existing facilities or installing new electricity plants with these technologies. Renewable energy accounts for around a quarter of the total electricity supply by 2030. Of the three scenarios, the renewable energy added is least here.

2. First-mover Advantage Scenario: This involves scaling up of wind and solar energy while thermal sources act as base load to account for the fluctuation in the electricity supply due to the intermittency of renewables. Solar and wind energy are upscaled at a higher rate than the current trend and lithium-ion battery storage is developed at a moderate rate. Increasing share of renewable energy is accompanied by the phasing out of fossil fuel based producers of electricity. About 30% of Alberta's electricity requirements come from renewable energy in this scenario.

3. Renewables and Storage Rush Scenario: There is aggressive adoption of wind and solar energy over the next decade along with limited deployment of thermal energy. There is increased adoption of battery storage to account for intermittent supply from renewable sources.

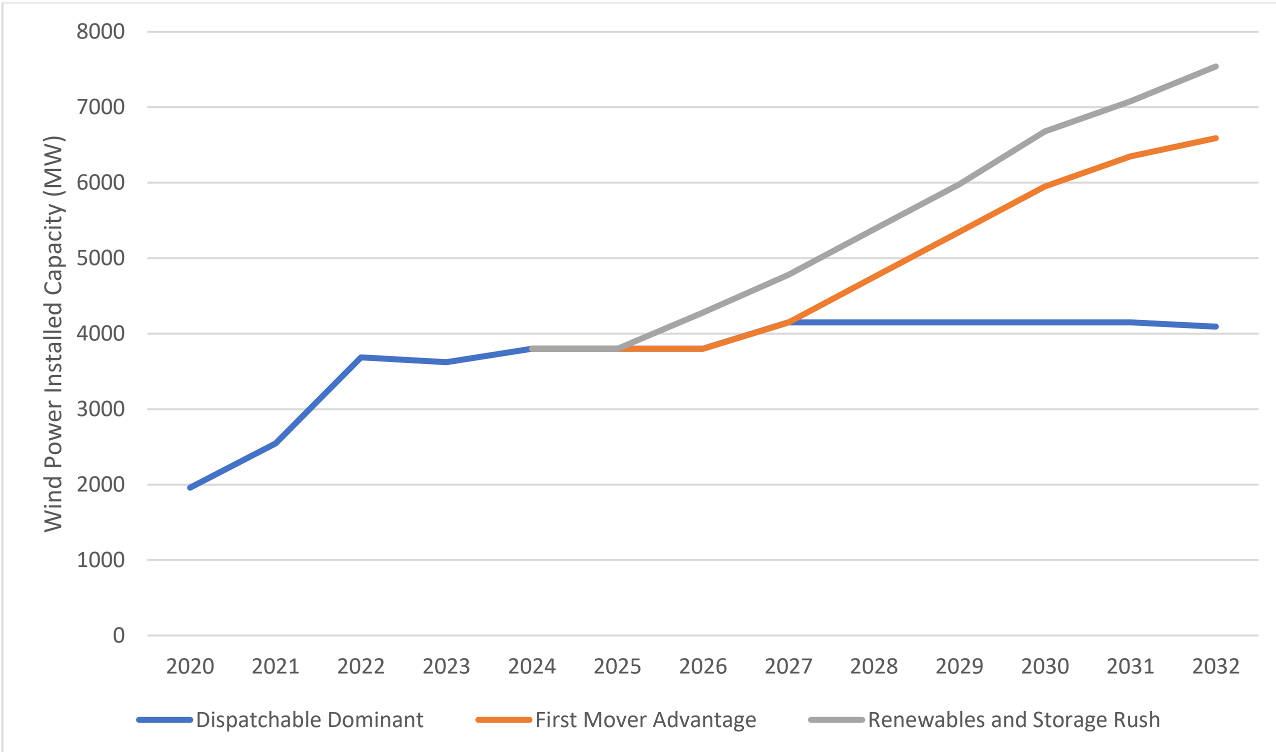

Figure 48 Wind Capacity Forecasts for the Three Scenarios

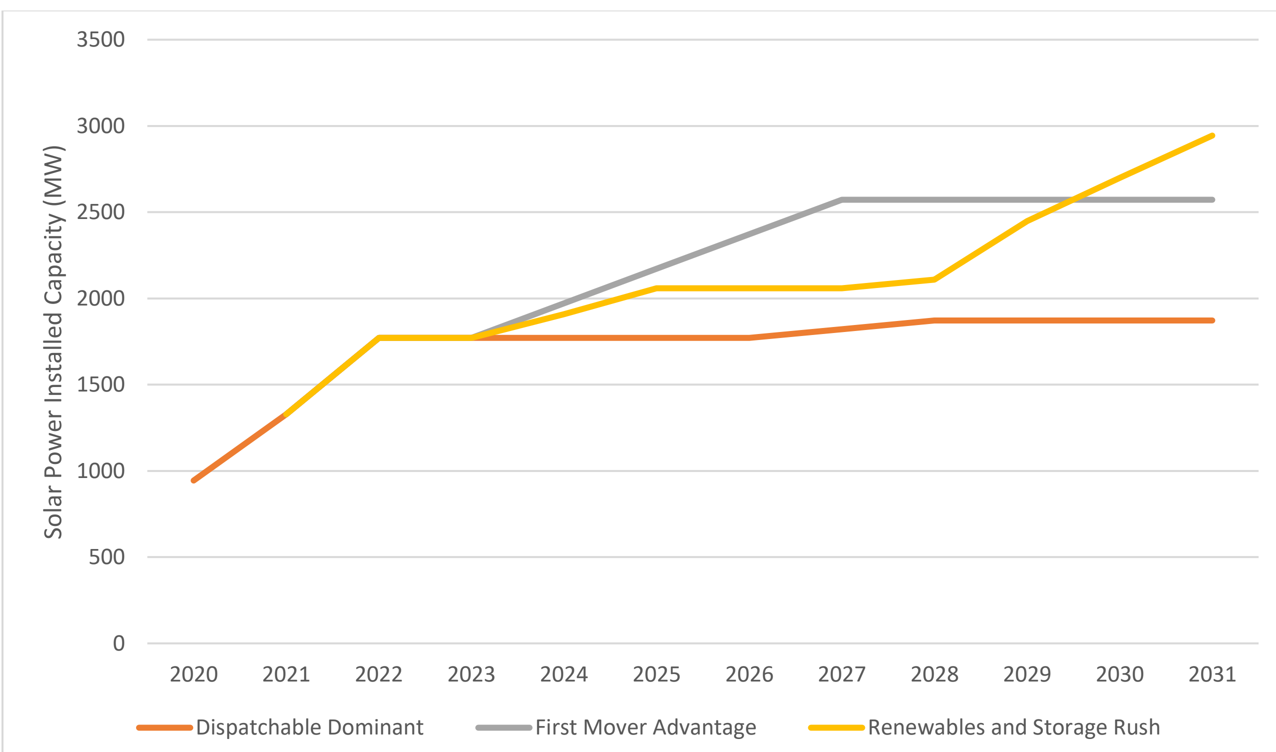

Figure 49 Solar Energy Capacity Forecasts for the Three Scenarios

3.6 Methodology

3.6.1 Price Forecast and Parameter Estimation

For this study, the pool price for the next decade was forecasted using a log linear regression analysis in the form:

$$\ln PP = A(Demand) + B\ln(NG) + C$$

Where,

PP is the hourly pool price

NG is the Natural Gas Price

A, B are parameters determining the dependency of the pool price on demand and the natural gas price respectively

C is a constant

The regression analysis was run on yearly pool prices for the last three years. The demand varied due to the season, month, time of day, weekday, and the weekend. The average monthly natural gas prices in Alberta were used and there was a marked increase in the natural gas prices due to external factors such as the pandemic and the war in recent years. The regression parameters are averaged and the plotted results for two of the analyzed months are shown below in figures 50 and 51.

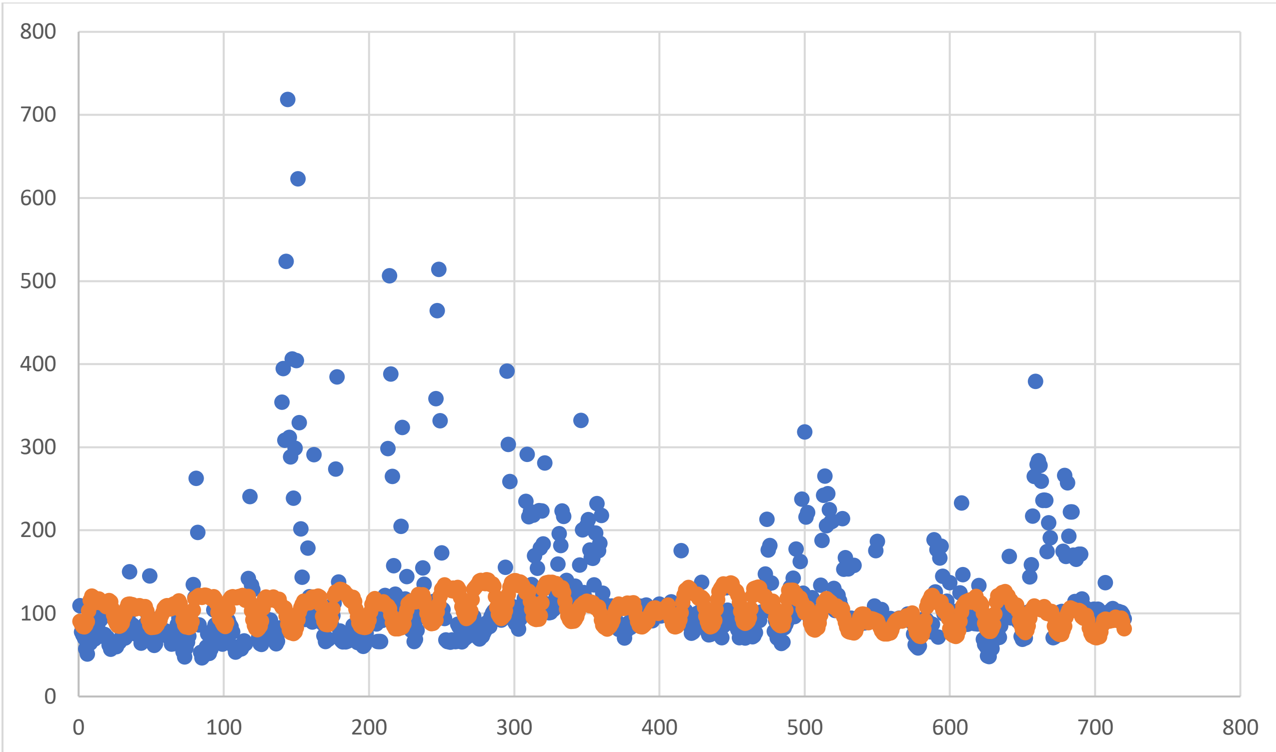

Figure 50 Regression Analysis

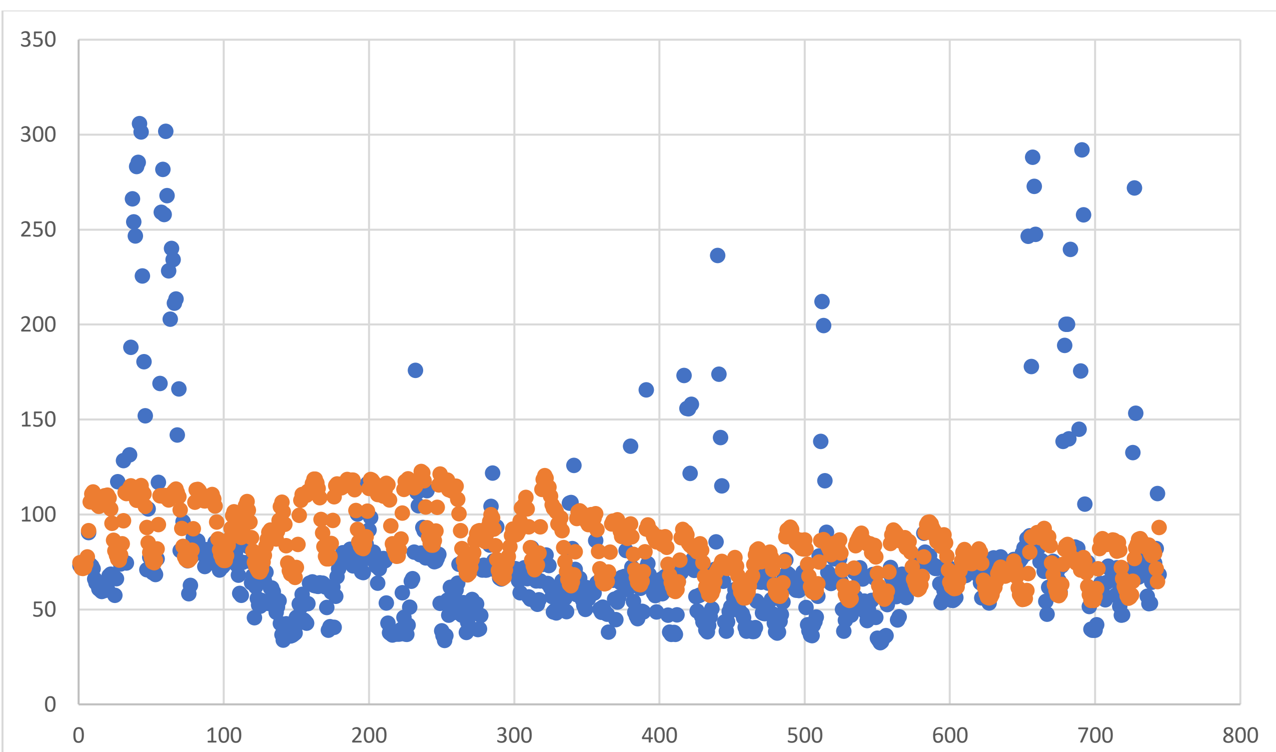

Figure 51 Regression Analysis

As can be inferred from the figures above, the calculated results show a good match with the actual pool prices during the months shown. There are a few outliers in the actual prices due to a highly dynamic supply demand market having pool price set hourly.

The future price projections are based on the above regression analysis. AESO has projected the load on Alberta grid for the next decade with an average increase of 0.5% compounded year on year (AESO 2021). The Alberta Energy Regulator (AER) has forecasted the natural gas price trends based on domestic demand, exports and market access and has defined three price cases low, medium, and high as shown in the figure 52 (AER 2023).

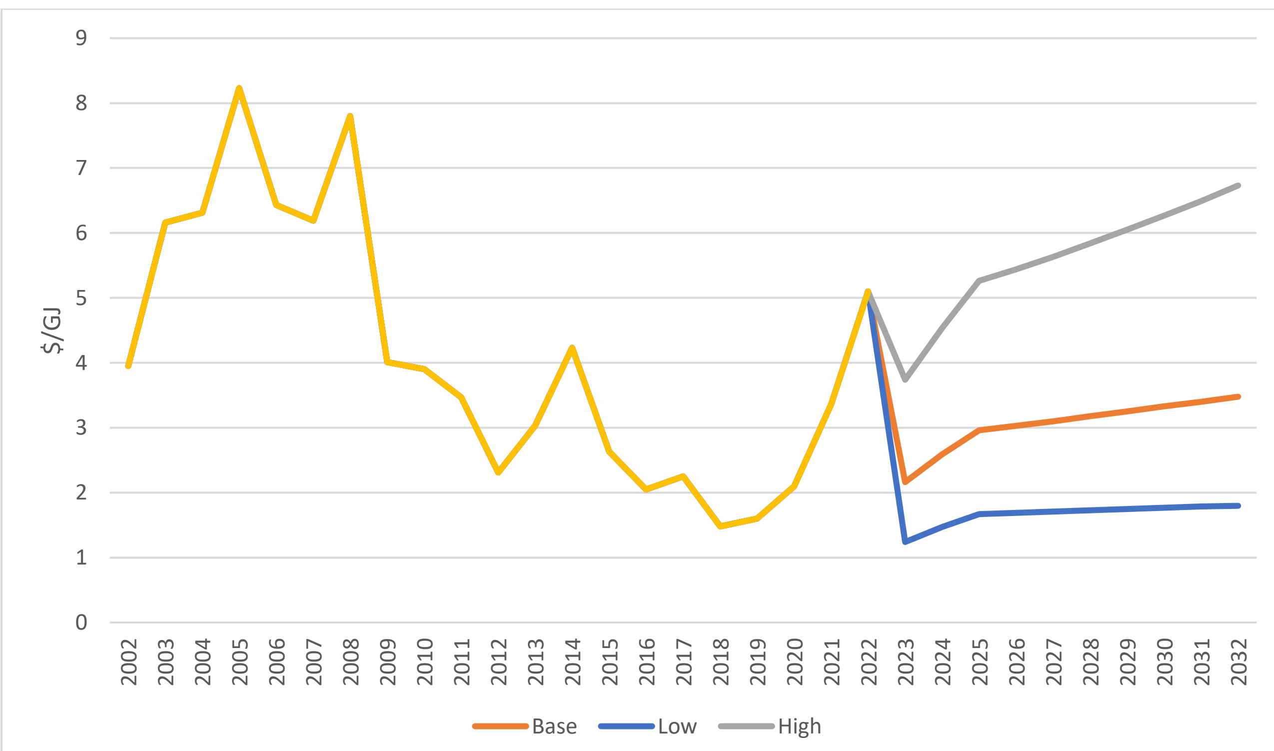

Figure 52 Natural Gas Price Forecasts, Data from Alberta Energy Regulator

Low-cost renewable energy - solar and wind, is used to produce green hydrogen in Alberta. The proposal consists of behind the meter curtailment of electricity wherein renewable energy producers sell the electricity to green hydrogen generators during periods of low electricity prices on an hourly basis. This reduces the number of hours of curtailment of clean energy in an electricity grid with an expanding share of renewable energy such as Alberta. Additionally, the diverted electricity produces clean hydrogen which can further reduce the carbon footprint of industries which use hydrogen as an input such as oil and gas. The green hydrogen producers can further avail the rebates available to decrease the overall cost of green hydrogen and bring it on par with conventional fossil fuel based hydrogen.

