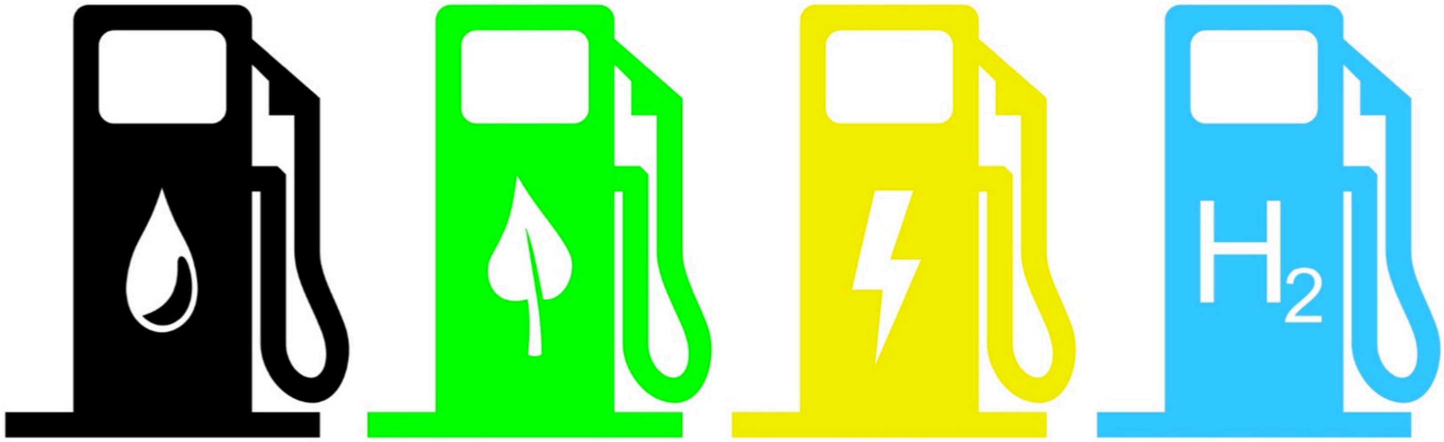

CESAR SCENARIOS

Volume 4 • Issue 2 • September 2019

THE FUTURE OF FREIGHT

PART B: ASSESSING ZERO EMISSION DIESEL FUEL ALTERNATIVES FOR FREIGHT TRANSPORTATION IN ALBERTA

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UNIVERSITY OF CALGARY

CESAR

A project associated with

The Transition Accelerator

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VERSION 3

About CESAR and The Transition Accelerator

CESAR (Canadian Energy Systems Analysis Research) is an initiative started at the University of Calgary in 2013 to understand energy systems in Canada, and develop new analytical, modeling and visualization tools to support the transition to a low-carbon economy.

In 2017, CESAR launched its **Pathways Project** to define and characterize **credible** and **compelling** transition pathways for various sectors of the Canadian economy that would help the nation meet its 2030 and 2050 climate change commitments made in Paris in 2015 (**Figure 1.1**).

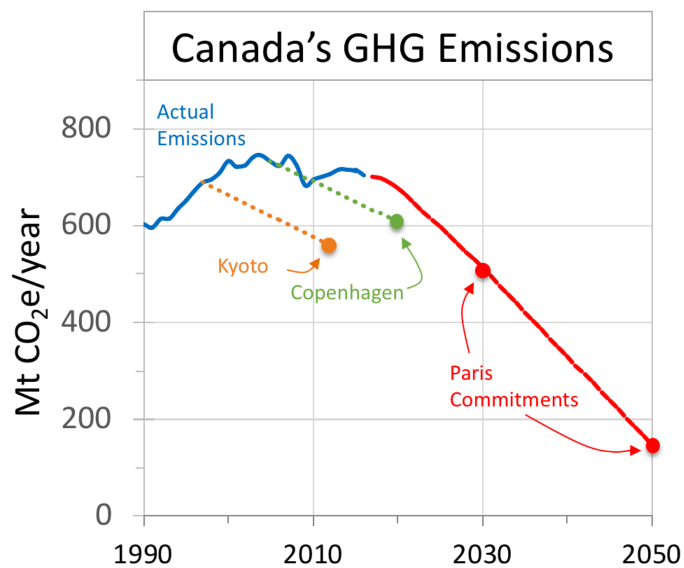

Figure 1.1. Canada's greenhouse gas emissions (solid blue line), showing the future trajectory needed to meet Paris commitments (red line). Past failed commitments are also shown. Data from the 2018 National Inventory Report for Canada for 1990-2016 (http://www.publications.gc.ca/site/eng/9.506002/publication.html)

A CESAR Scenarios publication in early 2018[1], and the support and encouragement from a number of charitable foundations led to discussions among CESAR's Director, **David Layzell**, Carleton University professor **James Meadowcroft** (Canada Research Chair in Governance for Sustainable Development, School of Public Policy and Administration) and Université de Montréal professor **Normand Mousseau** (Dept of Physics and Academic Director, Trottier Energy Institute) regarding the need for a pan-Canadian initiative to accelerate the development and deployment of Transition Pathways.

1 D. B. Layzell and L. Beaumier, "Change Ahead: A Case for Independent Expert Analysis and Advice in Support of Climate Policy Making in Canada," CESAR Scenarios, vol. 3, no. 1, Feb. 2018 [Online]. Available: https://www.cesarnet.ca/publications/cesar-scenarios/change-ahead-case-independent-expert-analysis-and-advice-support

With guidance and financial support from a number of private Canadian foundations, a charitable non-profit was launched in 2019 and called the **Transition Accelerator**. Associated with the launch, a report was published[2] to articulate a philosophy and methodology that is now used by both CESAR and the Accelerator.

In defining and advancing transition pathways, **CESAR** and the **Accelerator** recognize that transformative systems change is needed to achieve climate change targets (see **Figure 1.1**). However, for many, perhaps most Canadians, climate change is not a sufficiently compelling reason for large-scale systems change, especially if it has substantive costs. Nevertheless, we live in a time of disruptive systems change driven by innovations that both promise and deliver highly compelling benefits, such as enhanced convenience, comfort, status, value for money and quality of life. What if it were possible to harness these disruptive forces to also deliver societal objectives for climate change mitigation?

The **Accelerator**'s mandate is to work with key stakeholders and innovators to speed the development and deployment of credible and compelling pathways that are capable of meeting climate change targets using a four-stage methodology:

1. **Understand** the system that is in need of transformative change, including its strengths and weaknesses, and the technology, business model, and social innovations that are poised to disrupt the existing system by addressing one or more of its shortcomings.
2. **Codevelop** transformative visions and pathways in concert with key stakeholders and innovators drawn from industry, government, the academy, environmental organizations and other societal groups. This engagement process will be informed by the insights gained in Stage 1.
3. **Analyze** and model the candidate pathways from Stage 2 to assess costs, benefits, trade-offs, public acceptability, barriers and bottlenecks. With these insights, the researchers then re-engage the stakeholders to revise the vision and pathway(s) so they are more credible, compelling and capable of achieving societal objectives that include GHG reductions (see **Figure 1.2**)
4. **Advance** the most credible, compelling and capable transition pathways by informing innovation strategies, engaging

2 J. Meadowcroft, D. B. Layzell, and N. Mousseau, "The Transition Accelerator: Building Pathways to a Sustainable Future," vol. 1, no. 1, p. 65, Aug. 2019. [Online]. Available: https://www.transitionaccelerator.ca/blueprint-for-change

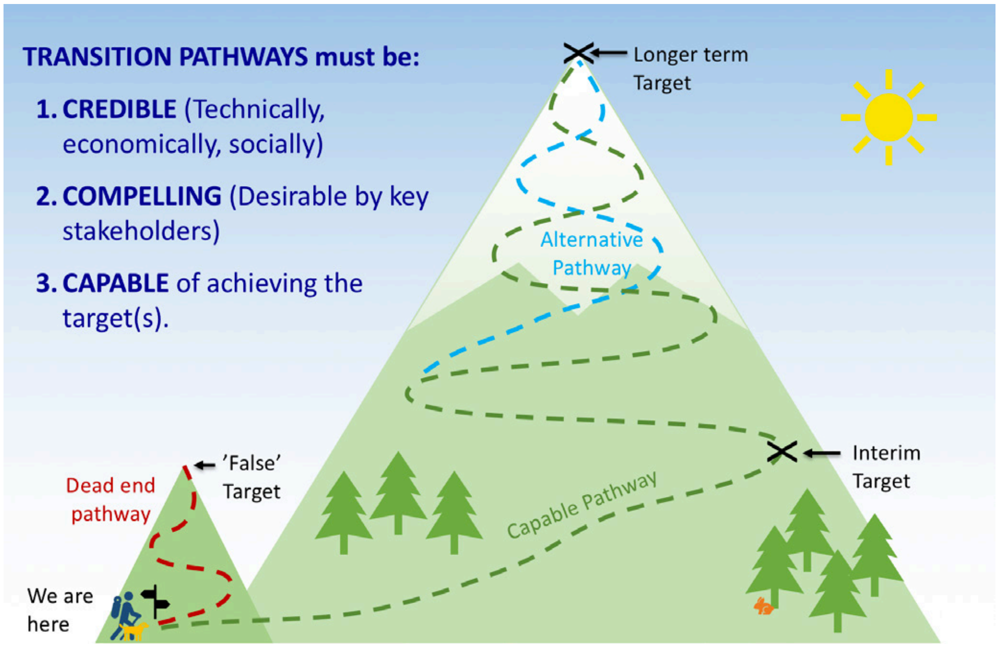

Figure 1.2. Criteria for a useful transition pathway. The two-mountain image is provided to stress the importance of pathways being capable of achieving longer term targets. Some climate change policies encourage dead end pathways to 'false' targets based only on incremental GHG reductions, but which clearly are not on a pathway to a longer-term target.

decision makers in government and industry, participating in public forums, and consolidating coalitions of parties enthusiastic about transition pathway implementation.

This study reports Stage 3 results for the freight transportation sector in Alberta.

About the Authors

Jessica Lof, B Comm, MSc (SEDV)

Jessica Lof is a Research Lead for the Canadian Energy Systems Analysis Research (CESAR) Initiative at the University of Calgary with a special interest in low carbon transition pathways for Canada's transportation systems. Jessica is also actively exploring hydrogen economy ecosystems and evaluating system-level opportunities and trade-offs while connecting with stakeholders.

Jessica joined CESAR with more than a decade of business experience in the railway and trucking sectors. Throughout her career, she has designed transportation and logistics solutions that enable economic potential and drive operational efficiency in a vast array of industries, including wind energy, oil and gas, automotive and global trade. Jessica has a Master of Science degree in Sustainable Energy Development, a Bachelor of Commerce degree, and a professional designation with the Canadian Institute of Traffic and Transportation.

Kyle McElheran, BSc, EIT

Kyle McElheran completed a Bachelor of Science in Mechanical Engineering at the University of Calgary, specializing in energy and the environment. Kyle's interest lies in nuclear energy. Some of his projects include a life cycle assessment comparison of using small modular nuclear reactors to generate steam in the oil sands, a review of Canada's current nuclear waste management plan, and a review of the DUPIC (Direct Use of Spent Pressurized Water Reactor Fuel in CANDU) nuclear fuel cycle to feed unprocessed spent fuel from pressurized water reactors into CANDU reactors.

Kyle completed a one year internship with Suncor Energy where he worked to optimize construction productivity on the Fort Hills oil sands mine project. In his final academic year, he began studying Canadian energy systems and investigated, as part of an Energy and Environment Specialization capstone course, how autonomous vehicles might impact the future emissions of personal transportation in Alberta. He hopes his contribution at CESAR will have a meaningful impact on driving Canada towards a sustainable future.

Madhav Narendran, BSc, BA

Madhav Narendran graduated from the University of Calgary with dual undergraduate degrees in Electrical Engineering (specializing in Energy and the Environment) and Economics. As an undergraduate student he worked with CESAR on a study that considered SAGD cogeneration in the oil sands as a means of greening Alberta's electrical grid. With a variety of interests in the study of energy systems, Madhav has experience working in several fields, including high voltage engineering with ABB, electrical transmission with Altalink LP, and most recently, natural gas trading with BP Canada Energy Group. Madhav is passionate about the use of data to impact real change in policy and decision making. Through his contributions at CESAR he hopes to do just that – provide simple and accessible information to corporate and government entities so they may make meaningful strides toward a more sustainable future.

Nicole Belanger, BSc

Nicole recently graduated with an undergraduate degree in Mechanical Engineering at the University of Calgary, specializing in Energy and the Environment. Passionate about sustainable energy systems, Nicole has worked and studied in several areas of the energy sector. She spent a research term in wind turbine optimization and also studied renewable energy and entrepreneurship abroad in China. For her internship, she worked for one year in Switzerland for GE Power, in gas turbine reconditioning and maintenance. In her Energy and Environment capstone course she developed a pathway with her team to transform Canada's agricultural residues into biochar, a more permanent form of carbon storage.

Nicole is interested in whole system design and the circular economy. She wants to design systems that combine opportunities for economic prosperity with the disruptive changes needed to make society more sustainable. Her interests encompass waste management, biodegradable alternatives to plastic packaging, alternative fuels and emerging technologies in carbon capture and storage.

Bastiaan Straatman, PhD

Bastiaan Straatman has been modeling complex systems throughout his career, but since early 2012, he has been focused on developing and using the Canadian Energy Systems Simulation (CanESS) model to study the past, present and possible future energy systems of Canada. His past work has involved spatial decision support models, models of evolutionary dynamics in economics and models depicting greenhouse gas emissions in municipalities. Bastiaan holds a Master degree in Mathematics and a PhD in Geography. He currently has a fulltime position as a modeller with whatIf? Technologies Inc.

Song Sit, PhD, PEng

Song P. Sit is a Chemical Engineer with 40 years of industrial experience. A veteran of oil sands operations, Song has been involved in many different aspects of the industry over the past 28 years. Most recently, he helped to establish the collaboration agreement for the Canada's Oil Sands Innovation Alliance (COSIA) greenhouse gas (GHG) Environmental Priority Area (EPA). This enabled COSIA members to work together to develop new GHG reduction technologies. Before that, as a member of the Joint Venture Owner Management Committee of an integrated mining/upgrading Joint Venture, he helped to launch a multi-phase expansion program that trebled its production. As a member of the National Oil Sands Task Force, Dr. Sit helped the Alberta Government implement the Generic Oil Sands Royalty regime in 1997, and as a member of the Canadian Association of Petroleum Producers (CAPP) task group working with Alberta Environment, he helped to establish the rules for the Specified Gas Emitter Regulations, including emission allocations for cogeneration. As an employee of a major oil sands producer for 28 years, he has been engaged in the development of technologies for new oil sands surface facilities, including innovations in GHG reduction and value-added oil sands products. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and the principal of GHG Reduction Consultancy, founded in 2015.

David B. Layzell, PhD, FRSC

David Layzell is a Professor at the University of Calgary and Director of the Canadian Energy Systems Analysis Research (CESAR) Initiative, as well as co-founder and Research Director of the Transition Accelerator. Between 2008 and 2012, he was Executive Director of the Institute for Sustainable Energy, Environment and Economy (ISEEE), a cross-faculty, graduate research and training institute at the University of Calgary.

Before moving to Calgary, Dr. Layzell was a Professor of Biology at Queen's University, Kingston (cross appointments in Environmental Studies and the School of Public Policy), and Executive Director of BIOCAP Canada, a research foundation focused on biological solutions to climate change. While at Queen's, he founded a scientific instrumentation company called Qubit Systems Inc. and was elected 'Fellow of the Royal Society of Canada' (FRSC) for his research contributions.

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Abbreviation	Definition
AESO	Alberta Electric System Operator
BD-ICE	Bio-based, diesel fueled internal combustion engine energy system
BE	Battery electric drivetrain for a vehicle (plug-in for recharging)
CanESS	Canadian Energy Systems Simulator Model (whatIf? Technologies Inc., Ottawa, ON)
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization and storage
CERI	Canadian Energy Research Institute
CESAR	Canadian Energy Systems Analysis Research Initiative, University of Calgary
CO	Carbon Monoxide
CO_2	Carbon dioxide
EPA	Environment Protection Agency
FD-ICE	Fossil-diesel fueled internal combustion engine energy system
FR	Feedstock retention
FT	Fischer-Tropsch
G-BE	Public grid to battery electric drivetrain energy system
GHG	Greenhouse gas
GJ	Gigajoule
GVWR	Gross Vehicle Weight Rating. Gross vehicle weight includes the weight of the vehicle plus the payload weight.
H_2	Hydrogen gas
HDV	Heavy duty vehicle: vehicles with a GVWR of ≥ 15 tonnes
HFCE	Hydrogen fuel cell electric drivetrain (typically hybrid, with batteries)
HHV	Higher Heat Value
HVDC	High voltage direct current
ICCT	International Council on Clean Transportation

ICE	Internal combustion engine
IRENA	International Renewable Energy Agency
LCOE	Levelized cost of electricity
LCV	Long combination vehicles
NACFE	North American Council for Freight Efficiency
NG	Natural Gas
NG CC	Natural gas fired, combined cycle gas/steam turbine for power generation
NG-HFCE	Natural gas-based hydrogen to hydrogen fuel cell electric drivetrain energy system
NG SC	Natural gas fired, simple cycle gas turbine for power generation
NO_x	Nitrogen oxides
NREL	National Renewable Energy Laboratory
O_2	Oxygen gas
Other Road Freight	Vehicles with a GVWR of between 3.9 and 15 tonnes with a primary purpose of moving freight
PADD	Petroleum Administration for Defense Districts
PEM	Proton exchange membrane
PEMFC	Proton exchange membrane fuel cell
$PM_{2.5}$	Particulate matter of <2.5 μm in diameter
PSA	Pressure swing absorption gas separation technology
RPP	Refined petroleum products
SCO	Synthetic crude oil
SI units	International System of Units
SMR	Steam methane reforming
SO_x	Sulphur oxides
Tare weight	Weight of the vehicle without payload
TEEA	Techno-economic and environmental assessment
Typical Shipment	Heavy duty road freight vehicle with a gross vehicle weight of 27 tonnes traveling 750km
WS-HFCE	Wind and solar power-based hydrogen to hydrogen fuel cell electric drivetrain energy system

Executive Summary

Long-haul freight transportation is the backbone of the Canadian economy. This is especially true in Western Canada where population centers are often several hundred kilometers apart, and Heavy-Duty Vehicles (HDVs) are the primary mode for goods movement.

The Fossil Diesel – Internal Combustion Engine (FD-ICE) energy system has been the dominant fuel of the freight industry for decades. Concerns with air pollution and greenhouse gas (GHG) emissions from diesel combustion have been the primary driver to develop alternative energy systems.

This report compares the incumbent FD-ICE energy system with four alternative energy systems (assuming deployment at scale) in terms of their ability to meet the needs of the freight sector and the environment in supporting the movement of a 27 tonne (gross) vehicle over a distance of 750 km (i.e. a 'Typical Shipment').

The alternative energy systems were:

- **BD-ICE:** The production and use of bio-based diesel fuels made from lignocellulosic biomass as a 'drop-in' fuel with vehicles having the existing internal combustion engine infrastructure;
- **G-BE:** Plug-in, battery electric vehicles where the electricity comes from an electrical grid with the carbon intensity of Alberta's public grid in 2016 (719 kg CO_2e/MWh) or a hypothetical 2030 grid which has no coal power generation and renewables account for 30% of the generation (270 kg CO_2e/MWh);
- **NG-HFCE:** A hydrogen fuel cell electric (hybrid) vehicle where the hydrogen is produced from Alberta natural gas either without or with carbon capture and storage (CCS) of 90% of the emissions associated with the production of the hydrogen;
- **WS-HFCE:** A hydrogen fuel cell electric (hybrid) vehicle where the hydrogen is produced by water electrolysis using wind (75%) and solar (25%) electricity generated in Alberta.

Using industry data for the FD-ICE system, the kinetic energy needed for a 'Typical Shipment' is 3.8 GJ, which equates to a retail requirement of 10.8 GJ diesel per trip, well-to-wheels system-level efficiency of 26% and well-to-wheels GHG emissions of 1085 kg CO_2e/trip.

To meet Canada's 2050 climate change commitments, the well-to-wheels emissions would need to be reduced by 84% or 178 kg CO_2e/trip, reflecting an 80% reduction of 2005 level of freight diesel emissions.

The BD-ICE energy system has the benefit of being a drop-in fuel with the incumbent system but given the scale of diesel demand in Alberta and North America, lignocellulosic biomass (wood and straw) is the only credible feedstock. However, the low efficiency (~51%) associated with converting lignocellulosic biomass to bio-based diesel (resulting in a well-to-wheels system level efficiency of 16%), and the distributed nature of the resources makes the fuel expensive compared to the FD-ICE energy system. Assuming a global warming potential for biomass of less than 0.1, the BD-ICE system could meet the GHG target. However, the bio-based diesel is not a zero-emission fuel, so air pollution from heavy duty vehicles would still be a problem.

