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Role of Hydrogen Supply-side Pathways in GHG Mitigation in Canada

By Environment and Climate Change Canada

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Abstract

Using the model Energy 2020 (E2020), this project explored the energy and GHG impact of different hydrogen supply pathways for a hypothetical future where large amounts of hydrogen end-use technologies are adopted over the next 30 years. The modeling undertaken for this project was exploratory in nature and should not be construed as reflecting government policy. Three illustrative scenarios (low, medium and high hydrogen cost) assuming various splits between hydrogen production approaches, specifically steam methane reformation (SMR), with and without carbon capture and storage (CCS) and electrolysis drawing on various sources of electricity (the electric grid, dedicated renewable generating units and interruptible power coming from otherwise curtailed VRE generation).

Total low-carbon emitting hydrogen production in the three scenarios was between 11.6 and 13.6 Mt H_2 by 2050. Under the hydrogen and electricity generating cost assumptions used in the model, electrolysis-based hydrogen production costs remained considerably more expensive compared to SMR+CCS throughout the projections. As a result, increased adoption of more efficient gas-burning equipment was observed in scenarios with more electrolysis. Compared to Environment and Climate Change Canada (ECCC)'s Reference Case 2020 scenario, GHG reductions by 2050 were between 140 and 171 Mt CO_2-equivalent, with higher reductions in higher cost scenarios because of preference for more efficient equipment. Hydrogen production emissions by 2050 in all scenarios were minor.

Increases to electric capacity and generation were substantial to support electrolysis. Required capacity and generation to meet all resulting electricity needs increased up to 129% (238 GW) and 84% (627 TWh), respectively, above reference scenario levels in 2050. The similar emissions observed in the three scenarios were strongly influenced by the model's electric dispatch, which favoured low variable cost VRE over fossil fuel generation as VRE construction dominated capacity expansion under the portfolio grid expansion plan.

Due to its integrated energy demand-supply nature, the E2020 model demonstrated its potential in evaluating the economy-wide GHG and electricity impacts of different hydrogen supply pathways. Future model development could involve refinements to the electric capacity expansion module, improved electricity storage dynamics and electric dispatch in order to improve the evaluation of the energy and emissions impacts of various hydrogen production pathways.

Résumé

À l'aide du modèle Energy 2020 (E2020), ce projet a exploré l'impact énergétique et les réductions de GES liées à différentes voies de production de l'hydrogène. L'analyse se situe dans un contexte de large adoption de l'hydrogène au sein de l'économie et ce à l'horizon 2050. La modélisation effectuée pour ce projet est exploratoire et ne devrait pas être interprêtée comme reflétant des politiques gouvernementales. Notre cadre de modélisation est axé autour de trois scénarios illustratifs (coût de l'hydrogène faible, moyen et élevé) qui supposent différentes proportions des méthodes variées de production d'hydrogène. Pour chaque scénario, les méthodes de production considérées incluent différents pourcentages de reformation du méthane à la vapeur (avec ou sans captage et stockage du CO_2) et l'électrolyse de l'eau provenant de diverses sources d'électricité (le réseau électrique, les unités dédiées à la production d'énergie renouvelable et la puissance interruptible provenant du surplus de production du réseau électrique).

À l'horizon 2050, nous estimons la production totale d'hydrogène à faible intensité carbone entre 11,6 et 13,6 Mt-H2. Sous les hypothèses de coûts de production d'électricité et d'hydrogène utilisées dans le modèle, les coûts de production d'hydrogène par électrolyse sont restés considérablement plus élevés que ceux du SMR+CCS tout au long des projections. Ceci a conduit à une adoption accrue d'équipements de combustion à gaz, plus efficaces dans des scénarios avec plus d'électrolyse. Par rapport au scénario de référence 2020 publié par Environnement et Changement Climatique Canada (ECCC), notre modèle estime les réductions de GES d'ici 2050 entre 140 et 171 Mt d'équivalent CO_2, avec des réductions plus importantes dans les scénarios de coûts plus élevés en raison de la préférence pour les équipements plus efficaces. Les émissions provenant de la production d'hydrogène d'ici 2050 ont été mineures.

Nos résultats témoignent qu'un large déploiement de l'hydrogène est tributaire d'une expansion considérable du réseau électrique. En effet, en 2050, les augmentations

en capacité et génération d'électricité pour répondre à tous les besoins sont respectivement de 129 % (238 GW) et 84 % (627 TWh) au-dessus des niveaux du scénario de référence. En outre, les faibles variations de réduction de GES observées entre les trois scénarios ont été fortement influencées par la distribution d'électricité à l'intérieur du modèle, préférence pour les carburants propres au détriment des combustibles fossiles. Ceci est dû au plan d'expansion du réseau utilisé et dans lequel la construction d'unités d'Énergie Renouvelable Variable (ERV) à faibles coûts est dominante.

Le modèle E2020 a démontré son potentiel pour évaluer les impacts sur les GES et la génération d'électricité à l'échelle de l'économie des différentes voies d'approvisionnement en hydrogène. Le développement futur du modèle pourrait impliquer des améliorations au niveau du secteur de l'électricité, une meilleure dynamique de stockage de l'électricité et la répartition de la génération d'électricité afin d'améliorer l'évaluation des impacts énergétiques ainsi que les réductions de GES issues de la filière hydrogène.

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List of Symbols and Abbreviations

APEI	Air Pollutant Emission Inventory
ATR	Auto-Thermal Reforming
CCS	Carbon Capture and Storage
CEEDC	Canadian Energy and Emissions Data Centre
CEEMA	Canadian Economic and Emissions Model for Agriculture
CER	Canada's Energy Regulator
CGE	Computable General Equilibrium
DRI-EAF	Direct Reduced Iron - Electricity Arc Furnace
E2020	Energy 2020
E3MC	Energy, Emissions and Economy Model for Canada
ECCC	Environment and Climate Change Canada
EIA	Energy Information Agency
EJ	Exajoule
GCAM	Global Change Analysis Model
GHG	Greenhouse Gas
GWh	Gigawatt hours
HDV	Heavy-Duty Vehicle
IEA	International Energy Agency
LCOE	Levelized cost of electricity
LCOH	Levelized Cost Of Hydrogen
MCE	Marginal Cost of Energy
Mt	Megaton
NEMS	National Energy Modeling System
NRCan	Natural Resources Canada
NREL	National Renewable Energy Laboratory
OBA	Output-Based Allocation
OBPS	Output-Based Pricing System
OEE	Office of Energy Efficiency
O&M	Operating and Maintenance
P2G	Power-to-Gas

PEM	Polymer Electrolyte Membrane
PT	Province / Territory
QCT	Qualitative Choice Theory
SMNR	Small Modular Nuclear Reactor
SMR	Steam Methane Reformation
UNFCCC	United Nations Framework Convention on Climate Change
VRE	Variable Renewable Energy

1 Introduction

In recent years many countries, including Canada, have made commitments to achieve net-zero emissions by 2050. Meeting these commitments requires full decarbonisation of the energy system. Electrification is feasible in the near-term for providing energy for passenger vehicles, buildings and light manufacturing. However, electrification may be less suitable for applications requiring high grade heat, chemical feedstocks or large amounts of energy storage in sectors such as in heavy industry, oil & gas and heavy duty freight. Given the limitations of electrification, decision-makers are turning their attention to the use of hydrogen for hard-to-decarbonize applications.

In 2020, the government of Canada released the *Hydrogen strategy for Canada, Seizing the Opportunities for Hydrogen* in an effort to reduce GHG emissions in hard-to-mitigate sectors, while stimulating economic growth. [1] The Strategy estimates a GHG mitigation potential of 190 Mt CO_2-e in 2050 given large-scale hydrogen uptake in the economy. However, the mitigation potential is highly sensitive to the hydrogen production pathway, which can be a source of emissions. Known methods to produce hydrogen include steam methane reformation (SMR) of natural gas and electrolysis. Unlike electrolysis, hydrogen production via SMR emits direct GHGs. All methods may have varying degrees of indirect emissions associated with electricity use or transportation. This paper examines the relationship between GHG reductions and various hydrogen production pathways from natural gas and electrolysis (Figure 1).

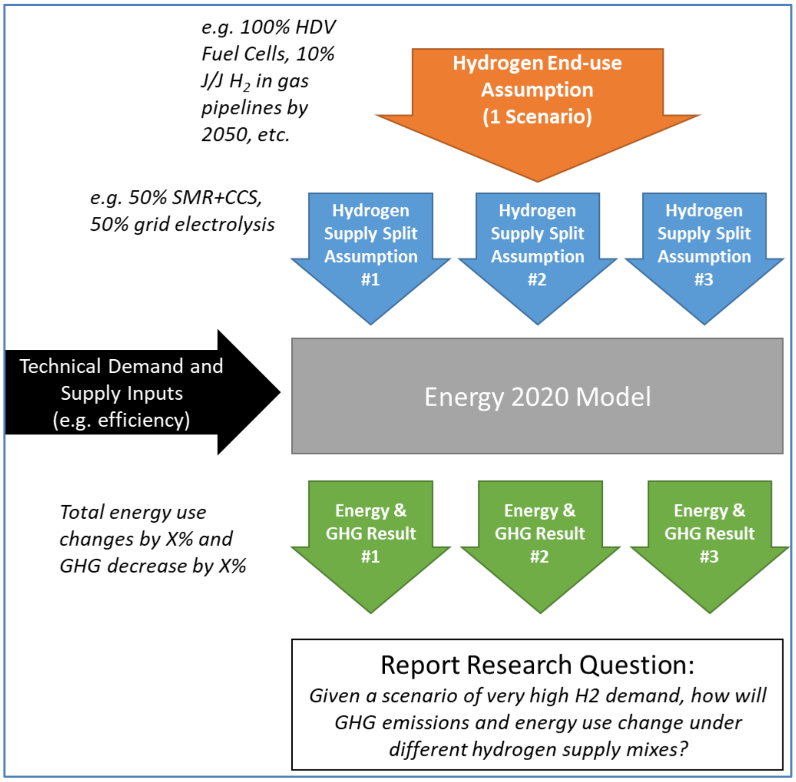


Figure 1: Schematic Diagram of Hydrogen Scenarios

As in many places in the world, Canada currently relies predominately on SMR to supply its existing hydrogen needs due to the low cost and readily available natural gas inputs. SMR may be coupled with carbon, capture and storage (CCS) to greatly reduce net emissions if there is access to suitable geological storage formations and related CO_2 transportation infrastructure. In Canada, considerable CCS potential exists in saline formations and oil & gas reservoirs of Western Canada where the practice, facilitated by the proximity of industrial facilities to pipelines, already occurs to a limited degree. Some more limited storage opportunities also exist in saline formations of Ontario and Quebec, although pipeline infrastructure is lacking at this time. Considerable storage potential also exists just south of the Canada-USA border.[2]

While an important tool to lower emissions, CCS coupled to the reforming of natural gas cannot currently achieve net zero emissions because existing CO_2 capture rates typically do not exceed 90%, although this rate can increase to 95% if pure oxygen rather than air is used during the creation of steam, in a process called auto-thermal reforming (ATR).[3],[4] In addition, there can be indirect emissions associated with the electricity used for CCS.

