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Review of hydrogen tolerance of key Power-to-Gas (P2G) components and systems in Canada

Final report

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Contents

EXECUTIVE SUMMARY

This report presents the codes, standards, and regulations (CSR), R&D needs and gaps, hydrogen tolerance of key components and systems, demo cases, and Technology Development Matrix (TDM) analysis identified and determined for Power-to-Gas (P2G) technology. P2G technology enables hydrogen produced from electrolysis and renewable natural gas (RNG) produced by methanation to be injected into national gas grids, which permits large scale storage of green energy. If economically feasible, methane injection in the grid could represent considerable volumes since RNG complies with grid specifications. However, the amount of direct hydrogen injected into the gas grid is limited by country-specific standards and regulations. In the European Union the maximum is 0-12 vol.% or 0-2 wt.%. A detailed investigation of CSR on the injection of renewable hydrogen and RNG into natural gas (NG) pipelines has clarified current constraints and safety considerations in terms of gas injection, transport and end-use systems.

The CSR for RNG injection into NG pipelines in Europe and North America is well established, as the technology is proven and adopted in the natural gas industries and utilities. Direct injection of renewable hydrogen into NG pipelines is not common in natural gas markets worldwide and very limited CSR information from Europe and North America was available.

Even at low levels, hydrogen blends can be a problem for appliances that are not properly maintained. High blend levels can be safe in transmission lines, but additional risks are posed from the city gate through distribution lines. Most pipeline materials are not subject to hydrogen-induced failures. In order to accelerate the implementation of hydrogen injection into natural gas pipelines in North America, harmonized standards specifying gas quality and composition (including hydrogen tolerance) for NG transmission and distribution will be required. Energy regulators and policy makers will need to identify ways to encourage the pipeline industry's adoption of gas quality standards for initial levels of hydrogen blending.

According to current understanding, a hydrogen concentration limit up to 20% poses some challenges with regard to end-use appliances and gas analysis methods. Further research is needed to address end-user concerns regarding process control, emissions and safety. Public acceptance relies on the proper identification and assessment of risks. Standardization needs to ensure the safety of hydrogen compressed natural gas (HCNG) use by considering the specific properties of hydrogen and NG blends and address all associated risks.

Much work has been done to address the need for codes and standards for renewable hydrogen technologies, but standards need further development to enable wide-scale transmission and distribution of renewable fuels.

Canada is a world leader in the production and use of energy from renewable resources, which currently provide about 18.9 per cent of Canada's total primary energy supply. Wind and solar photovoltaic energy are the fastest growing sources of electricity in Canada. However, wind and solar-based energy production is intermittent and fluctuating, which requires long term scalable energy storage to enhance grid stability and reliability. In late 2016, the Government of Canada announced its intention and plans to develop a national Clean Fuel Standard. This initiative aims to reduce up to 30 million tonnes of GHG emissions annually by 2030 with this proposed policy and, notably, planning to extend the clean fuel standard beyond transportation fuels to include fuels used in homes and buildings as well as in industry.

The power-to-gas valorisation pathways include power-to-power, power-to-gas, power-to-mobility, power-to-fuels, and power-to-industry. The total energy capacity of Canada's natural gas grid is much larger than that of its electrical generating capacity, indicating the significance of the gas grid for domestic energy supply. While the power-to-gas pathway allows the connection of electric and gas grids, there are challenging techno-economic aspects and regulation issues for the implementation and commercialization of P2G technology in Canada. The developing national low-carbon fuel standard (LCFS) regulation may accelerate the deployment of P2G technology by providing incentives to use renewable hydrogen and renewable natural gas in Canada.

Renewable hydrogen blending into natural gas grid networks is a low-cost, early stage solution for monetizing electricity surpluses in countries with highly developed natural gas infrastructure. In general, the entire gas grid should tolerate 5 vol.% blending anywhere, and up to 20% in distribution or regional transmission pipelines with no critical downstream appliances. More research and development work to quantify safe and practical upper limits of hydrogen blending is needed to support regulatory reform and harmonize HCNG standards.

Canada has one of the world's largest pipeline networks delivering natural gas from producing areas in western and eastern Canada to markets across North America. The blending ratio of H_2/NG is technically limited to 17-25 vol.% in some parts of the distribution grid and not above 5 vol.% in the transport grid. The H_2 blending limit is uncertain and very system specific, limited by grid integrity, safety, energy transport capacity, and by the specifications of end-use applications. The transmission pipelines with medium to high pressures are made of carbon steel with protective coating, where hydrogen-induced embrittlement can accelerate the growth of micro cracks and compromise pipeline safety. It is estimated that existing, unmodified steel pipes could sustain 20 vol.% of hydrogen and potentially up to 50 vol.% of hydrogen, depending on the quality of the steel used. The distribution pipelines made of plastic for low pressures are not suffering from embrittlement and may accommodate 17-25 vol.% of hydrogen without the need for case-by-case testing. It is also estimated that the hydrogen blending over 20 vol.% into NG pipelines may result in too much negative effects on energy transport capacity and grid energy efficiency.

In June 2013, the German electric and gas utility E.ON injected hydrogen into the natural gas pipeline for the first time and stated that their regulations allowed up to 5% hydrogen in the natural gas pipeline. In Canada, Alberta-based TransCanada Pipeline's (TCPL) natural gas quality specifications do not directly limit the amount of hydrogen that can be injected into TCPL pipeline; however, the lower limit on the heating value of 36 MJ/m^3 implicitly limits hydrogen content to around 5 vol.% in a TCPL pipeline at any point.

Natural gas can be stored in depleted oil or gas reservoirs, aquifers, salt caverns, LNG or CNG units, and pipeline network as line pack. In case of underground gas storage, a 2007 survey specified Canadian underground natural gas storage capacity as 583.8 billion cubic feet (Bcf), consisting of 44 depleted reservoirs, and 8 salt caverns. Salt caverns being used for storing natural gas could be suitable for much higher hydrogen concentrations in natural gas or even pure hydrogen, but require modification of equipment such as injection wells or compressors at gas storage facilities. However, since these major storage assets are linked to the existing natural gas grid, their practical capacity for hydrogen would be limited by existing pipeline standards / specification, so around to 5 vol.%.

According to the current consensus of international projects and studies investigated for hydrogen injection into NG pipelines, it seems that most parts of the natural gas system can be tolerant of the gas mixtures of up to 10% by volume of hydrogen. The requirements for blending hydrogen into the natural gas grid network and supplying blended gas mixtures to end-users should be determined based on system perspectives. The minimum threshold for requiring no or limited actions would be around 2% of hydrogen by volume in natural gas. It's also possible to mix up to 5% of H_2 by volume with NG, but this tolerance should be investigated further and could be a driver for innovation of end-use appliances. It's expected to be challenging to increase the allowable hydrogen concentration up to 20 vol.% without the generation of extensive performance and safety information for end-use appliances and gas analysis methods. In general, the natural gas grid would be tolerant for 1%-5% hydrogen blending by volume at any point of the network, and up to 20% in distribution pipelines with no critical downstream appliances. It is recommended to restrict the hydrogen concentration to 2 vol.% for gas engines, but higher concentrations up to 10 vol.% may be possible for dedicated gas engines with sophisticated control systems. If blending hydrogen into the existing natural gas pipeline network is implemented with relatively low concentrations, less than 5%-15% hydrogen by volume, this strategy of storing and delivering renewable energy to markets appears to be viable without significantly increasing risks associated with utilization of the gas blend in most end-use devices such as household appliances, overall public safety, or the durability and integrity of the existing natural gas pipeline network.

Fifty-seven recent P2G demo projects with key features were well-documented and reported in a Master's thesis prepared by Vesa Vartiainen and submitted to Lappeenranta University of Technology in 2016. The end products from over 70% and 25% of all the reviewed projects were hydrogen and methane, respectively for power generation, mobility, natural gas grid injection, and chemicals. The addition of methanation in P2G results in increasing the overall cost and complexity and decreasing efficiencies. Product gases of almost one third of the projects (18 out of 57) were injected into the NG grid for the integration of electric and gas grids. Most of these projects (12 out of 18) injected hydrogen into the natural gas grid.

Gerda Gahleitner also reported an international review of forty eight P2G pilot plants for stationary applications. 53% of the projects that were integrated with renewables utilized battery banks between renewable power source and the electrolyzer. Batteries are primarily employed in stand-alone power-to-gas pilot plants as short-term storage to minimize the cycling of the electrolyzer and compensate for transient peak power. Batteries can play an important role in control strategies of power-to-gas systems, since the state of charge (SOC) of the battery is used as the main control variable in many pilot plants. The design and sizing of the components of power-to-gas plants considerably influences their efficiency, reliability and economics. The overall efficiency of power-to-gas plants strongly depends on the control strategy and can be improved by higher efficient components, improved heat management and optimal system integration.

Among power-to-gas valorisation pathways including power-to-power, power-to-gas, power-to-mobility, power-to-fuels, and power-to-industry, none of the pathways is profitable at this moment, but the small scale industrial pathway where hydrogen is generated locally to replace externally sourced hydrogen, will be the first to turn positive before 2030. Also two of the mobility pathways, Power-to-Methanol and Power-to-Hydrogen for cars are expected to turn profitable before 2050.

Two Canadian P2G cases with 2MW Proton Exchange Membrane (PEM) electrolyzer for Power-to-Gas and 350kW alkaline electrolyzer for Power-to-Power were demonstrated by Hydrogenics, Ontario in 2017 and TUGLIQ Energy Co., Quebec in 2015, respectively.

The NRC's Technology Development Matrix (TDM) is a decision making tool that enables effective allocation of R&D resources to achieve commercialization in a desired market. The TDM accomplishes this by visualizing how an ES System compares to both State of the Art (SOTA) and to a Specific Application or Target Goal based on metrics or Attributes essential to that market.

P2G is an evolving technology and data was limited at the time of this report. The authors therefore used a top down approach to include what system level P2G data could be found. With respect to P2G ES technologies, the current version of the TDM only focusses on commercial electrolyzer technologies: PEM and Alkaline. Similarly, with respect to technology attributes, like application and target goals, this study is bound by electric grid services over other applications (natural gas grid injection, underground hydrogen storage, clean transportation, industrial hydrogen as a chemical feedstock) for two reasons. First, the P2G TDM has to align with all other TDM ES technologies which provide electric grid services, and secondly, data for other applications was limited. With respect to electric grid services, P2G can perform up to three, depending on the regenerative PEM electrolyzer / fuel cell technology, including arbitrage, electric supply capacity, and frequency response / regulation.