The G-BE energy system should be able to support a Typical Shipment at a fuel price that is equal to or less than the FD-ICE system, and the well-to-wheels system level efficiency is high at 34% assuming a 2030 public grid. However, the Typical Shipment requires batteries that would severely compromise the carrying capacity of the vehicle, so we assume only 375 km between refueling for this energy system. Even so, the refueling time with next generation high capacity chargers is an unacceptable 1.5 hours, more than 20 times that for the FD-ICE system. Roadway electrification strategies could address this problem, but the costs are expected to be prohibitive. Moreover, given the carbon intensity of the Alberta electrical grid in 2016, the well-to wheels GHG emissions in the G-BE system is 18% higher than that for the FD-ICE system. Assuming the hypothetical 2030 grid, the well-to-wheels GHG emissions are 50% of the FD-ICE system, but still about three times the target emission of 178 kg CO_2e/trip.

The NG-HFCE energy system assumes centralized production of hydrogen from Alberta's low-cost natural gas (NG), coupled to the capture and storage of 90% of the CO_2. It achieves a well-to-wheels system-level efficiency of 27%. The distribution (by tube truck) and compression of that hydrogen add significantly to the cost of the fuel for the Typical Shipment. While the fuel cost is higher than that for the FD-ICE energy system, it is less than that in the BD-ICE energy system. Assuming a coal-free, 30% renewable grid in Alberta supporting H_2 compression, the well-to-wheels GHG emissions from the NG-HFCE energy system is close to the target GHG emissions for a typical trip.

The WS-HFCE energy system makes hydrogen from electrolysis of water using electricity from wind and solar generation with a well-to-wheels, system-level efficiency of 30%. While no GHG or air emissions are generated, the relatively high cost of the feedstock electricity, the high cost of the electrolysis and the challenges in moving the fuel to the fueling stations positions this energy system as the most expensive of the alternative fuels studied here. As will be discussed in the next report in this series, there are other potential benefits of this energy system that could mitigate these higher costs.

The high torque, lower maintenance cost, fewer emissions and quieter operation of the electric drive HDVS (i.e. G-BE, NG-HFCE, WS-HFCE) are highly compelling for the freight sector. While the cost of these vehicles are currently much higher than comparable ICE vehicles, the freight sector we interacted with is keenly interested in the technology, and looks forward to cost reductions that could come with larger scale deployment.

Given the importance of North American diesel demand to the oil-dependent Alberta economy, the next report in this Series explores the resource and economic implications for Alberta should any of the alternative energy systems become the dominant energy system supporting the heavy freight sector or other sectors that are currently reliant on diesel.

1. Introduction

Canada's size and its role as a trading nation, underscores the importance of freight transportation to the nation's economy and the quality of life for its citizens. This sector is also important to the energy industry of Canada, since it consumes a significant portion of the diesel fuel that accounts for about 30% of each barrel of oil that Canada produces.

However, as noted in a previous study [1], the freight transportation sector across North America is poised for major transformative and potentially disruptive changes driven by both challenges within the sector and technology, business model, policy and social innovations arising from outside.

The problems include the sector's contribution to air pollution, greenhouse gas (GHG) emissions, accidents and road congestion. In addition, the trucking sector struggles with poor load factors, low asset utilization, sub-optimal productivity and labour shortages [1].

To address these problems, companies around the world are spending billions of dollars every year to develop technology or business model innovations in the quest for market share in the huge, global supply chain sector. Autonomous (driverless) trucks promise to significantly reduce trucking costs and accidents while increasing asset utilization and address the labour shortage [1]. Integrated with big data and robotics, new business models such as the physical internet promise to improve load factors and productivity.

Battery or hydrogen fuel cell electric trucks are also being developed by a number of companies to address air pollution and climate change concerns while reducing vehicle noise and maintenance costs and enhancing performance.

On the policy side, many countries and regions of the world have announced bans on internal combustion engines or diesel vehicles by 2030 or 2040 (**Figure 1.3**) [2]-[5].

Of all these innovations, the large-scale, wide-spread movement towards heavy duty vehicle (HDV) electrification provides the greatest threat to the Canadian and Albertan oil industry because it would reduce the demand for diesel fuel. The performance promises of these vehicles is attractive to the transportation sector, and may be even more attractive with the introduction of autonomous and connected vehicles, especially for long distance freight movement [6]

A key question for Canada, and the energy-rich provinces like Alberta involves the implications of battery electric (BE) heavy trucks such as those being promoted by Tesla [7], Daimler [8], and Thor Trucks [9], versus hydrogen fuel cell electric (HFCE) Trucks such as those being promoted by Nikola Motors [10], Toyota [11], and Kenworth/Ballard [12]. Which transformative technology will best meet the needs of the freight transportation sector, and also provide significant opportunities for economic growth?

"A key question for Canada and Alberta involves the implications of battery electric (BE) versus hydrogen fuel cell electric (HFCE) trucks. Which transformative technology will best meet the needs of the freight sector, and also provide significant opportunities for economic growth?"

This report is the first of two that addresses this question by carrying out systems-level techno-economic and environmental assessments (TEEAs) of low-carbon energy system alternatives to fossil-fuel based diesel in support of freight transportation in Alberta.

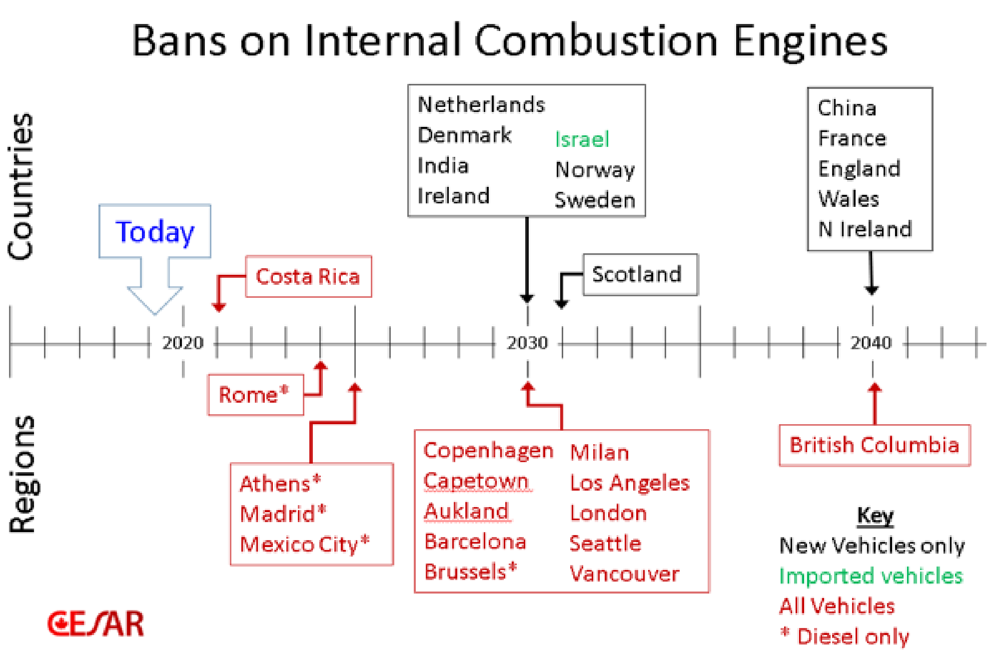

Figure 1.3. Timeline of announced bans on Internal Combustion Engines (ICEs) around the world [2]-[5]

While this study explores the per trip performance of these alternative energy systems, the next report [13] assesses the potential of these systems to contribute to the economy of Alberta, the Canadian province that benefits most from the current diesel-based transportation system.

Although most of the calculations reported here would be relevant to any region of Canada, some of the input assumptions (e.g. electrical grid carbon intensity, natural gas (NG) price, wholesale diesel price) would differ by province or region within a province. In these cases, values for the province of Alberta were used.

2. Methodology

To carry out this study, detailed analyses began with a quantification of the energy and dollar flows though the incumbent fossil-fuel-based diesel energy system. Other metrics of importance to the industry were also collected for this energy system, including fueling times, torque, maintenance costs, etc.

The analysis was then extended to include four alternative energy systems, one involving biodiesel, and three of which featured the production and use of zero-emission fuels. The following sections provide details of each energy system and the analyses that were carried out.

2.1. The Five Energy Systems

A system-level (well-to-wheel) approach was used to compare the energy system alternatives to the incumbent fossil diesel – Internal combustion engine (FD-ICE) reference energy system (**Figure 2.1**). Literature values were used to calculate the conversion efficiencies and other energy inputs and output associated with each energy system. The five energy systems include:

Fossil Diesel Fueled ICE (FD-ICE) Energy System

This reference system currently dominates the HDV trucking sector across North America. It is assumed that diesel consumed is a refined petroleum product (RPP) produced from a mix of Alberta crude oil and is refined across North America. Data from a number of government sources [14-22] for 2016 has been compiled and used to calculate average crude oil volume and energy contents and the corresponding RPP allocations.

Bio-based Diesel Fueled ICE (BD-ICE) Energy System

A second reference system involved the use of drop-in replacement diesel fuel made from bio-based lignocellulosic (wood and straw) feedstock using Fischer-Tropsch (FT) synthesis. This feedstock was selected because it was available in much higher quantities [13] than other biological sources (e.g. fats and oils). The Fischer-Tropsch conversion technology described by Vliet et al. in a 2009 study [23] was chosen since it did not require a exogenous energy input (e.g. hydrogen) to convert the biomass into a diesel-like product. The conversion technology is also well known and reasonably mature.

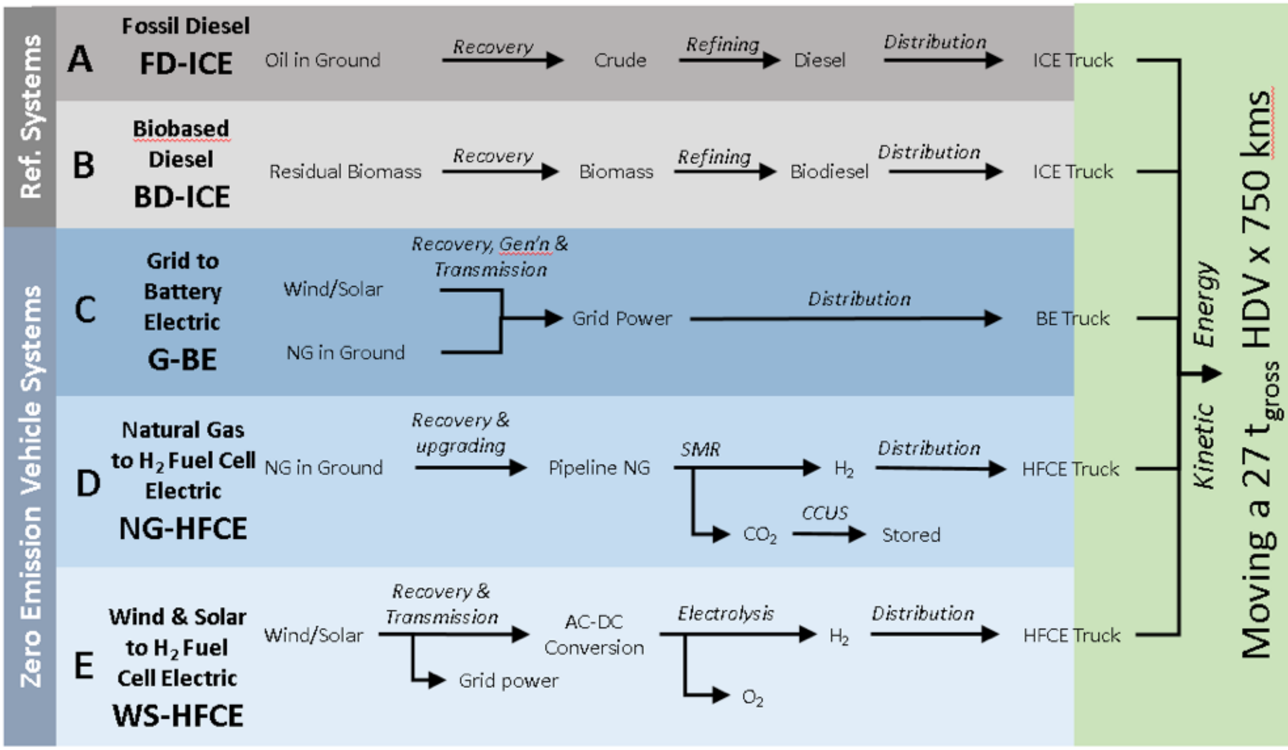

Figure 2.1. Summary of the five energy systems compared in this report. HDV, heavy duty vehicle; ICE, Internal Combustion Engine; SMR, Steam Methane Reforming; CCUS, Carbon Capture, Utilization, and Storage. See text for details.

Grid to Battery Electric (G-BE) Energy System

Power from the grid is used to charge batteries that then drive an electric motor to move the HDV. Two grid mixes were assessed, both for Alberta:

- A 2016 public grid mix (i.e. not counting behind the fence industrial cogeneration), consisting of 61% coal, 27% NG (17% cogeneration, 1% single cycle, 9% combined cycle), and 11% renewable power generation [24].
- A 2030 public grid mix (post-coal phase out [25]), consisting of grid mix is also considered with 0% coal, 70% NG (20% cogeneration, 4% simple cycle, 46% combined cycle) and 30% renewable power generation.

Natural Gas to Hydrogen Fuel Cell Electric (NG-HFCE) Energy System

Onboard hydrogen fuel cells are used to convert H_2 fuel to electricity to power an electric motor to move the HDV. In this energy system, the H_2 is generated from NG with steam-methane reforming (SMR) and part of the waste CO_2 is captured and stored (CCS) in the subsurface or otherwise utilized. Although there are other fossil fuel hydrogen production technologies available, SMR with CCS has been selected because of its maturity and industrial prevalence. Details of the efficiency in the conversion process were from the National Renewable Energy Laboratory [26].

Wind/Solar to Hydrogen Fuel Cell Electric (WS-HFCE) Energy System

This system is similar to energy system D, but the H_2 is generated from large wind and solar facilities that supply the grid when needed and generate H_2 and oxygen (O_2) from water electrolysis when generation is in excess of grid demand.

2.2. Defining the 'Typical' Long-Distance Shipment and the Kinetic Energy Demand

According to Statistics Canada [27], long-distance shipments represent between 80-84% of all commercial shipments in Canada, and the average shipment moves **17 tonnes (about 27 tonnes gross load, assuming a 10 tonne tractor unit) a distance of 750 km**. This 'Typical Shipment' was used to compare the performance of each of the five energy systems.

To compare the energy systems across various drivetrains (ICE, BE, HFCE), a calculation was made of the kinetic energy required for the Typical Shipment. This value was calculated from the FD-ICE system assuming an average fuel economy of 2.2 L diesel/t(load)-100km [28], equivalent to 1.4 L/t(gross)-100km. Therefore, for a 750 km trip, 283 L diesel would be required. Given a higher heating value (HHV) for diesel of 38.4 MJ_{HHV}/L [18], and assuming 35% efficiency for the ICE drivetrain [29], the kinetic energy requirement was calculated to be 3.8 GJ_{HHV}/trip. Because the HDVs associated with each system are performing the same work and are aerodynamically similar, a kinetic energy requirement of 3.8 GJ_{HHV}/trip was assumed for all energy systems (Table S1, [30]).

2.3. Assessment Criteria

Each energy system was assessed according to the following five criteria which were supported by values from literature and/or expert advice. In this presentation of the methodology, only the general approach is presented here. The particular conversions factors, assumptions and references associated with each energy system are presented along with the results, and in the Supplemental Materials [30].

Energy Flows

Starting with the 3.8 GJ_{HHV}/trip of kinetic energy required to move the HDV, the total energy demands are calculated for each conversion technology back to the primary energy extraction. Where possible, data from life cycle assessments were used to quantify the energy inputs and outputs and determine both the conversion efficiency (Eff) and the proportion of the energy in the primary feedstock that was retained (FR) in that conversion.

In this way, the energy inputs and losses at each stage in energy conversion were tracked and ultimately presented as Sankey diagrams where the height of each horizontal bar is proportional to the magnitude of energy flowing (units of GJ_{HHV}/trip).

For energy systems relying on grid power, the energy flows assumed a projected 2030 Alberta grid which has 30% renewables, and 70% NG (no coal) power generation.

Energy Costs

The estimated costs, assuming deployment at scale, of energy associated with each energy system were assessed using two metrics:

- The **Fuel price** is the estimated price of the energy intermediates throughout the energy system (e.g. crude oil, wholesale diesel, retail diesel). Where there is no price estimate (e.g. kinetic energy), the price was calculated based on the previous price divided by the conversion efficiency (summarized in Tables S4, S7, S10, S13 and S18 for each energy system [30])
- The **Embedded Feedstock Cost** is the cost of the primary feedstock energy resource divided by the proportion of feedstock retained (denoted as 'FR' or feedstock retention) by each conversion phase or technology (resources extraction, processing, transportation and distribution etc.), all the way through to kinetic energy. In the Grid-BE and WS-HFCE systems, the embedded feedstock cost was considered to be the recent cost of grid electricity or wind power in Alberta, respectively.

The difference between the embedded feedstock cost for kinetic energy and the calculated fuel price for kinetic energy provides a metric of the estimated cost of the infrastructure, labour and other expenses needed to deliver the envisaged system.

Energy prices can fluctuate with market forces and some costs are unknown because of the emerging nature of the technology and infrastructure. Therefore, where possible, ranges have been presented; Tables S5, S8, S11, S14, and S17 in the Supplemental

Materials document [30] summarize these price ranges and any related sources for each energy system.

All cost and price estimates are presented in 2016 Canadian dollars according to the ratio of the consumer price indexes [31].

Greenhouse gas (GHG) Emissions

Well-to-wheels GHG emissions associated with the trip were calculated for each energy system, including those from on-vehicle fuel combustion, the production, refining and transport of the fuels, and the emissions associated with the generation of electricity. **Table 2.1** summarizes the calculated and assumed emission parameters used in this study.

In the BD-ICE system, calculations were made of all bio-based CO_2 emissions to the atmosphere, including those associated with the production of the bio-based diesel fuel, and those associated with its combustion in the vehicle. These emissions are not typically counted as GHG emissions since the carbon is being returned to the atmosphere from which it was removed by photosynthesis a few years earlier. However, the combustion of the biocarbon returns the CO_2 faster to the atmosphere than if it were not combusted, so many researchers ([32]–[36]) have argued the global warming potential of bio carbon (GWP_{bio}) is greater than 0, but not as high as the 1.0 assigned to fossil fuel CO_2. In this study, we report on GHG emissions for the BD-ICE system assuming 100 year GWP_{bio} values ranging from 0 to 1.0. However, assuming residual forest biomass is the feedstock, recent literature reports ([32]–[36]) and our own analysis (data not shown), the 100 year GWP_{bio} should be less than 0.4 and possibly between 0 and 0.2.

For the energy systems that include electricity inputs from the grid (i.e. G-BE, NG-HFCE), an Alberta grid intensity was assumed for either 2016 (719 kg CO_2e/MWh; Table 1, Item 7) or for 2030 (270 kg CO_2e/MWh; Table 1, Item 8) when the coal phase-out is expected to be completed, renewables account for 30% of generation and NG sources provide the balance of generation.

In the NG-HFCE system, GHG emissions are evaluated based on either no carbon capture and storage (CCS), or with 90% capture of the carbon emissions associated with Steam-methane reforming (**Table 2.1**, Items 11-14).

For all systems, a GHG emissions reduction target for the year 2050 is set assuming that an 84% reduction from the FD-ICE system is required to achieve an 80% reduction from 2005 emissions levels.

Table 2.1. GHG Emission Parameters

Item	Parameter	Units	Value	Note
1	Diesel production (weighted average by source)		153	
2	*Canadian oil sands average*	kg CO_2e/bbl	172	{1}
3	*Canadian mixed sweet*		99	
4	Diesel combustion in heavy duty vehicle (with advanced control)	kg CO_2e/L	2.7	{2}
		kg CO_2e/GJ_{HHV}	71	
5	Biobased diesel production (Fischer-Tropsch)	kg CO_2e/GJ_{HHV}	184	{3}
6	Biobased diesel combustion in heavy duty vehicle	kg CO_2e/GJ_{HHV}	71	{4}
7	2016 AB grid	kg CO_2e/MWh	719	{5}
8	2030 AB grid	kg CO_2e/MWh	270	{6}
9	Hydrogen production via Steam Methane Reforming and distribution via tube truck			
10	*Natural Gas production and processing*	kg CO_2e/GJ_{HHV} NG	9.4	{7}
11	*SMR without CCS 2016 grid*	kg CO_2e/GJ_{HHV} H_2	68.5	{8}
12	*SMR without CCS 2030 grid*	kg CO_2e/GJ_{HHV} H_2	66.7	{9}
13	*SMR with 90% CCS 2016 grid*	kg CO_2e/GJ_{HHV} H_2	9.8	{10}
14	*SMR with 90% CCS 2030 grid*	kg CO_2e/GJ_{HHV} H_2	7.8	{11}
15	*H_2 distribution 2016 grid*	kg CO_2e/kg H_2	2.3	{12}
16	*H_2 distribution 2030 grid*	kg CO_2e/kg H_2	0.8	{13}

Notes:

{1} Adapted from IHS Energy report on GHG intensity of oil production [39]. Includes emissions associated with crude oil extraction, upgrading, refining, and transportation as well as emissions from fuel used upstream of those processes. The emissions associated with diesel production was calculated as a weighted average; *Item 1 = (Item 2 x 0.74) + (Item 3x 0.26)*, where 74% and 26% are the proportions of crude oil refined in Alberta from oil sands and conventional production, respectively.