Three price thresholds are assumed which are- $30/MWh, $40/MWh, and $45/MWh based on analysis of past pool prices and future price forecasts. When the market price of electricity falls below these thresholds, the renewable energy generated is used to produce green hydrogen.

Two types of electrolyzers are used to produce this hydrogen, the alkaline electrolyzer cell (AEC) and the proton exchange membrane (PEM). The AEC type of electrolyzers are the most widely used current technology made with widely available materials (IEA 2023). They have limited tolerance for variability in power supply and operating pressure but have the maximum efficiency. PEM electrolyzers require a greater amount of energy to produce a unit of electricity and currently have a lower capacity factor. But they can operate at lower loads and tolerate more variable loads (Lehner et. al., 2014). They are expected to be the major source of producing green hydrogen by the end of this decade in terms of economics and performance. The expected costs of setting up and operating these two types of electrolyzers over the next decade are shown in figure 53.

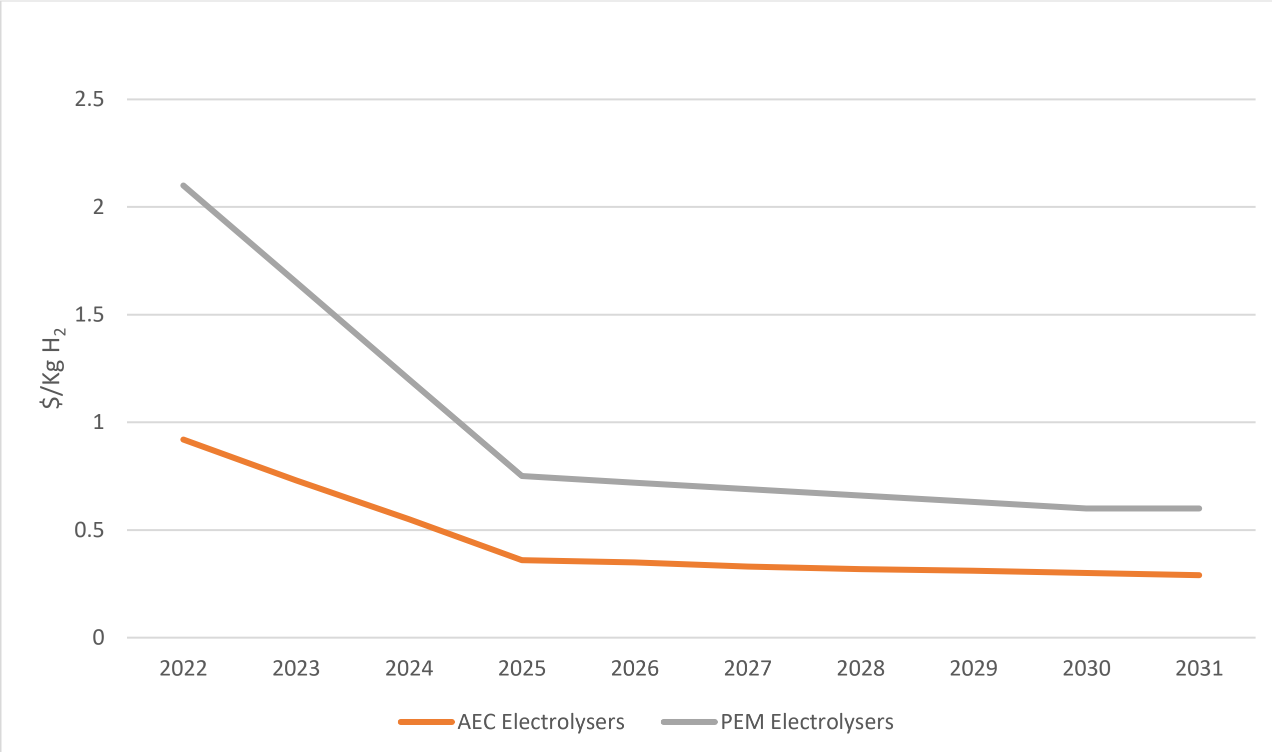

Figure 53 Electrolyzer Cost/Kg H_2 Trends

3.7 Comparison with natural gas-based hydrogen produced by Steam Methane Reforming (SMR)

Natural gas based hydrogen production forms a majority of the total supply of hydrogen in Alberta with the share around 80% from 2020-2023 (AER 2023). Globally, around 62% of the total hydrogen production comes from the SMR process (IEA 2022). The process consists of desulfurization of natural gas followed by pre-reformation with steam which converts it into methane and syngas. This mixture is then reformed, and heat is provided which gives out hydrogen and carbon dioxide.

The natural gas price is the major determining factor in the cost of Grey and blue hydrogen which is Grey hydrogen accompanied with carbon capture and storage (IEA 2023). The relation between natural gas price and the cost of hydrogen was calculated by performing a regression analysis on the regional gas and hydrogen prices in the US forecasted in 2050 (Ruth et. al. 2020). For our model, future hydrogen costs are based on the natural gas forecast shown above and the regression equation here. The figures 54 and 55 show this relationship and the regression results respectively.

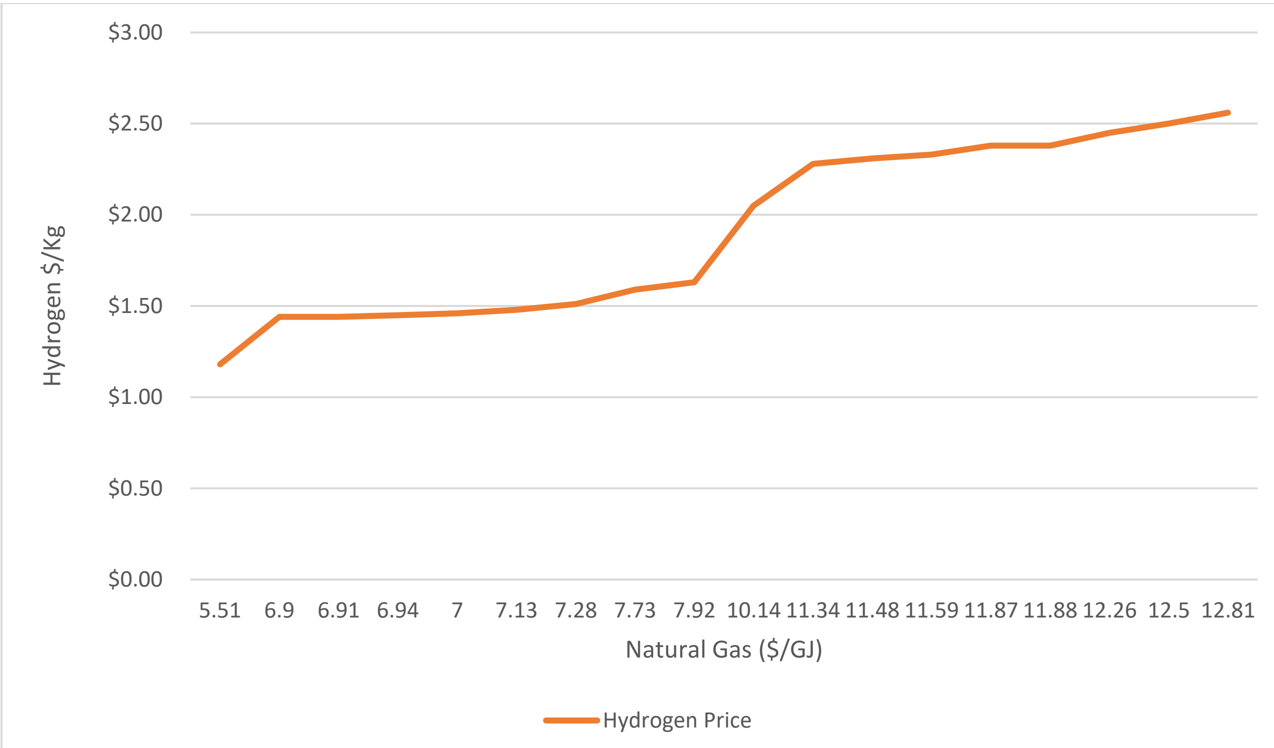

Figure 54 Hydrogen Price vs Natural Gas Price

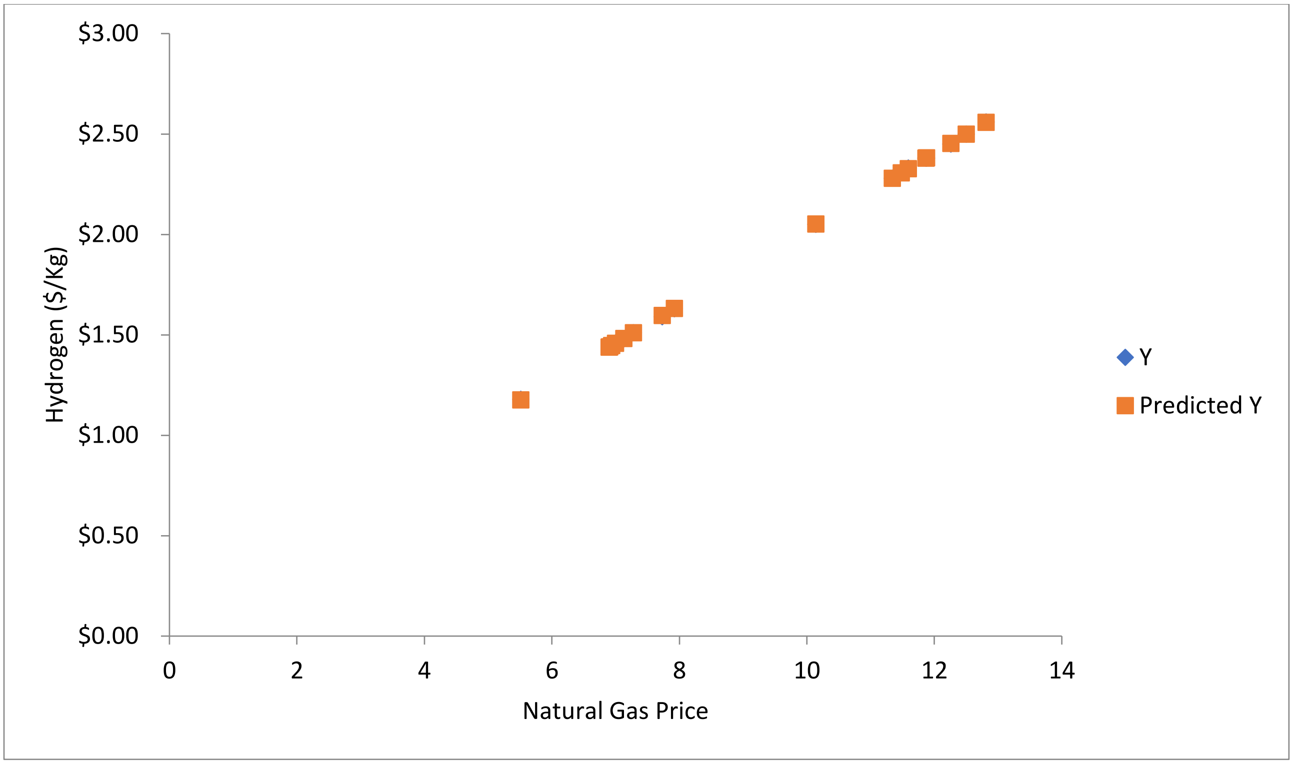

Figure 55 Line Fit Plot

The line fit plot shown above has a coefficient of determination (R^2) value of 0.999965 and is thus a good fit. The equation is calculated as:

$$Hydrogen\ (\$/Kg) = 0.189319 \times Natural\ Gas\ (\$/GJ) + 0.132725$$

3.8 Results and Analysis

3.8.1 Hours Curtailed

The total hours curtailed monthly in 2021 is shown in the figure 56. The highest number of curtailed hours is in the spring and summer seasons from March to July with a progressive reduction thereafter. November and December account for the least hours of low-cost electricity available with an average of 50-100 hours monthly.

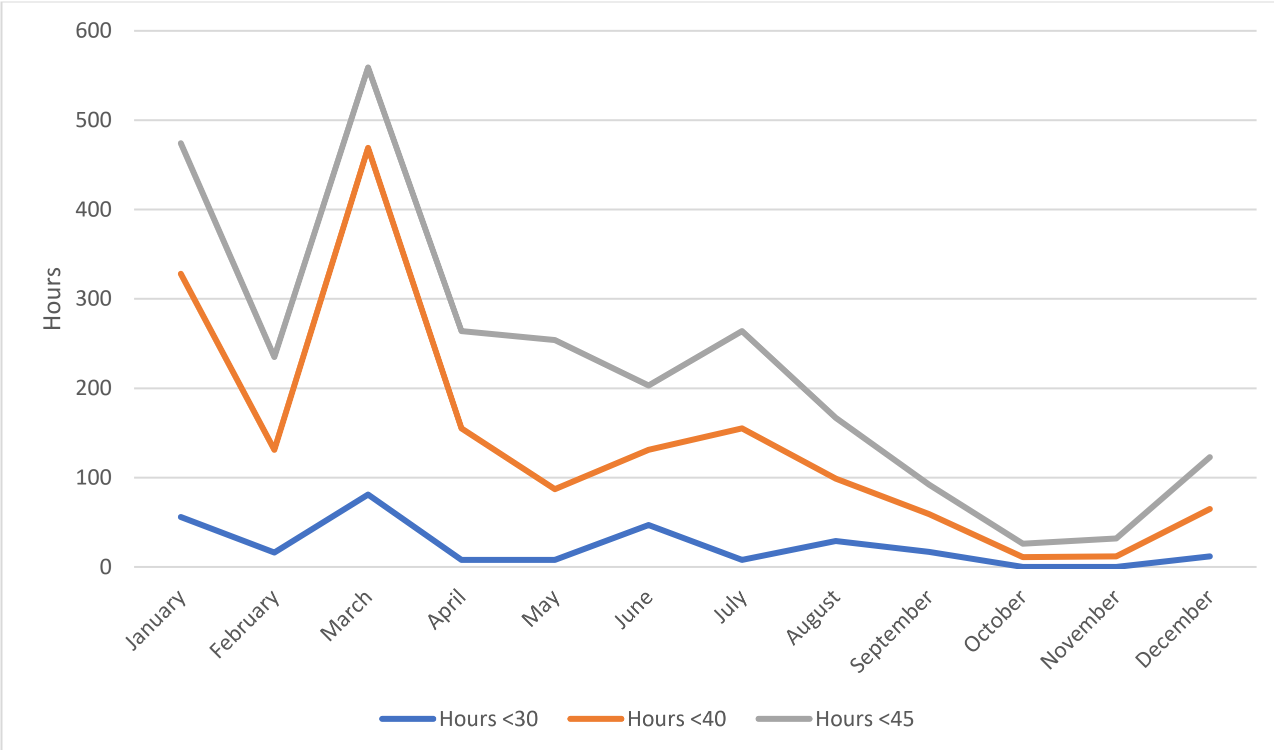

Figure 56 Monthly Curtailment Hours 2021

The following figures 57 and 58 show the curtailment hours for 2027 and 2032. A similar trend is observed in these years and intervening years with highest and lowest curtailment in the summers and winters respectively with an average curtailment of approximately hundred hours per month.