1. Introduction

Power-to-Gas (P2G) may provide a potential solution to enable the use of natural gas pipeline networks for scalable energy storage, transporting renewable hydrogen produced from intermittent renewable energy sources such as wind and solar.

Canadian-owned Hydrogenics is a leading developer and manufacturer of hydrogen generation and hydrogen-based power modules. In 2012, it formed a collaborative partnership with Enbridge for developing utility-scale energy storage in North America, and in 2014, Ontario's Independent Electricity System Operator (IESO) contracted with Hydrogenics and Enbridge Inc. to develop, build and operate a Power-to-Gas facility that will deliver 2MW of storage capacity to the Greater Toronto Area.

It would be highly valuable to investigate Canadian and international P2G demo cases made by Hydrogenics and others for identifying P2G opportunities for integrating renewables into the natural gas grid.

This report presents a detailed investigation of regulatory and technical requirements affecting P2G technologies in Europe and North America. Standards and regulations for renewable natural gas (RNG) blending into natural gas grid networks have also been investigated to collect baseline information that may apply to renewable hydrogen. The comparison of Canadian and international demonstration cases has been performed through literature review to verify P2G opportunities with Canadian key industrial clients and strategic partners in the fields of renewable hydrogen production and natural gas distribution.

In addition, the proposed project is one building block for a larger Energy Storage (ES) Technology Development Matrix (TDM) structure as part of ES Program Master Project 1.1. Each building block or TDM subcomponent must follow a common framework so that a complete ES TDM will enable stakeholders to identify technical R&D gaps and target suitable market opportunities.

2. Objectives

The objectives of this project are:

1) Identification of the codes, standards, and regulations as well as R&D needs and gaps associated with the P2G pathway in the Canadian context,

2) Determination of the hydrogen tolerance of key P2G components and systems (natural gas pipelines, storage facilities, gas pressure/flow control and monitoring, and CHP system components etc.),

3) Verification of P2G opportunities based on Canadian and international P2G demo cases, and

4) Completion of ES TDM to identify and prioritize R&D areas for each emerging grid-scale ES technology based on "apples-to-apples" comparisons.

3. Codes, standards and regulations of P2G

Generally, regulations and standards have different purposes. Regulations are mandatory and reflect legal constraints translated into safety objectives. They can have a direct effect on productivity growth and control the rate of catch up. They are set by governments in order to ensure the protection of citizens' health and fair trade. Standards set out the technical means through which safety objectives can be reached. Standards are important for the development of any industry and harmonization across countries or states, and will help to ensure the successful utilization of renewable natural gas and hydrogen for gas grid and mobility applications globally [1].

In Europe, standards play a key role in economic life and the attempts to better incorporate environmental aspects into standardization are a necessary task. Standards are voluntary instruments which act as a proxy to demonstrate compliance with a regulation or a directive. The European standardization bodies are private bodies, which are situated outside the EU institutions. The European voluntary standards sector (CEN/CENELEC and ETSI) is commissioned to define harmonized standards which offer technical solutions that ensure compliance with the corresponding essential requirements. The harmonized standards are not mandatory; the fact they are voluntary is presumed to ensure compliance with corresponding essential requirements [1].

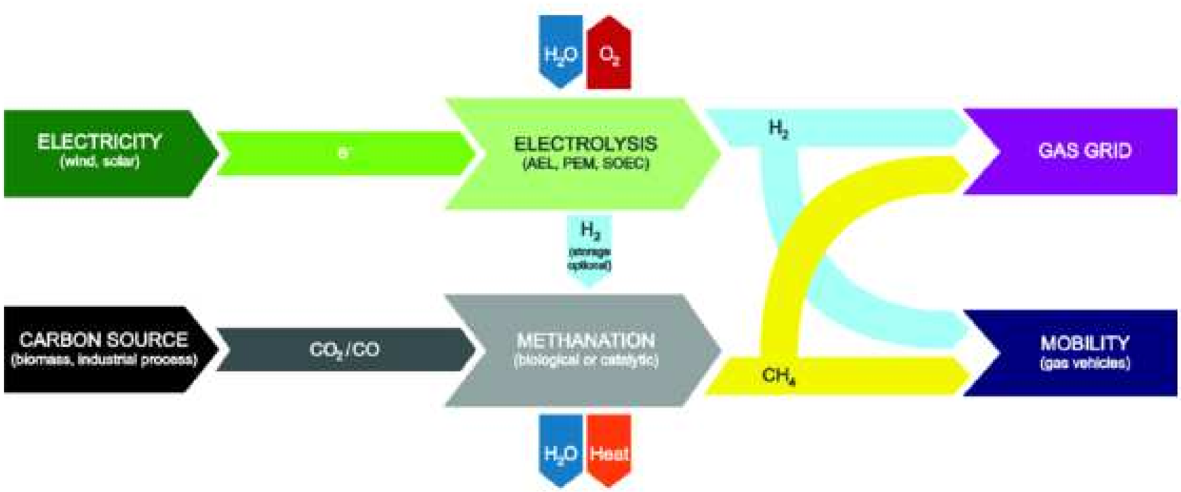


Figure 1: Power-to-Gas process chain [2]

The Power-to-Gas (P2G) technology enables the conversion of surplus renewable power to hydrogen produced by electrolysis and injection of the produced hydrogen or renewable natural gas (RNG) produced by methanation with CO or CO_2 into the existing natural gas grid network for long term, large scale energy storage and transportation fuel applications, as shown in Figure 1 [2].

Methane injection into the grid, if economical, could represent considerable volumes, since RNG complies with grid specifications [3]. In the case of direct hydrogen injection, the amount of hydrogen in the gas grid is limited by country specific standards and regulations to a maximum of 0-12 vol.% or 0-2 wt.% [2,4] as shown in Figure 2.

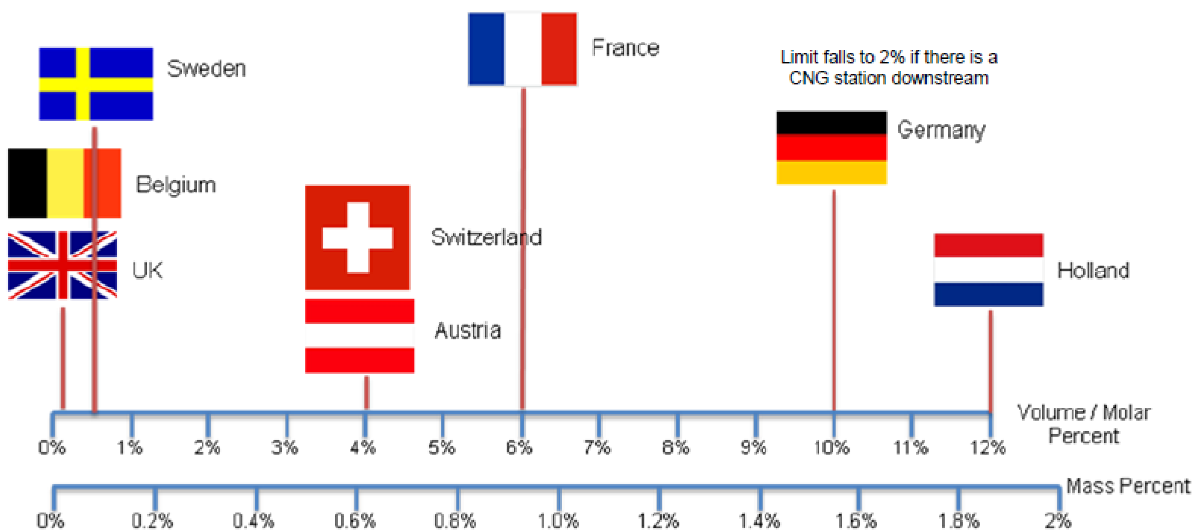


Figure 2: EU hydrogen limits for injection into the high pressure (HP) gas grid [4]

A detailed investigation of codes, standards and regulations (CSR) for the injection of renewable hydrogen and RNG into NG pipelines has clarified current constraints and safety considerations in terms of gas injection, transport and end-use systems.

RNG blending technology is already proven and adopted in the natural gas industry and utilities. On May 25, 2016, the Canadian Gas Association (CGA) announced natural gas utilities have set a target of 5% RNG-blended natural gas in the pipeline distribution system by 2025 and 10% by 2030, resulting in a reduction of 14 mega tonnes of greenhouse gas emissions per year by 2030 [5]. Direct injection of renewable hydrogen into NG pipelines is not yet common in the international natural gas market. Limited CSR information has been collected from Europe and North America.

3.1 Codes, standards and regulations of RNG blending

3.1.1 CSR of RNG in Europe

The CSR of RNG blending can be utilized as baseline information for consideration of renewable hydrogen injection. The assessment of current standards and legislation on injection of RNG includes gas safety management, gas monitoring and measurement, gas composition, injection methodologies, and injection limits.

Among European countries, Germany has very well established standardization for feeding RNG into the NG grid. The Netherlands, Sweden and Switzerland are the European countries with the most extensive experience in the upgrade and feed-in of biogas. The Netherlands, for example, features a biomethane plant with a feed-in capacity of 500 Nm^3/h which has been operating on a pressure swing adsorption since 1989. While Sweden owns the largest number of plants upgrading biogas to biomethane, Germany is leading in feed-in capacity in comparison to all other European countries. These differences are partly related to the state of the infrastructure of the public gas networks in the different countries, but also to the fields of application best supported by the respective political structures [6].

The German market has seen a significant growth in the last decade. Its first plants started operation in 2006. The parameters for the injection of biogas in Germany have been defined as a result of the implementation of the government's integrated energy and climate program, whereby the target is to exploit a potential of 6 per cent (60 bn kWh) of today's natural gas consumption by the year 2020 and 10 per cent (100bn kWh) by 2030 [6]. In recent years, a stable market growth can also be tracked in Austria, where high state-guaranteed feed-in tariffs have resulted in a significant boost, as they did in Germany.

The feeding of biogas into the natural gas grid is an efficient energy solution, even if the sites in which the gas is to be applied are far away from the sites at which it is produced. Gas feed-in is facilitated via a compressor, a device raising the pressure level of the biomethane to that of the gas in the closed pressurized lines of the grid. European policies permit new gas producers to feed gas into the conventional gas grid. This access to a large consumer market is attractive to biogas producers. For purposes of injection, however, the gas must meet the quality specifications of the relevant legal provisions and may only deviate within the limited range of the quality standards. Such standards are realized using technologies for reconditioning gas. Because a non-negligible quantity of energy is necessary for gas compression, the energy balance and the economic feasibility of the compression and feed-in process must be reviewed on a case-by-case basis [6].