The main alternative to SMR/ATR – electrolysis – does not produce any direct emissions, but may be associated with significant indirect emissions, depending on whether the supplied electricity is generated from fossil fuels or non-emitting sources, like renewables or nuclear. Indirect emissions associated with electrolysis may vary widely by province. For example, indirect emissions could be negligible in hydroelectricity dominated provinces like Quebec and British Columbia, which currently have zero or near-zero grid electric intensities, while other provinces like Alberta and Nova Scotia that rely on coal and natural gas could have significant indirect emissions since grid intensities can currently be up to 700 t/GWh.[5],[6]

As jurisdictions seek to integrate more variable renewable energy (VRE), such as wind and solar, into their electricity grids, system operators may turn to the use of hydrogen electrolysis, also referred to as power-to-gas (P2G) to produce hydrogen from surplus electricity generation rather than curtailing or exporting energy.[7] In a global analysis using the integrated assessment model MESSAGE, McPherson et al. found that P2G is deployed to reduce short-term and seasonal curtailment associated with large shares of VRE.[8] Certain stakeholders in Ontario desiring to use P2G for H_2 generation have proposed changes to the provincial electric market to facilitate P2G from exported or curtailed wind energy.[9]

VRE-powered electrolysis offers a promising option for generating hydrogen since wind and solar have among the lowest levelized cost of electricity (LCOE) in many parts of the world, and electrolysis has the lowest life-cycle GHG emissions of all known hydrogen generation pathways.[10] However, the intermittent nature of the power input may affect both the efficiency and operating life of some electrolysers. Furthermore, the low utilization rate (capacity factor) of the electrolyser arising from the intermittent power may result in unacceptably low rates of return on the capital investment.[11],[12] To avoid these undesirable consequences, battery or other forms of energy storage can be coupled to solar and/or wind generators (when their capacities greatly exceed those of electrolysers) to ensure more stable input to electrolysers (i.e. the battery is charged at high periods of generation and discharged at low periods of generation), increase their capacity factors and hence reduce H_2 production costs.[10],[13] Use of storage also enables VRE-hydrogen systems that are connected to the grid to take advantage of electricity price differentials between peak and base load demand.

Studies have estimated hydrogen production costs from various sources in Western Canada, including hydropower, wind, biomass, natural gas and coal.[14],[15],[16] While H_2 generation from SMR without CCS is currently the cheapest production method, production costs from renewable sources are anticipated to drop.[17] Moreover, the future H_2 production pathway employed in each province will likely differ depending on differences in prevailing electricity and natural gas prices, feedstock and renewable power potential, suitable geological storage formations for CO_2 and related pipeline infrastructure, in addition to different policy environments.

To date there has been little economy-wide modeling analysis within Environment and Climate Change Canada (ECCC) exploring the implications of various hydrogen production options in Canada. Using the Energy 2020 (E2020), the current project investigates how hydrogen supply-side pathways influence expected GHG reductions, and result in changes to the amount of grid generation in Canada. Three illustrative scenarios are presented that presuppose differing societal preferences for hydrogen production via various natural gas and electrolysis pathways. Scenarios explore various electricity sources for electrolysis, including the electric grid, devoted renewable units and interruptible power.

Since this study focuses on the impact of hydrogen production pathways on GHGs, the modeling scenarios presented are based on one set of high H_2 demand assumptions out to 2050 that targets hard-to-electrify sectors, in particular heavy duty freight (HDV) and industry. In addition, H_2 is modeled to displace 30% by volume (10% by energy) of natural gas in the pipeline network.

In this study, hydrogen supply was assumed to be generated either from SMR/ATR, which is coupled to CCS later in the projection period, and electrolysis. We assumed two sources of electricity for electrolysis – the electric grid and dedicated non-emitting electricity. For simplicity we also assumed that solar and wind were the only sources of dedicated non-emitting electricity, given limits to further hydro developments, logistical challenges in sourcing sufficient biomass for combustion, and the near-term economic infeasibility of small modular nuclear reactors (SMNR) compared to other technologies. We further explored the impact of interruptible power in Ontario to highlight the potential for using otherwise curtailed electricity, particularly at higher penetrations of VRE.

The results presented in the report should be considered preliminary, as several areas of model improvements are identified that could have material impacts on the results. While the impacts could change substantially as a result of model refinements, some observations discussed in the results section deserve attention, and could provide insights into the future development of hydrogen supply options.

This paper covers the model methodology, including a description of the E2020 model and its dynamics; data sources; scenario development; modeling results, including a discussion of contributions to decarbonisation pathways; and a discussion of implications of findings, model accessibility, usability for policy design, state of model development and data issues affecting model usage.

2 Model and Methodology

2.1 Description of Model

Energy 2020 is a bottom-up end-use energy model that in combination with a top-down macroeconomic model forms ECCC's integrated hybrid modeling framework Energy, Emissions and Economy Model for Canada (E3MC). Energy 2020 is an integrated regional, multi-sector energy analysis system that simulates energy supply, price and demand across thirty-five detailed fuel types. When coupled with the macroeconomic model, the modeling framework simulates macroeconomic feedback. (i.e. the energy supply and demand sectors feed impacts of policies to the macroeconomic model, which then sends economic impacts to the demand sector.) Indirect impacts from the macroeconomic model are sent to the supply sector through changes in energy demand. Only Energy 2020 was used for this project.

Energy 2020 uses economic drivers to drive energy demand, which must be met by energy supply (local or imports). Figure 2 illustrates the overall structural design of Energy 2020. The energy demand module consists of four sectors (residential, commercial, industrial, and transportation). Energy demands are calculated and sent as input to the supply module consisting of seven energy producing sectors – electricity, hydrogen, oil and gas, refinery, biofuels, coal, and steam. The supply module produces the energy required to meet the energy demand, calculates energy prices, and sends energy prices back as feedback to the demand sector. Both energy and non-energy related emissions are tracked covering eighteen separate greenhouse gas (GHG) pollutants and air pollutants.

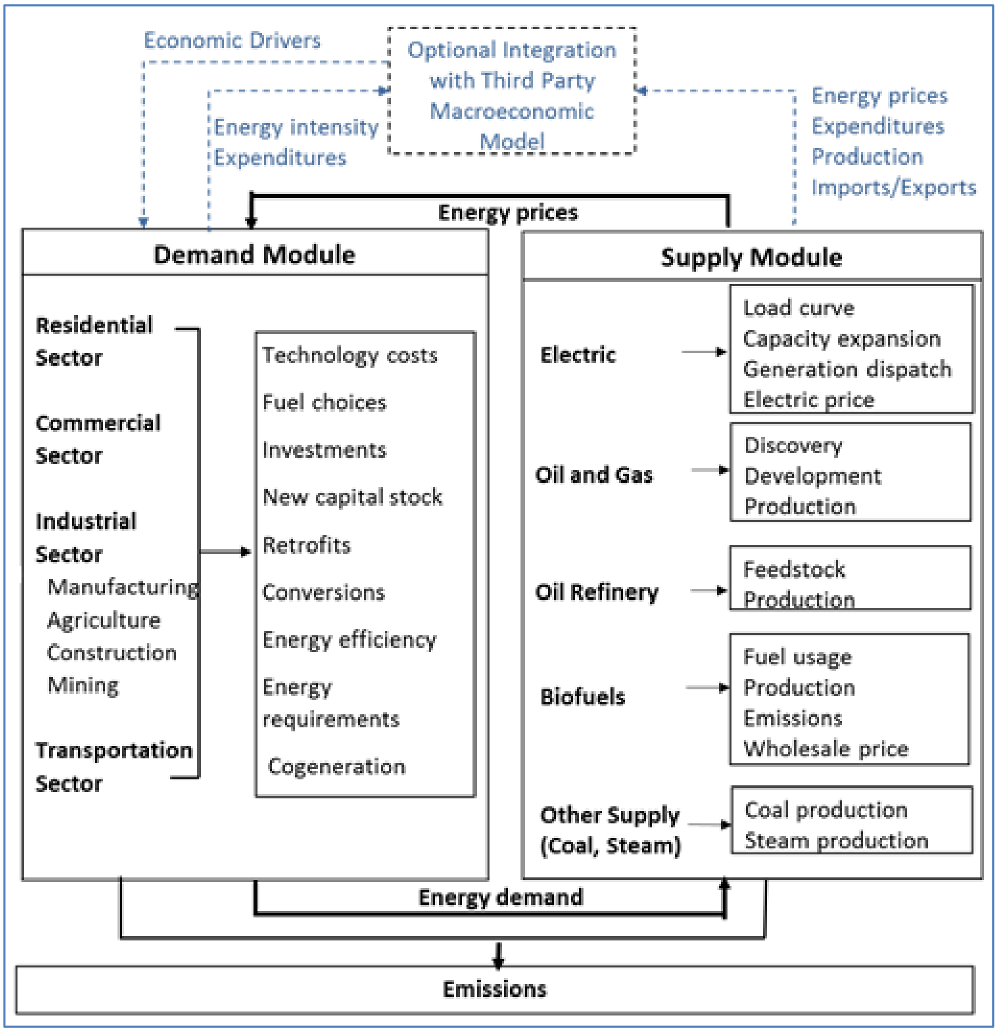


Figure 2: ENERGY 2020 Model Structure

2.1.1 Regions

The currently-defined areas in the model are shown on the map in Figure 3. Each Canadian province/territory is simulated individually within the model; on the United States (U.S.) side the current configuration aggregates the states into ten U.S. regions with California being split out from the Pacific region (for purposes of modeling the Western Climate Initiative's cap-and-trade system); and Mexico is represented at an aggregate national level.