{2} Adapted from Environment Canada's National Inventory Report (NIR) 2018 [18].

{3} Includes emissions incurred during harvest and transport of biomass [40]

{4} Assumed same as fossil diesel (*Item 4*).

{5} Calculated using electricity generation capacity and capacity factors from AESO Annual Market Statistics 2017 [24] along with emission intensity of electricity generation by source as listed in Table S3 [30].

{6} Calculated using CESAR's projection of Alberta's grid in 2030; assumes coal plants are phased out, combined cycle plants are ramped up in capacity factor (40% in 2016 to 75% in 2030), and 30% of grid generation is from renewable sources (Table S3 [30])

{7} Adapted from IHS Markit report on GHG intensity of oil sands production [41]

{8} Based on CESAR's analysis of NREL SMR model [26] with no Carbon Capture and Storage (CCS). Uses 2016 Alberta grid intensity of 719 kgCO_2e / MWh (*Item 7*).

{9} Just as in {8}, except using 2030 Alberta grid intensity of 270 kgCO_2e / MWh.

{10} Adapted from same NREL model as {8}, except using 90% CCS and 2016 Alberta grid intensity of 719 kgCO_2e / MWh.

{11} Just as in {10}, except using 2030 Alberta grid intensity of 270 kgCO_2e / MWh.

{12} *Item 15 = Item 7 x 3.2*, where 3.2 kWh/kg H_2 is the electricity demand of compressing and cooling hydrogen for transportation [42].

{13} *Item 16 = Item 8 x 3.2*, just as in {12}

This took into account the rise in freight transportation related GHG emissions between 2005 and 2016.

Air Pollution

Air pollutants including nitrogen oxides (NO_x), sulphur oxides (SO_x) and particulate matter 2.5 (PM2.5, i.e. particulate matter with a diameter of 2.5µm or less) were assessed at the HDV operation phase using conversion factors from US Environment Protection Agency (EPA) report on HDV emissions [37], [38]. Upstream air pollutants are outside the scope of this study.

Vehicle Performance

Data on other aspects of trip performance including vehicle weight, range between fueling, refueling time, maintenance, power and torque were obtained from a range of sources and used to evaluate fit for service in Canada's freight transportation sector.

3. Energy Flows and Energy Cost

Energy – the ability to perform work, through heat, movement, etc. – comes in many forms, and the conversion of one form of energy into another always comes at a cost, typically reflected as a loss of heat. Conversion efficiency is a metric that describes the proportion of the initial energy resource that is retained in a different, more useful energy resource.

To enable the movement of freight, the ultimate requirement is for kinetic energy, applied to the wheels of a moving vehicle. Each of the five energy systems described in **Figure 2.1** rely on different primary energy resources and different conversion technologies are used to provide the kinetic energy required for road freight transport.

Understanding the energy flows through each of these systems provides important insights regarding conversion efficiency losses for various technologies and the economic cost of delivering the desired kinetic energy. These results can be subsequently used to estimate GHG and air pollution emissions and demands on natural resources.

3.1. Fossil Diesel-Internal Combustion Engine (FD-ICE) Energy System

Diesel ICE is the dominant technology for road freight transportation and is supported with well-established fuel systems. After decades of continual improvement to each of the energy conversion stages of the FD-ICE system, including the HDV powertrain, distribution and retail, refining, and resource recovery, the system's performance is predictable and accepted. Like most mature systems, any future improvements in this system are likely expensive and limited to incremental performance gains [43].

Given the ubiquitous nature of the ICE technology, it is appropriate that it is the baseline for the comparison of alternative energy systems. To achieve wide scale adoption of an alternative system, the HDV performance must, at a competitive cost, be comparable to, or exceed that of the incumbent diesel ICE option.

Energy Flows. To provide the 3.8 GJ/trip of kinetic energy needed to move the Typical Shipment, we calculated that the FD-ICE system required 14.4 GJ/trip of primary energy inputs, resulting in an overall efficiency of 26%. The remaining 74% of the energy was primarily lost as heat or consumed in moving the primary energy to refineries or diesel fuel to the stations where it is delivered to the

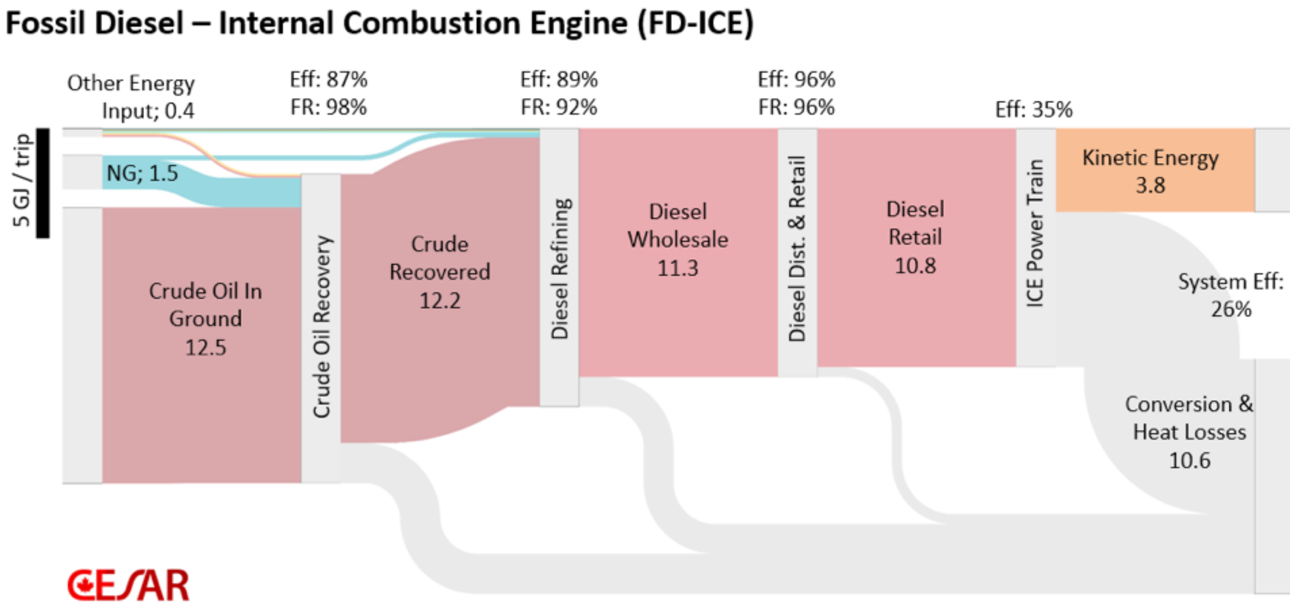

Figure 3.1. Flows of the energy (GJ/trip) in a fossil diesel – internal combustion engine (FD-ICE) energy system supporting a trip associated with moving a 27t_{gross} heavy duty vehicle a distance of 750 km. For details of calculations and conversion efficiencies, see Table S4. Eff, Energy conversion efficiency; FR, feedstock retention.

vehicles (**Figure 3.1**). Most of the heat loss in the FD-ICE system occurs at the ICE powertrain which is assumed to have an efficiency of 35% [29], [44] (Table S3, [30]).

The energy inputs and conversion efficiencies for crude oil recovery and upgrading were calculated assuming the mix of oil types produced in Alberta in 2016, with in situ oil sands having the lowest conversion efficiencies and conventional oil being the highest [39]. Over all, crude oil extraction required 1.5 GJ_{HHV}/trip of exogenous energy inputs and sustains 2% loss of the 12.5 GJ_{HHV}/trip of extracted crude oil to give 12.2 GJ recovered crude oil/trip [45]. Details on these calculations can be found in the companion paper [13] to the present study.

In refineries, 92% of the energy from input feedstocks (crude oil and other purchased feedstocks) is retained in the RPPs [45]. To operate the refinery, an additional 0.05 GJ_{HHV}/trip of electricity, 0.25 GJ_{HHV}/trip of heat, and 0.11 GJ_{HHV}/trip of other fuels are required, reducing the efficiency to 89%.

Over the years, there have been considerable efforts to reduce the energy losses in the FD-ICE system through improvement to the ICE powertrain with some positive results. For example, the 21st Century Truck Partnership that is made up of US government agencies and industry partners has been developing engine technology that can demonstrate a pathway to reaching high levels of thermal efficiency through their Super Truck initiatives [46]. At least two of the Super Truck demonstration trucks have been able to achieve a 50% efficiency at cruise speeds [46].

Canada also has been encouraging improvements to the ICE efficiency through its Heavy Duty Vehicle and Engine Greenhouse Gas Emission Regulations that set GHG emission standards for new HDVs [47]. With increasing stringency going out to the year 2027, and a regulatory focus put directly on the engine, manufacturers are motivated to improve engine efficiency.

The potential to raise the thermal efficiency of the engine to 50-55% efficiency could potentially be achieved from a variety of technological advancements such as turbo, bottoming cycle and technologies that decrease engine friction [48].

This study assumes 35% ICE efficiency as a number that is most likely to be reflective of the average HDV under real world operating conditions in Alberta, including heavy loads, low temperatures, and steep grades. [49].

The Cost of Energy. The price paid for transportation fuel at the pump has many components, including the cost of the feedstock energy resource, the cost for conversion / transport / delivery of the resource and fuel, profit and taxes. In our analysis, we have tracked the embedded feedstock cost and the price of fuel at different stages of the energy system.

At a crude oil price of US$32-US$64bbl (equivalent to C$6.20 - $12.50/GJ) [50], [51], the feedstock retention estimates (plus ICE conversion efficiency) resulted in an embedded cost for crude in the vehicle's kinetic energy of $20 - 40/GJ (**Figure 3.2** and Table S5 in [30]). Given a pretax retail price for diesel of $0.69-1.04/L [52] ($18 - $27/GJ) and the same ICE conversion efficiency, the price of the kinetic energy was estimated as $51-$78/GJ or about $194 - $295 per Typical Shipment (Figure 3.2 and Table S4 in [30]) based on diesel prices reported by The Kent Group [52].

Of the cost for kinetic energy, the value of the embedded feedstock (crude oil) accounts for C$20 - 40/$GJ_{HHV}$, leaving the difference ($31 - $36/$GJ_{HHV}$ kinetic energy) as the cost of transporting, refining and delivering the fuel to the end customer (**Figure 3.2**). The relatively low cost for transporting, refining and delivering the fuel is the reflection of a highly mature and efficient energy system. It also sets a high bar for alternative energy systems wanting to replace the FD-ICE system, especially if there is no allowance in the economics for the environmental footprint of the incumbent FD-ICE energy system.

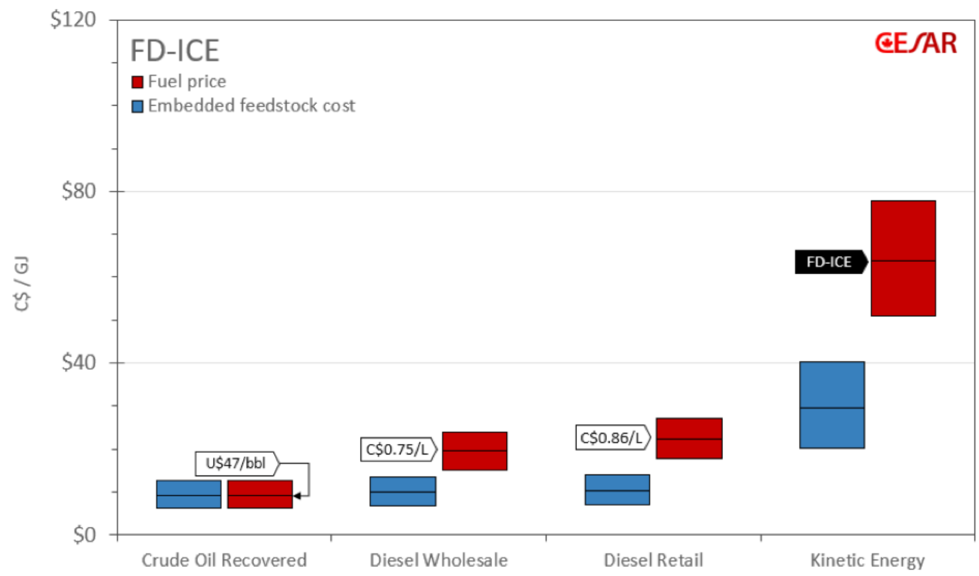

Figure 3.2. Flows of fuel supply dollars ($/GJ) through an energy system in which diesel fuel is used to support a trip associated with moving a 27 t_{gross} heavy duty vehicle a distance of 750 km. For details of calculations and references, see Table S5.

3.2. Bio-Based Diesel-Internal Combustion Engine (BD-ICE) Energy System

Bio-based diesel fuels are a renewable substitute for conventional diesel and can be made from plant or animal lipids/oils, or from lignocellulosic feedstocks such as wood or straw. Fuel standards are currently in place requiring their use across Canada (See **Box 3.1**) [53],[54].

First generation biodiesel is made by trans-esterification of lipids and the resulting fuel has some oxygen in the molecule which makes it less suitable as a drop-in fuel, especially at low temperatures. Hydrogenation of this fuel can remove the oxygen and improve its fuel properties. However, as discussed in a companion paper [13], the supply of plant or animal lipids/oils is highly constrained, so such feedstocks cannot supply a credible alternative to the FD-ICE system.

Box 3.1. Canadian and Alberta Bio-based Diesel Standards

Alberta's Renewable Fuel Standard [53] mandates that diesel fuel sold in the province contains at least 2% renewable diesel fuel by volume. A new Canada-wide Clean Fuel Standard [54] sets targets for improvements to the life cycle carbon intensity of the fuel.

For this reason, this study focused on the production of bio-based diesel from wood and straw, lignocellulosic feedstocks that are more readily available than lipid/oil-based feedstocks. They can be found as either residues from our existing forestry and agricultural operations, or as the product of purposely grown energy crops.

Technologies to convert lignocellulosic feedstocks into bio-based diesel fuel include gasification, pyrolysis, hydro-liquefaction and Fischer-Tropsch (FT) synthesis. Because of its relative maturity and its limited use of external energy inputs, such as H_2, this study focused on biomass gasification coupled with FT synthesis, as presented by van Vliet et al [23] and summarized in **Figure 3.3**.

The fuel produced in this process is a fully compatible, drop-in fuel for fossil diesel with chemical properties and energy content similar to that found in crude oil. In this study, the bio-based diesel-internal combustion engine (BD-ICE) is considered a second Reference energy system alongside the FD-ICE energy system.

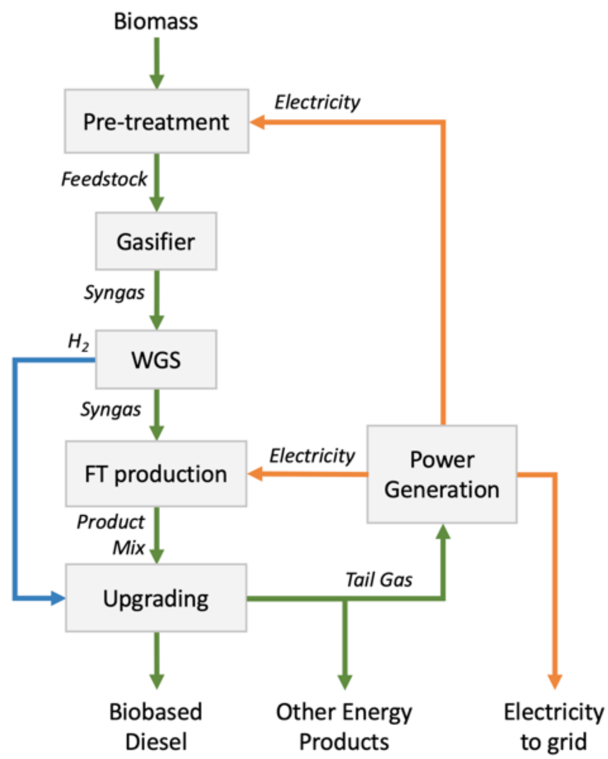

Figure 3.3. The production process for bio-based diesel fuels. Adapted from research by van Vliet et al., 2009 [23]. WGS, Water Gas Shift; FT, Fischer-Tropsch.

Energy Flows. To provide the 3.8 GJ of kinetic energy, the BD-ICE energy system was similar to the FD-ICE in the amount of retail and wholesale diesel fuel required (10.8 and 11.3 GJ_{HHV}/trip, respectively). However the relatively low conversion efficiency (~51% [23]) associated with biomass gasification and Fischer-Tropsch synthesis meant that 22.7 GJ_{HHV}/trip of input energy (**Figure 3.4.**, Table S7.) was required for the typical trip compared to 14.4 GJ_{HHV}/trip for the FD-ICE energy system (**Figure 3.1.**). Consequently, the overall efficiency of the system was only 16%.

Although not currently adopted at wide scale, gasification and FT are both mature processes that date back to the 1930s. While additional improvements may be possible with future innovations [23], making hydrocarbons from more oxidized biomass feedstocks is unlikely to ever approach the efficiency of a petrochemical refinery.

There are also feedstock and energy losses associated with the harvesting and transport of the biomass. This study accounts for 2% feedstock lost due to product losses during transport and handling

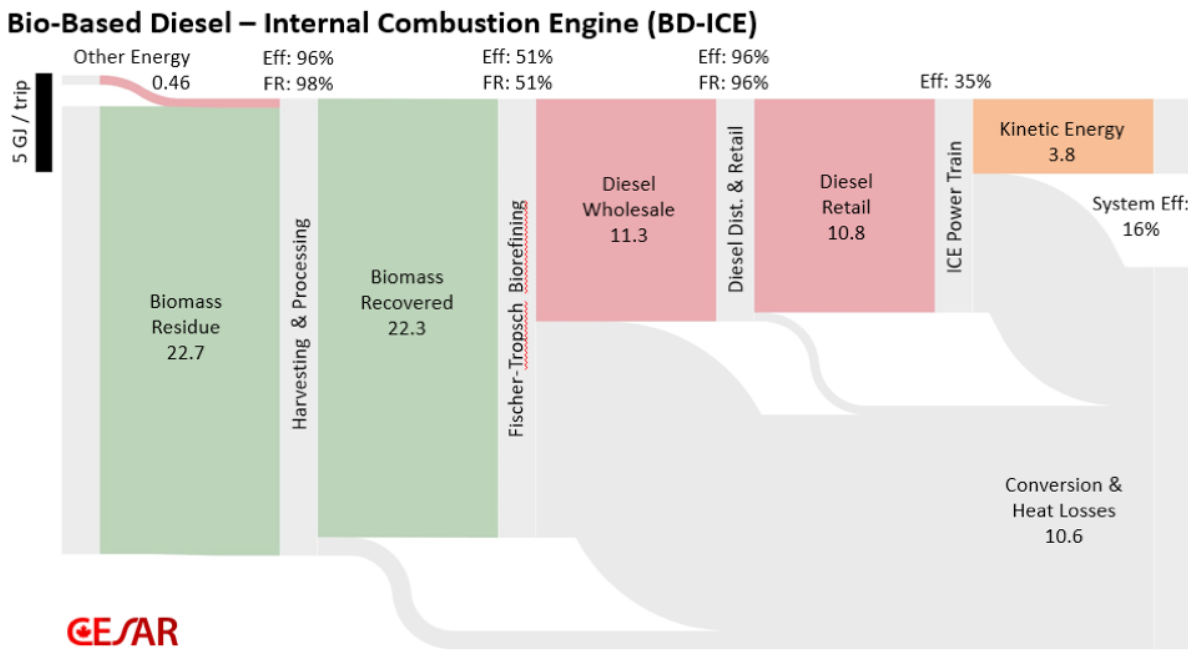

Figure 3.4. Flows of the energy (GJ/trip) in an energy system in which lignocellulosic bio-based diesel fuel is used to support a trip associated with moving a $27t_{gross}$ heavy duty vehicle a distance of 750 km. For details of calculations and references, see Table S7.

and assumes that 0.46 GJ_{HHV}/trip of bio-based fuel is consumed at this stage [40].