Regulations distinguish between low-quality natural gas ("Natural Gas L") and high-quality natural gas ("Natural Gas H"). Natural Gas L contains roughly 89 per cent flammable gases (primarily methane, but also small amounts of ethane, propane, butane, and pentane). Natural

Gas H contains about 97 per cent flammable gases (the same as those listed for Natural Gas L). Since upgraded and fed-in biomethane is currently not on a competitive basis with natural gas, the German government employs various measures and support schemes to develop demand in the markets. Biomethane is for heating, combined heat and power and natural gas-dedicated vehicles. Germany has developed several regulations to promote the injection of biogas. These include:

- Renewable Energy Sources Act (EEG)
- Gas Network Access Ordinance (GasNZV)
- DVGW (German Technical and Scientific Association for Gas and Water) Worksheets, German Biogas Register [6].

While the German market for the upgrade and feed-in of biogas is relatively young, the technologies for this special gas application have been in use for decades in other European countries. Not all European countries have implemented regulations on the upgrade and feed-in of biogas, but they have decades of experience with injection of biogas into natural gas grids. Government policies some incentives are also available in France, Great Britain, Luxembourg, the Netherlands, Austria, Poland, Sweden and Switzerland [6].

The case of RNG as an end product of the Power-to-Gas process chain is less critical than hydrogen, because natural gas consists to a large extent of methane. Therefore, a practically unlimited injection of RNG into the gas grid is possible. Natural gas qualities are categorized in H- and L-gas as shown in Table 1. H-gas contains >96 vol.% CH_4, L-gas >88 vol.% CH_4 [7].

Table 1: Specification of gas properties according to different regulations in Europe [7]

Parameter	Unit	DVGW G 260 (Weiβdruck May 2008)	ÖVGW G31	EASEE-gas	DIN 51624
Wobbe index	kWh/m^3		13.3-15.7		
L-gas		10.5-13.0		-	-
H-gas		12.8-15.7		13.6-15.8	-
Heating value	kWh/m^3	8.4-13.1	10.7-12.8	-	-
Relative density	-	0.55-0.75	0.55-0.66	0.555-0.75	0.555-0.7
Methane number	-	DIN 51624	-	-	70
Hydrogen content	vol.%	≤ 5	≤ 4	-	2

In 2014, the Swedish Gas Technology Centre reported that most biomethane standards are gas grid injection specifications, predominantly in European countries, noting that the European Union identified the lack of standards as a barrier for the implementation of biomethane [8]. In 2010, the European Committee for Normalization (CEN) was given the mandate to develop biomethane standards for both vehicle fuels and NG grid injection in order to facilitate the market penetration of biomethane either as a transport fuel or as a blending component to natural gas [9]. A joint project committee CEN/TC408 was formed to facilitate joint work between the gas and automotive businesses as show in Figure 3 [10]. In September 2016, a European standard of CEN - EN 16723-1, “Natural gas and biomethane for use in transport and biomethane for Injection in the natural gas network - Part 1: Specifications for biomethane for injection in the natural gas network” was approved [11].

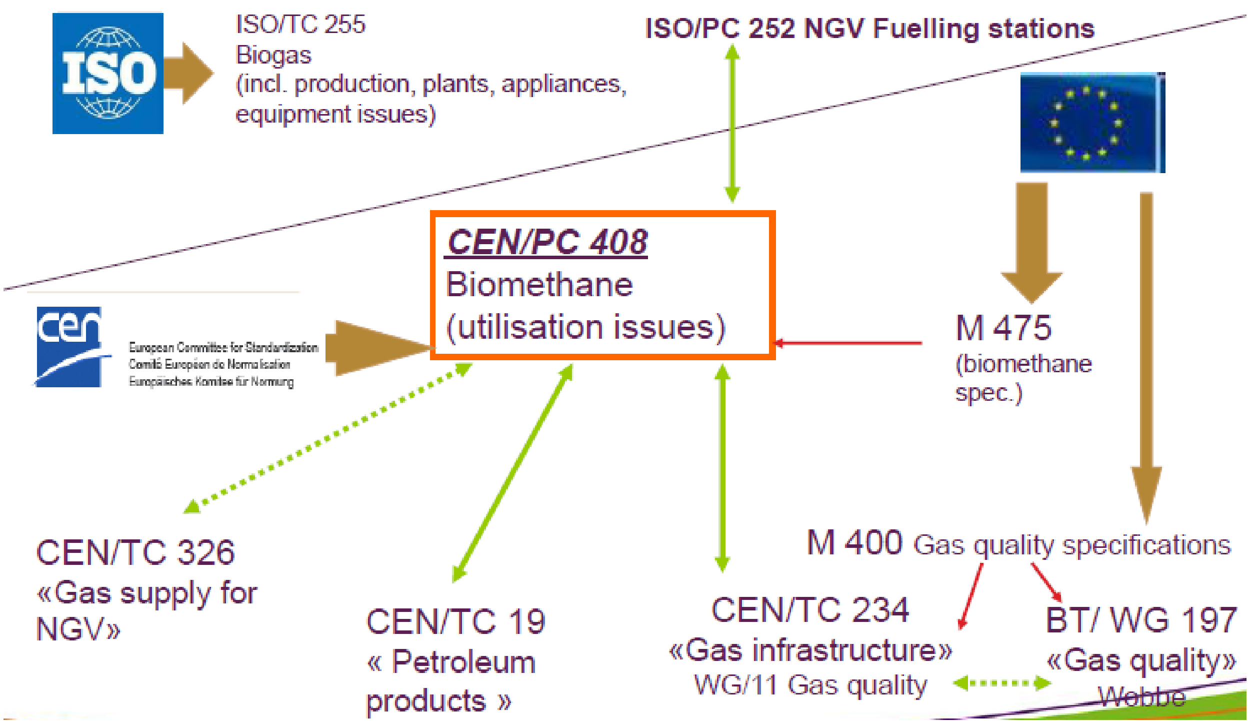


Figure 3: CEN/TC 408 Environment-biomethane mapping standardization structure [10]

In Germany, DVGW supervises the development of technical guidelines for biogas injection into the gas grid. Gas quality and safety aspects have been discussed in several task forces and working groups. Technical standards have been developed and revised. The technical guidelines of G 260, G 262, and DIN 51624 (for CNG) concern gas quality for renewable gases to be injected into the gas grid, as shown in Table 2 [12]. Table 3 gives a summary of gas quality requirements in Germany. For natural gas H, technical committee CEN/TC 234 has developed the draft standard prEN 16726 and CEN/TC 408 has designed the preliminary standards prEN 16723-1 for biomethane injection into the NG network and prEN 16723-2 for automotive fuel specifications in 2014 [12].

Table 2: DVGW-standards related to the injection of biogas into the natural gas grid [12]

Technical standard	Title
G100-B1 (2010)	Qualification requirements for DVGW authorized experts for gas supply – 1. Supplementary sheet: Qualification requirements for DVGW authorized experts for biogas upgrading and injection plants
G262 (2011)	Usage of gases from renewable sources in the public gas supply
G267 (2014)	Oxygen content in high pressure grids
G265-1 (2014)	Biogas upgrading and injection plants – Part 1: Gases produced by fermentation, planning, construction, testing and bringing into operation
G265-2 (2012)	Biogas upgrading and injection plants – Part 2: Gases produced by fermentation, operation, servicing and maintenance
G265-3 (2014)	Plants for the injection of hydrogen into the gas grid: Planning, manufacturing, erection, testing, commissioning and operation
G267 (2015)	Oxygen content in high pressure grids
G290 (2012)	Re-injection of injected biogas into upstream transportation pipelines
G291 (2013)	Recommendation for the interpretation of the Gas Grid Access Ordinance
G292 (2012)	Supervision and controlling of biogas injection plants with dispatching issues
G415 (2011)	Raw biogas pipelines
G493-1 (2012)	Qualification criteria for planers and manufacturers of gas pressure regulating and metering plants and biogas injection plants
G1030 (2010)	Requirements on qualification and organization for operators of plants for production, transmission, upgrading, conditioning or injection of biogas
Water Inform. 73 (2010)	Cultivation of biomass for biogas generation in consideration of soil and water protection
DVGW-BGK-Information (2013)	Suitability of digestate from biogas plants for agricultural recycling in drinking water protective areas

Table 3: Gas quality requirements for biomethane injection into the natural gas grid [12]

Term	Unit	Typical values for raw biogas (renewables)*	Typical values for raw biogas (residues)*	Technical standards G260/G262
Calorific value	kWh/m^3	5.5-6.1	6.6-7.8	8.4-13.1
Relative density		0.99-1.04	0.85-0.94	0.55-0.75
Wobbe-index	kWh/m^3	5.4-6.1	6.8-8.4	H-gas: 13.6-15.7 L-gas: 11.0-13.0
Water content	mg/m^3	Saturated at $T_{Fermenter}$, $P_{Fermenter}$ (Typical: >10,000)		200 (MOP ≤ 10 bar) 50 (MOP > 10 bar)
CH_4		50-55	60-70	≥ 95 (H-gas) ≥ 90 (L-gas)
CO_2	mol.%	45-50	30-40	Regulated by min. CH_4 content
O_2 MOP < 16 bar		0-1		Max. 3
O_2 MOP ≥ 16 bar				Max. 0.001
H_2		<< 1		< 10**
Carboxylic acids		trace		-
Alcohols		trace	< 22	-
BTEX		trace	< 10	-
Higher organic compounds	mg/m^3	trace	< 1,250	Condensation point: -2 °C (1 bar ≤ p ≤ 70 bar)
Sum of H_2S and COS		< 3,000	< 30,000	Max. 5
NH_3		< 1	< 10,000	Technical free
Si_{total}		< 30		< 5***

* Own measurements and literature references.
** Subject to other restrictions (e.g.,DIN 51624 fuel standards or requirements of certain gas applications).
*** No fixed limit, 5 mg/m^3 is recommended with respect to the limit for engines. Gas turbines can be more sensitive.

3.1.2 CSR of RNG in North America

United States – California

A low-carbon fuel standard (LCFS) is a rule enacted to reduce carbon intensity in transportation fuels as compared to conventional petroleum fuels, such as gasoline and diesel. The first low-carbon fuel standard mandate in the world was enacted by California in 2007, with specific eligibility criteria defined by the California Air Resources Board (CARB) in April 2009 but taking effect in January 2011. Similar legislation was approved in British Columbia in April 2008, and by European Union which proposed its legislation in January 2007 and which was adopted in December 2008. Several bills have been proposed in the United States for similar low-carbon fuel regulation at a national level but with less stringent standards than California, but the national LCFS has not been approved yet [13].