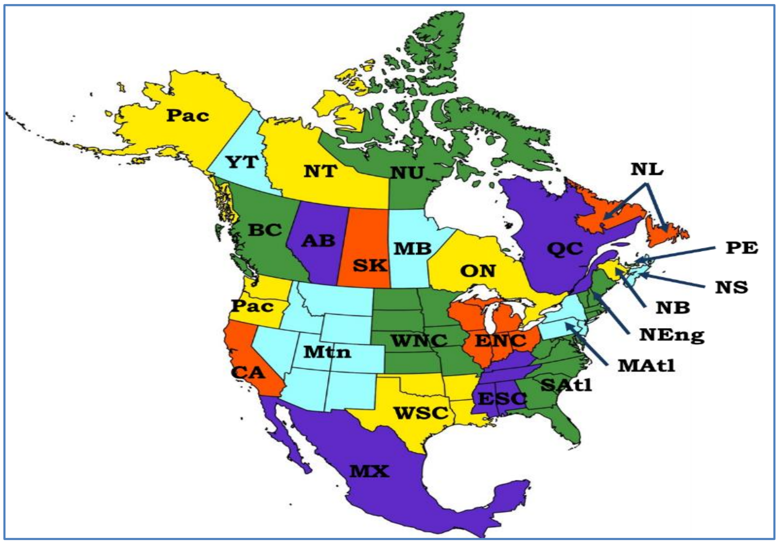


Figure 3: Default Demand Areas in ENERGY 2020

2.1.2 Demand Sectors

The demand module provides long-range projections of total energy demand (end-use, cogeneration, and feedstock), emissions, energy efficiency, and investments for each of the residential, commercial, industrial, and transportation sectors. Energy demands are projected for all economic categories (household types, building types, industry types, and transportation modes), end-use technologies, and areas represented in the model. The specific economic categories, or types of consumers, represented in the model currently include: three residential and twelve commercial classes, fifty industries, and eight transportation economic categories.

2.1.3 Supply Sectors

Energy 2020's supply module simulates the production of electricity, hydrogen, oil & gas, biofuels, refined petroleum products, coal, and steam to meet the fuel demands required by the demand sector. Since the focus of this project report is on the electricity and hydrogen sectors, details on the Electricity and Hydrogen Modules within Energy 2020 Model are provided below.

2.1.3.1 Electricity Sector

Energy 2020 model has a unit-by-unit representation of the electricity sector and contains:

- Over 1,500 individual generating units in Canada;
- Over 900 aggregated electric generating units in U.S.; and
- Ten aggregated electric generating units in Mexico.

Generating units are specified by defining characteristics, including a name, the node in which they are located (more information below), the type of plant, the heat rate, the online and retirement years of the unit, its generating capacity, and fixed and variable costs. These units may be flagged as "industrial" meaning their primary purpose is providing electricity for an industrial facility. Units may also be flagged as "must run", meaning the unit always runs. In addition to the units entered manually in the model, Energy 2020 can build "endogenous" units if needed to meet electricity demand during projection years.

Energy 2020 currently represents twenty-five plant types (see Table 1): nine conventional plant types, fourteen non-emitting and/or renewable types, and two other.

Table 1: Electricity Plant Types

Conventional	Non-Emitting and/or Renewable		Other
Gas/Oil Peaking (OGCT)	Nuclear	Solar PV	Fuel Cells
Gas/Oil Combined Cycle (OGCC)	Base Hydro	Solar Thermal	Other
Small OGCC	Peak Hydro	Geothermal	
Gas/Oil Steam	Pumped Hydro	Onshore Wind	
Coal	Small Hydro	Offshore Wind	
Coal with CCS	Wave	Biogas	
Natural Gas with CCS	Biomass		
Waste	Small Modular Nuclear Reactors		

The transmission network consists of a set of nodes connected by transmission lines (Figure 4). Electric transmission nodes are:

- U.S. - 22 electric supply nodes
- Canada - 14 nodes, one for each province and territory plus Labrador
- Mexico - 1 node

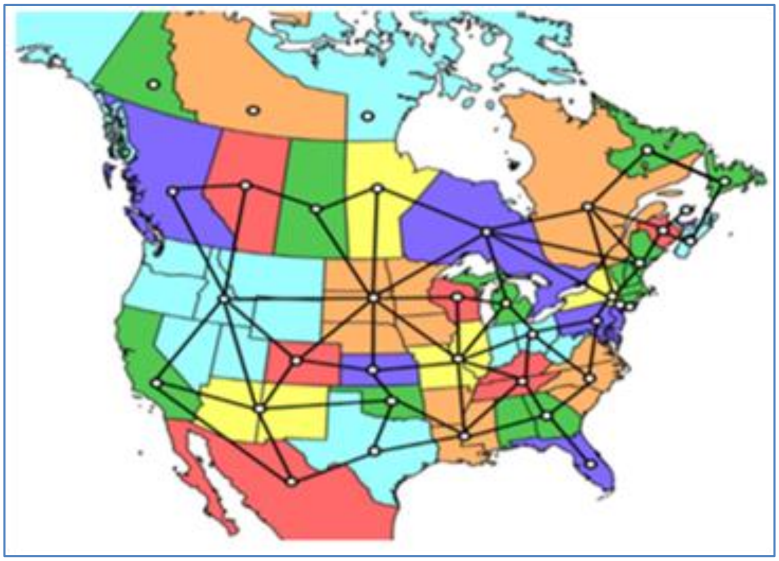


Figure 4: Default Transmission Nodes

Energy 2020 determines the amount of electricity needed at each node by minimizing the costs to meet demand (from all residential, commercial, industrial, and transportation demand sectors) across the entire network. The electric supply sector is simulated with individual electric generating units sending electricity over transmission lines connected by a set of electricity nodes. Inputs such as total electricity demand, generating unit characteristics, transmission costs and constraints are used to find an optimal solution (minimizing costs) of generation dispatch (Table 2). Outputs include projections of future capacity, generation, flows including imports and exports, and the resulting nodal prices. The entire geographic area of the model is dispatched as a single system. Generating units are dispatched across six time periods (from low load hours up to one peak hour) in each of the two different seasons (winter and summer). Imports and exports are also determined from the dispatch routine.

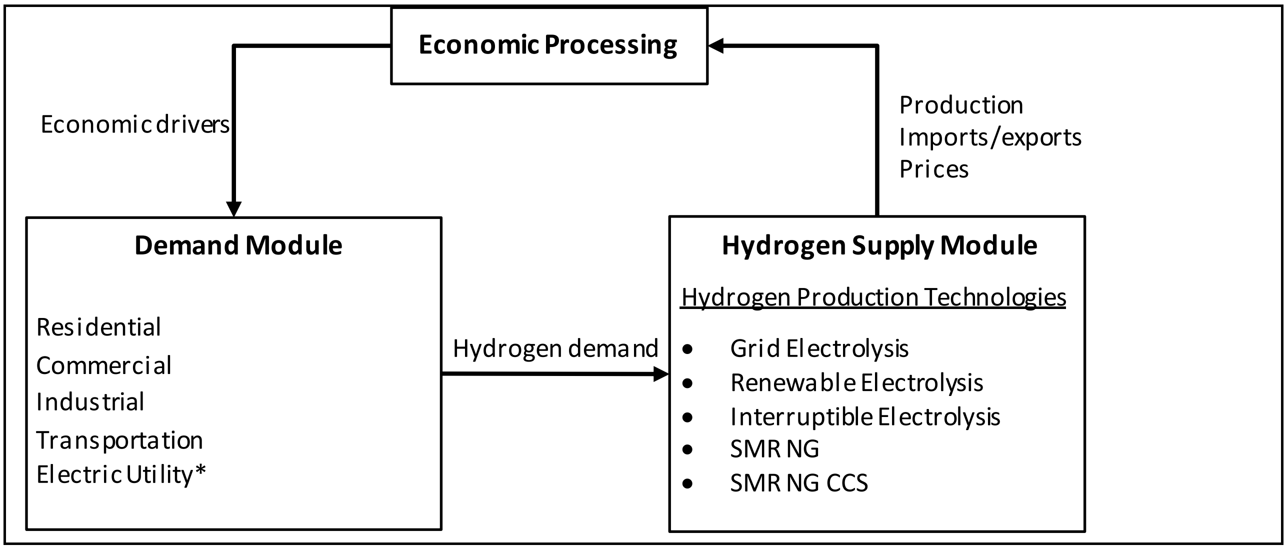
Table 2: Inputs and Outputs for the Electricity Sector

Sector	Outputs	Inputs from Energy 2020	Exogenous Inputs
Electricity Supply	Electricity capacity, generation, transmission flows, imports and exports Fuel usage required to generate electricity (energy demand for Electric Utility Generation industry) Emissions from electric generation Electricity prices Spending on fuel expenditures and emissions reduction permits	Consumer demand for electricity (residential, commercial, industrial, transportation) Peak, average, minimum load by season and time period	Existing and new plant characteristics (location, capacity, plant type, costs, historical generation, fuel demands, heat rates, etc.) Technology innovation curves Emissions coefficients or inventories Emissions caps or reduction requirements

2.1.3.2 Hydrogen Sector

ENERGY 2020's hydrogen supply module simulates hydrogen production such that domestic production and imports meet hydrogen demand and exports. Three types of electrolysis (grid electrolysis, renewable electrolysis and interruptible electrolysis) and two types of natural gas based (with or without CCS) hydrogen production technologies are available to meet the hydrogen demands. The different electrolysis types differ by the source of electricity used by the hydrogen plant. For grid electrolysis, we assume that hydrogen plants run on electricity sourced from the grid. For renewable electrolysis, hydrogen plant operators purchase electricity from dedicated VRE generators. It was assumed that 90% of this power came from wind and 10% from solar. Finally, in the case of interruptible electrolysis, surplus electric generation from the grid is redirected to hydrogen production in such a way as to avoid electric curtailment. SMR is mature technology for producing hydrogen using natural gas as feedstock, although CCS is not widely implemented.