The Cost of Energy. Even though lignocellulosic biomass used in the BD-ICE may be residual with no existing major sources of demand, there are still costs associated with handling, transportation, and processing. A review of literature on the cost of delivered biomass from sources such as hardwood, straw, and switchgrass resulted in a range of $4.42-$7.31/GJ (**Figure 3.5**, Table S8, Item 1 [30]). Applying the feedstock retention and powertrain efficiency numbers (Table S7, [30]) to this range resulted in an embedded cost of biomass residue in the vehicle's kinetic energy of $26 - $44/GJ (Table S8, Item 4 [30]).

Because the process has not been widely commercialized, there are many unknown factors in the costs of a FT biorefinery, at scale, that can affect the estimated cost of FT-diesel production. Therefore, CESAR conducted a separate literature review into the cost of FT-diesel production from lignocellulosic feedstock that placed the wholesale, pretax fuel cost as $0.99 - $1.26/L (or $26 - $33/GJ; Table S8, Item 5).

The retail price of the bio-based diesel fuel was calculated accounting for the historic average wholesale to retail mark-up seen in historic fossil diesel prices (approximately 13% mark-up for 2013-2017

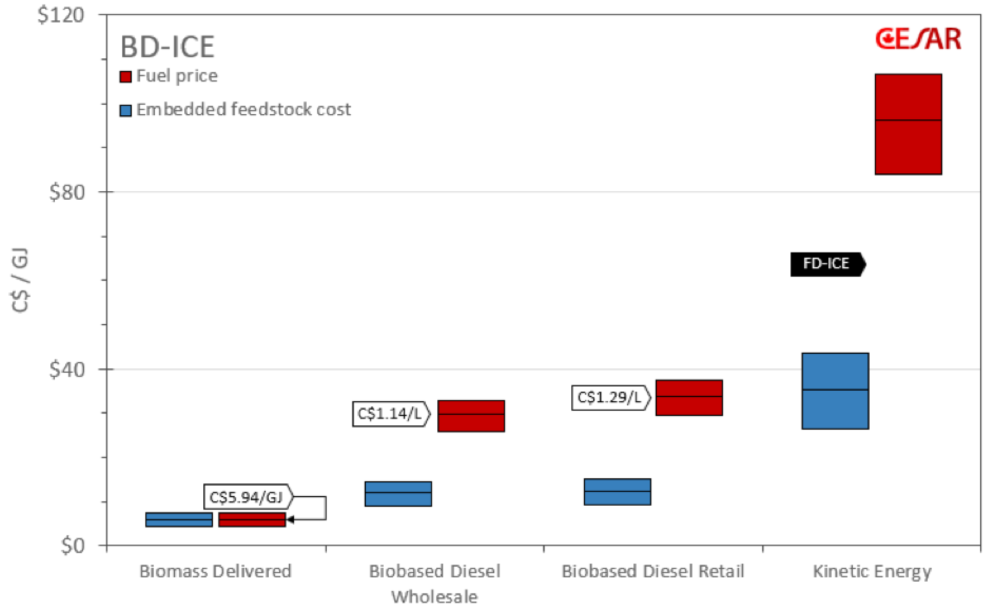

Figure 3.5. Flows of fuel supply dollars ($/GJ) through an energy system in which a lignocellulosic bio-based diesel fuel is used to support a trip associated with moving a 27t$_{gross}$ heavy duty vehicle a distance of 750 km. For details of calculations and references, see Table S8.

[52]), resulted in a range of $1.13 - $1.43/L. (Table S8, Item 5). This follows from the assumption that bio-based FT-diesel is a drop-in replacement for fossil diesel that can use existing transportation and distribution infrastructure.

The estimated energy costs of the BD-ICE system were high compared to the FD-ICE system. For the Typical Shipment requiring 3.8 GJ$_{HHV}$/trip, the average BD-ICE energy cost was estimated to range from $84 - $107/GJ$_{HHV}$ or $318 - $405/per trip (**Figure 3.5.**), 37% to 64% higher than that for the FD-ICE system.

In the BD-ICE system, the conversion stages with the largest spreads between the fuel price and the embedded feedstock costs are at the biorefinery and at the powertrain, both pointing to areas of large energy loss. Significant advances to the biorefining process will be needed for this system to become a compelling alternative to FD-ICE system. However, it may be suitable as a low percentage blend with fossil diesel fuel, as it is being used today.

3.3. Grid-Battery Electric (G-BE) Energy System

Battery electric HDVs are being developed as zero emission alternatives to serve the freight transportation sector by companies like Tesla [7], Daimler [8], Thor Trucks [9] and others. The energy to move these HDVs is pulled from public electrical grids and stored in batteries onboard the vehicle.

The G-BE system is commonly touted for its efficiency advantages [44], [55]; however, the extent of the benefit is dependent on the efficiency of the power generation to supply the grid.

The power taken from the grid is produced according to regional power generation strategies. In Alberta, the grid is made up of a mix of generation methods and energy sources. In 2016, the mix included 61% of power generated from coal, 27% from NG cogeneration, combined cycle (NG CC), and simple cycle (NG SC) and 11% from renewables including wind, hydro, and biomass [56]. By 2030, this grid mix is expected to be considerably different with the phase-out of coal power generation [25]. Table S3 in the Supplemental Materials [30] outlines the specific assumptions corresponding to each grid scenario.

Energy Flows. To provide 3.8 GJ of kinetic energy, the G-BE system requires 11.2GJ_{HHV} of primary energy in the form of NG and renewable generation. This corresponds to a 34% well-to-wheel efficiency (**Figure 3.6.,** Table S10.).

Compared to an ICE, electric motors are extremely efficient. At a 90% efficiency [57], the electric motor only needs 4.2GJ_{HHV} to provide sufficient energy for the Typical Shipment (Figure 3.6), compared to the 10.8GJ_{HHV}/trip required by the FD-ICE system (**Figure 3.1**). When the battery process losses are also accounted for, the electric powertrain needs 5.6GJ_{HHV}/trip from the grid (**Figure 3.6.**).

Unlike the FD-ICE system, most of the G-BE system's energy losses are upstream from the powertrain (battery and motor) and occur

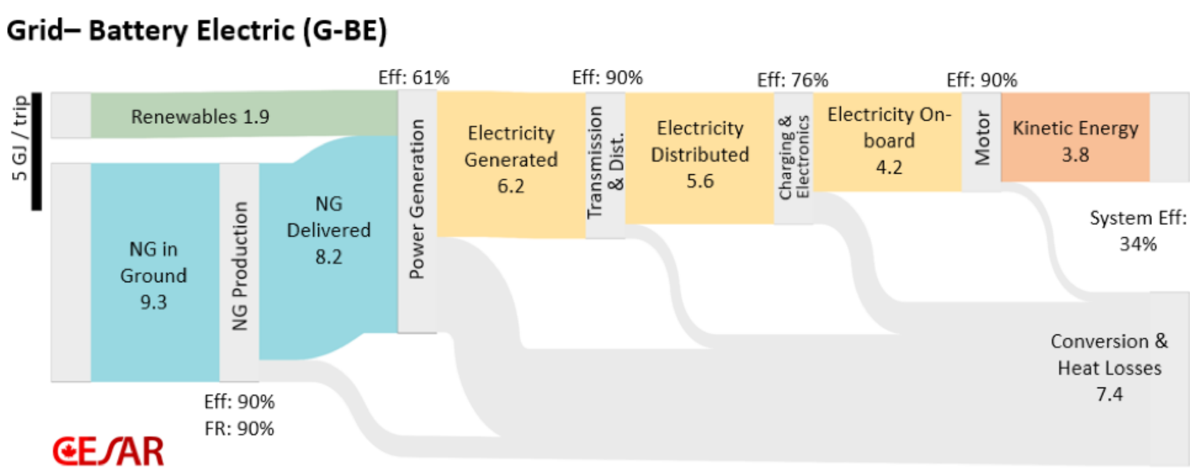

Figure 3.6. Flows of energy (GJ/trip) for an energy system in which grid electricity (assuming a 2030 grid mix for Alberta) is used with a battery electric drivetrain to support a trip associated with moving a 27t_{gross} heavy duty vehicle a distance of 750 km. For details of calculations and references, see Table S10.

at the point of power generation. The 2030 grid mix is expected to be dominated by NG power generation paired with 30% renewable power generation, equating to a combined average efficiency of 61% (Table S3, [30]) that contributes 2.0 GJ_{HHV}/trip of energy loss (**Figure 3.6.**). A further 1.5 GJ_{HHV}/trip in losses is attributed to the production and processing of NG for power generation (estimated to be 90% efficient [45]) and the transmission and distribution of electricity (also approx. 90% efficient [58], [59]).

In **Figure 3.6.**, the 'Charging and Electronics' process, which is inclusive of the on-board power electronics, charge controllers and the charging process itself, is determined to be 76% efficient. This is calculated assuming that the powertrain (motor and battery processes) is 68% efficient as reported by McKinsey and Co [44] and a 3-phase electric induction motor is 90% efficient as reported by Ravindra, Jape & Thosar [57].

With future advancement in battery technology and powertrain design including the incorporation of supercapacitors, changes in battery composition and electrode materials [60], there may be opportunity for efficiency gains.

The Cost of Energy. The range cost of grid power at the point of power generation is estimated to be in the range of $18 - $84/MWh (or $5 - $23/GJ, Table S11., Item 2) based off of the average hourly pool price between 2013 and 2017 published by Alberta Electric System Operator (AESO) [56]. Carrying this range through the transmission and distribution, charging, and powertrain efficiencies of the G-BE system (**Figure 3.6.**, Table S10., [30]) results in a range of $8 - $38/GJ for the embedded cost of electricity in produced kinetic energy.

To account for the high expected cost of providing rapid charging infrastructure for heavy duty vehicles, an infrastructure mark-up multiplier was applied in the range of 1.2 to 1.6 times the average annual electricity rates paid by commercial consumers in Alberta (2013-2017 rates as reported by the AUC [61]). A further transmission cost estimate of $43/MWh was also added per AESO's transmission cost projection [62], which corresponds to the recent build out of transmission infrastructure in Alberta (primarily two new High Voltage Direct Current (HVDC) lines).

As a result, at the point of charging (Electricity Distributed), the price of electricity is estimated to be $96 - $216/MWh ($27 - $60/GJ, **Figure 3.7.**, Table S11., Item 8 [30]). Of course, this is an estimate because such infrastructure does not exist. Applying charging and powertrain efficiencies of 76% and 90%, respectively results in a

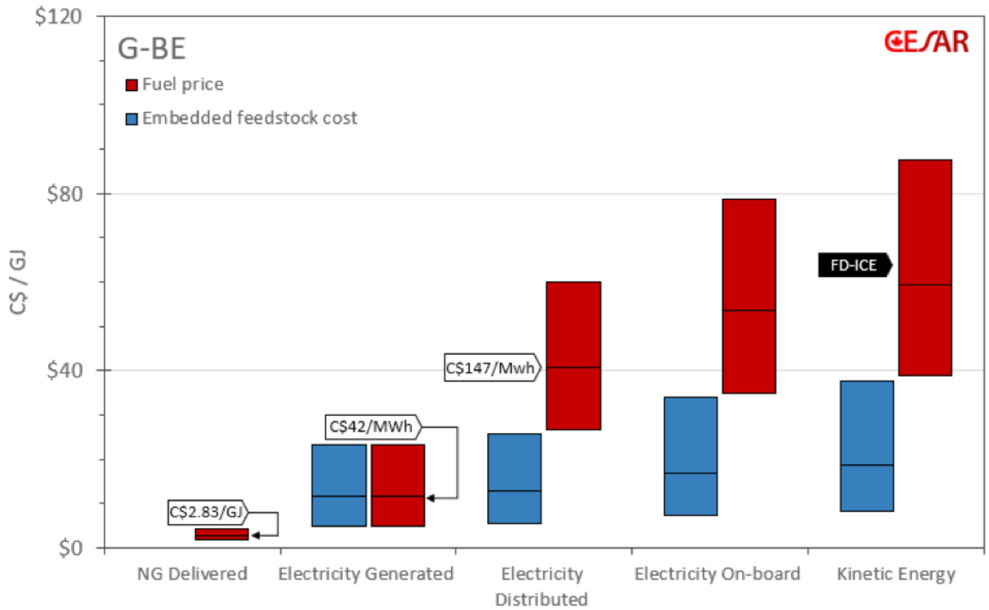

Figure 3.7. Flows of energy supply dollars (C$/$GJ_{HHV}$) for an energy system in which grid electricity (assuming a 2030 grid mix for Alberta) is used with a battery electric powertrain to support a trip associated with moving a $27t_{gross}$ heavy duty vehicle a distance of 750 km. For details of calculations and references, see Table S11.

range of $39-88/GJ for the cost of kinetic energy for the G-BE system.

Therefore, the cost of kinetic energy of the G-BE system is estimated to be similar to (or even lower than) the FD-ICE system at $148-$334/trip to move the Typical Shipment (**Figure 3.7.**, Table S11.), compared to $194 - $295/trip for the FD-ICE system.

Looking forward, there may be opportunity for the cost of power generation in Alberta to be reduced even further, particularly for renewables. According to a recent report published by the International Renewable Energy Agency (IRENA), there are three drivers of LCOE reductions: (1) technology improvements, (2) competitive procurement, and (3) a large base of experienced developers [63].

Contrarily, there are some that are projecting higher electricity costs in the future resulting from early retirement of coal power generation facilities, thereby disrupting the current supply and demand equilibrium [64]. There are also concerns with the cost of upgrades to transmission line infrastructure [65].

With reductions in power generation and charging infrastructure costs, along with efficiency gains from improved batteries and increased renewables in the grid mix, the G-BE system has the potential to be both very efficient and have a competitive cost of energy.

3.4. Natural Gas-Hydrogen Fuel Cell Electric (NG-HFCE) Energy System

Hydrogen Fuel cell electric (HFCE) HDVs are also actively being developed as a zero emission alternative for the freight transportation market including HDV models manufactured by Nikola Motors [10], Toyota [11], Kenworth [12], and others [29] .

The HFCE HDV differs from the battery electric option in that the electricity is generated on board the HDV by converting the H_2 gas that is stored in the fuel tank into electricity using a fuel cell. A bank of batteries is typically also included to make the vehicle a hybrid-electric. The fuel cell can charge the batteries when their output exceeds the demand for moving the vehicle. The hybrid electric features allows for regenerative braking (slowing the vehicle can be used to charge the batteries), to provide additional peak power for acceleration or climbing steep grades, or to extend vehicle range.

This energy system explores NG as a primary feedstock for H_2 production, an energy resource that is abundant and low cost in Alberta and Western Canada. A HDV fueling system that aligns with regional natural resource strengths would have economic benefits. This concept will be discussed further in the next document within the Future of Freight series [13].

Like electricity or diesel fuel, hydrogen gas is not found in large quantities as a natural energy resource so it must be produced from other energy sources to act as an energy carrier. Fossil fuels (NG, crude oil, and coal) and biomass can be used to produce H_2 and it can also be made with electricity by splitting water (i.e. electrolysis). Examples of hydrocarbon to H_2 technologies include, but are not limited to, coal gasification [66], barrier discharge non-thermal plasma [67], methane cracking [68], standing wave reformation [69], and in situ gasification with proton membrane technology [70].

However, most of the hydrogen produced in the USA today comes from steam methane reforming (SMR) of NG (predominantly methane, CH_4) to produce H_2 and carbon dioxide (CO_2) (**Box 3.2**) [71], [72]. This mature and cost-effective technology supplies H_2 to the chemical, fertilizer, and oil refining industries. It can be upgraded (removal of impurities) to make it suitable for hydrogen fuel cells by using pressure swing absorption (PSA) [66]. Therefore, it has been selected as a key technology to be reviewed in this study.

However, most current SMR facilities simply release the CO_2 to the atmosphere, contributing to GHG emissions and undermining much of the advantage in producing a zero-emission transportation fuel. While the life cycle GHG emissions associated with SMR will be discussed in more detail in Section 4.4, below the process modeled here incorporates pre-combustion CO_2 capture of geological storage for 90% of the CO_2 produced, as shown in **Box 3.2** [26][73].

Energy Flows. To generate the requisite 3.8 GJ/trip of kinetic energy, the NG-HFCE system requires 13.8 GJ_{HHV} /trip of primary energy (primarily NG). With 10.3 GJ_{HHV}/trip in conversion and heat losses (**Figure 3.8.**, Table S13.), this system is 27% efficient, comparable to the FD-ICE energy system.

Like the battery electric option, the NG-HFCE system uses an electric motor that is 90% efficient, therefore the fuel cell only needs to

Box 3.2. Steam Methane Reforming (SMR) Process with CCS

In the steam-methane reformer, H_2 production occurs via two reactions:

$$CH_4 + H_2O \longrightarrow 3H_2 + CO \text{ (Rxn. 1)}$$

$$3H_2O + CO + H_2O \longrightarrow 4H_2 + CO_2 \text{ (Rxn. 2)}$$

Reaction 1 converts methane and water (as steam) into H_2 and CO. Then the products of that reaction move to Reaction 2 which uses more steam in a water-gas shift reaction to convert the CO into additional H_2 and CO_2.

In the industrial process modeled here (see schematic in **Figure 3.8.**, below), the CO_2 is separated from the other gases using amine adsorption and a pure CO_2 stream is produced so it can be utilized or geologically sequestered (CCUS) [26]. SMR-coupled CCUS technologies are being tested in North America at Air Product's Port Arthur refinery and Shell's Scotford Upgrader to capture millions of tonnes of CO_2 per year[73].

After CO_2 removal, the H_2 is removed by Pressure Swing Adsorption (PSA), and unburned gases (some CO, H_2 and CH_4) are supplemented with additional natural gas and combusted to provide the heat needed to maintain the temperature of the steam methane reformer. We estimate that this process would keep 90% of the CO_2 out of the atmosphere.

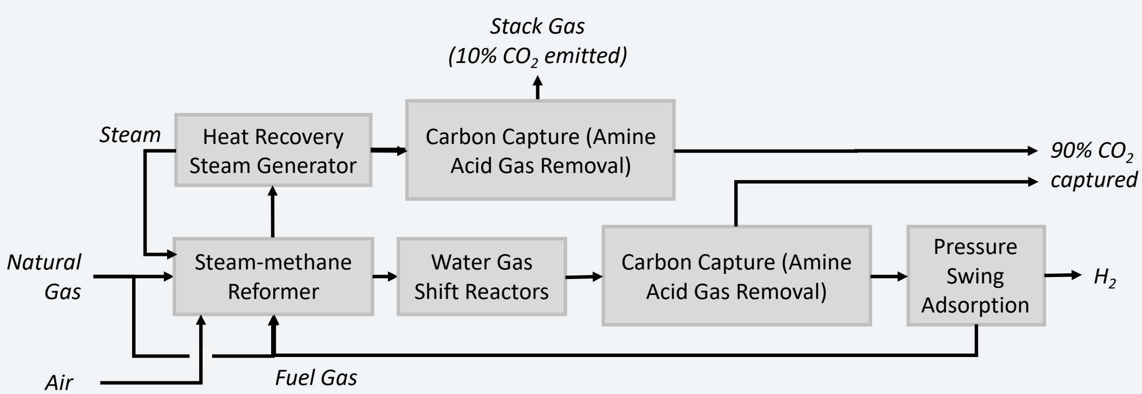

Figure 3.8. Schematic depicting the SMR process with 90% carbon capture and storage modelled in this study (adapted from [26]).

produce 4.2 GJ_{HHV}/trip of electricity (**Figure 3.8.**). Proton Exchange Membrane Fuel Cells (PEMFC) have an efficiency of 55% [74], [75], and when paired with power inverters and electronics that are 95% efficient, the overall efficiency was estimated to be 52%. Therefore, the powertrain is responsible for 3.9 GJ/trip (or 38%) of the total system losses.

It follows that the vehicle requires 8.1 GJ_{HHV}/trip in H_2 fuel (**Figure 3.8**), and with an energy content of hydrogen at 141 MJ_{HHV}/kg H_2 [45], the Typical Shipment will need 57 kg of H_2 from the onboard tank.

To deliver and dispense the hydrogen requires an additional 0.77 GJ_{HHV}/trip (**Figure 3.9.**), primarily for the electricity needed to compress the gas to 700 bars of on-board tank pressure including grid transmission losses. High pressure tanks are necessary to achieve the 750 km range without impacting the available payload capacity of the shipment. To compress gas using a reciprocal compressor to a pressure of 880 bar (the dispensing pressure for a 700 bar onboard storage tank), and cooling the gas so it can be filled at an ambient temperature as low as -40°C, 3.2 kWh/kg H_2 [76] is consumed. If a 350 bar tank were to be used instead, only 2.2 kWh/kg H_2 would be required [76].