There are more than 50 operating RNG projects producing and injecting biomethane into natural gas pipeline systems or providing biomethane for direct use in vehicles across the U.S. in 18 different states [14]. The lack of uniform federal or state specifications for gas acceptance and the absence of a national quality standard for RNG injected into the pipeline system require RNG project developers to negotiate acceptance with each gas utility. State-level renewable portfolio standard rules include incentives supporting production of high-Btu RNG for electricity generation. [15]. California's LCFS specified regulated parties for biomethane injection into NG grid network in § 95483(d) [16] are shown in Table 4.

Table 4: § 95483(d): Regulated parties for natural gas (including CNG, LNG, L-CNG, and biomethane) [16]

Destination	Biofuel-blended fuel		Fuel without biofuel blending
Regulated parties for fossil CNG and bio-CNG	With respect to the fossil CNG	The entity that owns the natural gas fueling equipment at the facility at which the fossil CNG and bio-CNG blend is dispensed to motor vehicles for their transportation use	The person that owns the natural gas fueling equipment at the facility at which the fossil CNG is dispensed to motor vehicles for their transportation use
	With respect to the bio-CNG	The producer or importer of the biomethane injected into the pipeline for delivery to the CNG dispensing station	
Regulated parties for fossil LNG and bio-LNG	With respect to the fossil LNG	The entity that owns the fossil LNG right before it is transferred to storage at the facility at which the liquefied blend is dispensed to motor vehicles for their transportation use	Initially the person that owns the fossil LNG right before it is transferred to storage at the facility at which the fossil LNG is dispensed to motor vehicles for their transportation use
	With respect to the bio-LNG	The producer or importer of the biomethane injected into the pipeline for delivery to the LNG production facility	

The producer or importer of biomethane injected into NG pipelines receives LCFS credits. The LCFS is designed to decrease the carbon intensity of California's transportation fuel pool and provide an increasing range of low-carbon and renewable alternatives. Executive Order S-1-07, the Low Carbon Fuel Standard (issued on January 18, 2007), calls for a reduction of at least 10 percent in the carbon intensity of California's transportation fuels by 2020 [17].

The LCFS is performance-based and fuel-neutral, allowing the market to determine how the carbon intensity of California's transportation fuels will be reduced. This program is based on the principle that each fuel has "lifecycle" greenhouse gas emissions that include CO_2, N_2O, and other greenhouse gas contributors. This lifecycle assessment examines the greenhouse gas emissions associated with the production, transportation, and use of a given fuel. It includes direct emissions and significant indirect effects, such as changes in land use for some biofuels. Subjecting this lifecycle greenhouse gas rating to a declining standard for the transportation fuel pool in California would result in a decrease in the total lifecycle greenhouse gas emissions from fuels used in California [17].

Assembly Bill 1900 (AB 1900) [18] was enacted into California law by Chapter 602 of the Statutes of 2012. AB 1900 requires the California Public Utilities Commission (PUC) to adopt standards for constituents of interest that are found in biomethane in larger concentrations than in natural gas, to adopt monitoring, testing, reporting, and recordkeeping protocols to ensure the protection of human health and safety, and to ensure the integrity and safety of the natural gas pipelines and pipeline facilities. The California Air Resources Board (ARB) and the California Office of Environmental Health Hazard Assessment (OEHHA) prepared a Joint Report [19] to the PUC that included a recommendation to include standards for 12 Constituents of Interest in the regulations and tariffs. The Joint Report included three levels of measurement and related action with respect to each of the 12 Constituents of Interest, including 5 carcinogenic constituents (Arsenic, p-Dichlorobenzene, Ethylbenzene, n-Nitroso-di-n-propylamine, and Vinyl chloride) and 7 non-carcinogenic constituents (Antimony, Copper, Hydrogen sulfide, Lead, Methacrolein, Alkyl thiols, and Toluene). These Constituents of Interest are found in biogas and may be present in biomethane at concentration levels that exceed those of the same constituents in natural gas [14].

The trigger level is set at the OEHHA health protective level for each constituent of concern and operators are required to monitor the levels of compounds to verify that the total potential cancer and non-cancer risks for the constituents of concern continue to stay within the trigger level and the lower and upper action levels. The constituents of concern that must be measured depend on the biogas source and the frequency of monitoring is dependent on the concentration level of a constituent of concern measured during an initial pre-injection screening evaluation. A facility must be shut-off (stop injecting into the pipeline) and repaired if the lower action level is exceeded three times in a 12 month period or at any time the levels exceed the upper action level [19].

In January 2014, the CPUC issued Decision (D) 14-01-034 adopting concentration standards for 17 Constituents of Concern (including ammonia, biologicals, hydrogen, mercury, and siloxanes) and the monitoring, testing, reporting, and recordkeeping protocols for biomethane to be injected into the gas utilities' pipelines [14]. Decision 14-01-034 was reflected in the California natural gas utilities' revised biomethane tariffs such as SoCalGas' Rule 30 as shown in Table 5 [20].

Table 5: Biomethane quality specifications in rule no. 30: Transportation of customer-owned gas [20]

Constituent	Trigger level mg/m^3 (ppm$_v$)	Lower action level mg/m^3 (ppm$_v$)	Upper action level mg/m^3 (ppm$_v$)
Health protective constituent levels			
Carcinogenic constituents			
Arsenic	0.019 (0.006)	0.19 (0.06)	0.48 (0.15)
p-Dichlorobenzene	5.7 (0.95)	57 (9.5)	140 (24)
Ethylbenzene	26 (6.0)	260 (60)	650 (150)
n-Nitroso-di-n-propylamine	0.033 (0.006)	0.33 (0.06)	0.81 (0.15)
Vinyl chloride	0.84 (0.33)	8.4 (3.3)	21 (8.3)
Non-carcinogenic constituents of concern			
Antimony	0.60 (0.12)	6.0 (1.2)	30 (6.1)
Copper	0.060 (0.02)	0.60 (0.23)	3.0 (1.2)
Hydrogen sulfide	30 (22)	300 (216)	1,500 (1,080)
Lead	0.075 (0.009)	0.75 (0.09)	3.8 (0.44)
Methacrolein	1.1 (0.37)	11 (3.7)	53 (18)
Toluene	904 (240)	9,000 (2,400)	45,000 (12,000)
Alkyl thiols (Mercaptans)	(12)	(120)	(610)
Pipeline integrity protective constituent levels			
Siloxanes	0.01 mg Si/m^3	0.1 mg Si/m^3	-
Ammonia	0.001 vol%	-	-
Hydrogen	0.1 vol%	-	-
Mercury	0.08 mg/m^3	-	-
Biologicals	4 x 10^4/scf (qPCR per APB, SRB, IOB* group) and commercially free of bacteria of > 0.2 microns		

* APB –Acid producing Bacteria; SRB – Sulfate-reducing Bacteria; IOB – Iron-oxidizing Bacteria

Assembly Bill 2773 (AB 2773), introduced in February 2016 would enhance RNG injection into NG grid network by modifying the minimum heating value requirement and siloxane standard of biomethane, allowing the injection of biomethane without blending with other fuel as well as performance guarantees from siloxane processing equipment manufacturers and suppliers [21].

Canada

In Canada, British Columbia (BC) included an LCFS as part of its Renewable and Low Carbon Fuel Requirements Regulation (RLCFRR) in 2010. Currently, both the Government of Canada and the Government of Ontario have proposed LCFSs, with the notable difference that the federal government's proposal also applies to fuels outside the transportation sector. In late 2016, the Government of Canada announced its intention and plans to develop a national Clean Fuel Standard. This initiative aims to reduce up to 30 million tonnes of GHG emissions annually by 2030 with this proposed policy and, notably, planning to extend the clean fuel standard beyond transportation fuels to include fuels used in homes and buildings as well as in industry [22].

Existing policies tend to set a ten-year target schedule with incremental annual compliance targets that escalate over time. British Columbia's 2016 Climate Leadership Plan has committed to extend the current target of a 10% intensity reduction by 2020 to 15% by 2030 from a 2010 baseline. Ontario has proposed a 5% reduction in the GHG intensity of gasoline by 2020, though the baseline is not clear. Designing targets for a national LCFS will require consideration of the achieved and planned trajectories in BC and Ontario, as well as the role of complementary policies in all provinces as shown in Table 6 [22].

The national LCFS regulation to be developed under the Canadian Environmental Protection Act 1999 will be a modern, flexible, performance-based approach that will provide incentives to use a broad range of lower carbon fuels and alternative energy sources and technologies. It will address liquid, gaseous and solid fuels, and will go beyond transportation fuels to include those used in industry, homes and buildings. The approach will not differentiate between crude oil types produced in or imported into Canada. It will build on the foundation set by the federal Renewable Fuels Regulations, and will consider the flexibilities and exemptions that are currently included in the Regulations [23].

The standard will provide incentives to create lower carbon fuel pathways and drive technology and innovation to achieve the desired outcomes. It will be non-prescriptive and designed to provide maximum flexibility to fuel suppliers, and will include a market-based approach, such as a crediting and trading system. Requirements will be set to reduce the lifecycle carbon intensity of fuels supplied in a given year, based on lifecycle analysis. Overall life-cycle carbon intensity reductions of approximately 10-15% by 2030 are being considered. The flexibility and the measure of performance on a lifecycle carbon intensity basis will increase emission reductions and minimize compliance costs. Alternative fuels or energy sources such as electricity, natural gas, biogas or renewable natural gas, and hydrogen, both from natural gas and from renewable electricity are part of the lower carbon fuel mix. Environment and Climate Change Canada

(ECCC) is considering regulating fuel suppliers (e.g., producers, importers and/or distributors) under this regulation. This would include both fossil fuel and alternative fuel suppliers. The requirements will also apply to the fuel used by a producer/importer (e.g. fuel oil or natural gas that is produced by an oil and gas company for its own use) [23].