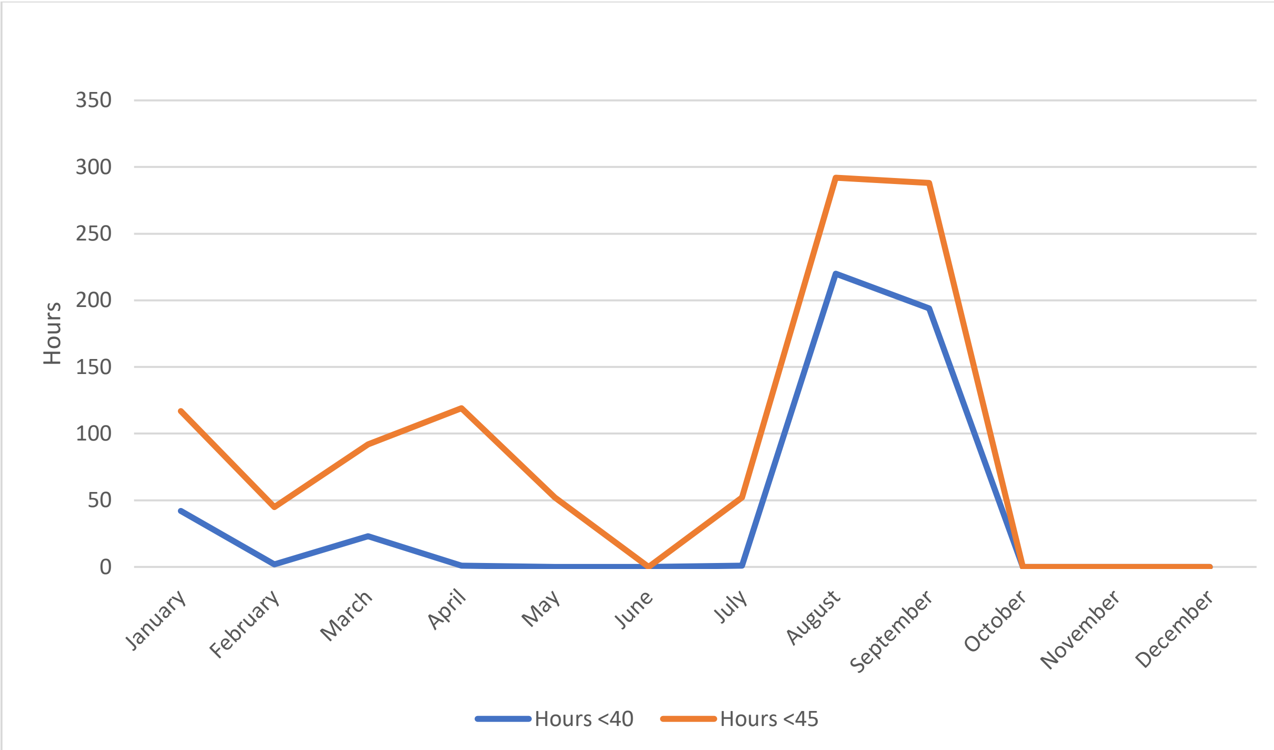

Figure 57 Monthly Curtailment Hours 2027

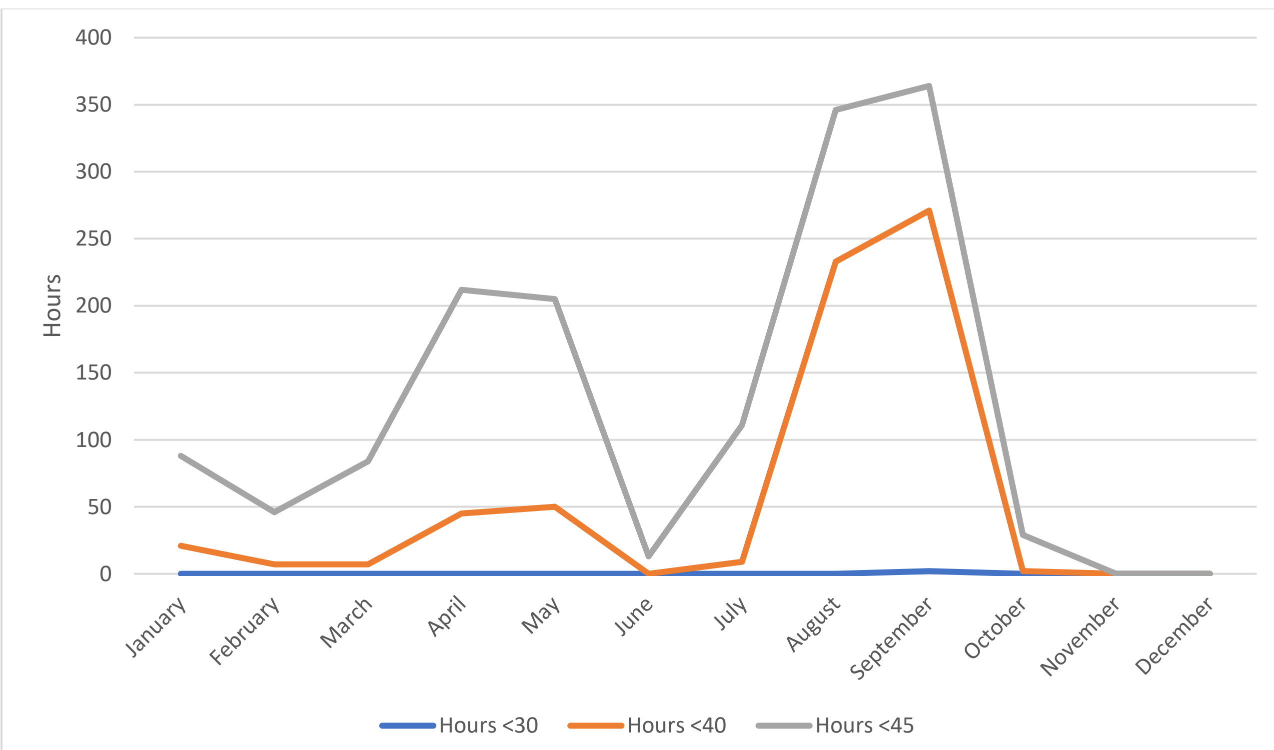

Figure 58 Monthly Curtailment Hours 2032

Figure 59 shows the total curtailment hours for each of the years under the three price thresholds. The peak in 2023 is due to low natural gas prices relative to 2022. The market prices are lower by almost 50% in 2023 compared to 2022 for the month of January to June. For the rest of 2023, forecasted natural gas prices are used which are also approximately 50% of the prices in 2022 and 65% of the prices in 2021. In later years, the annual curtailment is between 500-1000 hours with an increasing trend after 2028 of about 10% annually till 2032.

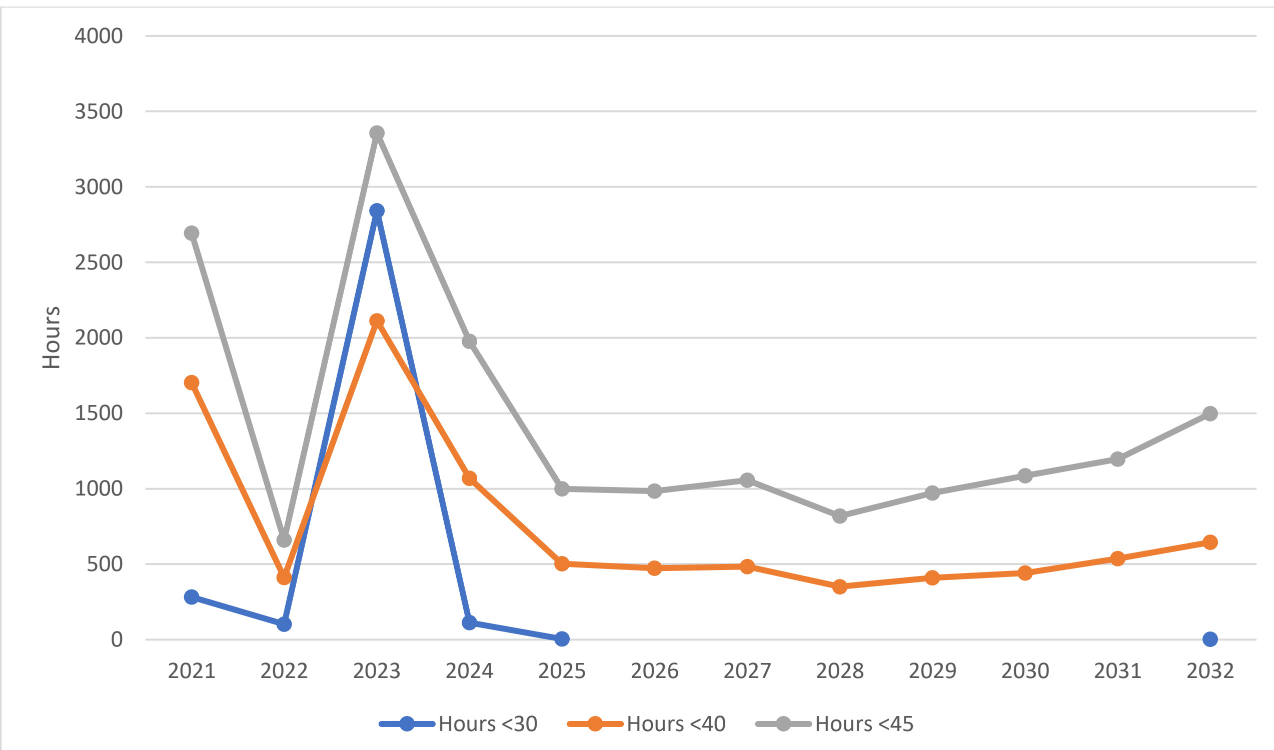

Figure 59 Total Annual Curtailment Hours

3.8.2 Energy Curtailment

Wind and solar energy curtailment analysis is based on the pool prices and thresholds described in the pervious sections. The curtailment in the initial years is based on provincial data and future projections are done according to the models defined. The results for volume of potential energy curtailed are given below. Figures 60 and 61 how the monthly wind and solar curtailment in the 2021.

The results show that curtailment during the months of May to July is driven by lower load on the grid and relatively lower natural gas prices. While in the winter the demand (load) on the grid is higher, the greater capacity factor of wind energy during these periods drives the capture of lower cost renewable electricity owing to much higher total installed capacity. The total number of hours curtailed vary from almost no hours due to high pool price to more than 500 hours in some months such as March 2021.

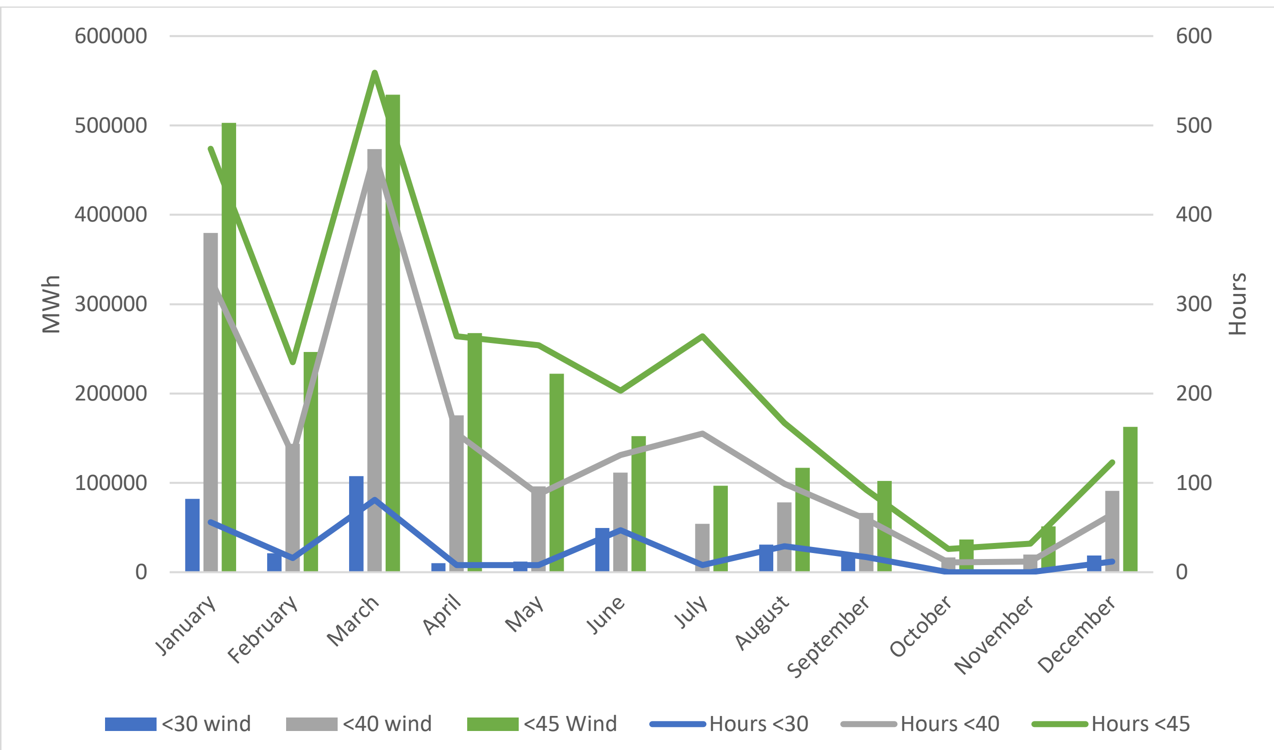

Figure 60 Wind Energy Volume 2021 and Number of Hours Curtailed

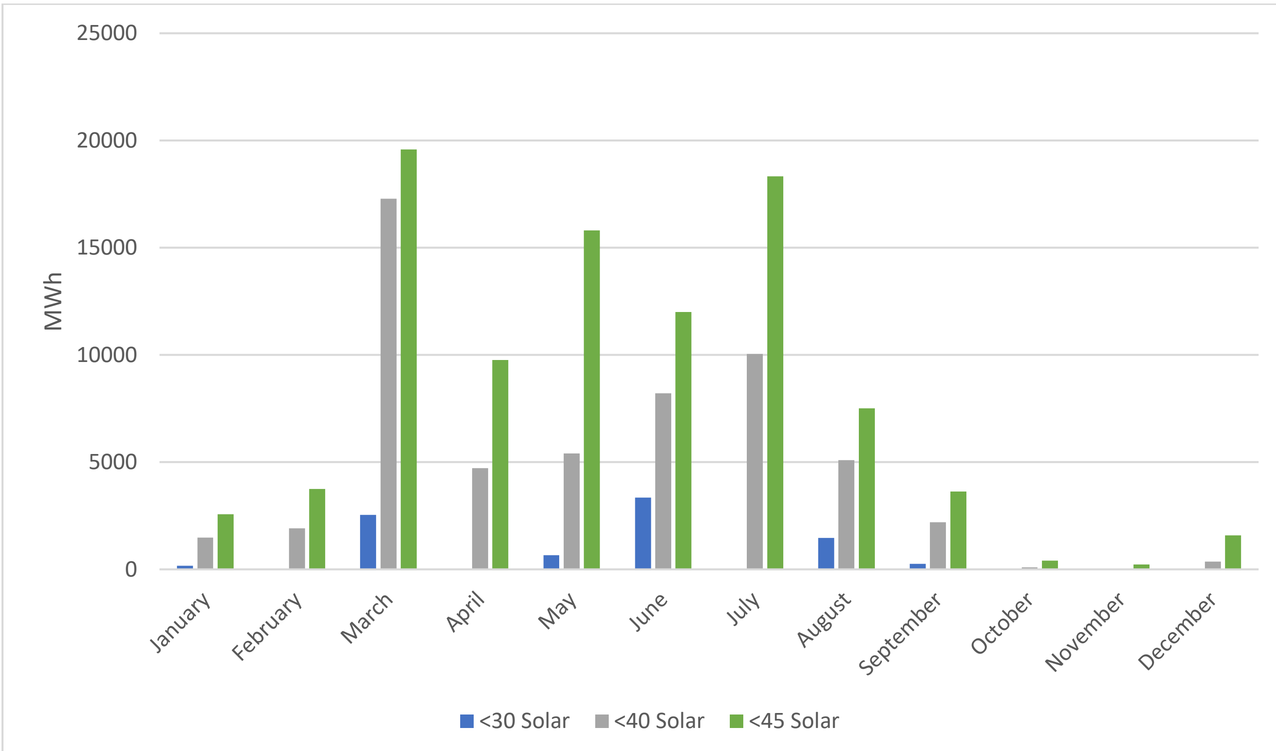

Figure 61 Solar Energy Volume 2021

By 2027, the curtailment of renewables below dollar 30 per MW hour is restricted to a lower number of months during the year. The highest curtailment is in the months of July to September while winter months have no low-cost electricity due to higher demand and natural gas prices. Figures 62 and 63 show this monthly variation.