In addition, hydrogen is consumed in moving the fuel from the production location to the local fueling stations. This study assumes

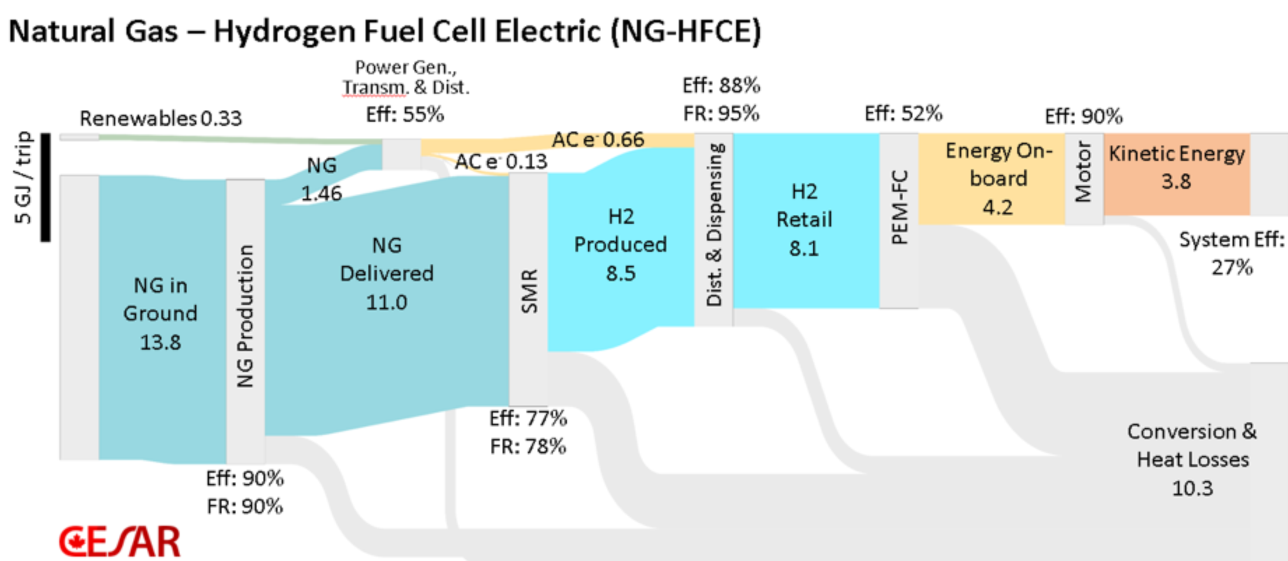

Figure 3.9. Flows of energy (GJ/trip) for an energy system in which hydrogen is produced from natural gas using steam methane reforming with 90% CCS, and the hydrogen used with a fuel cell electric hybrid drivetrain to support a trip associated with moving a $27t_{gross}$ heavy duty vehicle a distance of 750 km. For details of calculations and references, see Table S13.

that 700 kg of hydrogen gas (requiring many times that weight in chambers and associated equipment) is transported by tube truck a round trip distance of 500 km to the fueling stations. This process was estimated to consume 0.44 GJ_{HHV}/trip to support the Typical Shipment.

Trucking hydrogen may not be the most practical distribution method for long distances, especially when serving HDVs that may require 100+ kg H_2 or more for each fueling, and more than one fueling per day. In a more mature energy system, pipeline distribution of hydrogen is likely to be the most cost effective [75], but until then infrastructure and distribution strategies are needed to match the demand. Some of those being proposed include:

- Blending hydrogen into NG pipelines and using PSA to remove it from the NG at the fueling stations [76];
- Cooling the H_2 until it liquifies (-253C) and transporting that form to the fueling station or even to the vehicle itself [77]. This is the preferred technology for marine shipping of H_2 or for use as an airline fuel [78];
- Converting H_2 to ammonia and for transportation to the fueling station where it is converted back to H_2 using cracking and membranes or similar technologies [79];
- Making methanol from NG and transporting it to the fueling station where it can be converted to H_2 and CO_2 [80]. The CO_2 would need to be captured and prevented from entering the atmosphere; and
- Bind the H_2 into a hydride solution from which it can easily be released [81].

Further work is required to assess the costs and benefits of these various hydrogen production and transport alternatives, noting that there may be large regional differences in the optimal technologies.

The H_2 production process is another major contributor to energy losses in the NG-HFCE energy system with an energy conversion efficiency of 77%. To estimate these losses, we used a model from the National Renewable Energy Laboratory [26] to calculate the material and energy flows for hydrogen production by Steam Methane Reforming (SMR), the production of both fuel-grade H_2 and a pure CO_2 stream, and the geological sequestration of the CO_2 stream (see **Box 3.2.**). Because SMR is a well-established process and operating near its theoretical limits, it is not expected that there will be substantial efficiency gains to this process in the future. Although with

Box 3.3. The Relationship Between Input Energy and Hydrogen Cost Using Steam Methane Reforming

Alberta has an economic advantage for producing H_2 via SMR because the province's massive NG reserves are constrained by distance to North American markets and by pipeline and storage capacity. Over the 2012-2017 period, NG prices in Alberta ranged from C\$2.02 - C\$4.35/GJ_{HHV} or about half the Canadian dollar equivalent of the Henry Hub price in the USA (Table S14, Item 1).

The price of NG is an important determinant in the cost of hydrogen, as shown in **Figure 3.9**. Using a process cost model from the National Renewable Energy Laboratory (NREL) [26], modified to Canadian dollars, the cost of SMR hydrogen production with 90% of the CO_2 captured and sequestered, ranged from C\$1.34 – C\$1.85/kg H_2 (C\$9.47 – C\$13.10/GJ_{HHV} H_2) with Alberta's NG prices (2012-2017), but ranged from C\$1.72 – C\$2.35/kg H_2 (C\$12.21 – C\$16.67/GJ_{HHV} H_2) with American NG prices for the same time period.

In addition to the 22% cost benefit, the fact that the Alberta government owns the pore space in the sub-surface that is needed for permanent storage of the CO_2 (in the USA, this is a land owner right), gives the province a competitive advantage for hydrogen production relative to other jurisdictions in North America.

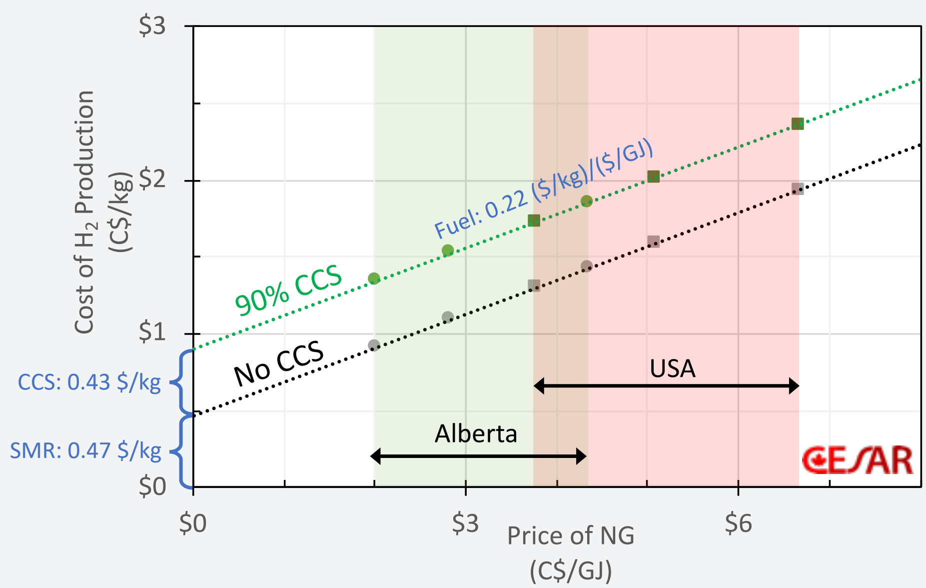

Figure 3.10. The effect of natural gas (NG) price on the cost of hydrogen (H2) production with or without 90% carbon capture and storage (CCS). Calculated using a NREL model [26]. Note the average NG cost in Alberta between 2012-2017 was less than the Henry Hub's price in the United States [22][56].

additional research and development, incremental improvements are possible [72].

Although PEM fuel cells have been in use in niche applications for decades (mainly aerospace [82]), widespread adoption of the technology and their incorporation in HDVs is likely to reduce costs, while also improving efficiency and performance [83] [84].

The Cost of Energy. Given the NG feedstock costs in Alberta between 2012 and 2017 of $2.02 - $4.35/GJ (average $2.83/GJ) and the feedstock retention rates shown in **Figure 3.9.**, the embedded cost of the feedstock in the kinetic energy applied to the wheels of the truck was calculated as C$5.83-C$12.57/GJ (**Figure 3.11.**, Table S14., Items 1,5)

The actual prices for the fuels at various stages in the energy system were more challenging to calculate since this energy system does not currently exist at scale. The NREL model [26] behind **Figure 3.10. and Box 3.3.** was used to estimate the wholesale price of hydrogen production assuming recent (2012-2017) prices for NG in Alberta. A price range for wholesale hydrogen was calculated to be $1.34 – $1.85/kg H_2 or $9.47 – $13.10/$GJ_{HHV}$ H_2 (**Figure 3.11.**, Table S14., Item 6).

To calculate the retail price for H_2, we estimated the cost of (a) producing the H_2 (previous paragraph), (b) distributing the produced hydrogen, (c) compressing and storing the H_2 so it can be dispensed, and (d) providing an additional 10% margin for the fueling station.

As noted previously, we assumed hydrogen distribution by tube truck; based on literature [42], [85], [86] and consultation with

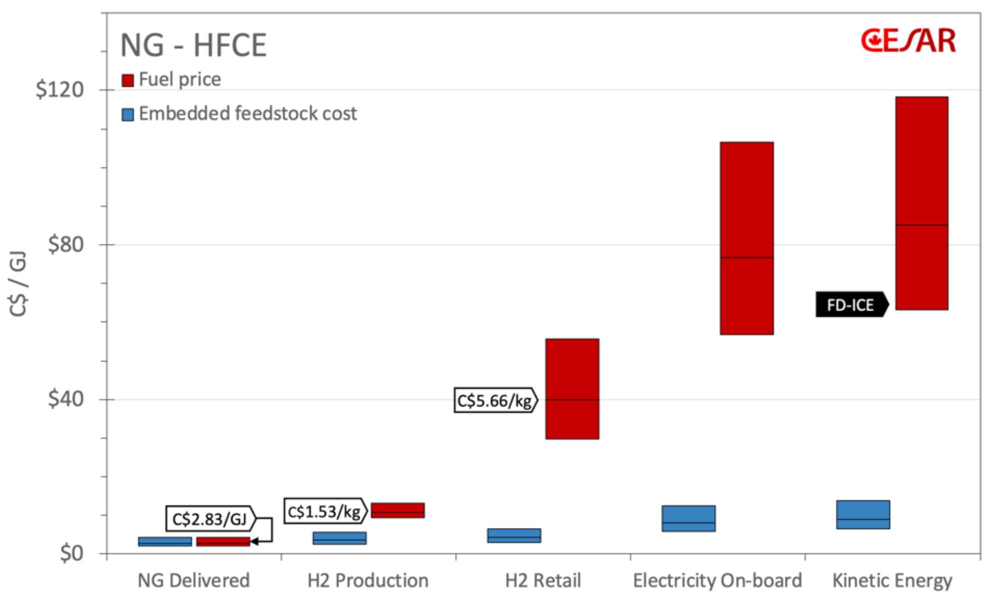

Figure 3.11. Flows of energy supply dollars (C$/$GJ_{HHV}$) for an energy system in which hydrogen is produced from natural gas using steam methane reforming with 90% CCS, and the hydrogen used with a fuel cell electric hybrid drivetrain to support a trip associated with moving a 27t_{gross} heavy duty vehicle a distance of 750 km. For details of calculations and references, see Table S14.

freight providers, the incremental cost of hydrogen delivery was calculated to be \$1.50 - \$3.71/kg H_2 or \$11- \$26/GJ_{HHV} (Table S14, Item 7). Clearly, when the cost of fuel distribution is 112% to 200% of the cost of producing the fuel itself, there is a need to explore other technologies for making H_2 available at fueling stations.

Another NREL report [87] was used to estimate the cost of hydrogen compression, and from this report we estimated a cost of \$0.98 - \$1.59/kg H_2 or \$7 - \$11/GJ_{HHV} H_2 (Table S14., Item 8). The costs here are dependent on the cost and efficiency of high capacity compressors and cooling infrastructure which represent nearly 60% of the total cost for this component [87].

The retail price range, including an additional 10% margin was estimated to be \$4.19 - \$7.86/kg H_2 or \$30 - \$56 per GJ_{HHV} H_2 (**Figure 3.11.,** Table S14., Item 9). Based on these numbers, the effective cost of on-board electricity was calculated to be \$57 - \$107/GJ, equivalent to \$205 - \$384/MWh (**Figure 3.11.**, Table S14., Item 10). Finally, the price of the kinetic energy needed to move the vehicle was estimated to be \$63 - \$118/GJ (**Figure 3.11.**, Table S14., Item 11), a range slightly higher than that for the FD-ICE energy system.

3.5. Wind/Solar to Hydrogen Fuel Cell Electric (WS-HFCE) Energy System

The WS-HFCE energy system reviews the production of H_2 fuel from the electrolysis of water using electricity generated from wind and solar. While the HFCE vehicle technology in this energy system is the same as that for the NG-HFCE energy system, there are differences in system efficiencies and costs in the WS-HFCE and NG-HFCE systems that are explored here.

In this analysis we have chosen the Proton Exchange Membrane (PEM) electrolysis technology (**Box 3.4. and Figure 3.12.**) for H_2 generation over a more tried and tested method such as alkaline electrolysis because comparative studies [84] [85] consider PEM electrolyzers better suited for use with intermittent power sources.

Energy Flows. The WS-HFCE system requires 12.6 GJ_{HHV} of primary energy (wind and solar) to provide the 3.8 GJ of kinetic energy needed for the Typical Shipment. This corresponds to 8.8 GJ_{HHV}/trip of energy losses by the system and a well-to-wheel efficiency of 30% (**Figure 3.13.**, Table S16.).

Working backwards from kinetic energy, the WS-HFCE system is identical to the NG-HFCE system until the "H_2 produced" stage.

The PEM electrolysis technology for H_2 generation, is 72% efficient in converting electricity into H_2 [88] to produce the 8.5 GJ_{HHV}/trip of H_2 required to support the Typical Shipment (**Figure 3.13.**).

To make this hydrogen, 11.8 GJ/trip of direct current (DC) electricity is required (**Figure 3.13.**), equivalent to 3.28 MWh/trip, that would be generated from either wind turbines and/or photo-voltaic solar panels.

To provide energy for the distribution and dispensing activities at the fueling station (e.g. H_2 compression), additional electricity production of 0.77 GJ/trip (3.2 kWh/kg H_2 at 700 bar [76] plus grid transmission losses) is required and assumed to be supplied from the public grid using wind and solar power generation. This electricity is inverted (converted from AC to DC), transmitted and distributed to the public grid; the combined efficiency of all these processes was estimated as:

Inverter efficiency x Transmission & Distribution efficiency = 95% x 90% = 86%

Summing these two power demands results in a total power requirement of 12.6 GJ/trip, or 3.49 MWh/trip, equivalent to the output of a 1 MW wind turbine running at full capacity for 3.5 hours. As is standard practice for renewable energy calculations, an efficiency of 100% is assigned to the wind and solar generation (**Figure 3.13.**).

The WS-HFCE system that is defined by this study does not include grid power transmission to feed into PEM electrolyzers because it is envisioned that the electrolysis facility is co-located with the wind and solar power generation installations. Power generated from these facilities could be dynamically

Box 3.4. Producing H_2 Fuel via PEM Electrolysis

Hydrogen production via electrolysis involves splitting water into H_2 and oxygen (O_2) using an electric potential difference across two electrodes. In Proton Exchange Membrane (PEM) electrolysis, the electric potential induces the following reactions [84]:

$$2H_2O \rightarrow O_2 + 4H^+ + 4e^- \text{ (Rxn 1, Anode)}$$

$$4H^+ + 4e^- \rightarrow 2H_2 \text{ (Rxn 2, Cathode)}$$

Resulting in the net reaction:

$$2H_2O \rightarrow 2H_2 + O_2$$

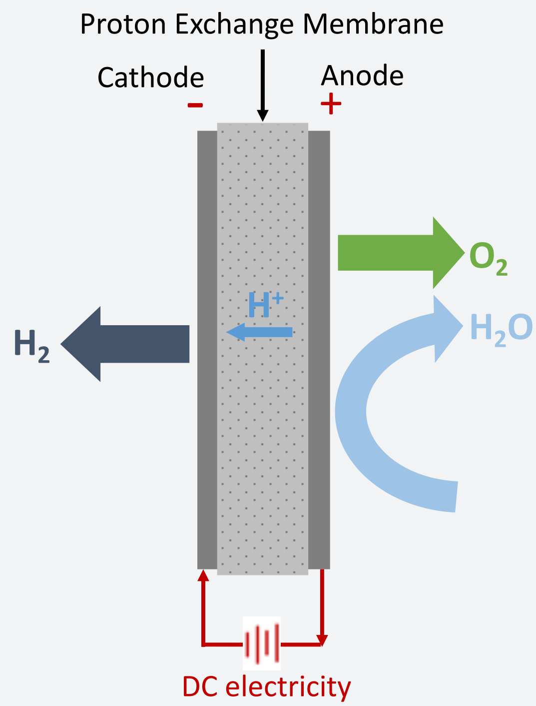

Figure 3.12. Schematic showing the operation of a Proton Exchange Membrane (PEM) electrolyser.

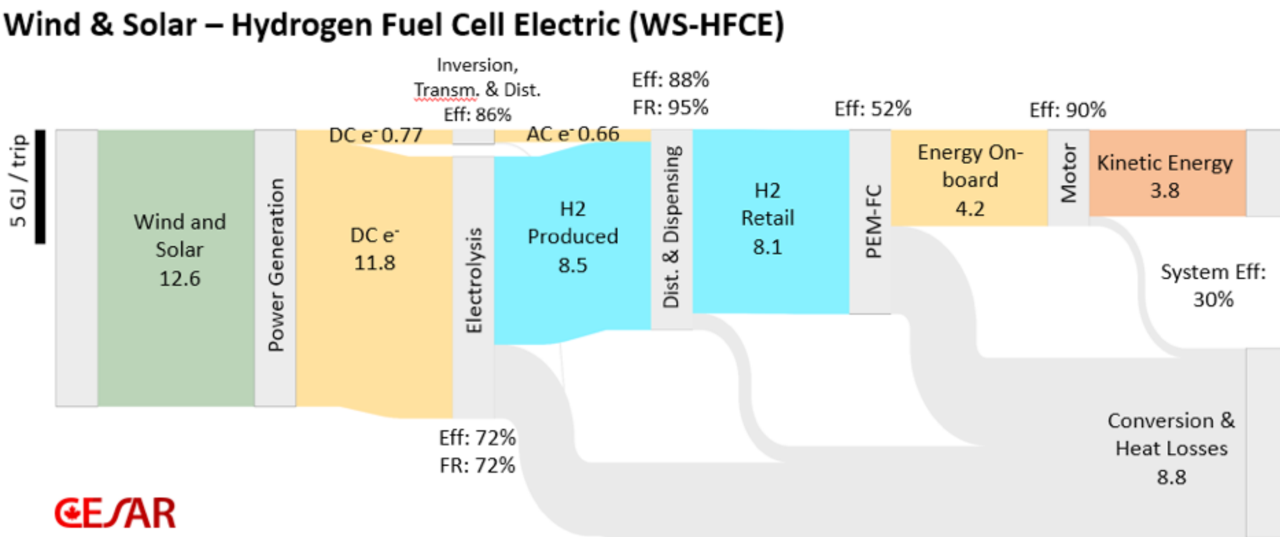

Figure 3.13. Flows of energy (GJ/trip) for an energy system in which hydrogen is produced from wind and solar generated electricity and used in a fuel cell hybrid electric vehicle to support a trip associated with moving a 27t_{gross} heavy duty vehicle a distance of 750 km. For details of calculations and references, see Table S16.

allocated to the grid or be used to produce H_2. The Sankey diagram in **Figure 3.13.** shows only the portion of wind or solar generation that is used to support the Typical Shipment.

Similar to the PEM-FC technology that powers the HDV, there is potential for PEM electrolysis technology to improve with advancements in areas such as membrane durability, alternate membrane material or synthesis method. Advances in these technologies have the potential to significantly improve the efficiency and reduce the cost of PEM electrolysis [89], [90].

The Cost of Energy. Assuming an average wind electricity cost of $40/MWh ($11/GJ^e) with an energy feedstock conversion efficiency of 72% (**Figure 3.13.**, Table S16, [88]), the embedded feedstock (electricity) cost for the produced hydrogen was calculated to be $15.30/GJ or $2.16/kg H_2 (**Figure 3.15.**, Table S17, Item 2).

The price of H_2 produced using electrolysis was estimated to range between $3.10 to $5.01/kg H_2 **(Figure 3.14. and 3.15.,** Table S17, Item 6) based on costs projections from the U.S Department of Energy [91] while accounting for the variability in electricity feedstock prices and are presented in more detail in **Box 3.5**.