Table 6: Low carbon fuel standards at a glance [22]

	British Columbia	California	European Union	Oregon	Canada*	Ontario*
Standard	Renewable and low Carbon Fuel Requirements Regulation	Low Carbon Fuel Standard	Fuel Quality Directive	Clean Fuels Program	Clean Fund Standard	Modern Renewable Fuel Standard
Year Enacted	2010	2007	2009	2010	TBD	TBD
First Compliance Year	2013	2011	Yet to be implemented by all parties	2016	TBD	TBD
Coverage	Life cycle of transport fuels, not including ILUC	Life cycle of transport fuels, including ILUC	Life cycle of transport fuels, ILUC reported but not counted, inclusion under review	Life cycle of transport fuels, including ILUC	Transportation fuels as well as fuel use in industry and residential and commercial buildings, ILUC inclusion TBD	Gasoline and its substitutes, ILUC inclusion TBD
Stringency: GHG Intensity Reduction Target	10% by 2020 (2010 baseline)	10% by 2020 (2010 baseline)	6% by 2020 (2010 baseline)	10% by 2025 (2015 baseline includes 10% ethanol gas and 5% ethanol diesel)	TBD	5% by 2020 (baseline unclear)
Flexibility Mechanisms	Tradeable credits, banking, C$200/tonne compliance penalty	Tradeable credits, banking, credit clearance mechanism	Not yet implemented	Tradeable credits, banking, credit price backstop under development	TBD	TBD
Complementary Policies	Federal and provincial RFS, carbon tax including fuel use (C$30/tonne)	Federal RFS, ETS including fuel use (approx. US$12.50/tonne)	Fuel Quality Directive RFS, individual countries have different transportation tax models	Federal renewable fuel mandate	Federal and 5 provincial RFSs, carbon taxes in BC and AB, C&Ts in ON and QC, carbon pricing in all provinces in 2018, potential additional interactions in industry and building GHG policy	Greener diesel regulation, RFS, cap and trade system

*Proposed LCFSs for Canada and Ontario are in the early stages of development and details have yet to be finalized.

3.2 Codes, standards and regulations of renewable hydrogen blending

3.2.1 CSR of hydrogen transportation in hydrogen pipelines

In the case of hydrogen, standards are needed to assure the safety of technology to produce, transport, utilize, dispense and store it. The science behind the technologies is well understood, but there is a strong need to standardize technical guidance for globally widespread deployment. Standards and regulations are the key to solving the 'chicken and egg' dilemma, which asks the question of what to roll out first – hydrogen technologies and equipment (chicken) or the infrastructure to distribute it (egg). The International Standardization Organization (ISO) currently has a technical committee responsible for developing standards on systems and devices for the production, storage, transport, measurement and use of hydrogen, ISO/TC 197 [24].

Table 7 gives the U.S. activities related to hydrogen regulations, codes and standards. The federal government plays a limited role in the development, adoption, and enforcement of codes and standards, but federal safety regulations are incorporated in the Code of Federal Regulations (CFR). Those that apply to hydrogen are embodied primarily in 49 CFR (1995) and 29 CFR (1996), under the jurisdictions of the Department of Transportation (DOT) and Occupational Safety and Health Administration (OSHA), respectively. The DOT regulates the transportation of hydrogen. The OSHA regulates the safe handling of hydrogen in the work place. OSHA regulations are intended to provide worker safety for the industrial use of hydrogen. The Department of Energy (DOE) has worked to harmonize national and international regulations, standards and codes that are essential for the safe use of hydrogen by consumers in the U.S. and throughout the world. The National Renewable Energy Laboratory (NREL) provides technical and programmatic support to DOE for this effort [1].

Once produced, hydrogen must be transported to markets. A key obstacle to making hydrogen fuel widely available is the scale of expansion needed to serve additional markets. Developing a hydrogen transmission and distribution infrastructure would be one of the challenges to be faced if the United States is to move toward a hydrogen economy. Initial uses of hydrogen are likely to involve a variety of transmission and distribution methods. Smaller users would probably use truck transport, with the hydrogen being in either the liquid or gaseous form. Larger users, however, would likely consider using pipelines. This option would require specially constructed pipelines and the associated infrastructure [25].

It is estimated that the existing hydrogen transmission system in the United States and Europe ranges from 450-800 miles and 700-1,100 miles, respectively. Hydrogen pipelines in the United States are predominantly along the Gulf Coast and connect major hydrogen producers with well-established, long-term customers. Since 1939, Germany has had a 130-mile pipeline carrying 20,000 lb/hour of hydrogen in a 10-inch pipe at 290 psi gauge (psig). The longest hydrogen pipeline in Europe is owned by Air Liquide and extends 250 miles from Northern France to Belgium [25].

Table 7: US and on-going activities for hydrogen codes and standards [1]

Activity	Objective	Organizations
U.S. Domestic Codes and Standards Development Activities		
Stakeholder Meetings and Technical Forums	Supports technical and coordination meetings to ensure communications among key stakeholders	NREL, PNNL, LANL, SNL, NHA
Technical Expertise	Supports hydrogen safety research and provides expert technical representation at key industry forums and codes and standards development meetings, such as the ICC and NFPA model code revision process	SNL, NREL, LANL
Consensus Codes and Standards Development	Supports coordinated development of codes and standards through a national consensus process	NREL, SNL, SAE, CSA, NHA, NFPA, ICC, ANSI
Information Dissemination	Supports information forums for local chapters of building and fire code officials, and the development of case studies on the permitting of hydrogen refueling stations	PNNL, NHA
Research, Testing and Certification	Supports focused research and testing needed to verify the technical basis for hydrogen codes and standards and equipment	SNL, NREL
Training Modules and Informational Videos	Supports the development of mixed media training modules and informational videos for local code officials, fire marshals and other fire and safety professionals	PNNL
National Template for Standards, Codes, and Regulations	Identifies key areas of standards, codes, and regulations for hydrogen vehicles and hydrogen fueling/service/parking facilities and designates lead and supporting organizations	NREL
Codes and Standards Matrix Database	Provides inventory and tracking of relevant domestic codes and standard: identifies gaps, minimizes overlap, and ensures that a complete set of necessary standards is written	NREL, ANSI

In theory, a blend of up to 20% hydrogen in natural gas can be transported without modifying natural gas pipelines [26]. Modifying the same pipelines to carry pure hydrogen, however, requires addressing a number of issues, including the potential for embrittlement of some steels and sealing difficulties at fittings that are tight enough to prevent natural gas from escaping, but possibly not hydrogen [25].

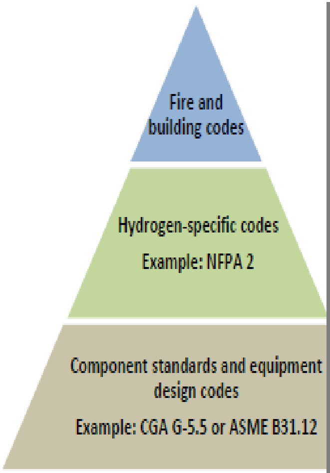
A number of US federal and state agencies have standards and regulations that affect natural gas pipelines and are likely to also impact hydrogen pipelines. These agencies include Department of Transportation, Federal Energy Regulatory Commission, Office of Pipeline Safety, National Transportation Safety Board, U.S. Coast Guard, Federal Emergency Management Agency, Public Utility Commission, and State and local fire departments [25].

Hydrogen pipeline construction standards are currently under development. The American Society of Mechanical Engineers (ASME) Board on Pressure Technology Codes and Standards has initiated the development of an independent consensus standard or code for hydrogen pipelines. Although it is anticipated that many of the codes and standards will be similar to those for natural gas pipelines, differences in physical properties will necessitate some differences such as explosive force, level of damage from explosion and fire, detonation in the open air, emissions during burning, energy density, flammability limits and ignition energy [25].

At a minimum, any proposed hydrogen gas facility would be designed, constructed, tested, and operated in accordance with all applicable requirements included in the U.S. Department of Transportation (DOT) regulations in Title 49, Part 192, of the Code of Federal Regulations (49 CFR Part 192), "Transportation of Natural Gas and Other Gas by Pipeline: Minimum Federal Safety Standards," and other applicable federal and state regulations. These regulations are intended to ensure adequate protection for the public and to prevent natural gas pipeline accidents and failures. Among other design standards, Part 192 specifies pipeline material and qualification, minimum design requirements, and protection from internal, external, and atmospheric corrosion [25].

Hydrogen technologies are controlled through codes and standards in a manner similar to other fuels. Fig. 4 illustrates the codes and standards hierarchy [27]. The top level of the pyramid consists of building and fire codes that are directly adopted by jurisdictions. Any code or standard referenced in the body of a building or fire code adopted by a jurisdiction becomes a legally enforceable document in that jurisdiction. In the topical area of hydrogen technologies these documents comprise the second level of the pyramid. Key documents at this second level include the NFPA 2 Hydrogen Technologies Code and the NFPA 853 Standard for Fuel Cell Energy Systems. These documents contain references to component standards, which comprise the bottom or third rung of the pyramid. These component standards must also be written in legally enforceable text to be referenced by these second-level codes and standards. Examples of these documents include the CGA S series of documents for pressure relief devices and the American Society of Mechanical Engineers (ASME) B31.12 standard for piping [27].

Viewed as a package, these documents address all key aspects of system design, construction, operation, and maintenance. Compliance with these requirements should reduce the system risk to a safe level. The timeline in Figure 4 reflects the development of hydrogen codes and standards over the last eight years [27].



2014	2013	2012	2011	2010	2009	2008	2007	2006	2005
California references NFPA 2 in CFC		IFC references NFPA 2							IFC Chapter 22 Hydrogen Fueling
Draft 2nd ed. NFPA 2 developed	NFPA 55 published with clarified setback tables	NFPA 52 authority added to NFPA 2		NFPA 2 1st ed.	NFPA 2 draft	Task Group Bulk Hydrogen	Task Group Bulk Hydrogen	NFPA 2 first committee meeting	NFPA 52 2006 ed. w/ hydrogen fueling
SAE J2601 revision complete	SAE J2579 reissue	CGA H-10 issued	SAE J2719 issued		CSA H series of drafts issued	ASME B31.12 issued	CSA HGV 4		UL2267

Figure 4: Timeline of codes and standards development and the codes and standards hierarchy [27]

At the US federal level there are regulations, such as 29 CFR 1910 Subpart H Hazardous Materials, that specifically address the storage, use, and handling of hydrogen. Table 8 gives an overview of the regulations, codes, and standards that address hydrogen technologies safety [27].

Although the industry has been safely pipelining gaseous hydrogen (GH2) for decades, these systems are not designed for frequently-varying pressure and for large-scale, long-distance, cross-country collection from many dispersed nodes from diverse sources, as required by renewables-hydrogen service (RHS). Design of cross-country GH2 pipelines is still uncommon. No industry-accepted codes and standards have been developed to guide the engineering and design of such facilities. A new specification for RHS is needed to define stresses on pipeline system components and limitations on pipeline operations, in order to optimize GH2 pipelining economics and to guide engineering of line pipe and other system components. This specification will also facilitate insuring and financing RHS pipelines [28].