The hydrogen production technologies are assigned production costs, including capital costs, fuel costs, feedstock costs, emission costs, operating and maintenance (O&M) costs, and transportation, distribution, and storage (TDS) costs. Resulting hydrogen prices are calculated by area and economic sector. ENERGY 2020 further calculates energy demand and emissions from hydrogen production, including energy consumption from combustion and feedstock in addition to any emissions that are sequestered (from CCS technologies). The relationships between the Hydrogen Module and other modules within ENERGY 2020 are shown in Figure 5.



*Note: Electric utilities may consume H_2 in the natural gas fuel mix or pure H_2 in fuel cells. Only the former use of H_2 was modeled in this exercise.

Figure 5: Hydrogen Supply Relationships to Other ENERGY 2020 Modules

2.2 Model Dynamics

E2020 is classified as a partial equilibrium or system dynamics (SD) model that is similar in structure to NEMS, which is used for energy and emissions modeling by the USA EIA. Unlike computable general equilibrium (CGE) models, the E2020 model does not fully equilibrate government budgets and the markets for employment and investment. Modeling results reflect rigidities of the economy such as unemployment and government surpluses and deficits. As a detailed energy end-use model, E2020 may be better suited to modeling energy and emissions, but less suited to modeling economic impacts of policies compared to CGE models. Integration of E2020 with the macroeconomic model as part of E3MC seeks to overcome this shortcoming. In contrast to many CGE models, which typically simulate five to ten year time intervals, E2020 models annual changes, which is important if the pathway to the target is to be considered.

E2020 is a recursive model, which means that the decisions of the agents in the model about savings and investments are based only on previous and current period variables. Recursive models such as E2020 have no foresight and thus do not exhibit long-term optimization behaviour for savings and investment decisions as is the case in CGE models. The absence of optimization may better represent the real economy where agents face high levels of uncertainty that likely lead to higher costs than if they knew the future with certainty.

In demand sectors, technological representation in Energy 2020 is achieved through general rather than discrete technology types. Such representation facilitates continuous long run changes in efficiency without being constrained by discrete technology types which are known at the present time. Unlike the demand sectors, the electric supply sector has discrete technologies, with an explicit individual representation of all existing or planned electric generating units.

Energy 2020 is a behavioral model; it uses algorithms that simulate a realistic decision-making process for each economic actor and associated real-world factors. For instance, in the real world, utilities dispatch electricity to minimize system costs with the help of a linear program. The algorithms within Energy 2020 mimic this process when simulating the dispatch for plants into the future. Consumers making decisions regarding purchasing a new appliance or car, however, generally do not act optimally, but rather make decisions based on limited information available combined with personal preferences. Energy 2020 utilizes Qualitative Choice Theory (QCT) to reproduce the consumers' decision-making process by simulating actual (rather than optimized) responses, allowing it to capture the nuances of technology selections.

Decisions made by the agents within the model are made on the margin. For example, a new vehicle would have a higher efficiency than an existing one, the average intensity of the fleet would change gradually as more and more efficient cars are entering the fleet, and as the stock of vehicles turns over.

2.3 Data Sources and Accessibility

The Energy 2020 model is populated annually with the most recently available energy data from Statistics Canada, as well emissions data reported in the *National Inventory Report: GHG Sources and Sinks in Canada* and *Canada's Air Pollutant Emission Inventory* (*APEI*).[6],[5],[18] ECCC uses the full data that arrive under the confidentiality provisions of the Statistics Act rather than the public versions that contain less details.

Various other data sources are used to further disaggregate historic data into sub-sectors and end-uses, in addition to populate model parameters related to capital costs, equipment efficiency and market shares. Key sources include Statistics Canada, Canada's Energy Regulator (CER), NRCan's Office of Energy Efficiency (OEE) *Comprehensive Energy Use Database*, the Canadian Energy and Emissions Data Centre (CEEDC), the Energy Information Agency (EIA), the National Renewable Energy Laboratory (NREL) and DesRosiers. The majority of these data sources are publicly available. Notable exceptions are industrial fuel amounts reported by Statistics Canada for smaller provinces and the DesRosiers reports on vehicle shares.

The macroeconomic model drivers for energy and emission projections are based on publicly available growth and population projections from Finance Canada and Statistics Canada, respectively. For the development of the annual emissions projections, E2020 is also populated with exogenous oil and gas price and production forecasts from the CER, in addition to agriculture emission projections from Agriculture and Agri-Food Canada. The former is published in the CER's Energy Future Reports, while the latter is data that ECCC receives from Agriculture and Agri-Food Canada, developed using the Canadian Economic and Emissions Model for Agriculture (CEEMA) model.

2.4 Model Potential

2.4.1 Model Accessibility and Transparency

E2020 is a private model for which the developer and ECCC share user rights. Although the models are not publicly available, substantial quantities of E2020 model documentation and sample code are available on the developer's website.[19] E2020 was subject to an external peer review in 2018 and reviewers found that "the model implements algorithms that are reasonable model-based representations of policy design alternatives" and would "expect results of the model to be reasonable and credible."[20]

In its annual projection publications, ECCC provides considerable detail on E3MC modeling assumptions. In addition, ECCC publishes on the Open Data Portal the resulting datasets on annual emissions to 2030 by province, by sector and by scenario, as well as energy demand and supply balances at a national level.[21]

2.4.2 Usability for Policy Design

E2020 is suitable for analyzing various energy and GHG or air pollutant emissions policies, including energy efficiency standards, conservation programs, fuel switching (including electrification), subsidies, CCS, emission performance standards, renewable portfolio standards, carbon taxes and cap-and-trade systems. E2020 can be used to conduct uncertainty analyses and sensitivity analyses (e.g. to variable economic growth and energy price assumptions).

Energy 2020 has been used by U.S. and Canadian electric and gas utilities as well as state and provincial energy planning departments for developing load forecasts, integrated resource planning, and analyzing the impact of energy policies on the environment and the economy.

The integrated E3MC modelling framework is used by ECCC to develop GHG and air pollutant projections for Canada that are published annually either in Canada's GHG and Air Pollutant Emissions Projections or Canada's National Communications and Biennial Reports to the United Nations Framework Convention on Climate Change (UNFCCC).[21],[22]

The Department uses the model to analyse various energy and environmental policies, regulations and programs. It has been used on numerous occasions in developing cost benefit analysis for the regulatory impact assessment statements. It has been used to model regulations on coal-fired electricity phase-out, air pollutants, renewable fuels, light- and heavy-duty vehicles, and halocarbons.[23],[24],[25],[26],[27],[28],[29]

2.4.3 Model Specificities Amenable to Pathway Development

Many energy models used in Canada are focused on a limited number of regions, sectors or types of analyses. However, E2020 is a multi-regional energy-economy model, which is focused not only on the electricity sector but also includes all other sectors of the economy

(Figure 6).[30] Since all provinces/territories and sectors are represented, it is possible to analyse a large variety of policies across all regions and sectors affecting both energy demand and supply. Moreover, the economy-wide nature of the model facilitates incorporation of interaction effects between various sectors. Accounting for interaction effects becomes increasingly important with the modeling of large numbers of policies, which would be expected as policy-makers seek to achieve Canada's net-zero target.

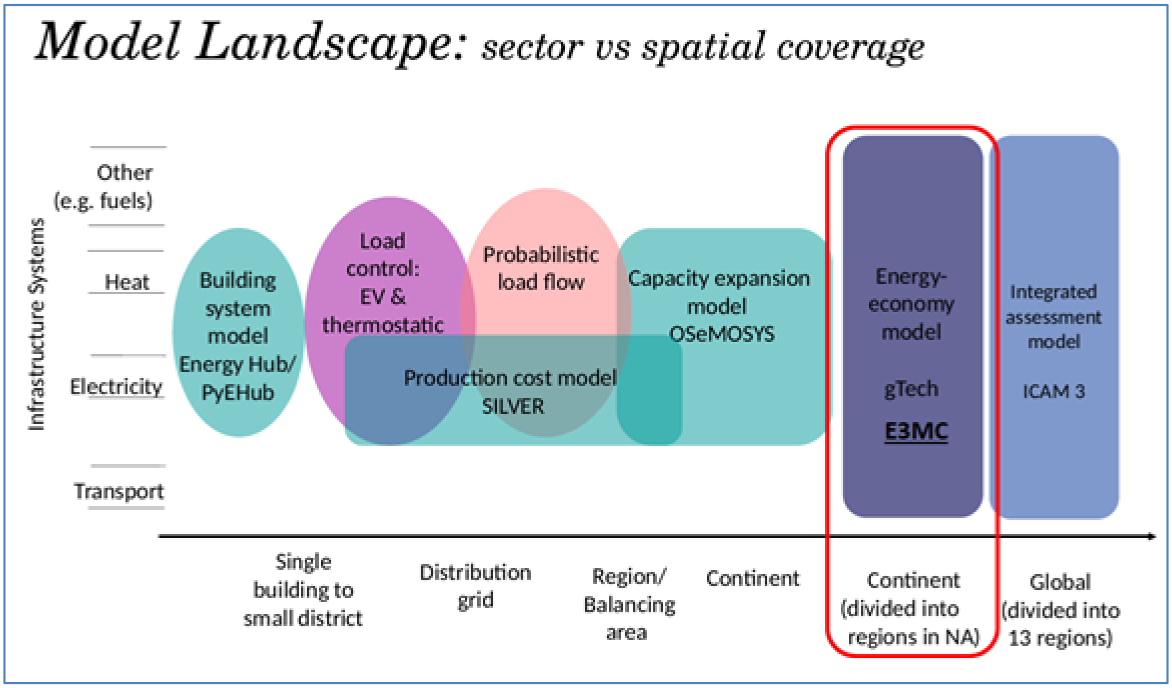


Figure 6: Model Landscapes

In this study, the multi-regional representation of the E2020 model enables analysis of dynamics which may differ significantly between different provinces and territories. Futhermore, the multi-sector nature of the E2020 model is crucial in analyzing interactive effects between demand and supply sectors, and estimating overall energy and emissions impacts of hydrogen production and use. Without such analyses, policy-makers could draw sub-optimal or even ill-conceived approaches to achieving net-zero emission pathways.