More work is needed to reduce the capital and operating cost associated with the electrolytic production of hydrogen since even without even considering the differences in energy feedstock cost, electrolysis is 1.7 times more costly than that estimated for SMR with carbon capture and storage ($0.90/kg H_2, **Figure 3.10.**). As an example, the

Box 3.5. The Relationship Between Input Energy and Hydrogen Cost Using PEM Electrolysis

Although wind and solar resources are free, the infrastructure needed to capture and convert the resources into electricity is not. The levelized cost of electricity (LCOE) for each conversion technology is a metric that quantifies the integrated cost of power production. Values for the USA have been published by Lazard [92], but for Alberta, LCOE numbers have been offered by CERI [96] and demonstrated through successful bid prices for renewable power projects in the Alberta Renewable Electricity Program [94].

Wind and solar generation costs have been declining in recent years, and in many jurisdictions, including Alberta, they are now the lowest cost source of power [88]. Indeed, bids for wind generation in Alberta have recently been received in the $30 - $40 /MWh range [94], equivalent to $8.33 – 11.00/GJe. However, their intermittent nature limits the contribution they can make to the electrical grid.

The calculations are based on the proven LCOE for renewable power generation, but since hydrogen would only be made when grid demand is satisfied, and grid power would be expected to deliver higher prices, the feedstock cost for hydrogen generation could be a little less than that shown in **Figure 3.14**. On the other hand, an intermittent use of the electrolysis infrastructure could increase its cost above the $1.50/kg H_2 [26].

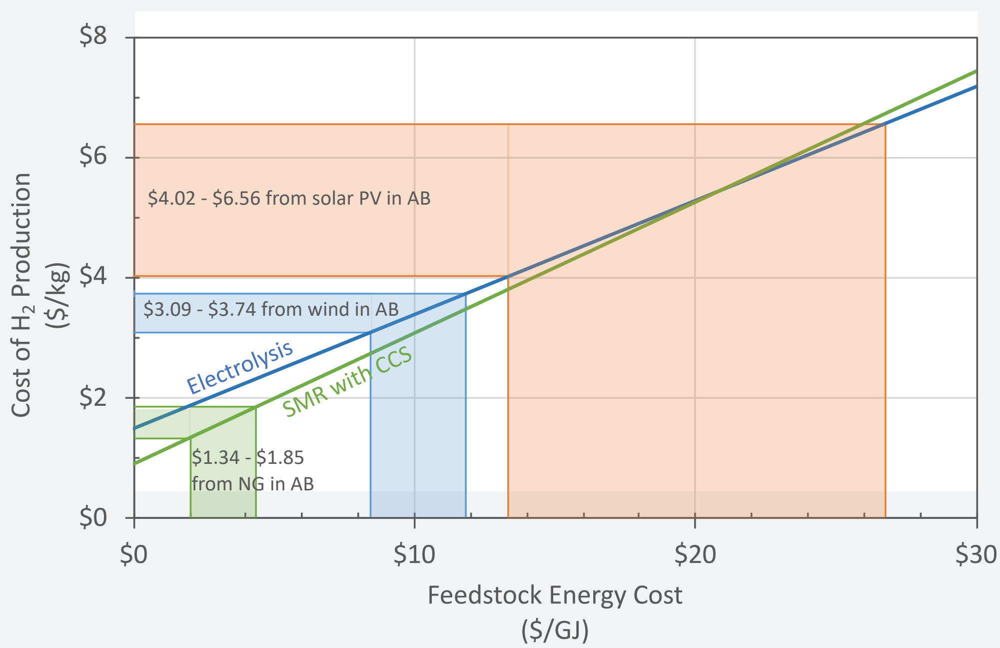

Figure 3.14. The impact of electricity cost on the cost of hydrogen (H_2) from PEM electrolysis as calculated from a US Dept of Energy study [93]. The blue and orange shaded areas show the Levelized cost of electricity (LCOE) for wind and solar respectively. The range of LCOE for wind ($30-$42/MWh) is based on successful bids from the Alberta Renewable Energy Program [94], whereas the range of LCOE for solar PV is based on recent CanSIA ($48/MWh, [95]) and CERI ($87-$96/MWh, [96]) reports. The three data points depict a 'low', 'mid' and 'high' scenario for the cost of renewable generation in Alberta (see Table S17. for details).

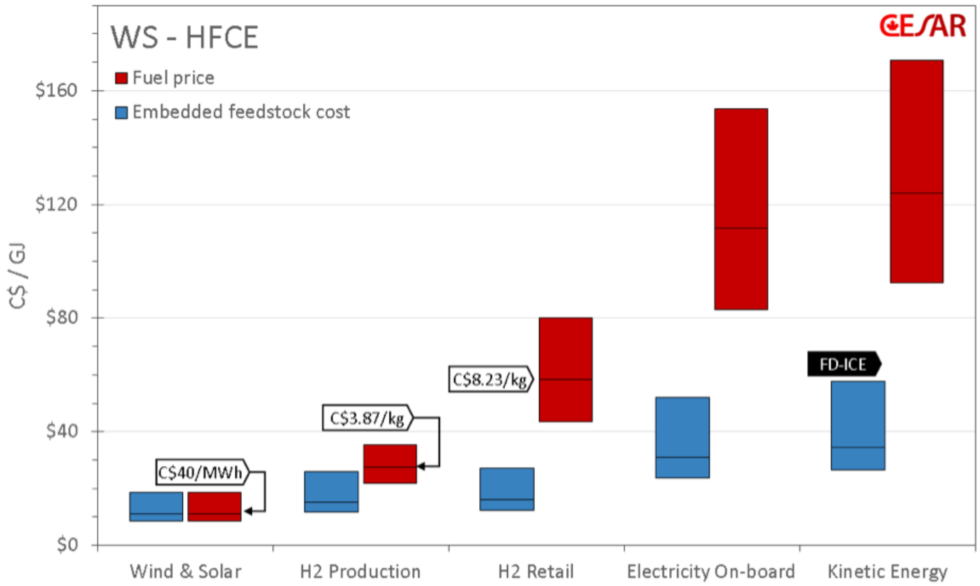

Figure 3.15. Flows of energy supply dollars ($C\$/GJ_{HHV}$) for an energy system in which hydrogen is produced from wind and solar generated electricity and used with a fuel cell electric hybrid drivetrain to support a trip associated with moving a $27t_{gross}$ heavy duty vehicle a distance of 750 km. For details of calculations and references, see Table S17

ability to electrolyze less than pure water, or the development of lower cost electrodes (e.g. avoid use of expensive platinum or iridium that are used today) [90] would be key to reducing the cost of PEM electrolysis.

It is also important to note that our estimates do not include the cost of grid distribution of the renewable power. At a cost of $43/MWh (typical for Alberta), grid distribution of the renewable power would add an additional $2.27/kg H_2 ($16.07/GJ H_2) to the H_2 cost. While it could avoid the need to distribute the H_2 to fueling stations, the capital and operating cost for smaller, distributed electrolysis units are likely to be greater than that calculated here.

Given the same feedstock retention rates for the rest of the energy system as was used for the NG-HFCE energy system, the embedded feedstock cost in the kinetic energy moving the vehicle was calculated at $34.32/GJ, with a range of $26.36 to $57.83/GJ (**Figure 3.15.**), values that are 32-45% higher than the embedded cost of crude oil in the kinetic energy of the FD-ICE energy system (**Figure 3.2.**).

To estimate the fuel price associated with the WS-HFCE energy system, we used the model behind **Figure 3.14** [93] and calculated a retail price for hydrogen of between $6.13 and $11.34/kg or $43.40 to $80.28/GJ H_2). Given a drive train efficiency of 47%, the price for the kinetic energy was estimated to range from $92 to $171/GJ, values that are 1.8 to 2.2 times higher than that calculated for the FD-ICE energy system (**Figure 3.15.**, Table S17, Item 11).

4. Greenhouse Gas and Air Pollution Emissions

Canada's road freight transportation sector is a large contributor of GHG emissions, accounting for about 8% of total GHG emissions [18], primarily from the combustion of diesel fuel in internal combustion engines. For Canada to do its share to limit global temperature increase to less than 2°C freight transportation emissions, it is widely believed that GHG emissions need to be reduced by at least 80% over 2005 levels by 2050 [95] and such targets have been set by several provinces including British Columbia, Ontario, and New Brunswick [97].

As discussed in the first Future of Freight report [1], alternatives are needed to the combustion of diesel made from fossil fuel. However, GHG emissions are not the only problem associated with diesel combustion; the fuel is also known for its contribution to air pollution, especially nitrogen and sulphur oxides (NO_X and SO_X), particulate matter (PM), and other volatile compounds. These emissions are linked to environmental and health hazards such as cardiac and respiratory disease, acid rain, and smog. Concerns regarding air pollution has led to many countries and municipalities to phase out or ban internal combustion engines by 2030 or 2040 [97].

4.1. Fossil Diesel-Internal Combustion Engine (FD-ICE)

Diesel fuel is currently the dominant fuel for HDV freight transportation and is a primary source of both GHG and air pollution emissions from the freight transportation sector.

GHG Emissions. The well-to-wheels GHG emissions for a Typical Shipment from the FD-ICE system was calculated to contribute 1085 kg CO_2e/trip (**Figure 4.1.**, Table S6 [30]). The combustion of the diesel fuel at the powertrain accounts for 74% of the emissions based on an emission factor of 71 kg CO_2e/GJ_{diesel} (2.7 kg CO_2e/L_{diesel}) [18].

The remaining 26% of the GHG emissions are upstream (well-to-tank) emissions that include 158 kg CO_2e/trip for crude oil production (venting, flaring, dilbit production, mine face, and tailings), 120 kg CO_2e/trip for oil refining, and 4 kg CO_2e/trip for distribution (**Figure 4.1.**).

The upstream emissions are based on emission factors adapted from IHS Energy [39] and are equivalent to 14 kg CO_2e/GJ_{diesel}

for crude oil production, upgrading, and transport and 11 kg CO_2e/GJ_{diesel} for refining and transport. The emission factors were adapted using a weighted mix of Canadian Mixed Sweet conventional oil and Canadian Oil Sands (mining and in situ) and includes the lifecycle emissions of the fuels consumed at each of the upstream processes (e.g. wide boundary).

When the annual growth in freight emissions since 2005 is considered, we estimated that to attain these reduction levels, GHG emissions from the Typical Shipment would need to be reduced by 84% from the 2016 emissions used as a reference in this study. Therefore, the well-to-wheel emissions from a Typical Shipment would need to be less than 178 kg CO_2e/trip to be consistent with Canada's international commitments (**Figure 4.1.**).

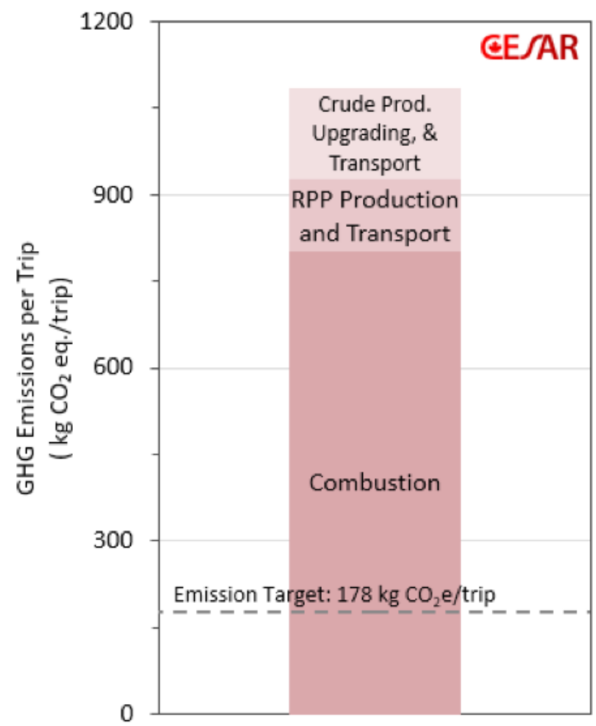

Figure 4.1. Greenhouse Gas (GHG) emissions (kg CO_2 eq./trip) from an energy system in which diesel fuel is used to move a typical heavy-duty vehicle shipment of $27t_{gross}$ x 750km. For details of calculations and references, see Table S6.

Air Pollution. This study examined the vehicle emissions of NO_X and $PM_{2.5}$ associated with fossil diesel combustion in heavy duty vehicles. SO_X emissions are not reported since with sulphur regulations introduced in 2004 [98], these emissions have been almost entirely abated [99].

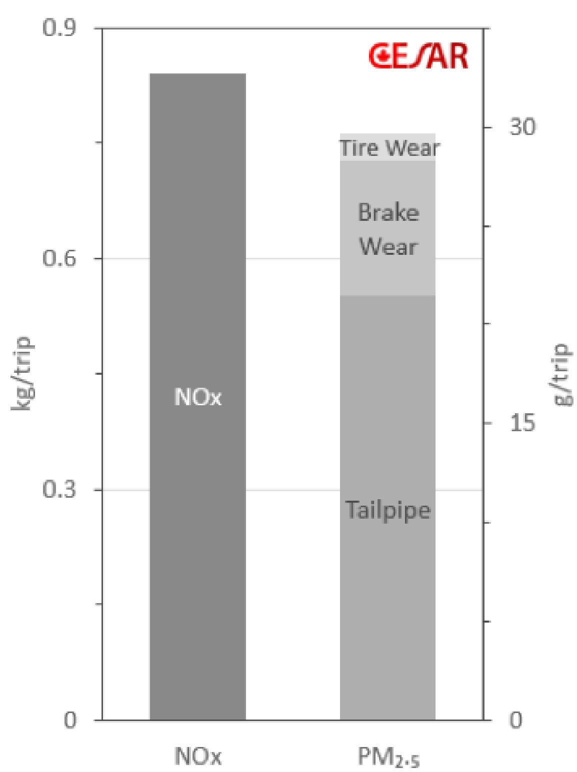

Figure 4.2. Nitrogen oxide (NOX)and Particulate Matter 2.5 (PM2.5) air pollutant emissions (kgNOX/trip and gPM2.5/trip) from an energy system in which diesel fuel is used to move a typical heavy-duty vehicle shipment of $27t_{gross}$ x 750 km. Emission factors from Environmental Protection Agency [37]-[38].

Using emission factors published by the United States Environmental Protection Agency [37], the Typical Shipment releases 841 g NO_X/trip from the tailpipe to the atmosphere (**Figure 4.2.**), contributing to smog, acid rain, and human health hazards.

Particulate matter emissions result from tire and brake wear [38] in addition to emissions from the combustion in the engine [37], producing a total of 30 g $PM_{2.5}$/trip. Particulate emissions with a diameter or 2.5µm or less are linked to cardiac and respiratory diseases and impacts visual air quality.

While on a mass basis, $PM_{2.5}$ emissions are an order of magnitude less than the NO_X emissions per trip, the health and environmental impacts of $PM_{2.5}$ are often considered to be as severe as or more severe than NO_x [37]-[38].

4.2. Bio-Based Diesel-Internal Combustion Engine (BD-ICE)

GHG Emissions. Because plant-based biological sources remove carbon from the atmosphere in the growth phase, emissions that are released upon combustion are negated, so bio-based fuels are typically considered to be carbon-neutral. While CO_2 emissions from fossil fuels are assigned a global warming potential (GWP) of 1.0 (e.g. 1 t fossil CO_2 emissions X GWP = 1 t CO_2 equivalent GHG emissions), bio-based emissions are typically assigned a GWP_{bio} of 0.

However, in recent years, the assumption of carbon neutrality for bio-based emissions has been challenged since there are situations in which the combustion of bio-based carbon is not being balanced by plant growth, and biosphere carbon stocks are being depleted. In such cases, researchers have been calculating GWP_{bio} values that are greater the zero, and often in the range of 0.1 to 0.4, and sometimes higher [32]–[36].

In this study, we report the total bio-based CO_2 emissions and then calculate the GHG emissions with a default assumption that the GWP_{bio} is 0, but also show what the emissions would be if GWP_{bio} was as high as 1.0.

The calculation of GHG emissions used the energy flow data that was presented in **Figure 3.4** where 22.7 GJ_{HHV}/trip of lignocellulosic biomass is consumed to produce 11.3 GJ_{HHV}/trip of bio-based diesel and an additional 0.46 GJ_{HHV}/trip of bio-based diesel is consumed to support the harvesting and transport of the biomass.

Assuming the energy content of the biomass is 20.1 GJ_{HHV}/t(dry), 50% (w/w) C in dry biomass [100] and 87% (w/w) C in bio-based

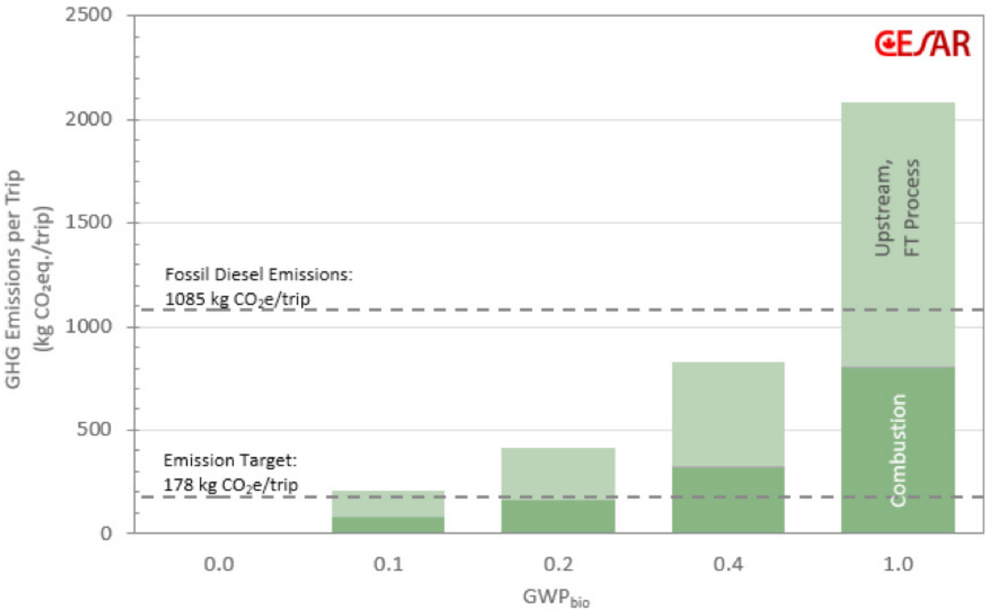

Figure 4.3. The effect of the global warming potential for biomass CO_2 (GWP_{bio}) on the estimates of greenhouse gas (GHG) emissions per trip for a bio-based diesel ICE energy system..

diesel [101], we calculated total carbon emissions of 2078 kg CO_2/trip. Five GWP_{bio} values were then used to calculate a range of CO_2e emissions, ranging from zero to 2078 kg CO_2/trip (**Figure 4.3**). At a GWP_{bio} value of about 0.5, the emissions from the BD-ICE energy system would be similar to the FD-ICE energy system. At a GWP_{bio} value of 0 to 0.1, bio-based diesel fuel should be able to meet or exceed the emission reduction target of 178 kg CO_2e/trip (**Figure 4.3**).

Air Pollution. Bio-based diesel fuels are chemically identical to fossil diesel and therefore the BD-ICE provides no NO_X or $PM_{2.5}$ air pollutant advantages to the FD-ICE system.

4.3. Grid-Battery Electric (G-BE)

The electric HDV is an environmentally attractive alternative to the incumbent ICE option because the vehicle powertrain produces zero GHG emissions and zero air pollutants. However, on a well-to-wheel basis, the G-BE system emissions are dependent on how the grid electricity is generated since it is needed to charge the onboard battery.

GHG Emissions. In 2016, the GHG emission intensity of the Alberta public grid (equivalent to about 63 TWhr/year, and does not include 'behind-the-fence' generation of about 20 TWh/yr) is calculated to be 719 kg CO_2e/MWh (**Table 4.1.**, [56]), based on a grid that is made up of 61% coal power generation and 27% NG generation.

However, there is a movement to eliminate coal from power generation and to increase renewable energy (especially wind) to as much

Table 4.1. Generation share and grid intensity - 2016 and 2030 (projection)

Source	2016		2030	
	Gen. %[1]	Carbon Intensity	Gen. %[2]	Carbon Intensity
	%	$kgCO_2e/MWh$	%	$kgCO_2e/MWh$
Coal	61%	1008	0%	1008
NG Cogeneration	17%	350	20%	350
NG Combine Cycle	9%	390	46%	390
NG Single Cycle	1%	525	4%	525
Hydro	3%	0	3%	0
Wind	7%	0	24%	0
PV	0%	0	1%	0
Biomass / Other	1%	0	2%	0
Imports	0.7%	0	0%	0
Total	**100%**	**719**	**100%**	**270**

Notes:

{1} Based on AESO Annual Market Statistics 2017 [53]

{2} CESAR projection; 70% NG and 30% renewables.

as 30% of total annual generation by 2030 [25]. If such a future grid were to be created (denoted here as '2030 Grid'), the carbon intensity would be about 270 CO_2e/MWh (**Table 4.1.**).