Table 8: Overview of regulations, codes, and standards related to hydrogen infrastructure safety [27]

Federal Regulations	
OSHA Regulations 29 CFR 1910 Subpart H	Safe storage, use, and handling of hydrogen in the workplace
DOT Regulations 49 CFR 171-179	Safe transport of hydrogen in commerce
U.S. National Codes	
International Building Code (IBC)	General construction requirements for building based on occupancy class
International Fire Code (IFC)/NFPA 1 Uniform Fire Code	Requirements for hydrogen fueling stations, flammable gas, and cryogenic fluid storage
International Mechanical Code (IMC)	Requirements for ventilation for hydrogen usage in indoor locations
International Fuel Gas Code (IFGC)	Requirements for flammable gas piping
Hydrogen Technologies Specific Fire Codes and Standards	
NFPA 2 Hydrogen Technologies Code	Comprehensive code for hydrogen technologies constructed of extract material from documents such as NFPA 55 and 853 and original material
NFPA 55 Compressed Gas and Cryogenic Fluids Code	Comprehensive gas safety code that addresses flammable gases as a class of hazardous materials and also contains hydrogen-specific requirements
NFPA 853 Standard for the Installation of Stationary Fuel Cell Power Systems	Covers installation of all commercial fuel cells including hydrogen PEM fuel cells
Hydrogen Technologies Component, Performance, and Installation Standards	
ASME B31.3 and B31.12 Piping and Pipelines	Piping design and installation codes that also cover material selection
ASME Boiler and Pressure Vessel (BPV) Code	Addresses design of steel alloy and composite pressure vessels
CGA S series	Addresses requirements for pressure relief devices for containers
CGA H series	Components and systems
UL 2075	Sensors
CSA H series of hydrogen components standards	
CSA FC1	Stationary fuel cells
SAE J2601/SAE J2600	Dispensing and dispenser nozzles

3.2.2 CSR of renewable hydrogen blending into the NG grid network

National gas grids are generally composed of a transmission grid connected to supply points, storage facilities, distribution grids and some large gas consumers. A power-to-gas plant can inject gas into the transmission or the distribution grid by connecting the plant to the grid with a pipeline and an injection station similar to those used for biomethane injection. For hydrogen injection, the station must be suited for pure hydrogen and the pipeline has to have enough capacity for injection without exceeding the maximum hydrogen fraction according to the national standards. The gas must be compressed to sufficient pressure to be injected into the grid, typically 40 to 60 bar in the transmission grid and 5 to 10 bar in the distribution grid [3].

Power-to-methane plants aim at producing a synthetic natural gas (SNG) with composition similar to natural gas. Therefore, no particular constraint shall be expected on SNG injection into the grid. Pipelines used in the natural gas grid have not been designed to withstand the specific properties of hydrogen such as higher permeation and corrosion. For safety reasons, hydrogen concentration in the gas grids must be controlled. In Europe the maximum hydrogen content allowed by national standards for biomethane injection into the grids generally varies from 0.1 to 10 % in volume depending on the country [3,8].

According to ongoing work on European standardization of power-to-hydrogen applications, most of the European natural gas infrastructure can withstand a volume concentration 10 % of hydrogen. More investigation is still required to assess the tolerance to hydrogen of several gas grid components, including storage caverns, surface facilities, storage tanks, gas flow monitors and gas analysis instruments [29]. Downstream uses of gas also impose constraints on hydrogen mixture in the gas. For instance, Compressed Natural Gas (CNG) vehicles and gas turbines are currently designed for a fuel gas containing less than 2 or 3 % of hydrogen in volume [30].

Several Technical Committees (TCs) are working on the establishment of limits for H_2 concentration. The maximum hydrogen content has been discussed in several of the TCs, but setting a clear limit is currently viewed as premature. A harmonization of existing and future standards with regard to the allowed hydrogen concentration in gas mixtures is needed. Examples of standardization activities affected include:

- CEN/TC 234 (Gas infrastructure)
- CEN/TC 408 (Biomethane for use in transport and injection in natural gas pipelines
- CEN/TC 238 (Test gases, test pressures, appliance categories)
- ISO/TC 193 (Natural gas)
- ISO/TC 22/SC25 (Road vehicles using gaseous fuels)
- ISO/TC 197 (Hydrogen technologies)
- ISO/PC 252 (Natural gas fueling stations for vehicles)
- ISO/TC 192 (Gas turbines) [29].

The injection of hydrogen into the natural gas grid will affect all gas users, and all appliances fueled with natural gas will be affected by the change of gas mixture properties. Direct hydrogen injection into the gas grid is the simplest form of P2G technology. After leaving the electrolysis module the H_2 has to be dried and is ready for injection or for other applications.

In Germany there is no public hydrogen infrastructure exists in Germany at this time. Up to now, according to the DVGW standard G 262, the content of hydrogen in the distributed natural gas is limited to max. 5 vol.%. Therefore, in order to keep the H_2 content of the natural gas reliably below 5 vol.%, direct hydrogen injection from big electricity suppliers such as off shore wind parks is only possible into big natural gas streams, e. g. in the northern part of Germany. In other regions with more decentralized electricity production (e. g. by photovoltaic cells) or in the absence of big natural gas transportation pipelines, direct hydrogen injection is not feasible [31].

Hydrogen can be injected directly into natural gas pipelines and analysis is ongoing to determine what proportions of hydrogen can be supported. Originally it was thought that no more than 5% hydrogen could be used, but depending on the pipeline engineering and downstream uses, ratios up to 12% have been achieved. Older cast iron and steel pipes don't contain hydrogen well because they are embrittled by the hydrogen which also leaks through seams. Modern plastic pipes contain the hydrogen much more effectively and can take higher ratios, but users must be consulted to ensure their operations are not impacted by higher hydrogen ratios. This is an ongoing area of investigation and pipeline standards for direct hydrogen injection have not been established in Germany [32].

The U.S. natural gas pipeline system includes 2.44 million miles of pipeline and ~400 underground storage facilities. There are over 50,000 city gate facilities are several of which are located near major urban areas where transmission lines drop in pressure to feed natural gas into local distribution systems [33]. The Gas Technology Institute and NREL have generated a report reviewing the concept of blending hydrogen into natural gas pipelines for transporting hydrogen and storing/utilizing renewable or stranded hydrogen. Though a broad range of issues must be taken into consideration, blending as a means of transport (with downstream extraction) or storage is technically feasible and may be economically viable under the right conditions. Hydrogen blends, even at even low levels, can be a problem for appliances that are not properly maintained. As the blend level increases from 1% to 12%, additional precautions must be taken to minimize the impact on end-use systems. High blend levels can be safe in transmission lines, but additional risks are posed from the city gate through distribution lines. Most pipeline materials cannot withstand to hydrogen-induced failures [34].

In order to accelerate the implementation of hydrogen injection into natural gas pipelines in North America, harmonized standards specifying gas quality and composition (including hydrogen tolerance) for NG transmission and distribution will be required. Energy regulators and policy makers should identify ways to encourage the pipeline industry's adoption of gas quality standards for initial levels of hydrogen blending [35].

The determination of requirements for admixing hydrogen into the natural gas grid and for its end-users should be approached from a system perspective. A minimum threshold for no or limited action would be around 2%. Mixing up to 5% could also be possible but this is to be further investigated and could be a driver for appliance innovation. According to current understanding, a hydrogen concentration limit up to 20% poses some challenges with regard to end-use appliances and gas analysis methods. Further research is needed to address end-user concerns regarding process control, emissions and safety. Public acceptance relies on the proper identification and assessment of risks. Standardization needs to ensure the safety of hydrogen compressed natural gas (HCNG) use by considering the specific properties of hydrogen and NG blends and address all associated risks [29].

Much work done to address the need for codes and standards for renewable hydrogen technologies, but it is time to for the US Environmental Protection Agency (EPA) to include hydrogen in the federal RFS2 Renewable Fuel Standard, allowing renewable electricity credits (RECs) for electrolysis into the LCFS in California, and expanding the biofuel blending mandate to include renewable hydrogen used in refining in Canada [36].

4. R&D needs and gaps associated with P2G pathway in Canadian context

Canada is a net exporter of most energy commodities and is an especially significant producer of conventional and unconventional oil, natural gas and hydroelectricity. Canada's economy is relatively energy intensive compared to other industrialized countries, and is largely fueled by petroleum, natural gas, and hydroelectricity. Canada ranks fifth in dry natural gas production and is the fourth-largest exporter of natural gas, behind Russia, Qatar, and Norway [37].

According to a detailed study on the future of energy in Canada published by the National Energy Board (NEB), it is expected that the demand for energy in Canada will continue to increase in all of the scenarios up to 21-30% between 2012 and 2035. The proportions of each energy source in the Canadian energy basket will not vary much between 2012 and 2035; however, the energy demand for natural gas will increase from 31% of national demand in 2012 to 37% in 2035 [38].

Canada is a world leader in the production and use of energy from renewable resources, which currently provide about 18.9 per cent of Canada's total primary energy supply. Wind and solar photovoltaic energy are the fastest growing sources of electricity in Canada. Canada has excellent wind resources and significant potential for the expansion of wind-generated power. Installed wind power capacity in Canada has expanded rapidly in recent years and is forecasted to continue to grow at a rapid pace due to increased interest from electricity producers and government initiatives [39].

Parts of Canada have good potential for solar energy development, with levels that are generally higher than those in Germany, which had the most installed solar PV capacity in the world in 2014. This suggests that there could be significant potential for higher adoption of solar in Canada [40]. However, wind and solar-based energy production is intermittent and fluctuating, which requires long term scalable energy storage to enhance grid stability and reliability.

Figure 5 shows the power-to-gas valorisation pathways [41]. Renewable Hydrogen produced by wind or solar system can be utilized in a variety of applications including power-to-power, power-to-gas, power-to-mobility, power-to-fuels, and power-to-industry.