2.4.4 Contribution to Electrification and Decarbonisation Pathways

The modeling results and analyses presented in this paper are useful for the development of electrification and decarbonization pathways by providing an order of magnitude of the potential GHG reductions possible through high adoption of hydrogen in demand sectors. The results also demonstrate the inter-relationship of H_2 demands, H_2 production and the electricity generating sector. Such results may differ substantially by province, and suggest the importance of considering regional differences in electricity generation mixes when promoting any particular hydrogen production pathway.

2.4.5 Integration in a National Modelling Platform

Since E2020 is subject to a developer's license, the model cannot be hosted on the modeling platform. Nevertheless, substantial quantities of E2020 model documentation and sample code are available on the developer's website.[19]

Considerable value exists in leveraging the combined outputs of E2020 and other models. For example, the outputs (e.g. energy and emissions projections) from E2020 model are used by other models within ECCC, such as EC-Pro, EC-MSMR, and GCAM for Canada, since all of them are calibrated to the projections developed in E2020.

Outputs from electricity models with high spatial and temporal resolution could be used to improve E2020 modeling on electricity and hydrogen. The capability to simulate hourly cycles of electricity generation versus demand across seasons, while providing a more detailed representation of electric transmission and distribution, would provide invaluable information concerning VRE back-up requirements, curtailment, and short and long term storage needs. The latter is important for evaluating the seasonal generation potential of hydrogen.

2.4.6 The State of Development and Future Work

Developed by Jeff Amlin and George Backus in 1981, Energy 2020 was built as a multi-fuel energy model with a similar design to the U.S. Department of Energy's FOSSIL2 and IDEAS (Integrated Dynamic Energy Analysis Simulation) system dynamic models.[31] Energy 2020 also built on the foundation of Andy Ford's EPPAM model, a dynamic simulation of the U.S. electricity sector.[32] Energy 2020 provided clients the ability to perform regional analysis and simulation of detailed energy-demand, energy-supply, and pollution-accounting sectors.

Over time Energy 2020 has changed dramatically in response to client needs. During the 1980s, model changes included increasing level of detailed industries and end uses, splitting of the energy efficiency representation into two types (process and device energy efficiency) and enhancement of the demand sector to incorporate consumer choice methodology to simulate realistic consumer decisions. Moving into the 1990s, Energy 2020 evolved to provide electric utility level financial detail and simulation of retail and generation companies allowing for simulation of electric industry deregulation. The model also included electric unit detail and an optimization routine for electric dispatch. In addition, automated linkages were created that would allow integration between Energy 2020 and any desired third party macroeconomic model in order to obtain economic feedback of policies. Furthermore, capacity was added to the model to simulate multiple geographic areas, including all US states and Canadian provinces, in addition to modeling of all types of GHG and air pollutants.

Model development continues to occur on an annual basis, primarily driven by the policy analysis needs of ECCC. Recent examples of model development include the development of the modules incorporating endogenous oil and gas production, waste generation, and biofuel production.

Current policy attention to hydrogen and electrification is driving current model development focused on refining hydrogen production and use assumptions, in addition to improving the electricity capacity expansion and generation dispatch of the model. Recent improvements to the electricity module include addition of seasonal generation differences and modeling of curtailment in Ontario. Future work remains to allow extra VRE capacity to compensate for its limited availability, improve electricity storage dynamics and reflect seasonal generation differences in hydrogen production.

2.4.7 Data Issues Affecting Model Usage and Development

Various data issues affect model use and development. Statistics Canada energy data currently lack sufficient sectoral disaggregation for mining and oil and gas extraction, lack data on end-uses (including heat pumps), do not contain balanced sets of electricity demands and supplies, and do not include all renewable power sources, particularly those that are off-grid. While ECCC draws on other sources to fill in data gaps, such efforts are time-consuming and subject to methodologies inconsistent with those used by Statistics Canada. In addition, considerable amounts of energy efficiency and capital cost data used in the model come from US sources, so may not be reflective of Canadian realities. Of particular relevance to this study are USA-based H_2 production capital, O&M and variable costs, in addition to H_2 transmission and distribution costs and HDV fuel cell costs. Data that are available in Canada may be difficult to convert into model appropriate values.

Model development related electricity dispatch and curtailment is challenging due to limitations in temporally-resolved data on electricity capacity, generation and curtailment for smaller jursidictions. Another challenge is the lack of Canadian-specific projections for renewable electricity capital costs. Addressing such challenges is of increasing importance as various jurisdications seek to integrate increasing levels of VRE into their electric grids and leverage H_2 both as a long-term storage mechanism for excess electricity production, and as a means to reduce emissions in hard-to-decarbonize sectors.

2.5 Scenario Development and Assumptions

To accommodate the hydrogen modeling, the E2020 modeling framework was expanded to include capability to model hydrogen demand and supply, in addition to curtailed electricity. Expansion of the modeling framework had no appreciable impact on the Reference Case 2020 projections (presented in *Canada's Greenhouse Gas and Air Pollutant Emissions Projections 2020*) which formed the basis for all modeling scenarios.[21] Baseline data and assumptions for the reference scenario can be found in this publication. Wholesale crude oil and natural gas price projections were exogenous given the negligible impact of Canadian supply/demand on the highly integrated North American market. Marginal cost of energy (MCE), variable costs, overnight capital costs and plant capacity factors for selected baseload electric generation plant types in Alberta are shown in Table 3.

Table 3: Key Cost Variables for Selected Electricity Generation Technologies in Alberta

Variable	2025	2050
Gas/Oil Combined Cycle		
Marginal Cost of Energy (CN$2018/MWh)	19	29
Variable Cost (CN$2018/MWh)	8	21
Overnight Construction Cost (CN$2018/KW)	1,110	808
Plant Capacity Factor (MW/MW)	0.95	0.95
Coal with CCS		
Marginal Cost of Energy (CN$2018/MWh)	122	121
Variable Cost (CN$2018/MWh)	51	51
Overnight Construction Cost (CN$2018/KW)	7,225	7,146
Plant Capacity Factor (MW/MW)	0.87	0.87
Onshore Wind		
Marginal Cost of Energy (CN$2018/MWh)	9	10
Variable Cost (CN$2018/MWh)	(27)	(27)
Overnight Construction Cost (CN$2018/KW)	1,536	1,523
Plant Capacity Factor (MW/MW)	0.40	0.40
Solar PV		
Marginal Cost of Energy (CN$2018/MWh)	28	28
Variable Cost (CN$2018/MWh)	(27)	(27)
Overnight Construction Cost (CN$2018/KW)	1,286	1,262
Plant Capacity Factor (MW/MW)	0.21	0.21
Pumped Hydro		
Marginal Cost of Energy (CN$2018/MWh)	94	103
Variable Cost (CN$2018/MWh)	16	42
Overnight Construction Cost (CN$2018/KW)	6,987	5,314
Plant Capacity Factor (MW/MW)	0.70	0.70

Notes: Negative variable costs are due to credits from the output-based pricing system (OBPS)

Included in the 2020 Reference Case are all policies and measures funded, legislated and implemented by federal, provincial and territorial governments as of September 2020. The carbon price increase to $170/tonne CO_2-e by 2030, the clean fuel standard and other measures that were part of Canada's strengthened climate plan were not included.[21],[33] The federal carbon pricing backstop in Canada covers non-combustion emissions through the Output-Based Pricing System (OBPS). However, facilities only pay for net emissions (after accounting for CCS) exceeding their Output-Based Allocation (OBA). This modeling exercise did not apply the OBPS to the H_2 production sector, which currently does not attempt to allocate

OBAs arising from H_2 production to probable centralized SMR+CCS hydrogen-producing sectors, such as chemicals & fertilizers, oil sands upgraders and refineries, that are subject to the OBPS.

The modeling scenarios in this paper represented three illustrative hydrogen supply responses to the same hypothetical high H_2 demand-side assumptions targeting the natural gas distribution network and hard-to-decarbonize sectors, such as industry, heavy duty freight (HDV). Percentage replacement of conventional fuels with H_2 increased linearly according to Table 4. H_2 substitution percentages modeled were informed by literature reports on iron production through direct reduced iron + electricity arc furnace (DRI-EAF), fuel cell vehicle projections, potential for fuel mixing in diesel, and maximum H_2 quantities tolerated in pre-existing natural gas utilizing equipment.[34],[35] Additional transmission pipeline power requirements to offset friction losses associated with increased H_2 content were ignored, as were slight declines in pipeline capacity related to reduced energy density of H_2 compared to natural gas.[36]

Table 4: Hydrogen Demand Assumptions for Low, Medium and High Scenarios

Demand Assumption	Units	2025	2050
% H2 in Natural Gas Distribution Pipelines	% (J/J)	1%	10%
% Industrial Heat from H2 Boilers	% (J/J)	1%	5%
% Coal/Coke feedstock replacement with H2 in Iron & Steel	% (J/J)	5%	100%
% Natural Gas feedstock replacement with H2 in Fertilizers, Refineries & Upgraders	% (J/J)	5%	100%
% Fuel Cell Market Share in Freight Heavy-Duty Trucks and Trains	% ($/$)	2%	100%
% H2 fuel mix in Heavy-Duty Diesel Trucks (Off-Road and On-Road)	% (J/J)	2.5%	5.0%

Notes:

1. Scenario assumptions apply to all provinces, but exclude territories.
2. Scenarios will only replace natural gas feedstocks with H_2 from electrolysis or CCS-capable SMR/ATR facilities, since SMR is already assumed for natural gas feedstocks in the reference scenario.