Including upstream emissions for resource extraction of coal [18], [102] and NG [41], lifecycle GHG emissions for a battery-electric HDV using a 2016 grid are 1,284 kg CO_2e/trip (**Figure 4.4**), or 18% higher than for a fossil diesel powered trip. This suggests that with the current grid mix in Alberta, the Grid-BE is not a lower carbon alternative to the FD-ICE.

However, in a 2030 grid that is free of coal and that has 30% renewables, the Typical Shipment will only emit 544 kg CO_2e/trip (**Figure 4.4**), a 50% reduction from the incumbent system. Unfortunately, even though such a grid has a much lower carbon intensity, the Grid-BE system will still be unable to reach the 178 kg CO_2e/trip target.

Air Pollution. Since a battery electric HDV has no tailpipe emissions, brake and tire wear are the sole source of air pollution emissions from vehicle operation, calculated as 8.3 g $PM_{2.5}$/trip (**Figure 4.4**), or 72% lower than the FD-ICE system.

Air pollutant emissions from power generation are outside the scope of this study, but there is strong evidence that coal power generation is a significant source of air pollution in Alberta thereby supporting the need for a lower emission grid (including NG power generation options) [103].

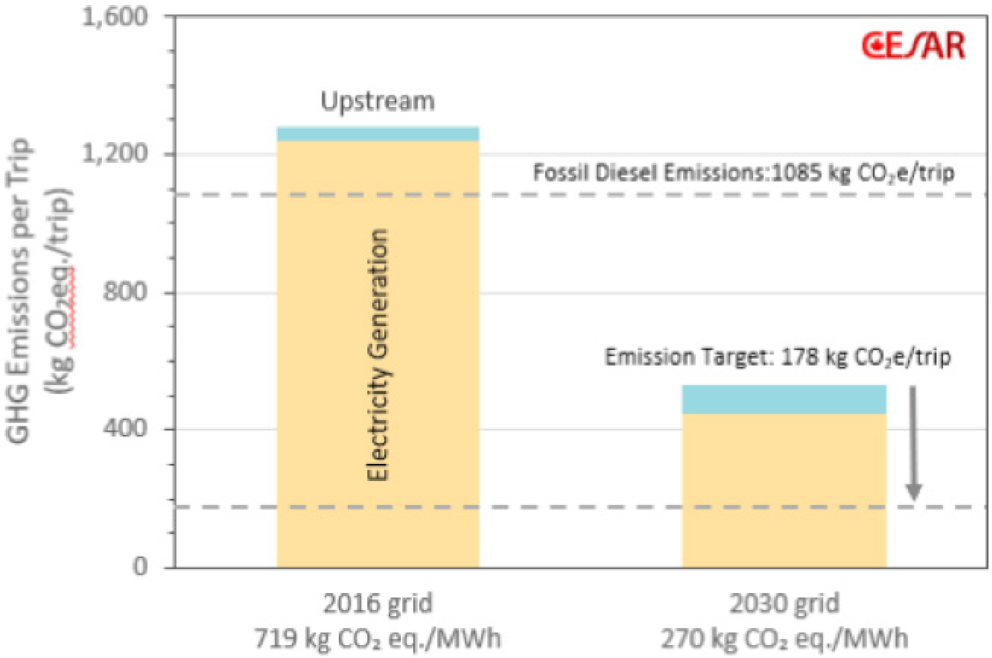

Figure 4.4. Greenhouse Gas (GHG) emissions (kg CO_2 eq./trip) from an energy system in which grid electricity is used in a battery electric heavy-duty vehicle to move a typical shipment of $27t_{gross}$ x 750 km. For details of calculations and references, see Table S12.

4.4. Natural Gas-Hydrogen Fuel Cell Electric (NG-HFCE)

Like the G-BE energy system, the emissions profile for the NG-HFCE system will have zero emissions from the HDV powertrain (other than water vapor). However, there are likely to be GHG and air emissions from the upstream processes.

GHG Emissions. In the NG-HFCE energy system, there are three main sources of GHG emissions: (1) upstream NG production and processing, (2) H_2 production using SMR, and (3) power generation where electricity is consumed for NG and H_2 compression and distribution.

For the Typical Shipment, the well-to-wheel emissions of the NG-HFCE system sum to 812 kg CO_2e/trip with the assumption that the 2016 grid mix is in place (**Figure 4.5.**, Table S15). These system emissions are 25% lower than the FD-ICE system. With the 2030 grid mix utilized for the system's power requirements, the NG-HFCE system would release 716 kg CO_2e/trip, a 34% savings from the FD-ICE system.

Most of the emissions (70% to 80%) of this system occur during SMR, and include both process and energy emissions. As discussed in **Box 3.2.**, the SMR emissions of carbon can be either released to the atmosphere or about 90% of them can be captured and stored (CCS) (**Figure 4.6.**), or possibly used for enhanced oil recovery or other commercial uses [104]. The CO_2 produced in the SMR process is 'pre-combustion' which generates a relatively pure CO_2 stream

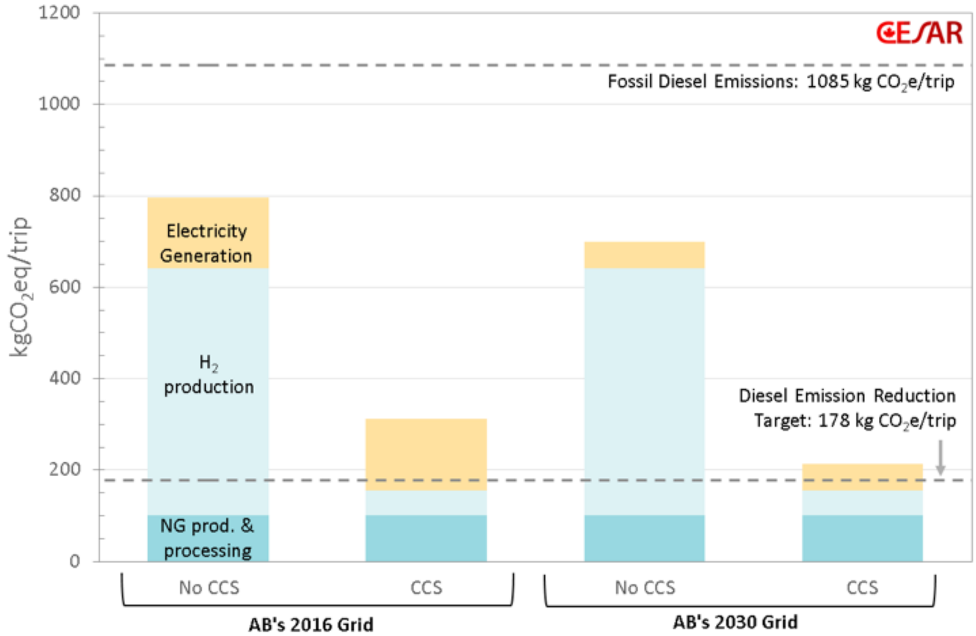

Figure 4.5. Greenhouse Gas (GHG) emissions (kg CO_2 eq./trip) from an energy system in which hydrogen is produced from natural gas using steam methane reforming and used in a hydrogen fuel cell electric heavy-duty vehicle to move a typical shipment of $27t_{gross}$ x 750 km. . For details of calculations and references, see Table S15.

that can be purified at a lower cost than CO_2 captured from a more dilute post-combustion flue gas [105].

If 90% of the process and combustion emissions are captured as depicted in **Figure 4.6.** where 59 kg CO_2e/trip is captured, the NG-HFCE system emissions are reduced to 315 kg CO_2e/trip assuming the 2016 equivalent grid mix is in place or 216 kg CO_2e/trip assuming the 2030 grid mix (**Figure 4.5.**), a 71% and 80% drop from the FD-ICE system, respectively.

However, even with CCS and a lower carbon grid, this system is still 20% higher than the emission reductions targets that are needed to reach climate change commitments (**Figure 4.5.**).

Air Pollution. Like the battery electric alternative, the HFCE powertrain does not produce air pollution. The only powertrain emissions are water vapour, and brake and tire wear are the sole source of air pollution emissions from vehicle operation.

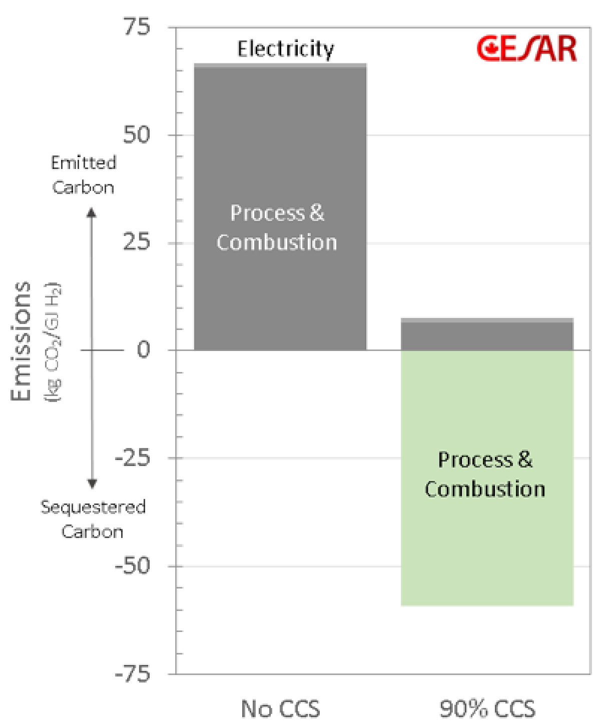

Figure 4.6. Greenhouse gas (GHG) emissions from hydrogen production using Steam methane reforming (SMR) processes with and without carbon capture and storage (CCS).

Other criteria air pollutant emissions in the NG-HFCE system would occur with NG production and transportation and comparatively small amounts of NO_x and SO_x released in the SMR process [106].

4.5. Wind/Solar to Hydrogen Fuel Cell Electric (WS-HFCE)

The WS-HFCE energy system makes hydrogen by electrolysis of water using power from large wind and solar installations that first serve the public grid. However, when their production exceeds demand, and the grid prices are low, the power is diverted to hydrogen production.

In this energy system some renewable electricity is also needed to compress the hydrogen, both at the site of power generation, and at the fueling sites. As will be discussed in the next report in this Future of Freight series[13], the WS-HFCE energy system has the potential to also supply a large proportion of the Alberta electrical grid with very low or zero emission power.

GHG Emissions and Air Pollution. As with the NG-HFCE energy system, the powertrain of the WS-HFCE energy system produces no GHG or air emissions except for water vapour. Due to the assumptions for this energy system mentioned above, the grid is effectively 100% renewable and so without emissions.

Like the other systems that operate using an electric powertrain, brake and tire wear are a source of air pollution emissions from vehicle operation.

5. Vehicle and Fuel Performance Characteristics

For more than 100 years, the energy system that uses FD-ICE technology has been successful in supporting road and other modes of freight transportation, plus backup or small community power generation, as well as some personal mobility, agriculture, earth moving equipment, etc.

When considering alternatives to FD-ICE for HDV transport, it is critical that the alternatives are fit for the service that they need to provide. The existing FD-ICE system sets the current performance standard that any alternative powertrain must either meet or outperform.

5.1. Power, Torque, & Drivability

The FD-ICE HDV provides the necessary pulling power to transport freight across a variety of terrain and conditions. It also provides sufficient torque to gain traction and accelerate while pulling heavy payloads. These performance traits are important in Alberta where long combination vehicles (LCV) such as B-train configurations with heavy payloads are utilized [49].

In contrast to the ICE (either FD-ICE or BD-ICE), electric motors (BE or HFCE) are able to provide instant high torque at periods of low power and speeds [107] which is desirable for HDVs pulling heavy loads that are currently challenged to get moving, accelerate and climb steep grades with the ICE.

Another possible advantage of the electric motor is the option to design for direct drive motors, commonly known as e-axles, that can direct power to the individual axles, for more dynamic performance and greater reliability [108].

5.2. Range and Refueling / Recharging Time

To complete the Typical Shipment in the FD-ICE energy system, 282 L of diesel fuel would be consumed. That quantity of fuel would require about 4 minutes to refuel, including the time needed to fill the diesel exhaust fluid tank [109], [110]. Furthermore, the range of the ICE HDV can easily be extended with larger or multiple diesel tanks. For example, the Kenworth T680 long-haul HDV model is

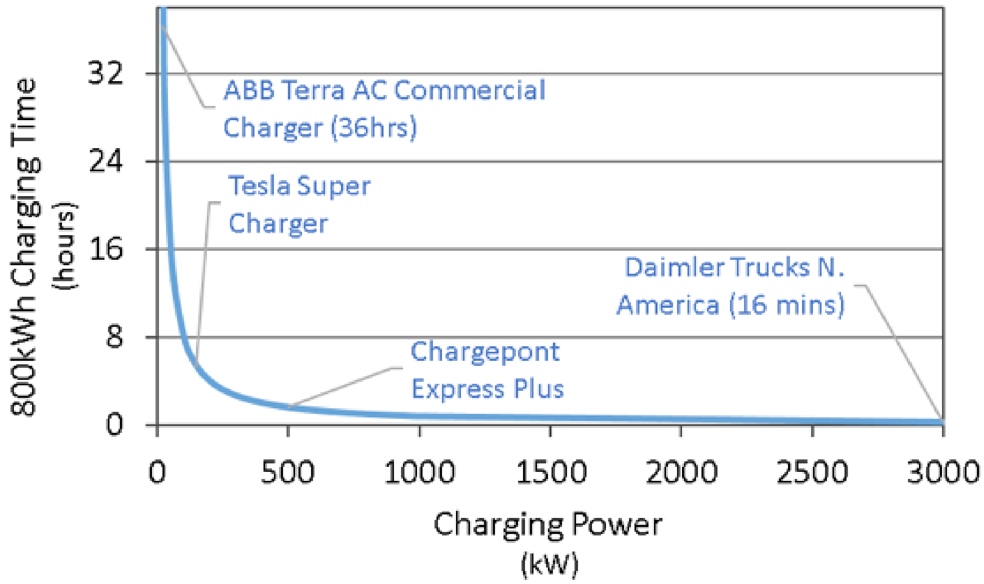

Figure 5.1. Estimated charging time for an 800kWh battery using simplified analysis and power levels from charging stations promoted by ABB [112], Tesla [114], and ChargePoint [113], and Daimler [115].

equipped with a standard 380 L tank with larger tank options as high as 670 L [111] thereby more than doubling the range needed for a Typical Shipment.

Through CESAR's per trip analysis, the Typical Shipment in the Grid-BE energy system would require 1,550 kWh (**Figure 3.6.**) of energy without recharging, however a battery of this size is not currently practical for HDV application due to physical size and weight constraints. Therefore, a mid-trip recharge would need to be accommodated to complete the Typical Shipment.

If an HDV with an 800-kWh battery can be developed, using a simplified analysis that does not take into account the complexities of the charging design and battery management, it could take ≈ 36 hours to recharge using a 22 kW AC charger [112] or 1.5 hours to recharge using a 500 kW DC charge [113] (**Figure 5.1**).

Recharging time that leads to extensive downtime would impact the ability of the HDV asset to generate an acceptable return on investment. For a 750km long haul trip, it is hard to envision a truck being out of service in the middle of the trip for 1.5 hours, and then for another 1.5 hours before the vehicle is put back into service for another trip, especially while managing labour shortages and hours of service regulations[1]. However, there are significant strides being made in high power charging infrastructure such as Daimler announcing plans in April 2019 to develop 3MW charging for heavy duty vehicles [115]. A charger of that capacity would charge an 800kWh BE-truck in as little 16 minutes **(Figure 5.1.)**.

Several countries are also piloting electrified roadways as a means of overcoming the challenge of long charge times in battery electric and hybrid electric heavy duty freight transportation. Seimens' *eHighway* is a 6 mile stretch of highway near Frankfurt, Germany which allows hybrid electric trucks to charge while in motion with the use of overhead wires [116]. Sweden is also piloting road electrification in the form of embedded 'electric rails' which charge vehicles in motion via a movable arm that attaches to the bottom of the chassis [117]. However, in both cases, vehicles will be limited to specific lanes and maximum speeds in the range of 50-60 mph (80-97 km/h) which could have significant implications on the flow of traffic. Moreover, the cost of these systems may be harder to justify under Canadian conditions where the incumbent diesel fuel is less costly, the distances are larger and – in some cases – the traffic is less intense.

In contrast, the HFCE HDV would be less constrained by range and refueling time. By storing the energy onboard as hydrogen as opposed to in a battery, the HFCE has the potential to travel distances that are comparable to the FD-ICE HDV between refueling. For example, for the HFCE HDV to complete the Typical Shipment, existing technology would require about 57 kg of hydrogen (Figure 3.8) with a refill time of less than 15 minutes [118]. This is longer than the FD-ICE system, but our discussions with the companies suggest that it may be acceptable.

There are some inherent challenges with storing hydrogen on board the HDV. It is a voluminous gas and the 57 kg would take up 1.4 m^3 of space when pressurized to 700 bar (assuming a density of 0.04 kg/L [119], 2.4 m^3 for 350 bar) in addition to the tank that it is stored in. According to research that was supported by the US Department of Energy, there are design options that can reasonably accommodate the storage tanks either behind the cab or on the side rail and under the chassis to potentially achieve ranges as high as 1,600 km [120].

5.3. Tare Weight

Alberta Transportation regulates and enforces maximum gross allowable weights [121], the sum of HDV tare (unladen) and payload weight, on the road in the province. Any increase in tare weight will reduce allowable payload and that could impact revenue. Total tare weight in a FD-ICE HDV can range between 9,000 to 12,000kg with the engine and exhaust systems contributing around 1,800 kg to the tare weight [123].

For a BE HDV that is capable of transporting the Typical Shipment, an extremely large battery, in weight and space, would be needed to carry the required 1,550 kWh of energy storage (**Figure 3.6.**). A battery of this size would not be practical and would severely impede the vehicle's payload capacity.

Even if a mid-trip recharge could be accommodated, an 800kWh battery would weigh around 6,400 kg/HDV, based on a weight ratio of 0.125 kWh /kg [124], which could be more than half of the full tare (unladen) weight of a diesel HDV and the battery would take up almost 4 cubic meters of space, assuming a volumetric battery density of 0.2 kWh/L [124] (**Figure 5.2.**).

Similarly, the tare weight of HFCE option is impacted by weight of the H_2 tanks. At a tank weight to hydrogen weight ratio of 19:1 [125], the type III storage tanks for 70 kg of H_2 (57kg per Typical Shipment plus 25% buffer) would contribute around 1,400 kg to the total tare weight. The weight of a 300 kW fuel cell would only add another 300kg with a weight ratio of 0.94kW/kg [126] and the electric motor would add 219kg with a weight ratio of 1.6kW/kg [127].

Much of the additional weight of either the BE or HFCE is offset by absence of the engine and exhaust system in an electric HDV design, particularly for the HFCE option. When comparing the weight of the powertrain components that can differ between systems, using

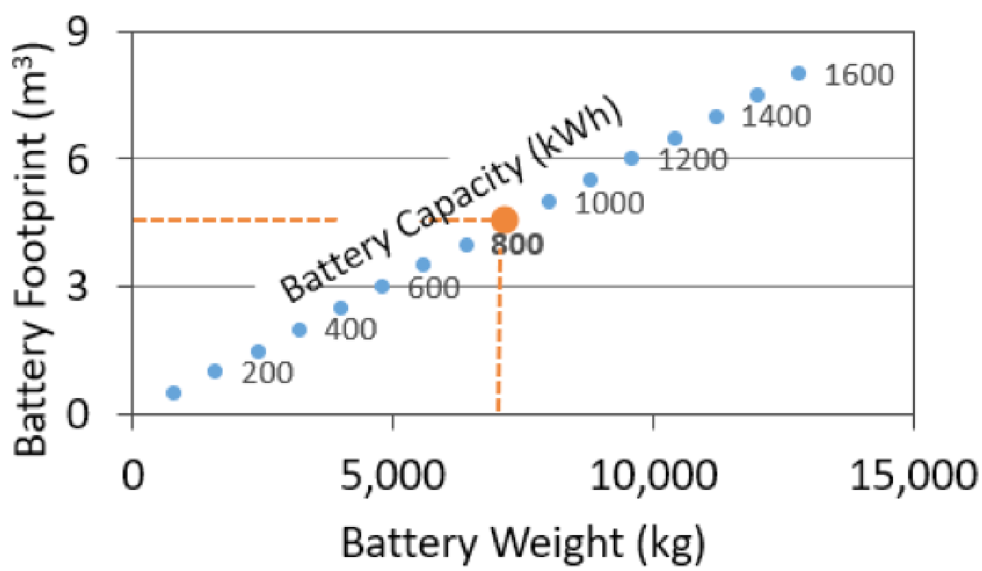

Figure 5.2. Estimated battery weight by kilowatt hour (kWh) of storage assuming a battery weight ratio of 0.125 kWh/kg and a volumetric density of 0.2kWh/L [124].