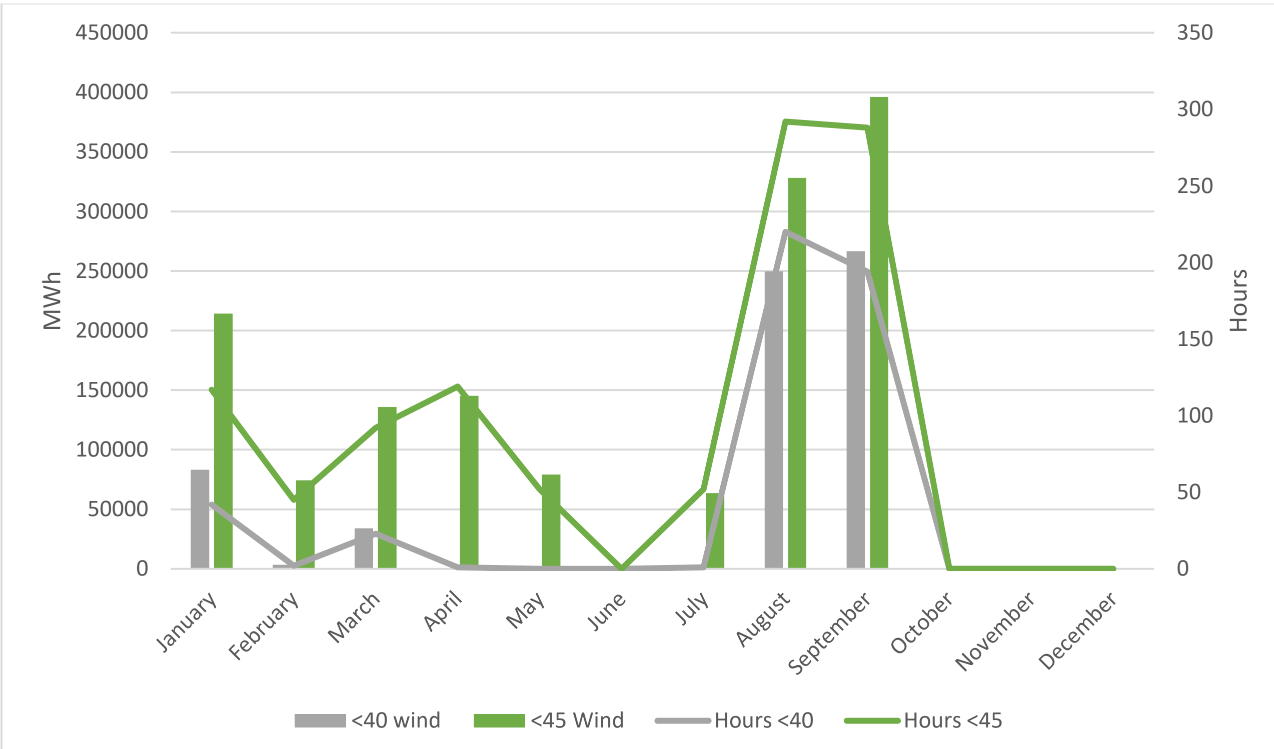

Figure 62 Wind Energy Volume 2027 and Number of Hours Curtailed

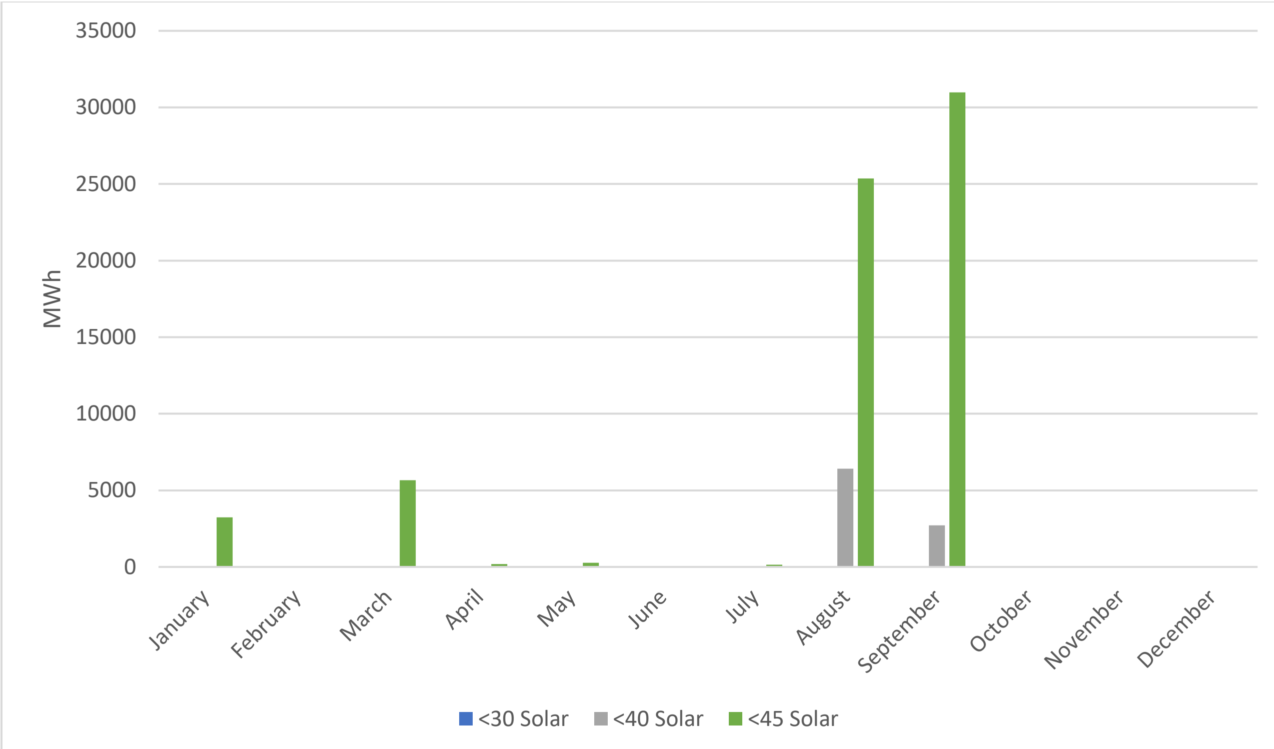

Figure 63 Solar Energy Volume 2027

In 2032, the curtailment volume increases due to an increasing share of renewables in the grid and also due to a lower dependence of the pool price on natural gas costs, there is a possibility of low-cost renewables curtailment throughout the year. Figures 64 and 65 show this trend.

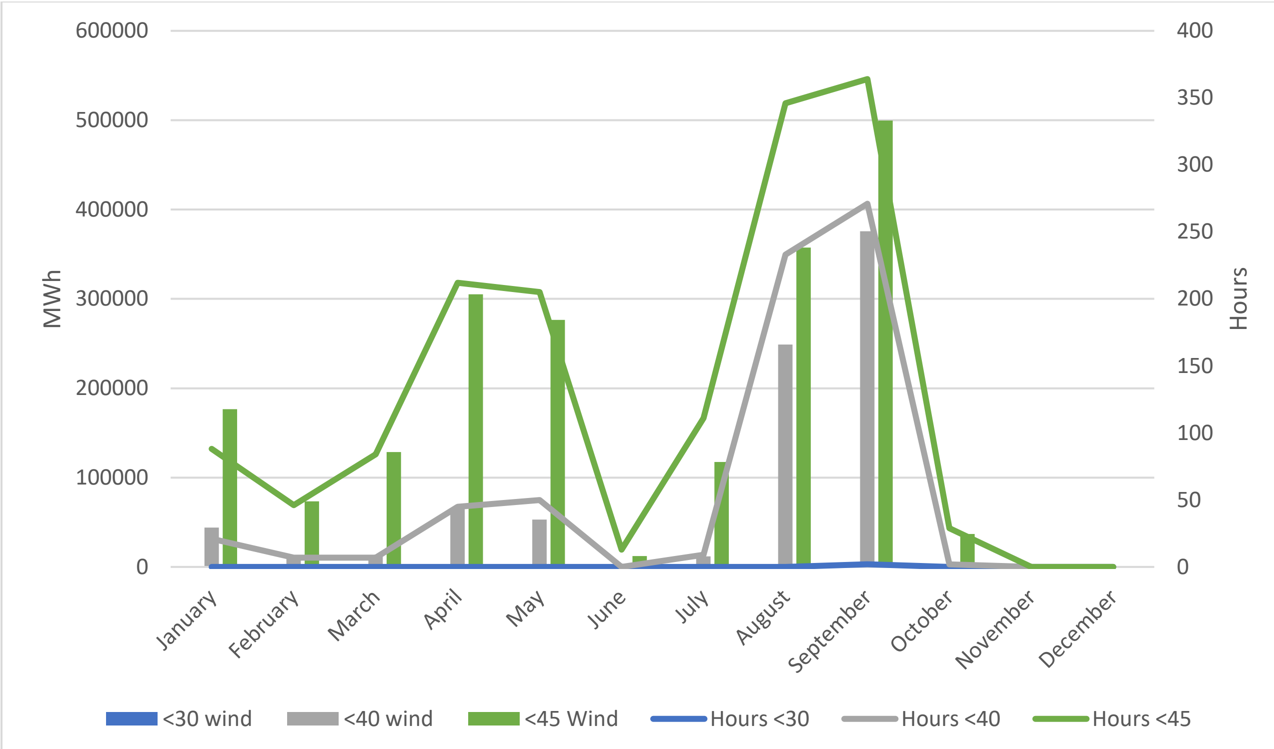

Figure 64 Wind Energy Volume 2032 and Number of Hours Curtailed

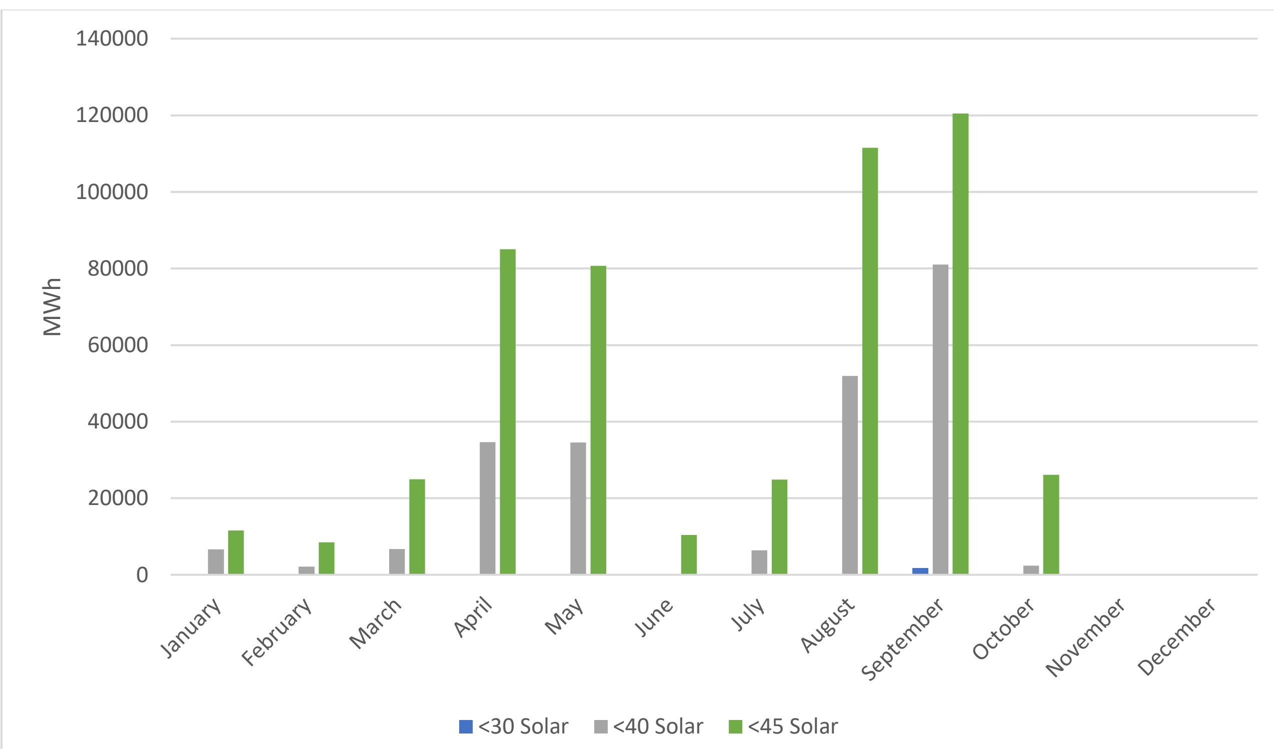

Figure 65 Solar Energy Volume 2032

The graphs comparing all the scenarios are shown in the figures 66, 67, 68, and 69. These show the total curtailment in each year for the three scenarios for all the modeled years till 2032. The overall trend for both wind and solar energy is a progressive increase in the amount captured with solar energy seeing exponential growth due to a massive increase in the installed base over the next decade. The axes on the left show the share of curtailed energy in the total supply of renewables in each year. Around 7-8% and 10-15% wind energy is curtailed per year for the $40 and $45 threshold respectively. The percent of solar energy curtailed is lower- in the range of 4-5% and 8-10% for the two price thresholds. This is due to the daylight hours of production of solar energy coinciding with higher demand and no solar energy production during the night when demand goes down.

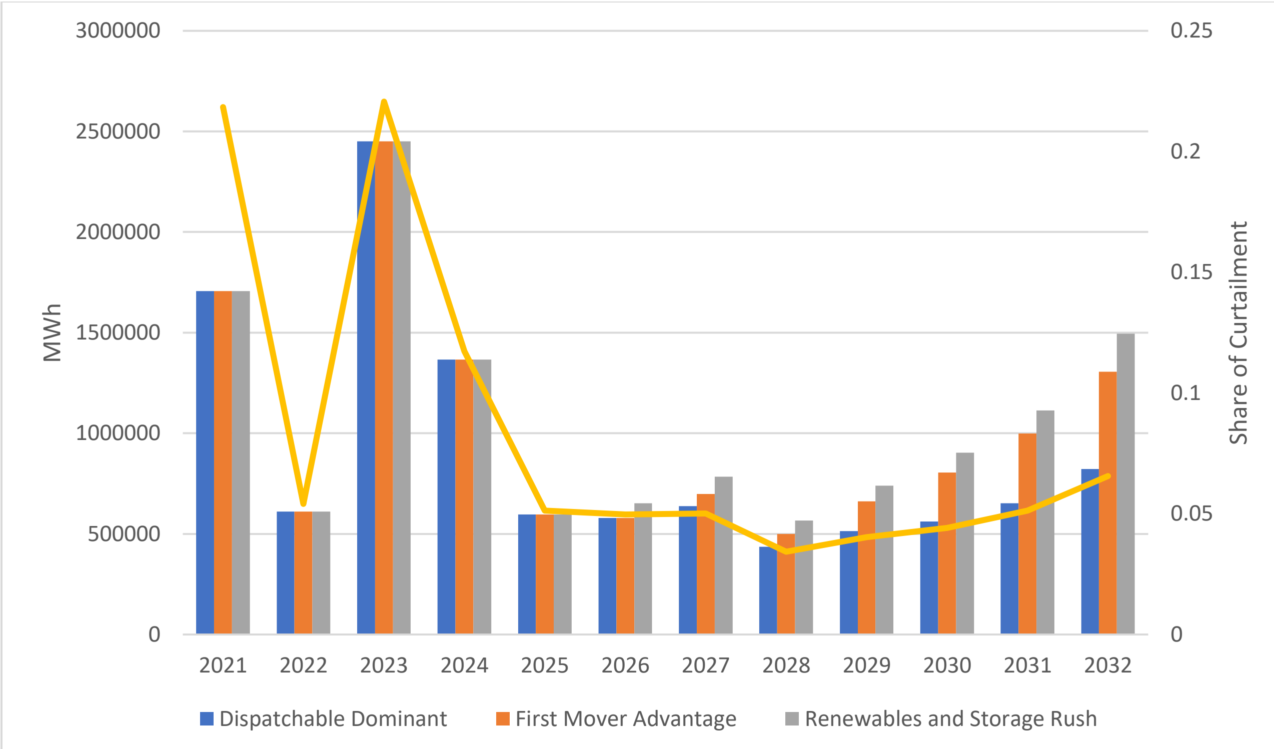

Figure 66 Wind Energy Volume (<$40) Curtailed (MWh)