H_2 production was simulated through two main routes: natural gas (with or without CCS) and electrolysis. Key parameters for CO_2 capture fractions, energy requirements, plant capacity factors, assumed conversion efficiencies, capital costs, variable operating and maintenance (O&M) costs and fixed operating cost were based on NREL for centralized SMR-CCS and decentralized polymer electrolyte membrane (PEM) electrolysis (Table 5).[37]

Table 5: Hydrogen Production Costs for the Medium Scenario in Alberta

		2019	2050
Electrolysis			
LCOH (2019 US $/kg H_2)	E3MC	5.0	6.7
	IEA	3.2 - 7.7	1.3 - 3.3
Capital Costs (2019 US $/kW)	E3MC	1010	449
	IEA	872	269
OPEX (% CAPEX)	E3MC	4.0%	3.8%
	IEA	2.2%	1.5%
Electricity Price (2019 US $/kWh)	E3MC	0.06	0.12
	IEA	36.12	20.60
Efficiency	E3MC	61%	66%
	IEA	64%	74%
Utilization Factor	E3MC	86%	86%
	IEA	34% - 46%	23% - 34%
SMR+CCS			
LCOH (2019 US $/kg H_2)	E3MC	1.0	1.1
	IEA	1.2 - 2.1	1.2 - 2.1
Capital Costs (2019 US $/kW)	E3MC	970	856
	IEA	1583	1282
OPEX (% CAPEX)	E3MC	4.7%	5.0%
	IEA	3.0%	3.0%
Natural Gas Price (2019 US $/GJ)	E3MC	0.15	2.2
	IEA	1.4 - 6.3	1.7 - 7.0
Yield from Natural Gas Feedstock (J/J)	E3MC	73%	73%
	IEA	69%	69%
Utilization Factor	E3MC	90%	90%
	IEA	95%	95%

LCOH = Levelized Cost of Hydrogen
E3MC electrolysis values quoted are for Alberta grid electrolysis in the Medium Scenario
Sources: NREL 2018, IEA 2020

It was assumed that only large-scale centralized natural gas reforming facilities amenable to CCS would be constructed (CCS capture rates were assumed to increase from no to full adoption as CO_2 transportation and storage were built). Furthermore, electrolysis was assumed to be decentralized since transmission and distribution costs for electricity are less costly than those for hydrogen. H_2 storage, transmission and distribution pipeline costs were based on Bloomberg New Energy Finance.[38] Transmission costs were only assigned for centralized SMR-CCS, not decentralized electrolysis, since only the former required transportation to distribution centres.

Electricity for electrolysis was sourced through the grid, dedicated VRE units (wind and solar), or interruptible power that would otherwise be curtailed due to excess generation. Cost of water required for electrolysis was included in modeling. However, at this stage of model development, required volumes of water for electrolysis was not tracked in model output.

The modeling exercise in this study examined three illustrative supply scenarios: Low, Medium and High Cost for H_2 production (Supply assumptions by province are shown in Table 6). Low cost scenarios rely on natural gas for H_2 production in provinces with CCS potential – British Columbia, Alberta, Saskatchewan and Ontario. To account for time needed to build required CO_2 transport and storage infrastructure, CCS adoption is assumed to increase from no adoption to full adoption between 2025 and 2040. Percentage capture rates are assumed to increase from 90 to 95 percent between 2040 and 2050 as the preferred approach in producing H_2 from natural gas shifts from SMR to ATR – a process amenable to higher capture rates due to a more concentrated CO_2 effluent stream. Higher cost scenarios displace the cheaper production method from natural gas with increasing levels of electrolysis sourced through the grid, dedicated renewable or interruptible power.

Table 6: Hydrogen Supply Scenario Assumptions

		Scenario								
		Low Costs			**Medium Costs**			**High Costs**		
H2 Production Method	**H2 Production Subtype**	**BC/AB/SK**	**ON**	**Other PTs**	**BC/AB/SK**	**ON**	**Other PTs**	**BC/AB/SK**	**ON**	**Other PTs**
Electrolysis	Grid			100%	50%		50%	25%	25%	25%
Electrolysis	Renewable					40%	50%	75%	65%	75%
Electrolysis	Interruptible*					10%			10%	
Natural Gas - CCS**		100%	100%		50%	50%				

* available only in Ontario, pending model development for other provinces

** CCS increases from no adoption to full adoption between 2025 and 2040

In this study, we adopted a portfolio approach for grid expansion that sought to ensure minimum firm power requirements to back-up VRE. When E2020 determined the need for more electricity generation, the new capacity being built was divided across the different unit types as per the fractions specified (see Table 7).

Table 7: Electricity Capacity Expansion Portfolio

Technology	Capacity Additions Ratio
Onshore Wind	0.45
Solar PV	0.35
Gas (OGCC, OGCT, Small OGCC)	0.15
Peak Hydro	0.05

H_2 trade between provinces/territories was not allowed under the assumption of unfavorable transportation infrastructure and cost considerations. While foreign exports were also not allowed, imports from the international market were permitted in this modeling exercise to meet temporary H_2 supply shortfalls.

3 Modeling Results and Analysis

The views expressed in this paper are those of the authors and do not necessarily reflect those of Environment and Climate Change Canada or the Government of Canada

3.1 Energy Demand

Hydrogen demand increased to between 11.6 and 13.6 Mt H_2 (1.39 and 1.64 EJ) by 2050 with lower increases for higher cost scenarios as a result of higher end-use natural gas equipment efficiencies (Figure 7). The preference for the latter was a consumer response to the higher natural gas prices resulting from mixing in more expensive H_2. Hydrogen demands were split approximately evenly between H_2 used in transport fuel cells, the natural gas mix and as feedstock replacements. H_2 used in the diesel fuel mix had a minor share (see Figure 8).

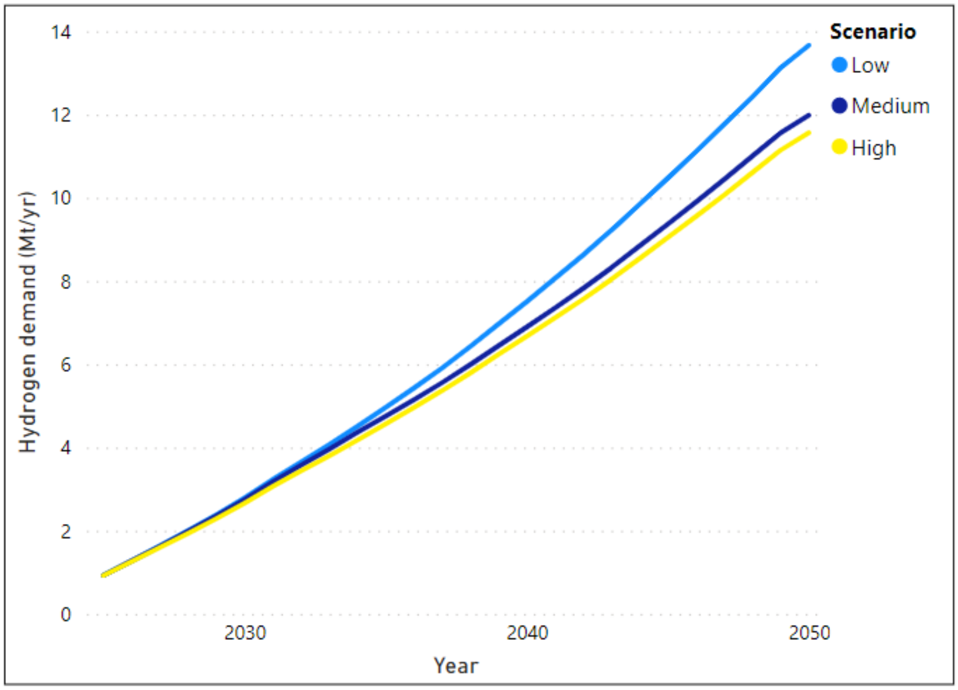


Figure 7: Hydrogen Demand by Scenario

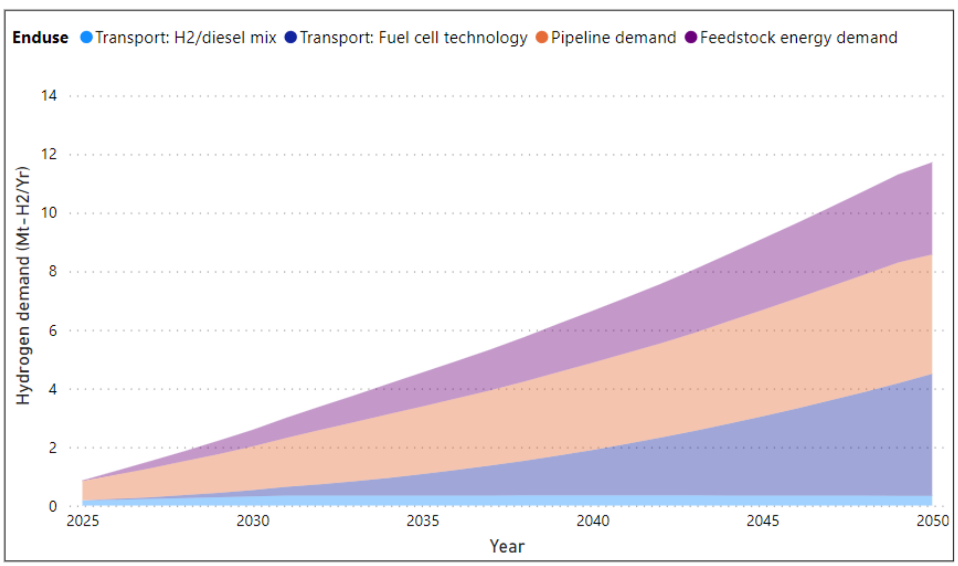


Figure 8: Hydrogen Demand by Use for the Medium Scenario

3.2 Hydrogen Production & Prices

Depending on the scenario, total hydrogen production attained 11.6 to 13.2 Mt H_2 (1.39 to 1.59 EJ) by 2050, with the lower cost scenario requiring slightly more production to meet hydrogen demands. Hydrogen production differed slightly from the 1.39 to 1.64 EJ of demand due to imports from the international market. Production profiles were consistent with scenario assumptions (Figure 9). The profile for the medium scenario in this study showed that production provided by interruptible power was negligible at a national level (Figure 10).