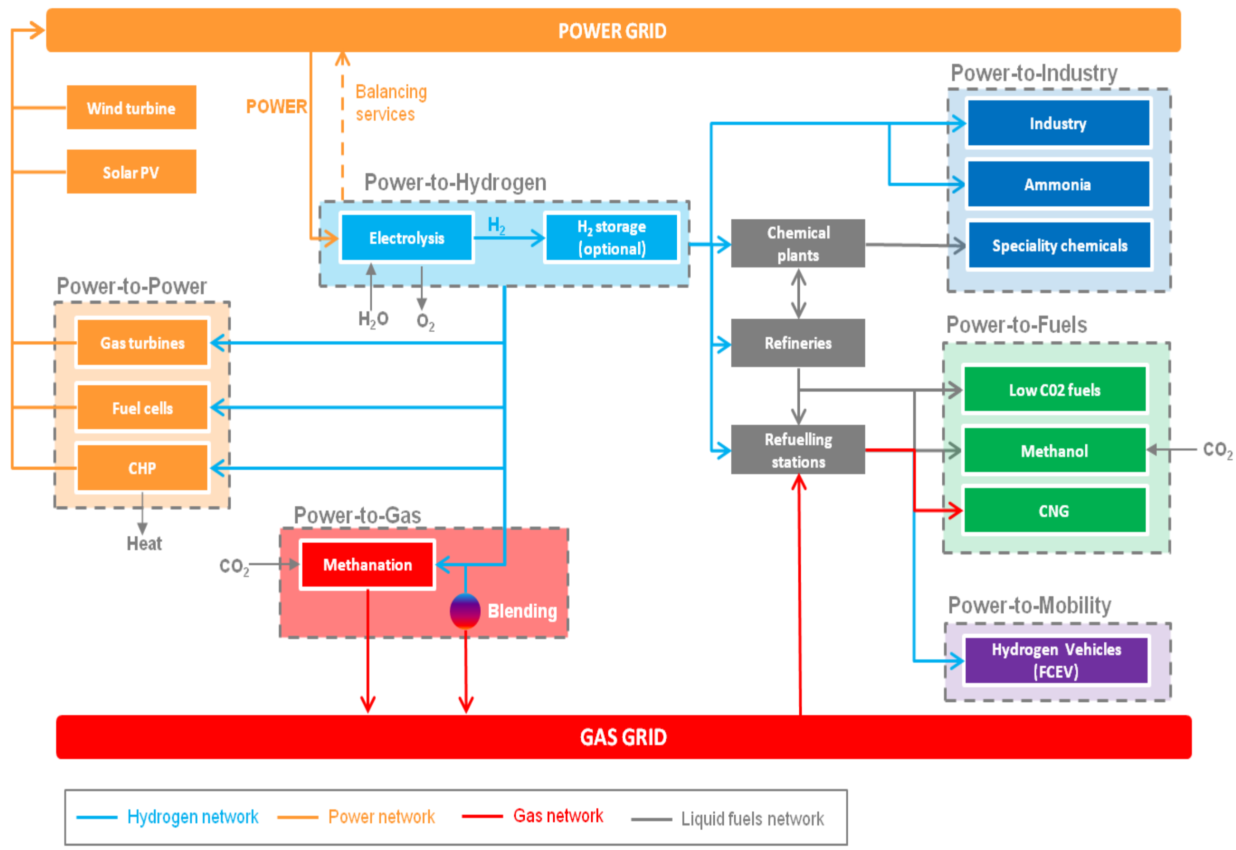


Figure 5: Power-to-Gas valorization pathways [41]

Canada's energy resources are among the largest in the world. Canadian rivers discharge close to seven per cent of the world's renewable water supply. This resource provides tremendous hydroelectric generating capability. In addition, Canada ranks third globally in proven oil reserves, 97 per cent of which are in the oil sands, and 15th in both proven natural gas and coal reserves. This large and diversified resource base contributes to Canada's status as a significant global energy producer and exporter. In terms of production, Canada ranks among the top five in the world for hydroelectricity, crude oil, natural gas and uranium [40]. Table 9 illustrates Canadian energy production of electricity, gas and crude oil in 2014 [40,42].

Table 9: Canadian energy production of electricity, gas and crude oil in 2014 [5,42]

Energy	Energy production in 2014	
	TWh	m^3/day
Electricity	650	-
Gas	1,700*	444
Crude Oil	2,700**	682

*1,000 m^3 of NG = 38.3 GJ, 1MWh electricity = 3.6 GJ [42]
** 1 m^3 of crude oil = 39.0 GJ [42]

The total energy capacity of Canada's natural gas grid is much larger than that of its electrical generating capacity, indicating the significance of the gas grid for domestic energy supply as shown in Figure 5. The electricity fuel mix change in 2014 and 2040 in Canada as shown in Figure 6 shows that the share of natural gas and renewables increases while coal, oil, and uranium decreases due to retirements and lower growth compared to other types of generation. The proportion of capacity from non-hydro renewables increases from 9 % to 16 %, indicating deeper penetration of renewables such as solar and wind for producing electricity. Most wind power capacity is installed in Ontario, Quebec, and Alberta; while the majority of solar capacity is in Ontario [40]. The excessive intermittent and fluctuating electrical power can be utilized for grid stabilization and reliability by producing hydrogen or methanation via further conversion of renewable hydrogen with CO_2 as a long-term and large-scale energy storage as shown in Figures 5 and 6.

While the power-to-gas pathway allows the connection of electric and gas grids, there are challenging techno-economic aspects and regulation issues for the implementation and commercialization of P2G technology in Canada. The production of hydrogen from renewable using alkaline and PEM electrolyzers as Power-to-Hydrogen has been done worldwide, but the direct use and transport of hydrogen require a large-scale hydrogen infrastructure, market and regulations. The limitation can be overcome by injecting renewable hydrogen directly into existing natural gas pipelines or producing renewable natural gas or liquid fuels from renewable hydrogen as Power-to-Gas and Power-to-Fuels as shown in Figure 5, enabling injection and transport of products through existing gas infrastructure. The developing national LCFS regulation may accelerate the deployment of P2G technology by providing incentives to use renewable hydrogen and renewable natural gas in Canada.

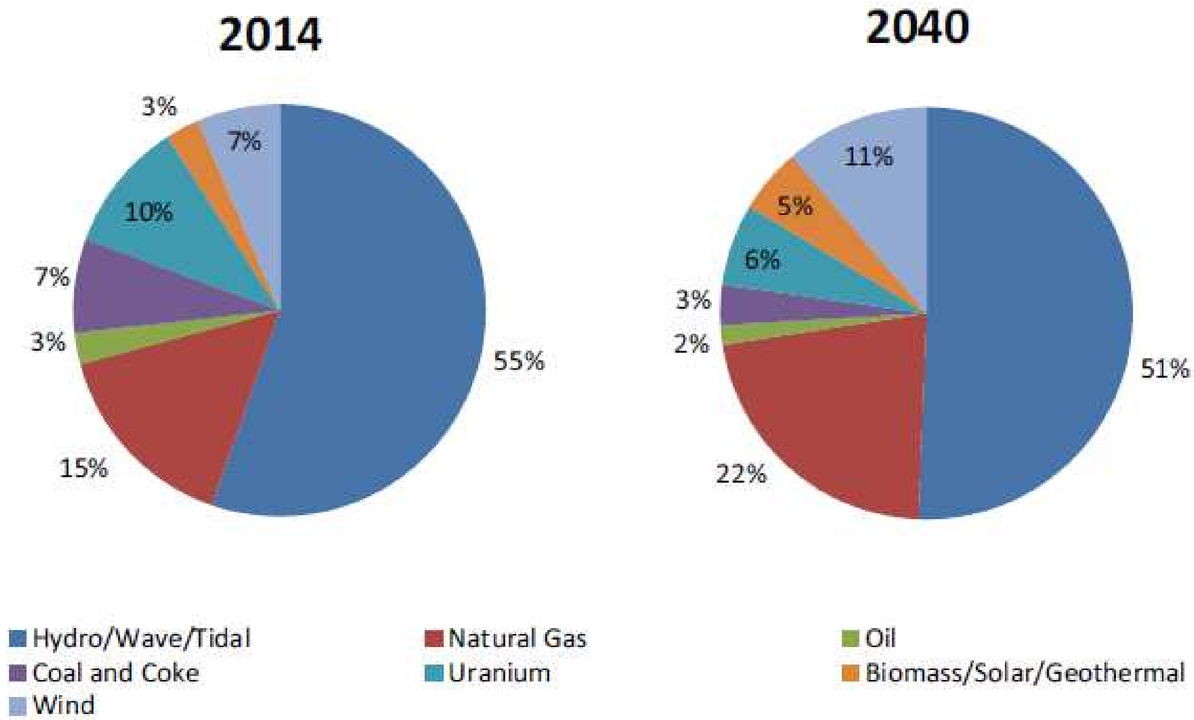


Figure 6: Canadian electricity fuel capacity mix by primary fuel in 2014 and 2040 [40]

5. Hydrogen tolerance of key P2G components and systems in Canada

Renewable hydrogen blending into natural gas grid networks is a low-cost, early stage solution for monetizing electricity surpluses in countries with highly developed natural gas infrastructure. The additional costs of injection facilities are minimal and pure hydrogen storage could be reduced to small buffer tanks [30]. The maximum blending ratio tolerated by existing and unmodified gas infrastructure remains difficult to assess precisely and is determined by pipeline integrity and safety issues, hydraulic constrains on grid transport capacity, and most importantly, by the sensitivity of end-use appliances to hydrogen/methane blends [30]. Legislation for hydrogen enriched natural gas remains sparse in most countries. In general, the entire gas grid should tolerate 5 vol.% blending anywhere, and up to 20% in distribution or regional transmission pipelines with no critical downstream appliances. More research and development work to quantify safe and practical upper limits of hydrogen blending is needed to support regulatory reform and harmonize HCNG standards [30].

Hydrogen can be injected into NG pipelines at the distribution or regional transport level, creating hydrogen compressed natural gas (HCNG) as unreacted mixture of hydrogen and natural gas. Hydrogen blending incurs negligible energy losses and requires little additional investment, but volumes are constrained by the limited concentration of hydrogen that can be blended into the NG grid without any need for modification. Methanation to transform hydrogen and carbon dioxide into methane enables to utilize much higher amount of produced renewable hydrogen for transport through existing NG pipelines, but the conversion process needs additional capital investment and incurs energy loss [30]. In addition, the produced renewable hydrogen can be also injected into existing underground gas storage caverns, and when required, the stored hydrogen can be injected into NG pipelines [30].

5.1 Hydrogen tolerance in Canadian NG pipelines

There are an estimated 825,000 kilometres (km) of transmission, gathering and distribution lines in Canada — including 100,000 km of large-diameter transmission lines — with most provinces having significant pipeline infrastructure. Of this amount, approximately 73,000 km are federally regulated pipelines, which are primarily transmission lines. Pipelines are generally buried underground and operate in both remote and populated areas, with major crude oil and natural gas pipelines servicing most major Canadian cities as shown in Figure 7 [43].