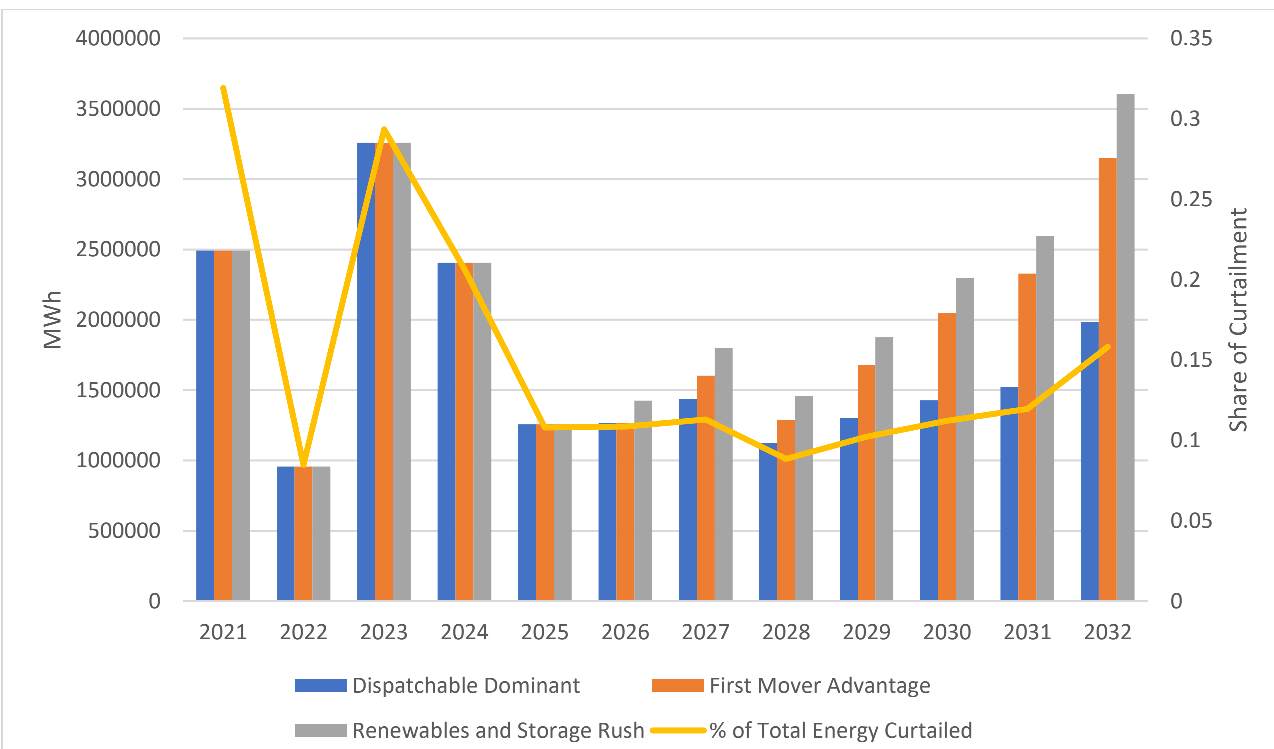

Figure 67 Wind Energy Volume (<$45) Curtailed (MWh

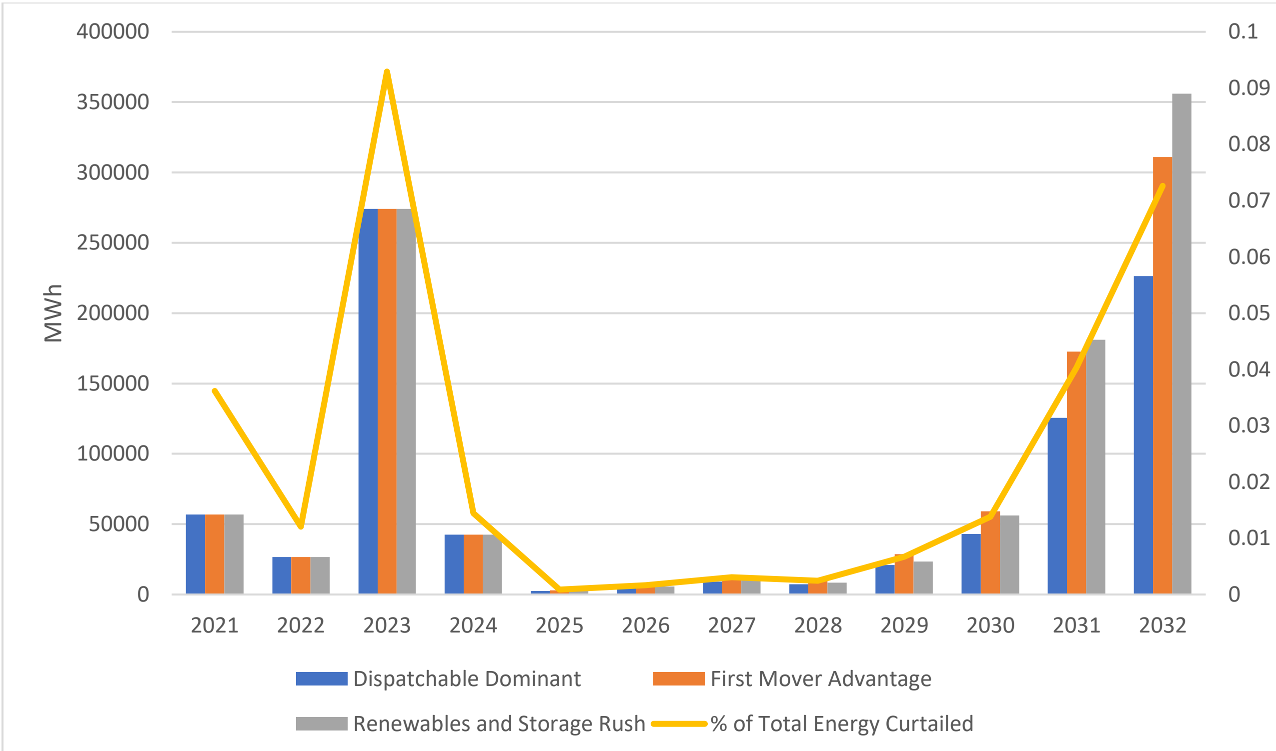

Figure 68 Solar Energy Volume (<$40) Curtailed (MWh)

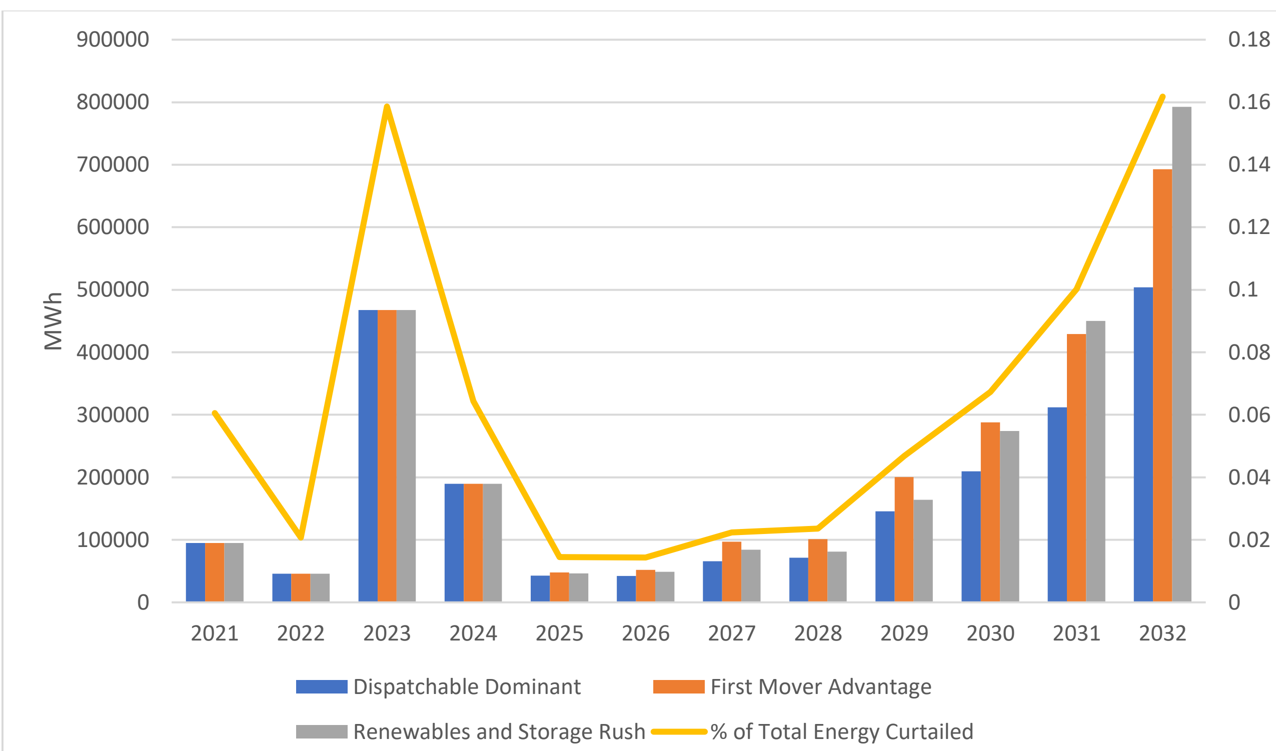

Figure 69 Solar Energy Volume (<$45) Curtailed (MWh)

3.8.3 Hydrogen Production

The results from dispatchable dominant scenario, where the majority of the grid is still powered by fossil fuel sources is shown in the figures 70 and 71. Annual hydrogen production is 50,000 to 80,000 tonnes in the initial years followed by a decrease to an average of 20,000 to 30,000 tonnes for both the electrolyzer technologies. The yearly production rises to an average of 40,000 tonnes in the last three years.

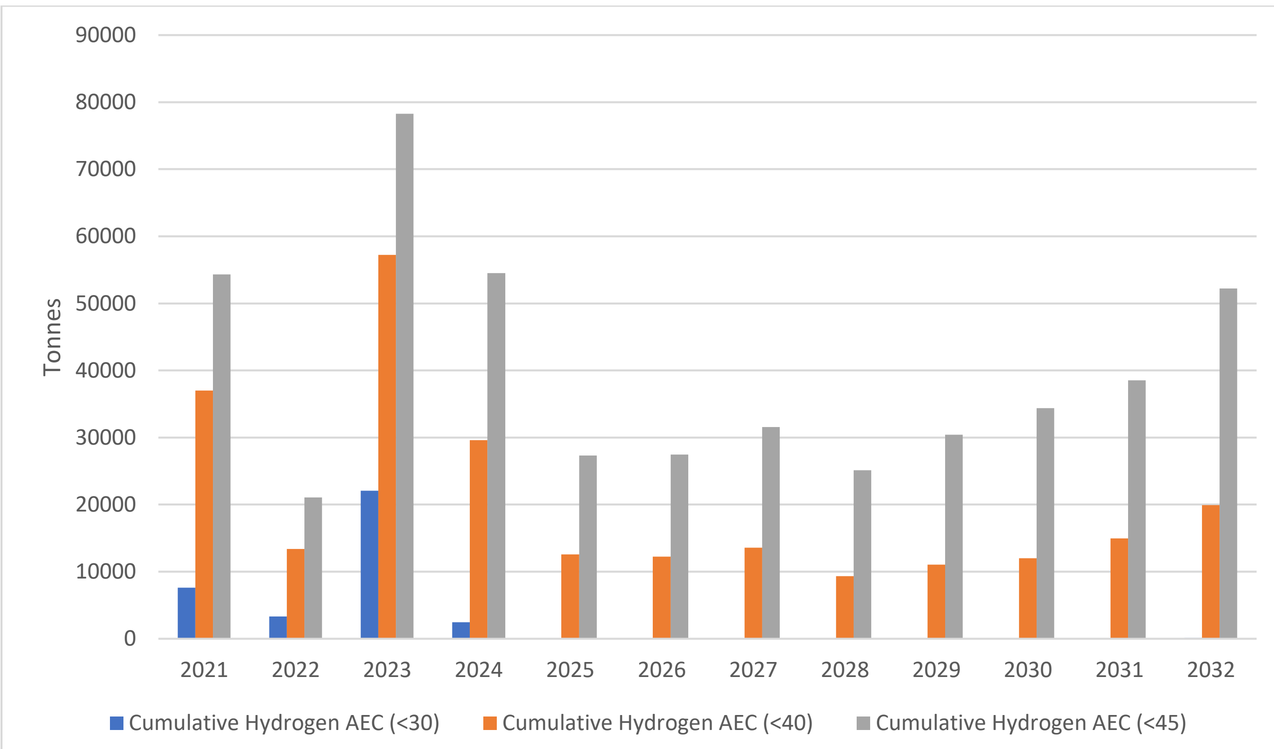

Figure 70 Annual Production- Dispatchable Dominant in an Alkaline Electrolyzer

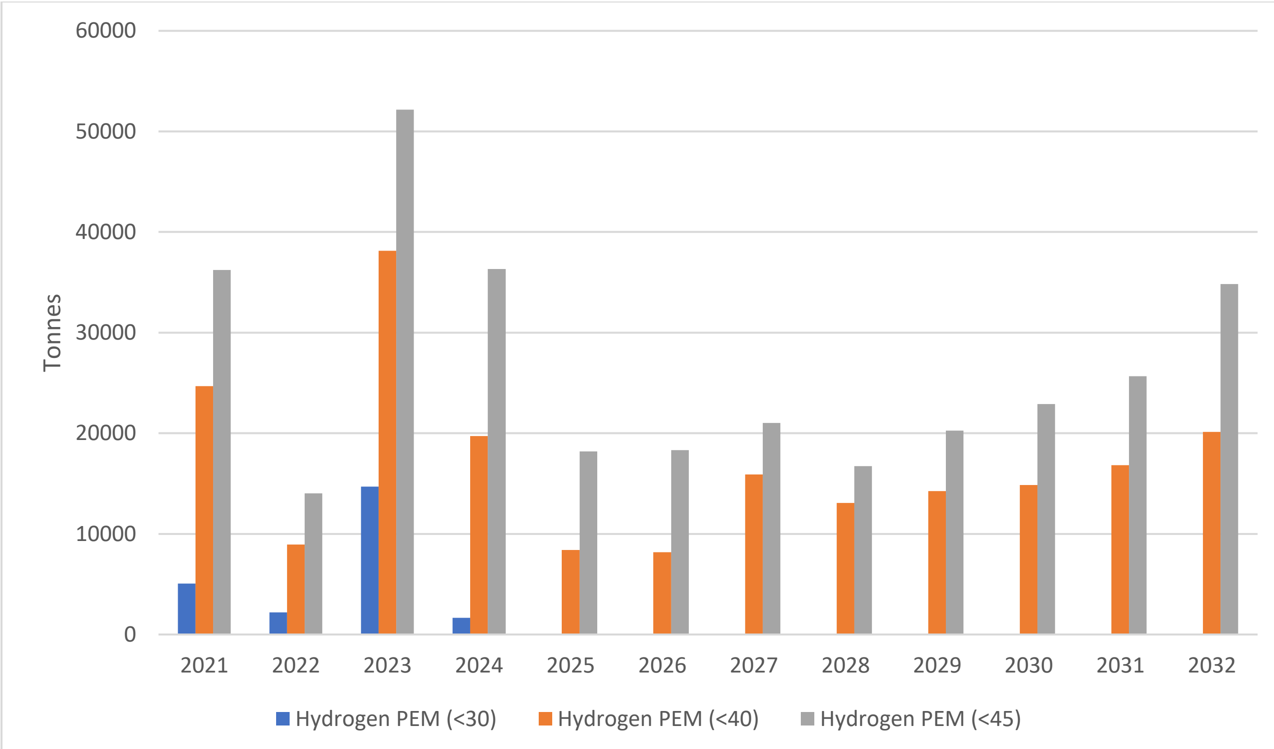

Figure 71 Annual Production- Dispatchable Dominant Proton Exchange Membrane

The First Mover Advantage scenario achieves a low emission grid through scaling up of renewable energy in Alberta. The results from this scenario are shown in the figures 72 and 73. For alkaline electrolyzers, annual production goes up to 80,000 tonnes in three years 2023,2024, and 2032. The remaining years have a production of 40,000 to 50,000 tonnes. PEM electrolyzers require more electricity to produce a unit of hydrogen. Therefore, the production maximum for PEM is 50,000 tonnes with an average of 30,000 tonnes in the intervening years.

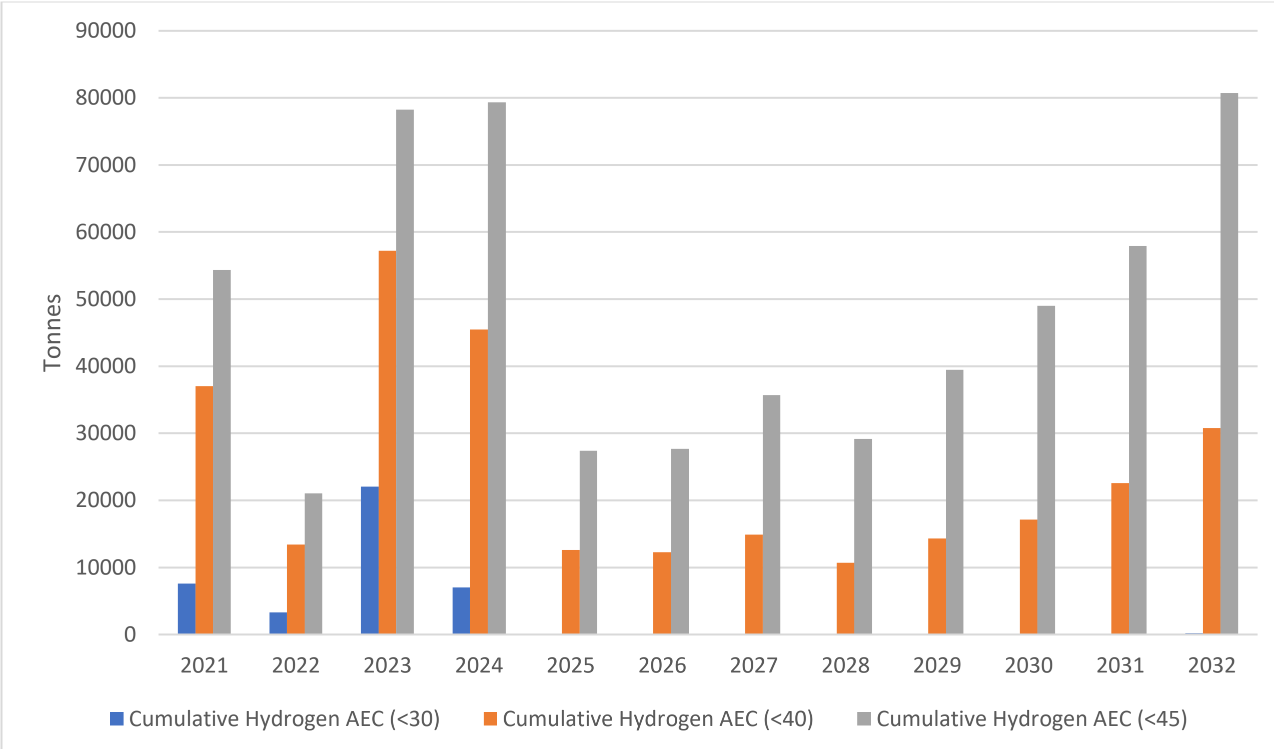

Figure 72 Annual Production- First Mover Advantage AEC

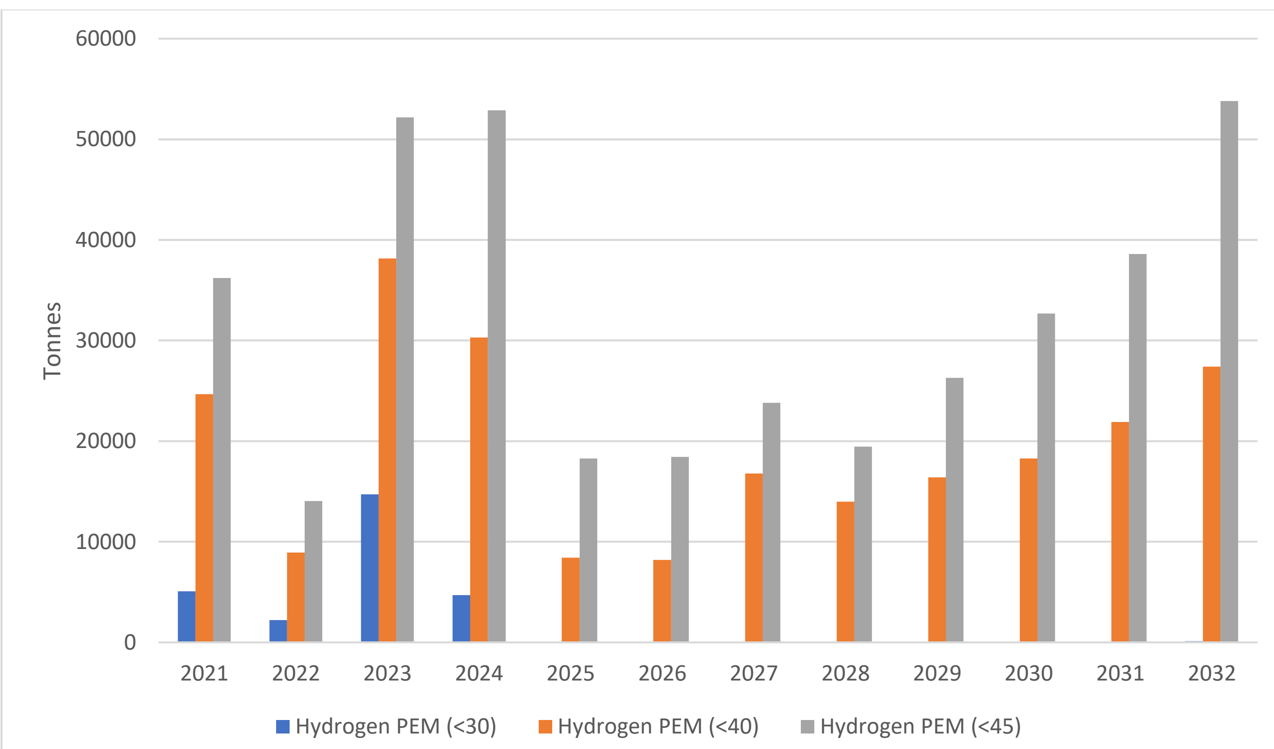

Figure 73 Annual Production- First Mover Advantage PEM

The third scenario, Renewables and Storage Rush has the highest installation of renewable energy among three scenarios. The hydrogen production in the lower price threshold case is an average of 30,000 tonnes per year with a maximum of 50,000 tonnes. In the higher price threshold, the maximum annual production is 92,000 tonnes in 2032 with an average of 50,000 tonnes in the preceding years as shown in figures 74 and 75.