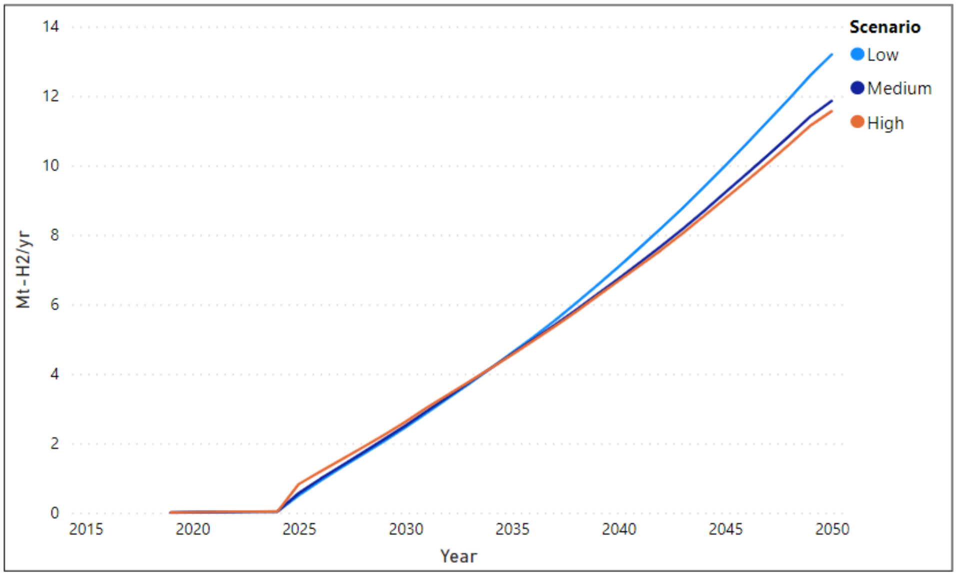


Figure 9: Hydrogen Production by Scenario

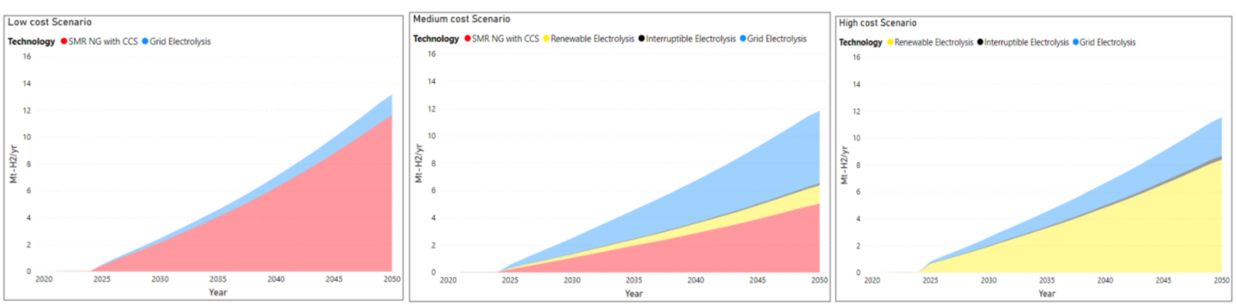


Figure 10: Hydrogen Production Pathways by Scenario

Hydrogen supply production costs were a function of input capital, variable O&M and fixed O&M costs, in addition to fuel costs and H_2 transmission costs. Unlike natural gas fuel costs, which were based on exogenous wholesale fuel prices, electricity fuel costs could vary between scenarios depending on endogenously calculated wholesale prices. Throughout all time periods SMR-CCS was cheaper than all types of electrolysis for the production of hydrogen (Figure 11).

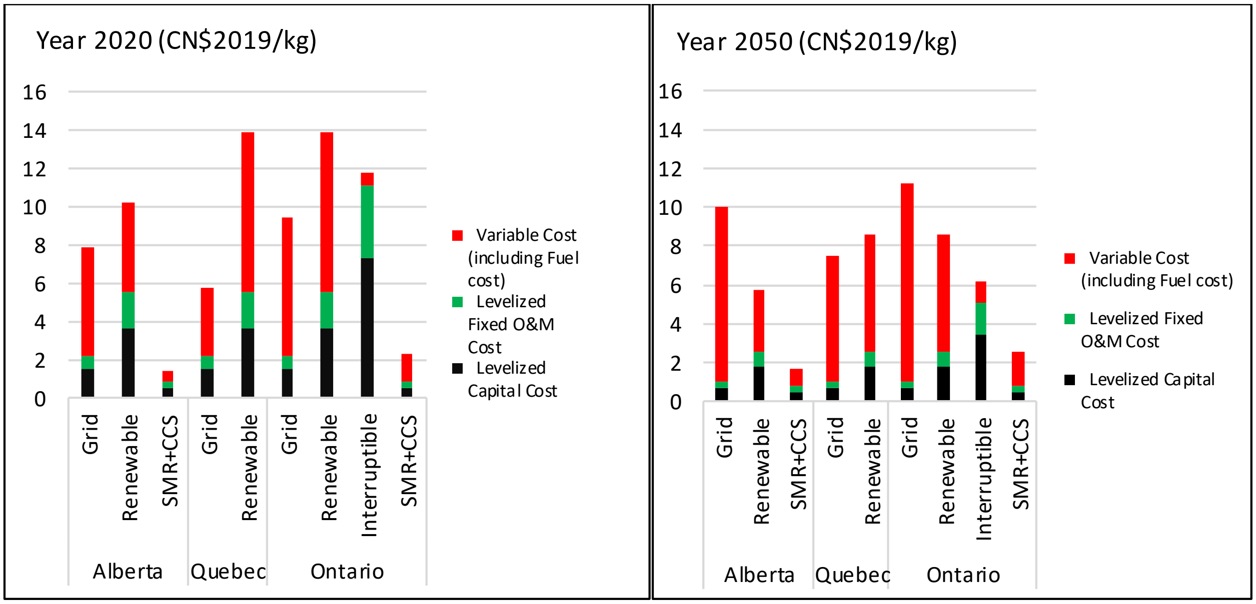


Figure 11: Hydrogen Supply Costs for Hydrogen Production Pathways

Fuel costs as reflected through variable costs dominated production costs for grid and renewable based electrolysis. While interruptible electrolysis had relatively low variable costs due to preferential electric prices, low capacity factors for electrolysers resulted in high proportions of levelized capital costs. We assumed that the capacity factor for interruptible electrolysis plants was 17%. By way of comparison, the capacity factor of grid electrolysis plants was 86%, while that of SMR plants was 90%.

Cost of production for SMR-CCS and grid-based electrolysis was seen to increase over time as a consequence of projected increases in natural gas and electricity prices. The latter was influenced by assumptions concerning increasing transmission costs. In contrast, electrolysis based on dedicated renewable units or interruptible power was seen to drop over time as a result of capital cost reductions related both to electrolysers and VRE units reflected through decreased variable fuel costs.

3.3 GHG Emissions

Compared to the reference scenario, annual GHG reductions by 2050 were between 140 to 171 Mt CO_2-e, with higher reductions under higher cost scenarios that were generally due to the aforementioned increase in equipment efficiency (Figure 12). Prior to 2038, the medium scenario exhibited the lowest overall GHG reductions due to a considerable amount of grid-based electrolysis being supplied by unabated fossil fuel fired electricity generation in Alberta.

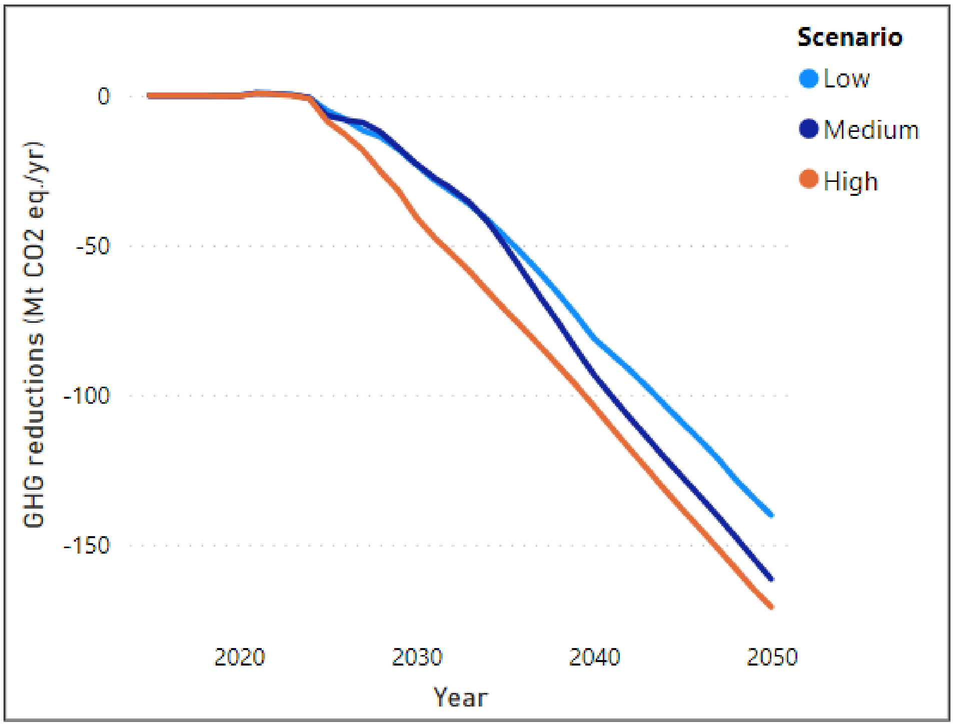


Figure 12: GHG Mitigation for Hydrogen Supply Production Scenarios

Overall GHG mitigation impacts in 2050 associated with fuel substitution exceeded impacts from efficiency gains in the low scenario, while the reverse was true for the medium and high scenarios (Table 8). At a sectoral level, higher costs scenarios had more GHG reductions by 2050 in most demand sectors due to higher end-use natural gas equipment and train fuel cell efficiencies. The hydrogen production sector had the highest emissions in the low cost scenario due to the largest share of emitting H_2 production. The electricity and steam generating sector exhibited emission reductions in all scenarios due to both the switching of fossil fuel to VRE generation and the H_2 mix in the natural gas. The medium cost scenario had the lowest GHG mitigation for the electric utility generating sector because it had the highest grid-based electrolysis requirements.