350 L of diesel (282 L for the Typical Shipment plus a 25% buffer), 800 kWh of battery storage, or 70 kg of H_2 for the FD-ICE, BE, HFCE vehicles, respectively, the HFCE alternative has a slightly higher tare weight to the traditional FD-ICE (**Figure 5.3**).

However, it should be noted that increasing the H_2 tank size to achieve even longer ranges between refueling will have a noticeable impact on the tare weight because of the heavy tanks whereas adding more diesel tanks will only marginally increase the tare weight for the FD-ICE HDV.

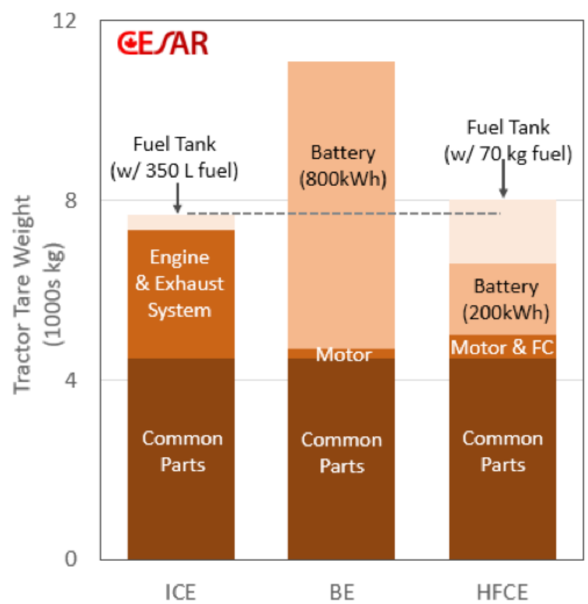

Figure 5.3. Estimate of tractor tare weights for diesel internal combustion engine (ICE), hydrogen fuel cell electric (HFCE) and battery electric (BE) heavy duty vehicles.

With the still very large 800kWh battery, the BE HDV remains substantially heavier than the FD-ICE equivalent (**Figure 5.3**). However, because batteries for transportation are emerging technologies, it is fair to expect advancements to battery weight ratios and the North American Council for Freight Efficiency (NACFE) projects that HDVs will reach tare weight parity to the diesel ICE by 2030 [128].

5.4. Capital Costs

The FD-ICE HDV is a mature technology in an active market. With a capital cost of C$165,000/HDV[27], new technologies trying to break into the market will need to be able to be compete against this relatively low-cost standard. Initially, government incentives could help in the transition to a more sustainable technology and over time, the costs for the alternative HDVs should come down.

A drawback of the BE HDV compared to the incumbent diesel option, is the upfront capital cost. Although Tesla is promoting its long-haul HDV at a cost around C$300,000[7], CESAR estimates, based on data from the ICCT [129], that an HDV with an 800kWh battery that the upfront cost is likely upwards of C$440,000 which is 2.7 times higher than its diesel equivalent.

While battery costs have dropped dramatically over the last 10 years, the battery remains a significant cost component that will impact the competitiveness of the BE truck option over diesel HDV. The

2016 market price of a battery pack has been estimated at US$227/kWh [130] driving the battery cost to C$240,000 for an 800kWh battery. But as an emerging technology, large reduction in battery costs paired with substantial performance gains are likely [128].

Similar to the BE HDV, while still widely unknown, the capital costs for the HFCE vehicle are expected to be between C$335,000 [129] and C$455,000 [131], or around 2 to 3x the cost of its fossil diesel equivalent diesel. Likewise, because HFCE vehicles are not currently available at commercial scale and the technology is advancing rapidly with falling costs, the future cost of these vehicles are expected to be even lower [127].

5.5. Maintenance Costs

Maintenance costs represent close to 10% of a commercial freight carrier's operating expenses in Canada [132], and are one of the top concerns for the freight industry. In addition to the actual costs for repair and upkeep, there are opportunity costs associated with HDVs needing to be taken off the road for planned and unplanned maintenance. Such vehicles do not generate revenue.

Contrarily, electric HDVs (BE and HFCE) should have considerably lower maintenance costs because of the simpler design, fewer friction sensitive mechanical parts, and less fluids. Based on the demonstration projects performed at the Port of Los Angeles, the maintenance costs of electric HDV are expected to be about 36% of the maintenance costs of its diesel equivalent [29]. While battery replacements could prove to be a significant maintenance cost, it is anticipated by NACFE that the battery would likely exceed the HDV life [128].

When the low maintenance costs are combined with the energy efficient powertrain and low energy (electricity) costs, and a longer vehicle lifespan [29], the total cost of ownership may be comparable to the diesel option within the lifespan of the truck[129]. Of course, there are many other factors that would need to be accounted for in a total cost of ownership analysis including technology advancement rates, market and regulatory issues and indirect factors such as driver attraction [133] that are beyond the scope of this report.

6. Energy System Comparison

This section will attempt to bring together the key findings from all the previous sections of this report and do a comparative assessment on a number of key parameters.

6.1. Efficiency Comparison

On a well-to-wheel basis, only 26% of the energy inputs to the FD-ICE system make it through to the kinetic energy driving the wheels. Of the alternative energy systems, all but the BD-ICE energy system out-perform the FD-ICE in terms of systems efficiency (**Figure 6.1.**). The lower overall efficiency in the BD-ICE energy system can be attributed to the substantial losses at the refinery where the diesel is made from biomass. The most efficient energy system is G-BE at 34% (**Figure 6.1.**).

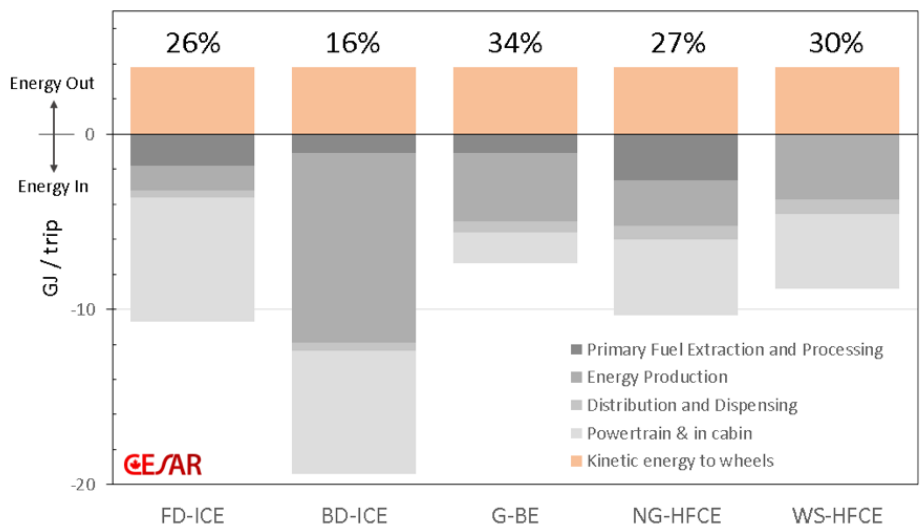

Figure 6.1. System efficiency summary for the five energy systems moving a typical shipment of $27t_{gross}$ x 750 km.

Of course, energy efficiency is only one indicator of system performance and not a definitive qualifier to determine the value of one system over another. However, system efficiency does have a direct effect on the cost of kinetic energy.

6.2. Energy Cost Comparison

For an alternative energy system to be compelling for wide scale adoption, it will also need to be cost competitive with the incumbent FD-ICE system. **Figure 6.2.** (red bars) summarizes the estimated fuel price (at scale) and embedded energy feedstock cost in the kinetic energy moving the vehicle in all five energy systems. The

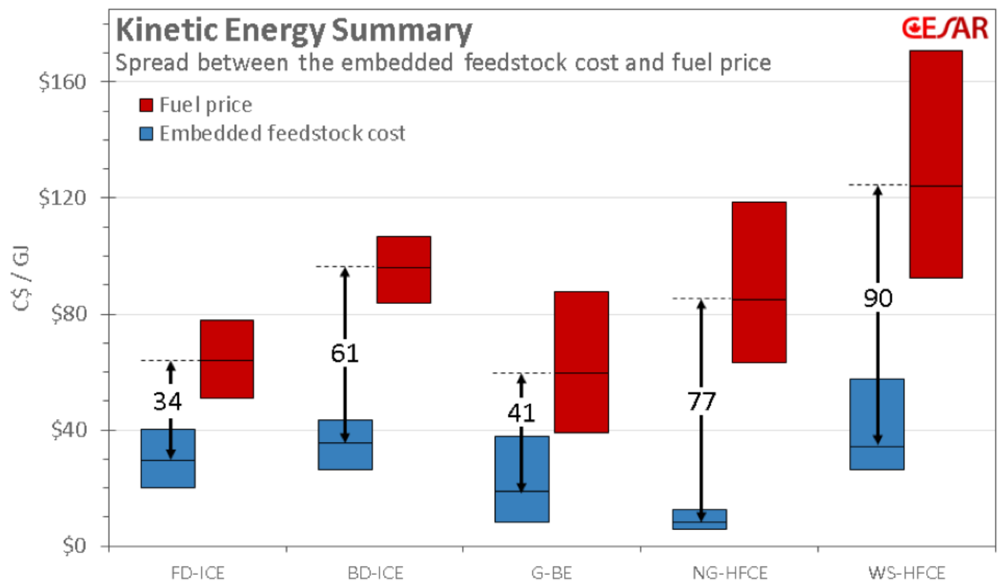

Figure 6.2. Cost of energy summary for the five energy systems moving a typical shipment of 27t_{gross} x 750km. The spread between the embedded feedstock cost and the fuel price can represent an opportunity for future price reductions.

FD-ICE and G-BE energy systems are the lowest, while the BD-ICE and NG-HFCE energy systems are higher (by 30-50%) and the WS-HFCE energy system are even higher (around 95%).

Figure 6.2 (blue bars) also shows the contribution of the embedded feedstock cost to the price of kinetic energy. The low cost of NG distinguishes the NG-HFCE energy system from all others.

The spread between the embedded feedstock cost and the estimated fuel price in a mature energy system is perhaps the most notable. The high efficiency of fossil fuel production and refining results in a spread of only $34/GJ kinetic energy between the two cost/price estimates (**Figure 6.2.**).

At $41/GJ kinetic energy, the G-BE energy system is similar; not surprising since it relies on electrical grid technologies that have been around for decades. The BD-ICE and the two HFCE energy systems show a much higher spread ($61/GJ to $90/GJ), highlighting the need to focus research, development and commercialization in the following areas to make the kinetic energy price more competitive:

- In the BD-ICE energy system, the low conversion efficiency of the bio-refinery needs attention;
- In the NG-HFCE energy system, the challenge is either the cost of distributing and compressing the hydrogen, or the cost of distributed production of the hydrogen without carbon emissions;
- In the WS-HFCE energy system, the cost of electrolysis needs to come down, but also the cost of distributing and compressing the hydrogen.

From an Alberta perspective, the NG-HFCE energy system offers the most promise in adding value to an under-valued feedstock.

6.3. Emissions Comparison

The target of an 84% emission reduction relative to the FD-ICE system in 2016 is clearly an ambitious one. While each of the alternate systems analyzed pose an opportunity for significant emission reductions, only the WS-HFCE and NG-HFCE energy system with 90% CCS and a 2030 grid (no coal, 30% renewable) come close to achieving the target (**Figure 6.3.**).

The BD-ICE energy system can achieve this target only if the Global Warming Potential of the bio-based diesel (GWP_{bio}) is less than 0.1. That is to say, the decision to divert biomass feedstocks to bio-based diesel fuels does not increase atmospheric CO_2 by decreasing biosphere carbon stocks more than 10% of the total biomass carbon transferred to the atmosphere. As discussed previously, the GWP_{bio} of bioenergy systems are heavily dependent on the source of the lignocellulosic biomass used to produce it, and what would have happened to this biomass if it were not used for energy production.

The G-BE system would emit 18% more than the FD-ICE energy system (and over 7x the reduction target) under a 2016 (coal dominant)

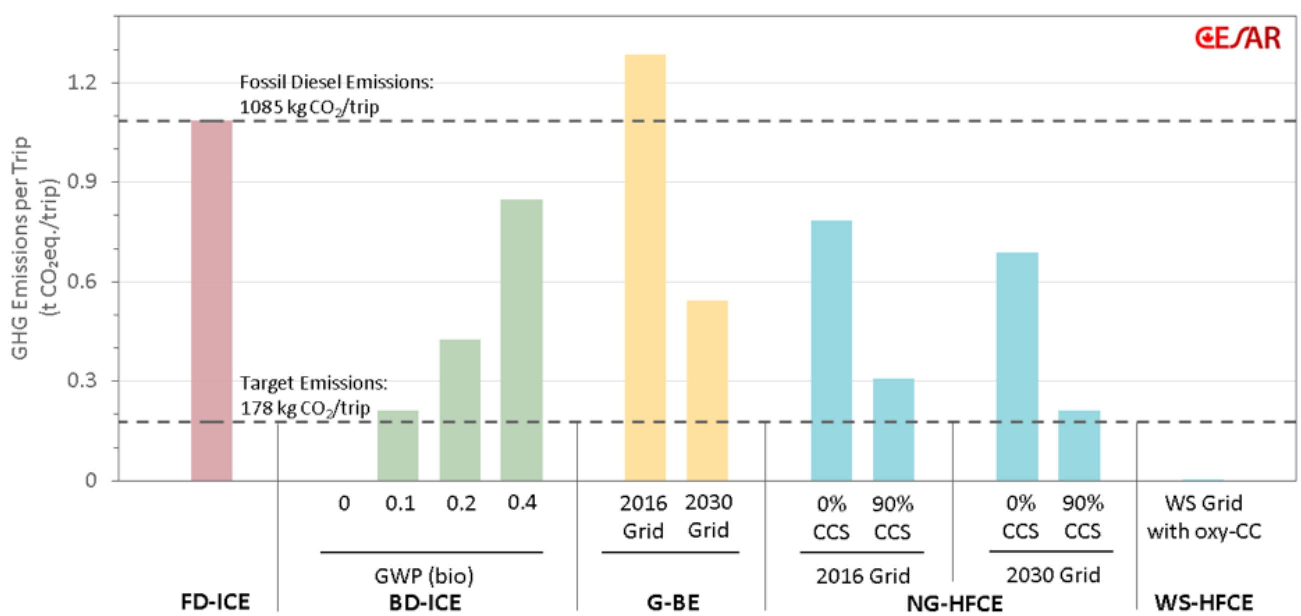

Figure 6.3. Calculated 'well to wheels' greenhouse gas (GHG) emissions from five different energy systems supporting a typical HDV trip of moving $27t_{gross}$, 750 km. See Figure 2.1 for descriptions of the energy systems.

public grid in Alberta (**Figure 6.3.**). Whereas a 2030 grid makeup would reduce emissions by 50% relative to the FD-ICE system; total emissions would still be three times higher than the target level. Therefore, the G-BE energy system cannot meet the emission reduction target without a significant overhaul of the Alberta electrical grid, well beyond a goal of 30% renewables.

Even without CCS, the NG-HFCE energy system would reduce total emissions for a Typical Shipment by 25%. The addition of 90% Carbon Capture and Storage (CCS) to the SMR process would reduce emissions by an additional 46%. Grid makeup also has an impact on the emissions from the NG-HFCE system – a move to the 2030 grid would decrease emissions by a further 9%. Altogether, this poses a potential reduction per Typical Shipment of 81%, just shy of the 84% reduction target (**Figure 6.3.**). This target would be met if upstream emissions associated with NG recovery and processing is reduced, or if the province had a lower carbon electrical grid, since that is needed to compress the hydrogen.

The WS-HFCE energy system is effectively zero emission in this analysis (**Figure 6.3.**). While the public electrical grid is also needed to compress the hydrogen at fueling stations in this energy system, this energy system has the advantage of also dramatically reducing the carbon intensity of the public grid. More details on this aspect of the WS-HFCE energy system will be discussed in the next report in the Future of Freight series [13].

6.4. Vehicle Performance Comparison

Despite a long history as the dominant energy system for freight transport, the FD-ICE energy system is challenged by key performance criteria by both the G-BE and HFCE HDV options. **Figure 6.4.** offers a comparative summary of the two HDV alternatives against the FD-ICE standard. The two alternatives are desirable to the freight sector because of its high power, torque and drivability traits and their potential to substantially reduce maintenance costs with improved reliability.

Also, as reported in Section 3 of this report, there is potential for savings in the cost of the energy consumed by the HDV. Because of the high system efficiency of the Grid-BE system, and the relatively low cost of electricity, the BE option is likely to have lower energy costs than the diesel equivalent.

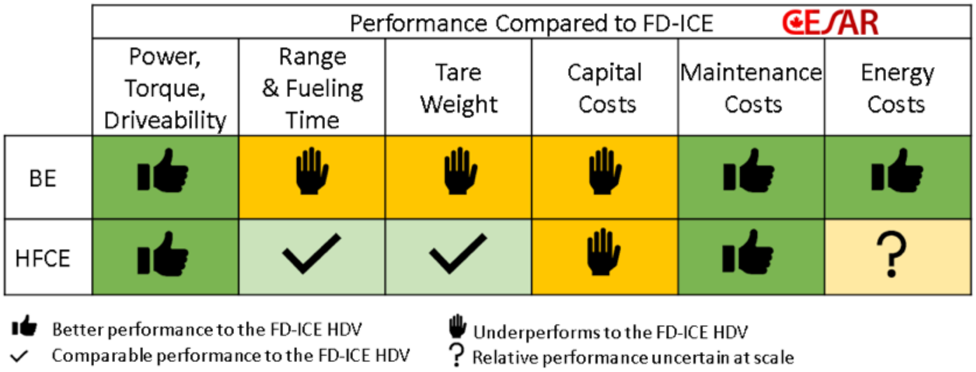

Figure 6.4. Fit for service performance characteristics of hydrogen fuel cell electric (HFCE) and battery electric (BE) heavy duty vehicles compared to a fossil diesel internal combustion engine (FD-ICE) heavy duty vehicle.

The energy costs for the HFCE option could have the potential to be competitive to diesel but this is dependent on the production method for the H_2 and deployment of supporting infrastructure at scale.

The lower maintenance and energy costs would partially offset the substantially higher capital asset costs of both the BE and HFCE compared to the FD-ICE vehicle and with the anticipated future cost reduction to the emerging vehicle technology. For example, with autonomous connected vehicles that are operating around the clock, it is possible that the electric alternatives could achieve a significant reduction in the total cost of ownership when compared to ICE vehicles.

The HFCE and the BE options differ in their freight handling capabilities. The BE HDV is constrained by limited range and lengthy recharge time for its batteries, and the corresponding battery weight and sizes that can negatively affect the allowable payload and negatively impact the possible return on asset. Where these constraints may make the BE option unsuitable for long distance transportation, they may not be an issue for local drayage or urban operations where duty cycles are shorter, and/or freight is lighter.

The HFCE option is not as encumbered by these constraints. The technology has the capability to travel comparable distances to the diesel equivalent and the potential payload may not be restricted by the weight of the vehicle.

There are trade-offs between the electric HDV technologies and there likely will be markets and duty cycles best served by either the BE or HFCE options. However, it is evident that the FD-ICE is being challenged in its performance advantage and may not be the dominant choice in the future of freight transportation.

7. Conclusion

As the incumbent, the FD-ICE energy system benefits from having been the dominant system for road freight movement for several decades, with no significant challengers until very recently. This report has examined four alternative, lower-carbon energy systems that industry proponents are bringing forward to complement and eventually displace the FD-ICE energy system for freight movement. This per-trip techno-economic and environmental assessment of the various energy systems did not identify a clear winner from the perspective of the freight carrier.

The BD-ICE energy system has the benefit of being a drop-in fuel with the incumbent system, but the cost of producing that fuel is a major challenge. Moreover, this alternative does not fully address the air pollution problem inherent in ICE systems.

The three electric vehicle energy systems (G-BE, NG-HFCE, WS-HFCE) have the benefit of being able to generate higher torque at low speeds than the FD-ICE energy system, but the G-BE energy system is challenged by battery weight demands that limit range as well as a long refueling time.

The two HFCE systems have many positive features, but are challenged by the lack of the infrastructure capable to producing and delivering the fuel without carbon emissions, contributing to higher costs.

The next report in the Future of Freight series [13] will extend this work by assessing the feasibility of scaling up each of these alternative energy systems in Alberta. Could these systems make a contribution to the Alberta economy and to North American transportation at a scale that is similar to the contribution currently made by the crude oil production and conversion to diesel or export to other North American jurisdictions?

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