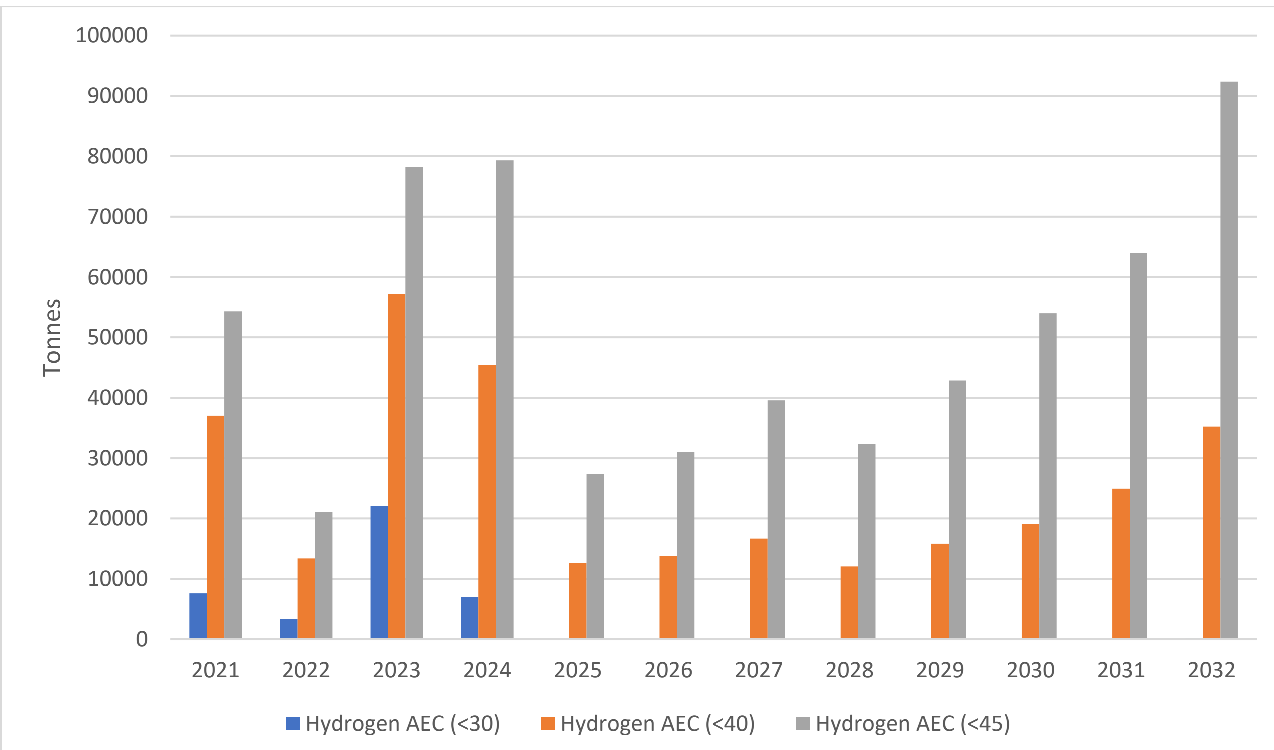

Figure 74 Annual Production- Renewables & Storage Rush AEC

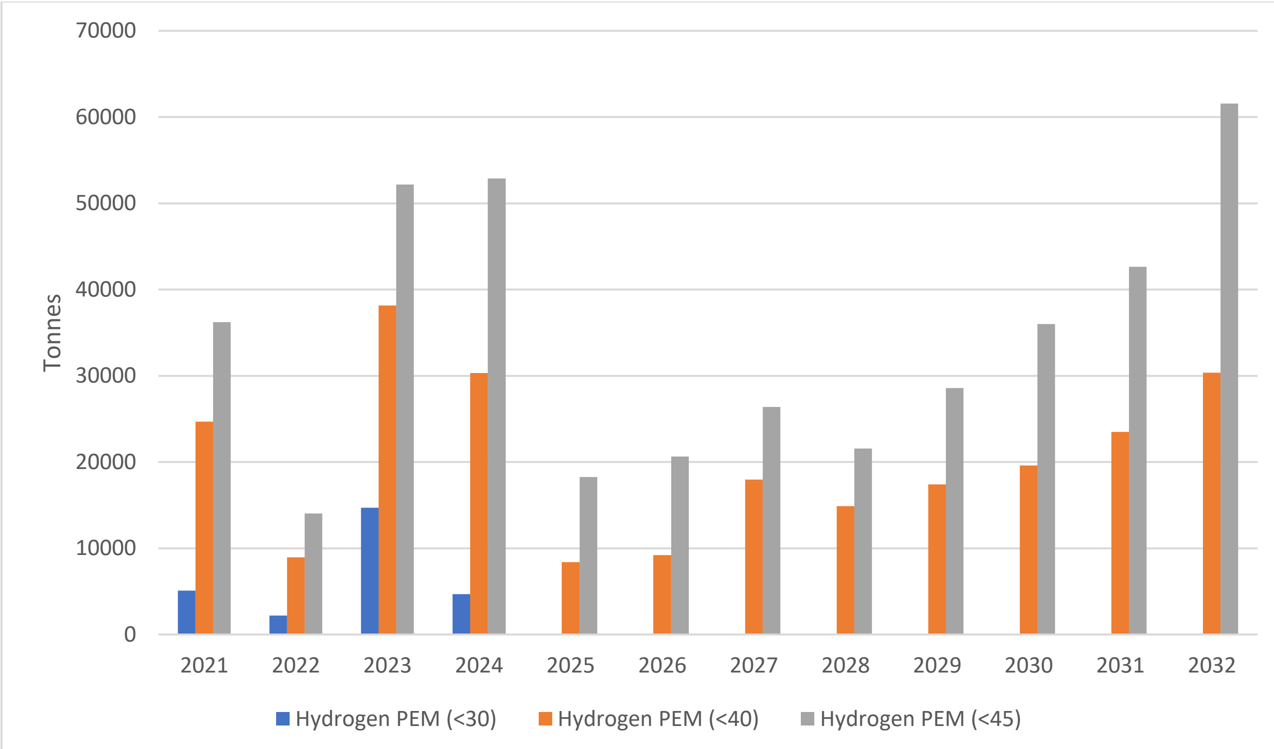

Figure 75 Annual Production- Renewables & Storage Rush PEM

Figures 76 and 77 show a comparison of total hydrogen produced in three scenarios during the modeled years and the share of demand fulfilled for clean hydrogen. Under the $40/MWh price threshold, 3 to 10% of the total clean hydrogen required can be produced from wind and solar curtailment. Capturing renewable electricity under the higher price threshold can meet 6 to 15% of the annual low emission hydrogen demand. This approach does not require the setting of dedicated renewable power plants which increase the initial investment required to establish a clean hydrogen hub.

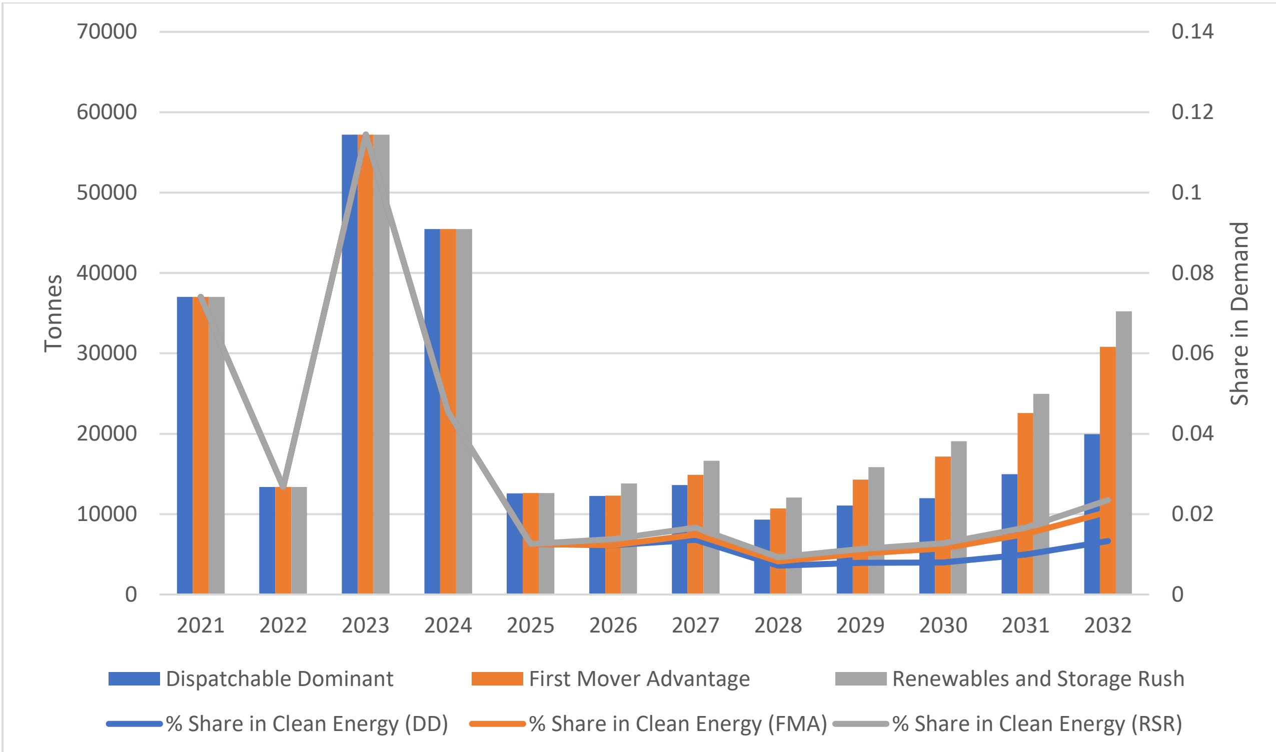

Figure 76 Scenarios AEC (<$40/MWh) and % of Clean Hydrogen Demand Fulfilled

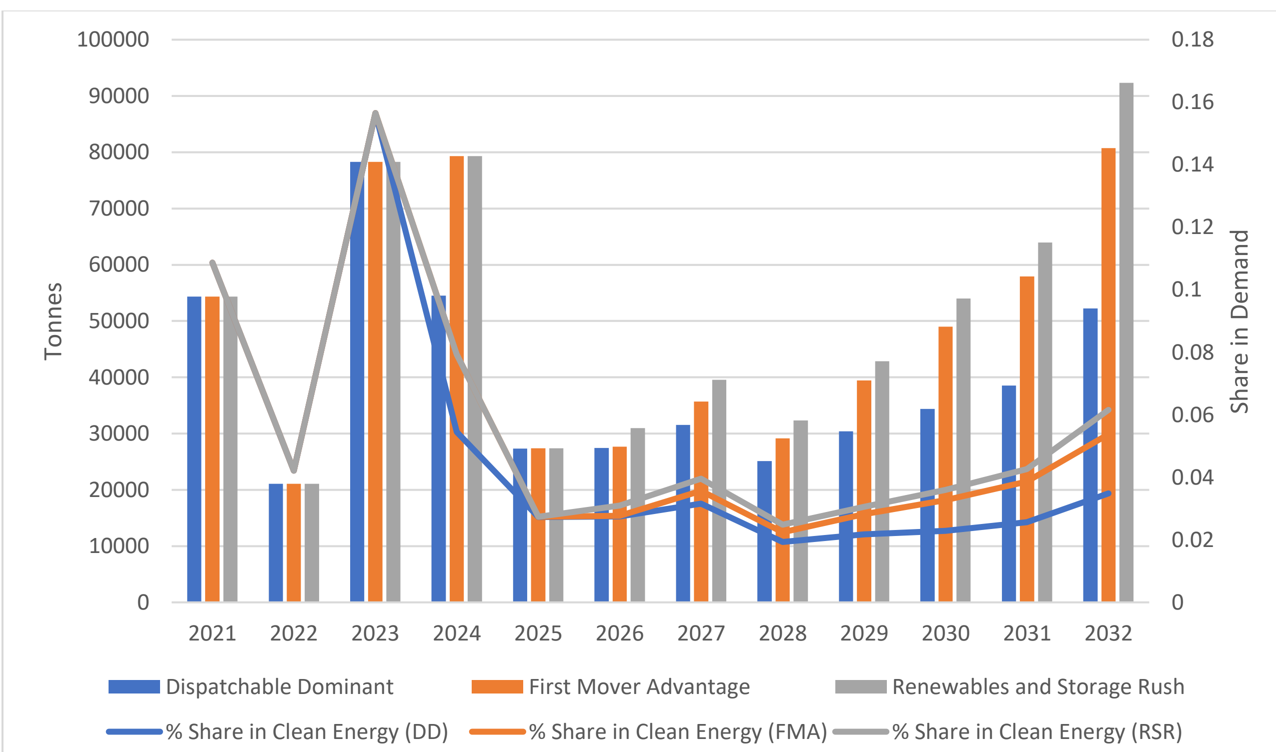

Figure 77 Scenarios AEC (<$45/MWh) and % of Clean Hydrogen Demand Fulfilled

3.8.4 Hydrogen Cost

The graphs 78, 79, and 80 show the monthly variation of hydrogen prices in three of the modeled years. Two types of electrolyzers described previously are used to generate this green hydrogen. The cost includes electricity input price, setting up, and operating the different types of electrolyzers. The expected cost improvements due to technology and scale are also considered for the analysis.

In 2021, the cost to produce hydrogen in an alkaline electrolyzer varied from $2.1-2.8 per kg and in the Proton exchange membrane electrolyzer from $3.9-$4.9 per kg. The higher price is due to PEM electrolyzers having a higher production cost and lower efficiency currently. By 2027, the average price to produce hydrogen in an AEC electrolyzer comes down to $2.2 per kg and there is a greater decrease in PEM produced hydrogen of almost 30% with an average price of $3.54 per kg. By 2032, there is a further decrease in the unit prices. AEC electrolyzer produces hydrogen at an average cost of $2 and PEM electrolyzer costs are 3.3 dollars per kg.