Table 8: GHG Mitigation by Sector Compared to the Reference Scenario in 2050 (Mt CO_2-e/yr)

	Low			Medium			High		
Sectors	Fuel switching	Efficiency gains	**Total**	Fuel switching	Efficiency gains	**Total**	Fuel switching	Efficiency gains	**Total**
Agriculture	0	-1	**-1**	0	-1	**-1**	0	-1	**-1**
Buildings	-5	-2	**-7**	-5	-4	**-9**	-5	-5	**-10**
Electricity and Steam	-1	-14	**-15**	-1	-12	**-13**	-1	-13	**-14**
Heavy Industry	-24	-12	**-36**	-23	-16	**-39**	-23	-17	**-40**
Oil and Gas	-22	-31	**-53**	-20	-46	**-66**	-19	-51	**-70**
Transportation	-27	-1	**-28**	-21	-8	**-29**	-20	-9	**-29**
Waste and Others	-2	-3	**-5**	-2	-5	**-7**	-2	-6	**-8**
Hydrogen Production	5	0	**5**	2	0	**2**			
Total	**-75**	**-65**	**-140**	**-69**	**-93**	**-162**	**-69**	**-103**	**-171**

*Notes: 1) Totals may not add up due to rounding

2) Values reported under efficiency gains for Electricity & Steam refer to reductions associated with substitution of VRE for fossil-fuel generation

3.4 Electric Capacity and Generation

All scenarios exhibited increases to electricity capacity and generation to support electrolysis. As the level of electrolysis increased in moving from low to high cost scenarios, total grid+dedicated VRE capacity and generation also increased (Figure 13). Compared to reference levels, the high scenario required 129% (238 GW) more capacity and 84% (627 TWh) more generation in 2050.

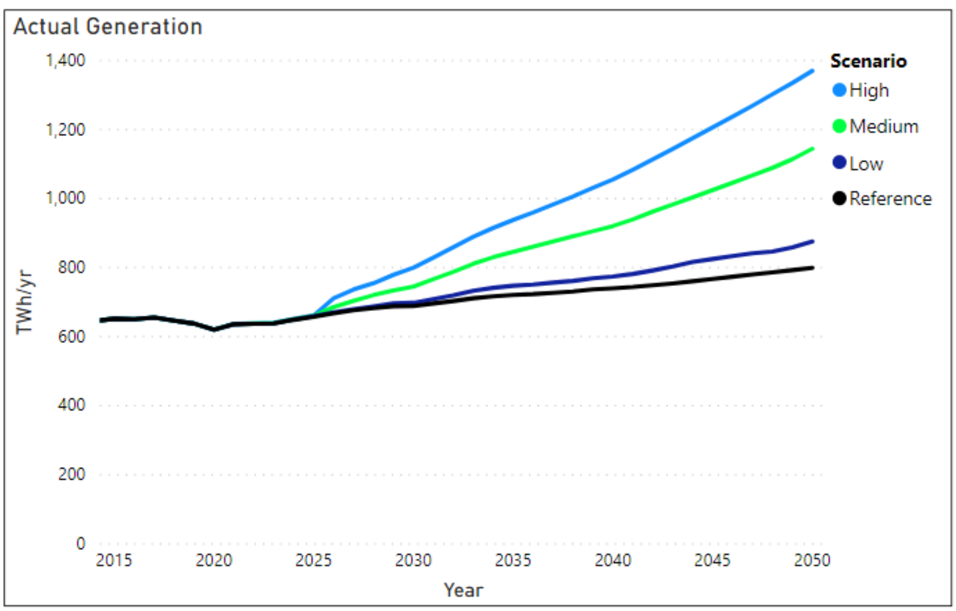


Figure 13: Canada Electric Generation (Grid + Dedicated VRE) by Scenario

Emissions from the electricity generation sector were dominated by Alberta, which had the largest provincial level of emitting units. While fossil fuel generating capacity in Alberta increased according to the portfolio throughout the projections, generation from these fossil fuels increased only in the early years before declining after 2035 when VRE generation started to increase sharply (Figure 14). These opposing trends in generation from fossil fuel compared to VRE were most pronounced in the medium scenario (since the share of grid electricity was highest in this scenario), thereby explaining why the medium scenario had lower GHG reductions prior to 2035 compared to the other scenarios.

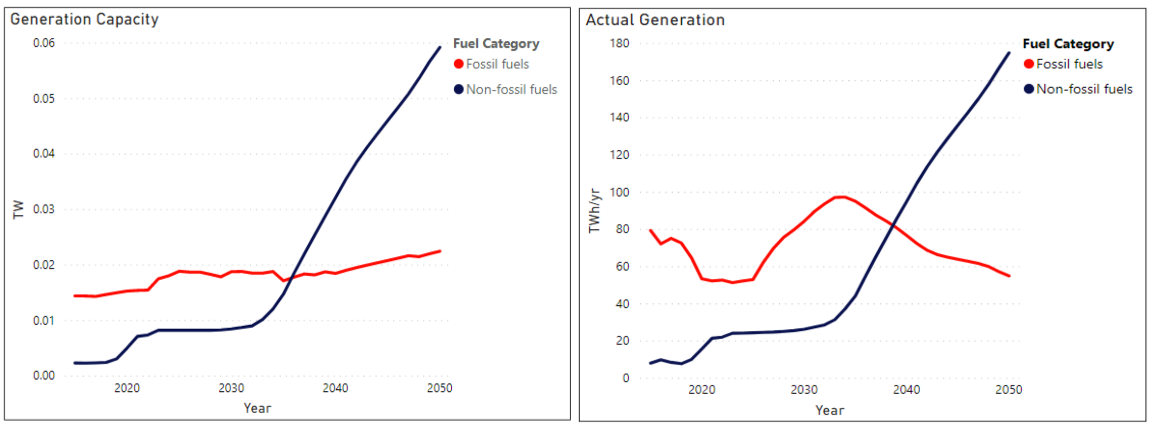


Figure 14: Alberta Electric Capacity and Generation by Fuel Category for the Medium Scenario

4 Discussion

In this study, the maximum scenario H_2 production (14 Mt of H2) and maximum GHG mitigation (171 Mt) achieved by 2050 were less than potentials quoted in the *Hydrogen Strategy for Canada* (20 Mt and 190 Mt, respectively) largely because the latter document included an additional estimation for hydrogen-based low carbon liquid fuels.[1]

Levelized cost of hydrogen (LCOH) production through electrolysis was similar to those reported by the International Energy Agency (IEA) in 2019 but diverged by 2050 due to higher projected electrolyser overnight capital costs (Table 5).[36],[39] LCOH production via SMR+CCS was similar to the IEA values throughout the projection period. While H_2 production pathways in this paper were forced regardless of production costs, natural gas and electricity fuel price projections would be important for modeling pathways based on levelized cost of production given the large proportion of costs attributed to fuels. Furthermore, the large proportion of fuel costs inherent in electrolysis production costs underline the importance of reducing electricity prices in addition to electrolyser capital costs in order for electrolysis to become cost-competitive with SMR without CCS. Canada's recently announced plan to increase the carbon price to $170/tonne CO2e by 2030 would increase the emission charge for SMR without CCS and reduce its relative cost advantage over electrolysis or SMR+CCS.[33]

Realistic cost projections for H_2 production were also demonstrated to be important in determining hydrogen demands, even under conditions of similar demand-side H_2 policies. The lower H_2 demands required under higher cost electrolysis scenarios as a result of higher efficiency end-use equipment emphasize the importance of considering GHG emissions both at the supply and demand side when choosing any H_2 production pathway.

The GHG impacts of this study were influenced by the electric dispatch, which favoured VRE over fossil fuel generation due to VRE's lower variable costs. The large proportion of VRE capacity that was built under the portfolio approach for grid expansion allowed the displacement of increasing amounts of fossil fuel generation in all scenarios. This resulted in similar GHG reductions for the electricity generating sector in all scenarios. The relatively minor share of reductions represented by the electricity sector in this study suggest that GHG mitigation of any chosen H_2 pathway are likely to be dominated by fuel-switching and energy efficiency gains in other sectors. However, electricity-related emissions are dependent on assumptions concerning integration of high levels of VRE with the electricity grid. A more conservative view on VRE integration would lead to fewer GHG reductions or even emission increases in the electricity generating sector. Further work is required to evaluate grid-integrated VRE upper limits, which depend on many factors including relative levelized capital costs of competing generation types, VRE availability, storage characteristics, regional transmission links and jurisdictional preferences. Careful examination of all of these factors is crucial to interpreting results.

The substantial increases in overall and non-emitting electric generation for electrolysis is comparable to that projected in hydrogen strategies for Canada and other countries, such as Australia and Germany.[1],[40],[41] Although substantial in this study, electricity generating capacity additions to support grid-based electrolysis could be either pessimistic or optimistic, given the storage back-up assumptions for grid VRE units and uncertainty regarding future electricity costs and grid operation approaches.

5 Conclusions

In order to properly assess the potential contribution of hydrogen to GHG mitigation goals for hard-to-decarbonize applications, comparing different hydrogen production pathways will become increasingly important. The three hydrogen production scenarios examined in this study all exhibited noticeable emission reductions by 2050, but that nevertheless varied noticeably from the lowest cost (140 Mt) to the highest cost (171 Mt) scenario.

While work remains to improve modeling of various hydrogen production pathways, the current project demonstrated the potential of the E2020 model to evaluate the economy-wide GHG and electricity impacts of these pathways due to the model's integrated energy demand-supply nature. As such, E2020 is expected to continue to serve as an important tool in evaluating electrification and decarbonization pathways into the future.

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