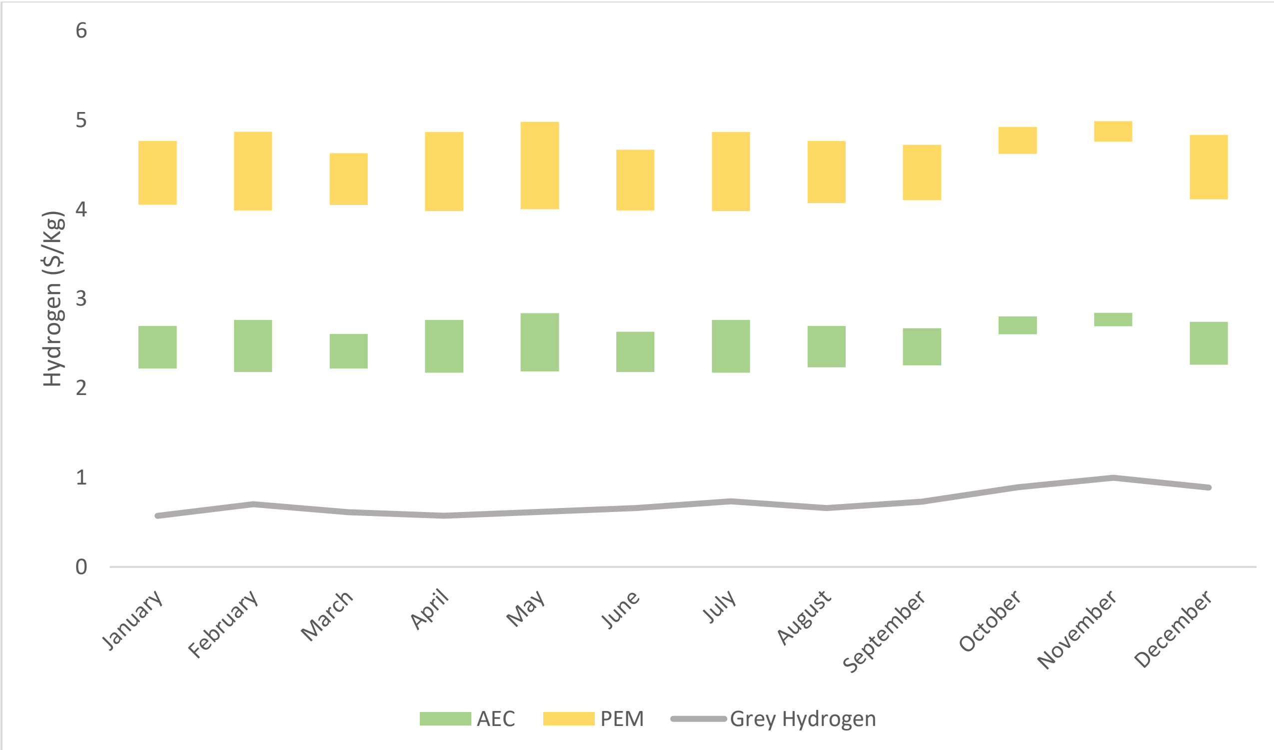

Figure 78 Unit Price Monthly Variation- 2021

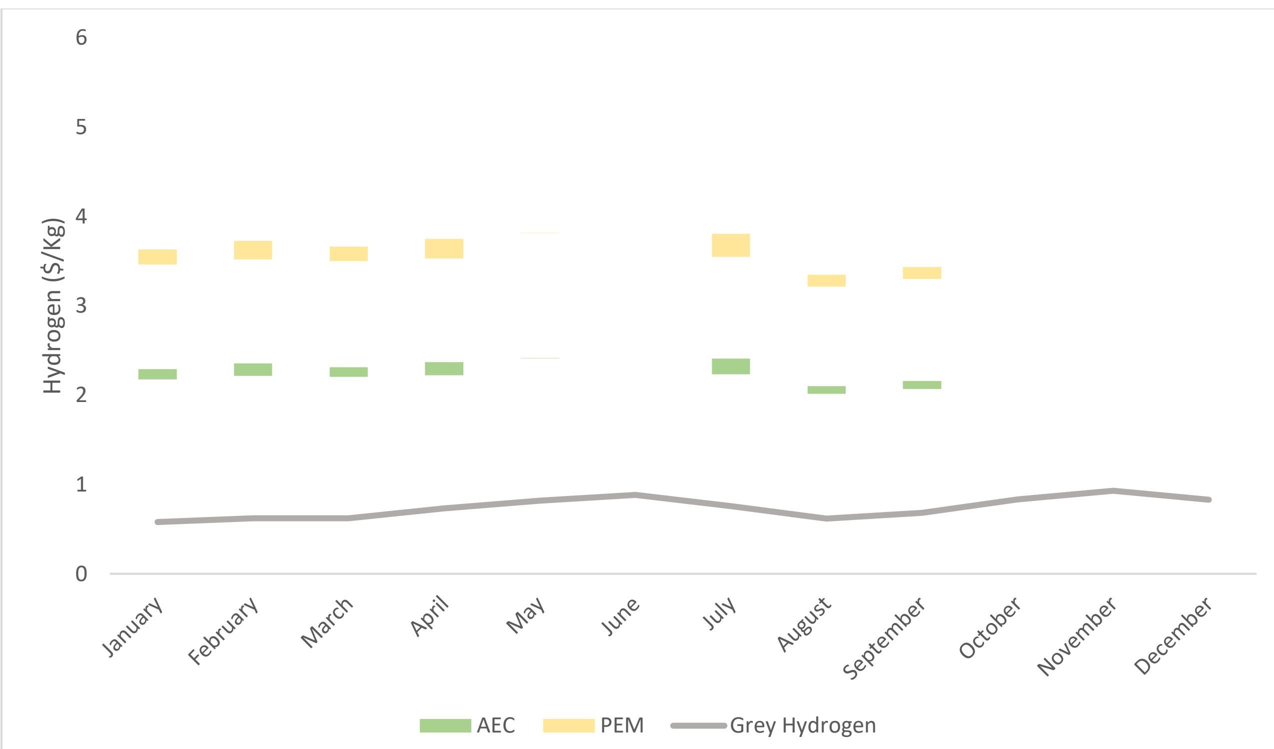

Figure 79 Unit Price Monthly Variation- 2027

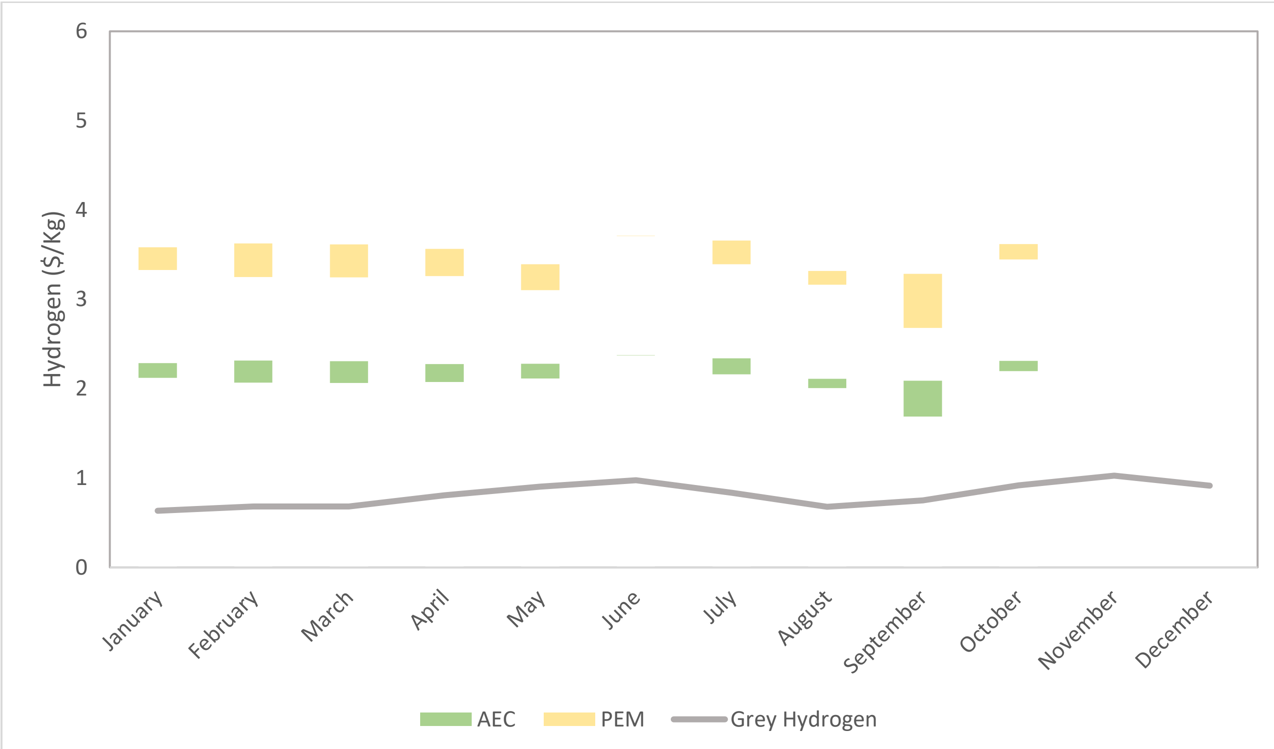

Figure 80 Unit Price Monthly Variation- 2032

Figures 81 and 82 show the average annual prices of the hydrogen under the three thresholds for alkaline electrolyzer and PEM electrolyzer respectively. These are compared with hydrogen produced in a Steam Methane Reforming (SMR) process with natural gas as source (grey hydrogen). The grey hydrogen prices are based on the three natural gas forecasts described in the previous section. The average price difference between green and grey hydrogen narrows to about $0.50 in the high natural gas price scenario for alkaline electrolyzers and about $1.00 per kg for PEM electrolyzers.

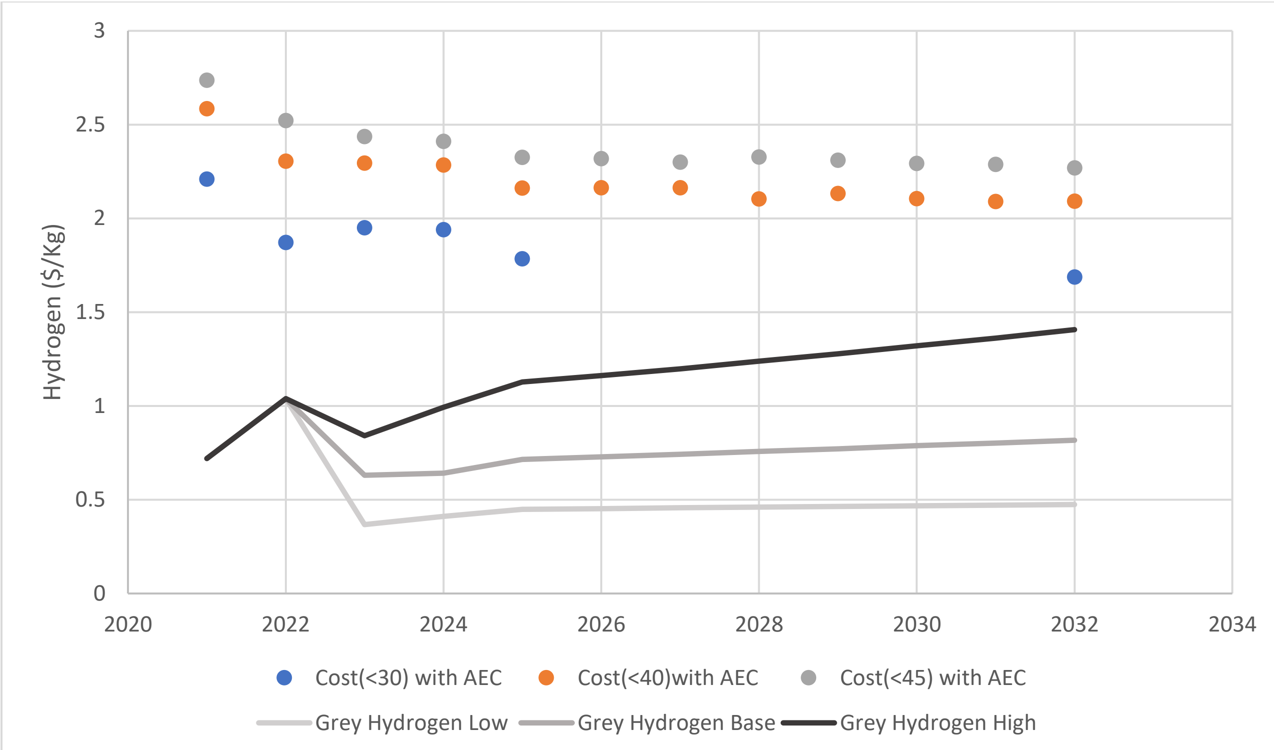

Figure 81 Average Annual Hydrogen Production Costs- Alkaline Electrolyzers

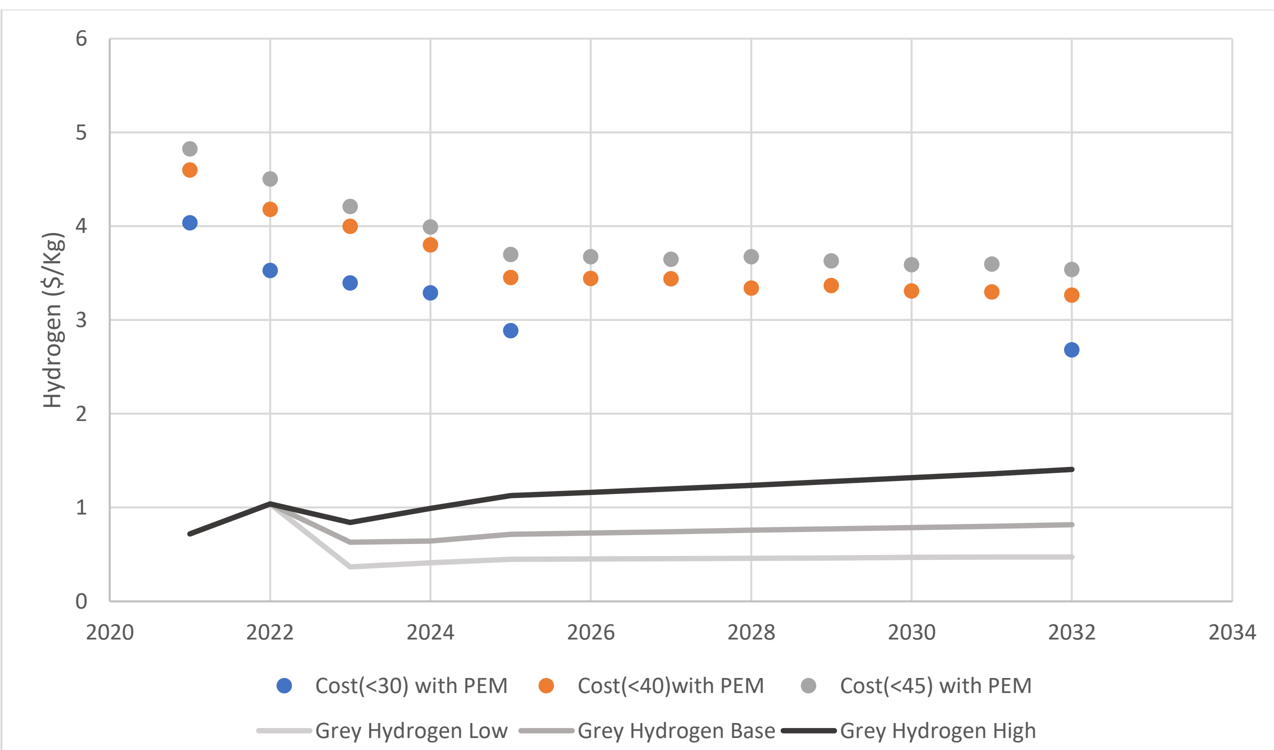

Figure 82 Average Annual Hydrogen Production Costs- PEM

Figures 83 and 84 show the comparison between the average prices if a tax credit for clean hydrogen, such as the Inflation Reduction Act, 2020 in the USA is implemented. The program provides a subsidy of \$0.60-\$3.00 per kg of hydrogen If the produced hydrogen emits less than 0.45 Kg CO_2e/kg of H_2 over its lifetime. The goal of the act is to have a supply of green hydrogen for as low as \$0.73 per kg to make it competitive with natural gas based hydrogen (IRS 2022). The unit costs in these cases become comparable with fossil fuel based hydrogen. For alkaline electrolyzers, the unit cost is almost equal to grey hydrogen in the short term and then becomes lower in the medium term. In the case of PEM electrolyzers, a similar trend is observed with price parity with grey hydrogen achieved by the end of this decade in a high natural gas price scenario.

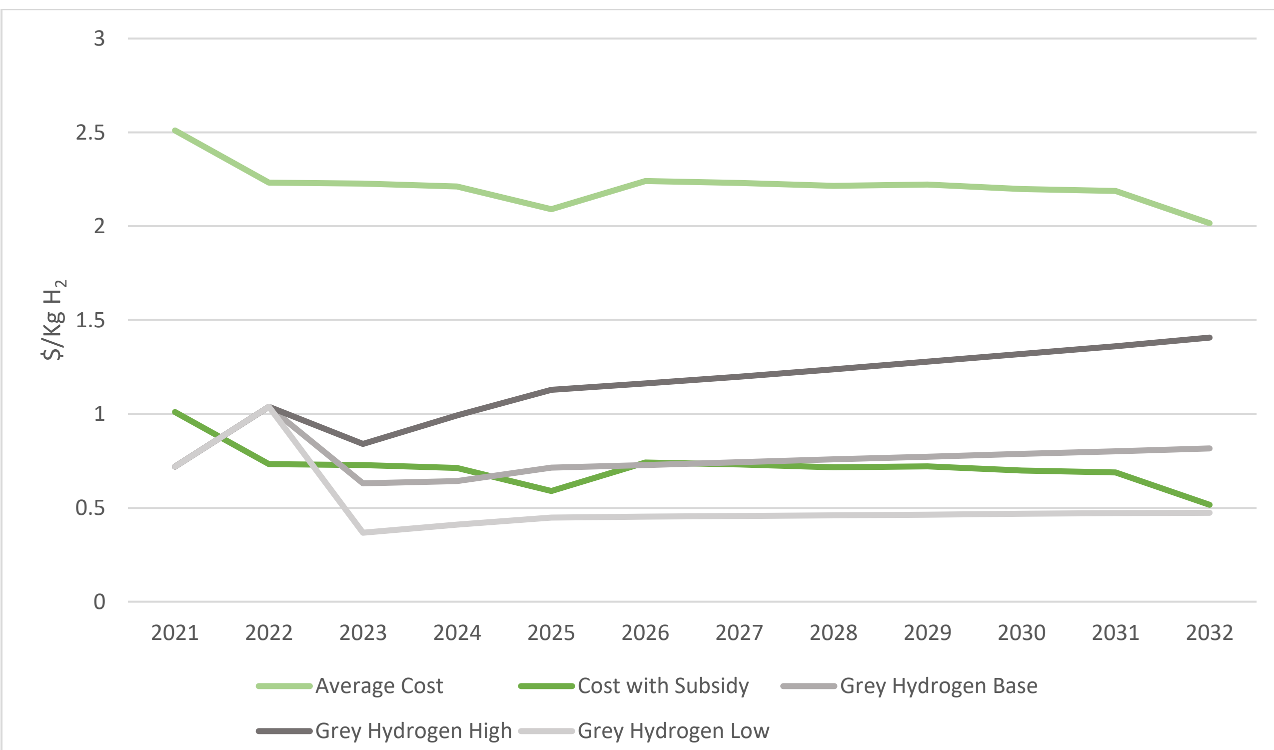

Figure 83 AEC Unit Cost Comparison with Tax Credits

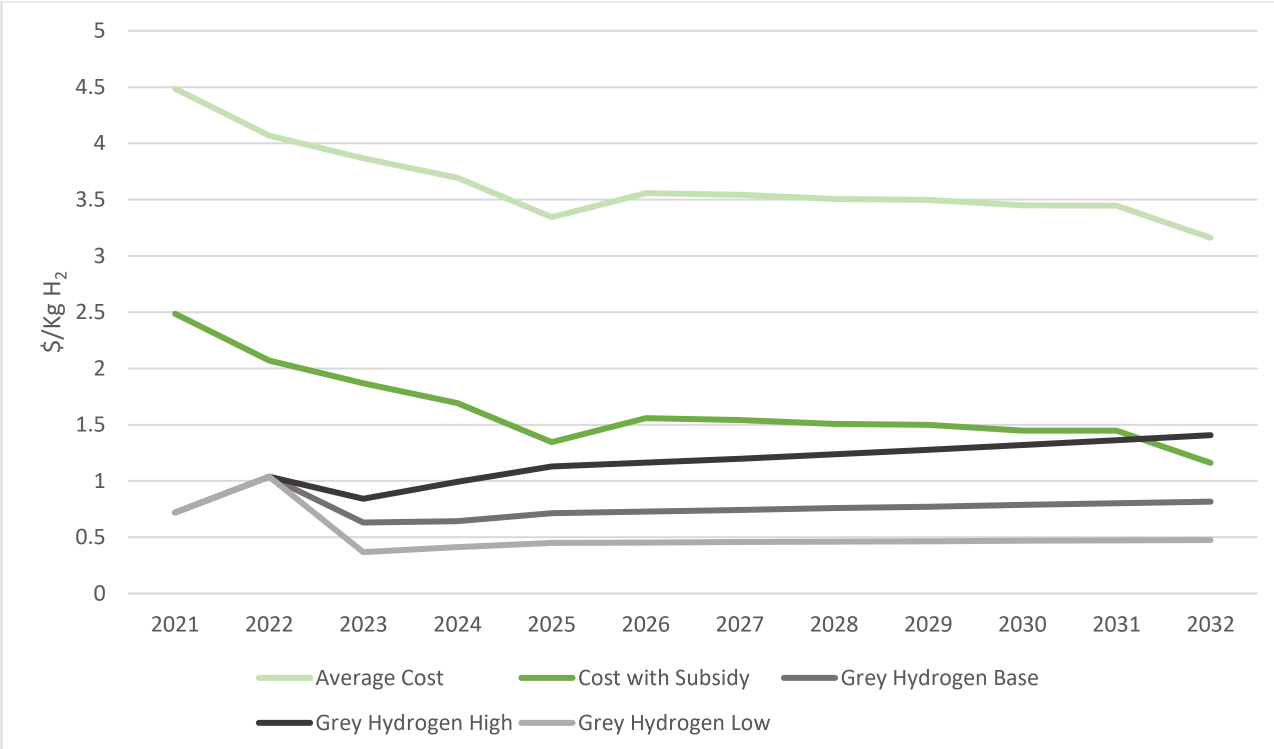

Figure 84 PEM Unit Cost Comparison with Tax Credits

3.8.5 Emissions Analysis

The emission reductions and energy development plan of the government of Alberta aims to reduce annual emissions by 1.2 million tonnes of CO_2e from hydrogen production processes. The following figures 85 and 86 show the relative emissions when a similar amount of hydrogen (as produced in the higher price models) is manufactured as either grey (SMR) or blue (SMR+CCS) hydrogen. Yearly emission reductions range from 0.1 Mt CO_2e to 0.8 Mt CO_2e

Therefore, hydrogen production method described in this model can help contribute to the provinces emission reduction targets and there is further potential to decrease the emissions by increasing the price threshold or introducing subsidies or tax credits to encourage greater green hydrogen production.

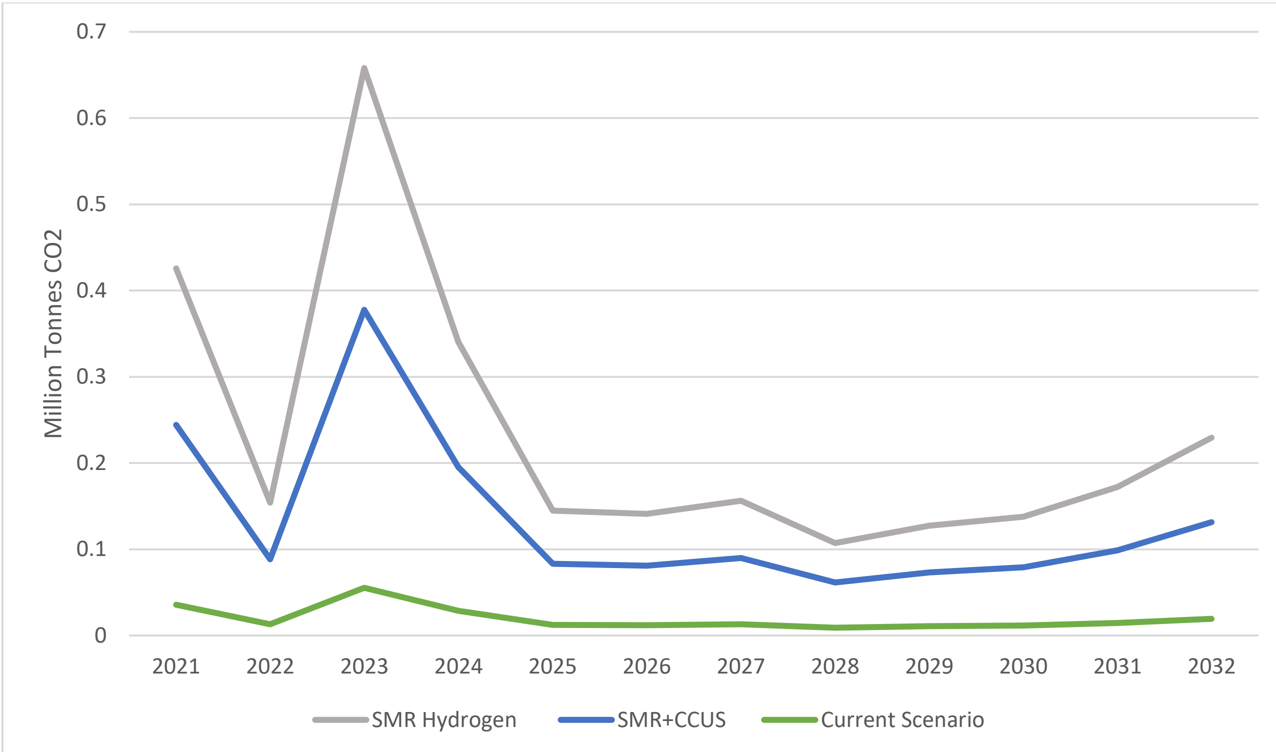

Figure 85 Emissions CO_2e (<$40/MWh)

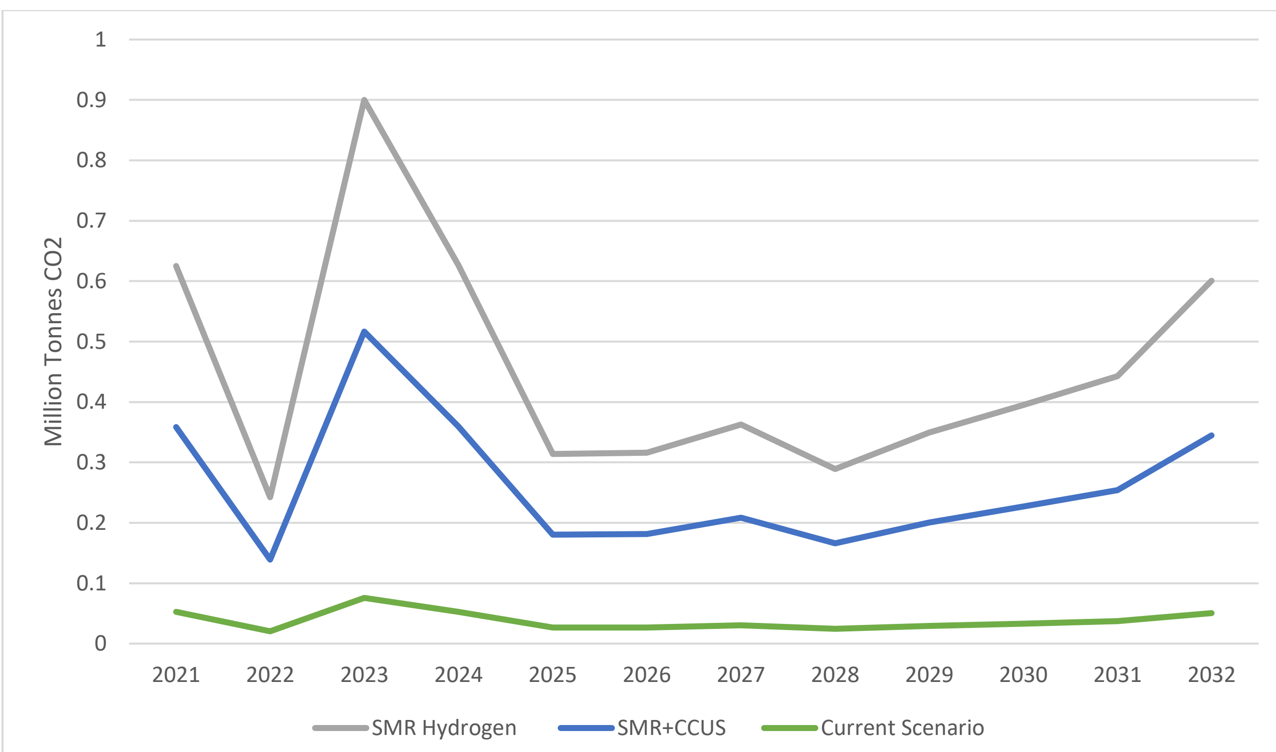

Figure 86 Emissions CO_2e (<$45/MWh)

3.9 Summary

The study presents a method to increase green hydrogen production in Alberta by behind the meter diversion of renewable electricity- wind and solar, during hours when prices in the electricity market are low. This hydrogen helps fulfill up to 15% of the demand for clean hydrogen in the province. To further scale up the volume of green hydrogen, dedicated renewable supply may be required, the LCA of which has been done in our earlier research where large-scale transition to green hydrogen (up to 50% of total) was modeled. The dynamic nature of Alberta's electricity market and hourly matching of demand and supply makes forecasting prices challenging and a regression model has been developed based on historical data. The volatility of natural gas prices is accounted for by considering three price forecast trends.

The emission analysis shows that even a 10% supply of green hydrogen can contribute significantly to Alberta's long-term net zero goals. As electrolyzer technology is improved, hydrogen produced using dedicated renewable sources will achieve price parity over the longer term with the model proposed. The subsidies and tax credits used here are those introduced under the Inflation Reduction Act (IRA) in the USA. However, if such benefits are applied in Alberta or Canada wide, green hydrogen can become more economical than fossil fuel based hydrogen. These results will serve as a reliable way to transition from grey hydrogen that is currently being produced to green hydrogen, without increasing costs exponentially and with minimal change in availability and help minimize curtailment of low cost, emission free renewable energy.

Chapter 4: Conclusion and Recommendations

This work aims to gauge the feasibility and implementation of ramping up green hydrogen production in Western Canada over the medium term. Green hydrogen is considered to be a critical component in the energy mix required to meet the internationally mandated net-zero targets. Western Canada is well positioned to establish itself as the hub of green hydrogen production at low costs and high capacity in Canada due to its geographic suitability of producing renewable electricity, and a well-established industry with high existing demand for hydrogen. Alberta is the largest producer and consumer of hydrogen in Canada, with an annual capacity of 2.4 million tonnes with oil and gas, and chemical upgrading industries using a majority of this. The province envisions itself as a hydrogen export hub in the near future with exports of up to 3 million tonnes low carbon hydrogen annually. Most of the current production of hydrogen is from fossil fuel based sources and the future increase is expected to be of blue hydrogen which is fossil fuel sourced accompanied by CCS. Green hydrogen could complement these production targets as its emissions are much lower than blue hydrogen as shown previously and additionally help create a low emission hydrogen economy in the region.

This work shows that a phased transition towards green hydrogen is economically viable over the medium and long term with price parity between Alkaline Electrolyzer Cell produced hydrogen and blue hydrogen by 2030. The cost parity is achieved without considering an increase in the carbon taxation or penalties due to high emissions from fossil fuel sourced hydrogen produced currently. The emissions analysis and a comparison between the various models shows that emissions reduction is observed in the short term with a saving of up to 8 million tonnes of CO_2eq annually in the aggressive capacity addition scenario. The input costs including installation of solar and wind energy facilities are expected to decrease due to decreasing manufacturing costs and economies of scale in the province. A higher proportion of wind energy in the electricity mix for electrolyzers results in lower costs and emissions due to a higher capacity factor and annual production per unit capacity. Electrolyzer costs, another major cost contributor with more than 50% of the total costs, will decrease by 5% per year and up to 60% by 2030, and have higher capacities as Alkaline electrolyzer are phased out and Proton Exchange Membrane (PEM) and Solid Oxide Electrolyzers are adopted at scale. These electrolyzer technologies have shorter start up times, lower sensitivity to load variation, and higher current densities. Resources availability including water, land, and critical materials is a factor of consideration while designing a sustainable adoption strategy. A further avenue for containing costs harnessing the electricity grid to generate green hydrogen by reducing the current high rate of emissions. Currently, the Alberta electricity grid is not suitable for direct generation of green hydrogen due to high emissions associated with its generation from natural gas fired power plants.

The Alberta electricity market follows a dynamic pricing scheme with hourly prices depending on demand and supply. This leads to a high variability in hourly prices paid to electricity producers as there are dips in demand on a daily, weekly, and seasonal basis. Additionally, the supply of electricity changes particularly during periods of high renewable energy supply- during the day for solar energy and late evenings and early mornings for wind energy. This variability in supply is expected to go up as the share of renewable energy in the electricity grid increases to meet clean energy targets. There is thus scope for using this renewable electricity behind the meter when the pool prices are low. The proposed scheme will help reduce wastage and curtailment of renewable electricity and ensure new renewable projects are viable and cost effective. Various price thresholds are considered to help determine a floor for electricity prices and future price projections done based on a semi log regression analysis of past hourly pool prices. The results show a possible curtailment of 300-400 hours per month with higher curtailment observed in the summer months due to high production and lower demand which is on average 10% of the total renewable energy produced. The annual hydrogen production gradually increases under the various price thresholds and electricity generation scenarios to 80,000-100,000 tonnes per year by 2032 contributing up to 10% of the province's hydrogen demand. The hydrogen production costs in these scenarios are comparable to blue hydrogen costs and are higher than grey hydrogen costs by a factor of 1.5-2. However, the addition of a carbon tax on fossil fuel based hydrogen and subsidies and incentives for clean hydrogen will lead to cheaper green hydrogen with prices on par with grey hydrogen even in cases of low natural gas prices rise. A higher percentage of green hydrogen in the mix (up to 50%) can be achieved by installing dedicated renewable energy plants at scale as shown in the earlier analysis. Therefore, this study ties in both to the decarbonization pathways and the goal of making Western Canada a hub for clean hydrogen use and exports in the short and medium term.

4.1 Recommendations

Future work on expanding this study could include:

- Considering a wider boundary in the Life Cycle Assessment (LCA) by including various methods of hydrogen transport such as pipelines, trucks, and shipping and end industrial uses.
- Identifying specific areas having existing hydrogen end users and feasibility of developing these as hydrogen hubs where the hydrogen may be produced, thus, reducing transport costs.
- Further research on hydrogen hubs to include locations where green hydrogen can be produced alongside blue hydrogen since this can help leverage existing infrastructure.

- Using a dynamic modelling software such as Regional Energy Deployment System (ReEDS) Model developed by the National Renewable Energy Laboratory (NREL) to dynamically predict the curtailment rates for renewables.
- Consider other alternatives to renewable energy curtailment such as battery storage, smart charging, and their feasibility in the Western Canadian context.

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