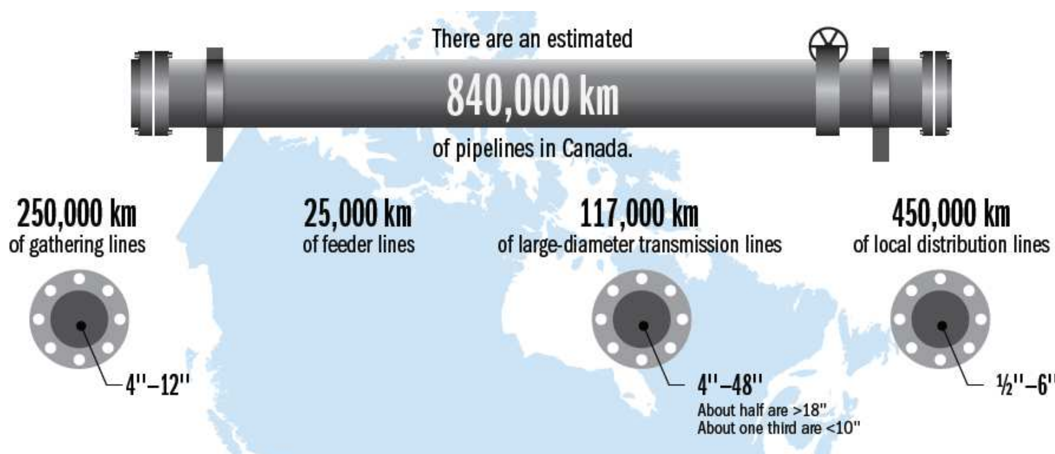


Figure 7: Canada's pipeline infrastructure [43]

Canada has one of the world's largest pipeline networks delivering natural gas from producing areas in western and eastern Canada to markets across North America as shown in Figure 8 [44]. Canada is a part of an integrated North American network for natural gas. There are three major types of natural gas pipelines along the transportation route: gathering pipelines, transmission pipelines and distribution pipelines as shown in Table 10 [45].

Source: Canadian Energy Pipeline Association

Figure 8: Major natural gas transmission pipelines in Canada [44]

Table 10: Canadian natural gas pipelines [43,45]

Type of Pipelines	Function	Diameter	Materials	Internal Pressure
Gathering	To collect and move raw gas to processing facilities in producing areas	4”-12”	-	low
Transmission	To deliver purified natural gas to local distribution utilities at city gate stations for delivery to the end users	4”-48”	Carbon steel with protective coating	200-1,500 psi
Distribution	To deliver gas to customers through local distribution networks made up of control and measurement stations, mains, service lines, and customer meters	½”-6”	Steel, plastic or cast iron	low (5-200 psi)

The blending ratio of H_2/NG is technically limited to 17-25 vol.% in some parts of the distribution grid and not above 5 vol.% in the transport grid. The H_2 blending limit is uncertain and very system specific, limited by grid integrity, safety, energy transport capacity, and by the specifications of end-use applications. H_2 blending offers a low-cost solution for monetizing surplus electricity supply. The easiest option is to inject H_2 produced by decentralized electrolyzers into low/medium-pressure distribution pipelines, which have no buffer storage. Further economic benefits would come from the recognition of hydrogen enriched natural gas as a green fuel, because of its renewable energy content. Hydrogen blending is gas-system specific and poses regulatory challenges [30].

The transmission pipelines with medium to high pressures are made of carbon steel with protective coating, where hydrogen-induced embrittlement can accelerate the growth of micro cracks and compromise pipeline safety. It is estimated that existing, unmodified steel pipes could sustain 20 vol.% of hydrogen and potentially up to 50 vol.% of hydrogen, depending on the quality of the steel used [30]. The distribution pipelines made of plastic for low pressures are not suffering from embrittlement and may accommodate 17-25 vol.% of hydrogen without the need for case-by-case testing [30].

The technical limitations related to transport of hydrogen-blended NG are the increase of pressure drop and the decrease of energy efficiency and transport capacity, resulting from much lowered energy densities of blended gases in comparison to natural gas. It is estimated that the hydrogen blending over 20 vol.% into NG pipelines may result in too much negative effects on energy transport capacity and grid energy efficiency [30].

In June 2013, the German electric and gas utility E.ON injected hydrogen into the natural gas pipeline for the first time as a full system test and the plant operations commenced in August 2013. The company stated that their regulations allowed up to 5% hydrogen in the natural gas pipeline [46]. In Canada, Alberta-based TransCanada Pipeline's (TCPL) natural gas quality specifications do not directly limit the amount of hydrogen that can be injected into TCPL pipeline; however, the lower limit on the heating value of 36 MJ/m^3 implicitly limits hydrogen content to around 5 vol.% in a TCPL pipeline at any point [46].

5.2 Hydrogen tolerance in Canadian NG storage facilities

Canada has approximately 0.8 trillion cubic feet (Tcf) of working natural gas storage capacity equivalent to approximately 30% of domestic annual natural gas demand. Natural gas can be stored in depleted oil or gas reservoirs, aquifers, salt caverns, LNG or CNG units, and pipeline network as line pack. In Canada, the majority of storage is located in Western Canada with Alberta having the greatest storage volume, and smaller storage capacity in British Columbia and Saskatchewan as shown in Figure 9. Storage in Eastern Canada is located primarily in southwestern Ontario for meeting winter demand in Ontario and Quebec [47].

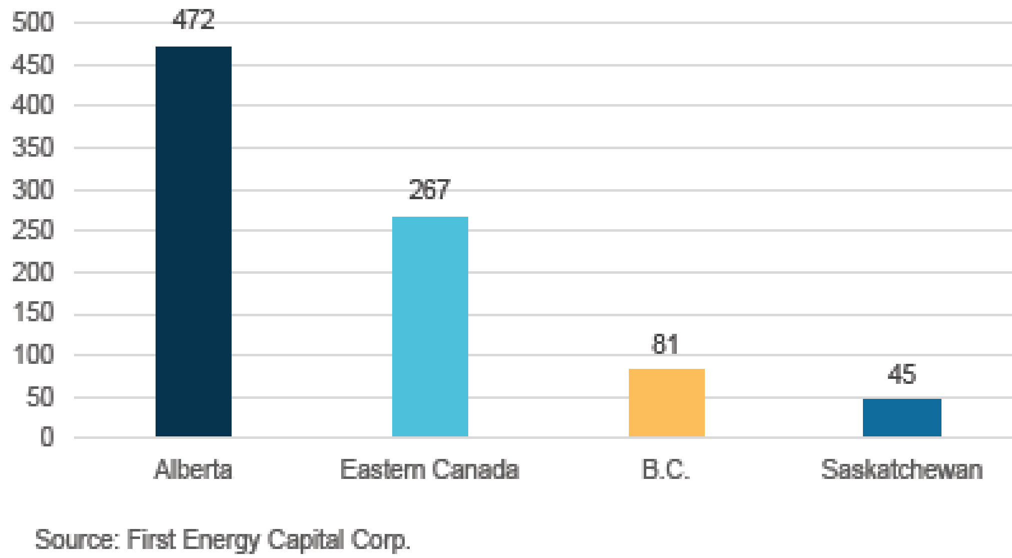


Figure 9: Canadian NG storage – implied capabilities (billions of cubic feet, Bcf) [47]

In case of underground gas storage, a 2007 survey specified Canadian underground natural gas storage capacity as 583.8 billion cubic feet (Bcf), consisting of 44 depleted reservoirs, and 8 salt caverns [48]. The majority of gas storage is split between Ontario and Alberta. In Alberta, storage facilities are owned by utilities, midstream companies, pipelines and producers. Storage facilities in Ontario were developed and are owned primarily by utilities [48].

Five common types of natural gas storage facilities in Canada are shown in Table 11 [30,46,47,49]. A depleted natural gas field consists of an underground rock formation that has already been trapped of its recoverable natural gas. Porosity and permeability of these facilities are low, meaning its injection or withdrawal occurs at a slower rate than salt caverns or LNG storage [47]. The first depleted gas field that was converted to an underground gas storage was a gas field in the Welland County, Ontario in Canada and started operation in 1915. There are no existing depleted pure hydrogen fields so far worldwide. In some cases of depleted fields with town gas, it was reported that the increased micro-bacterial activity induced biological and geo-chemical reactions, resulting in H_2 consumption, conversion to methane, and H_2S production. Therefore, the conversion of depleted NG fields to hydrogen storages requires full and integrated assessments of the processes involved in the conversion for ensuring secure and safe operations [49].

The geology of an underground aquifer is similar to a depleted field or reservoir, but aquifers usually require more gas and greater monitoring of withdrawal and injection performance since deliverability rates are affected by the pressure from any residual water in the aquifer. Operators inject gas into the formation displacing the water. The porosity and permeability from aquifer storage is low [47]. The amount of unrecoverable gas is large because a certain amount of gas will remain in the aquifer and cannot be recovered again. This physically unrecoverable gas will be lost. The flow velocities in aquifers consisting of a porous matrix are always much slower than in an open cavity like a cavern. Due to low flow rates, aquifer-based natural gas storage facilities are mainly used for seasonal storage with only one annual storage cycle at steady injection and withdrawal rates. There are required R&D issues for injecting hydrogen into aquifers, including gas tightness, bio-degradation of H_2, mineral reactions, bio-chemical reactions, and chemical reactions. In addition, hydrogen-safe cemented bonding, steels and plastic materials should be used for well cementation and completions [49].

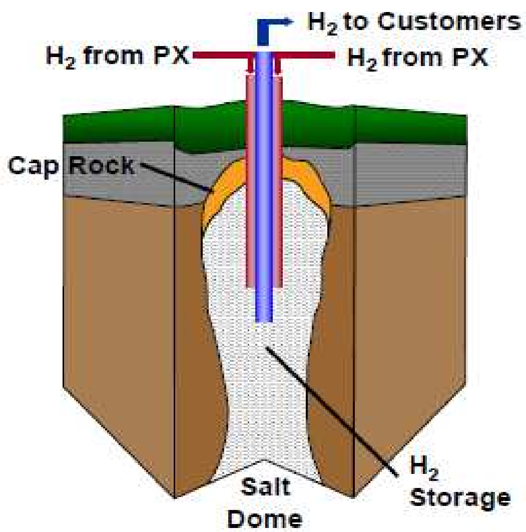
Table 11: Types of natural gas facilities in Canada [30,46,47,49]

Type of Storage facilities		Definition	Features	Conversion into NG storage	Ability to inject H_2
Under-ground	**Depleted gas fields**	Geological traps that were filled with hydrocarbons	- Not completely depleted - Existing subsurface and surface installations - Slower injection and withdrawal rates than cavern storage - Appropriate for seasonal gas supply - Not scalable - 15-30% porosity - Permeability of 2,000 mD - Depth of 200-3,000 meters - Gas Volume range of 1-3,000 Mm^3	- Possible with only limited exploration effort and investment - Not all depleted fields are suitable for conversion - Required gas treatment processes to remove high contents of water and impurities from the withdrawn gas	- So far no existing depleted pure H_2 gas fields worldwide - Only some fields with town gas
	Aquifers	Geological traps that were filled with formation water	- Low porosity and permeability - Low flow rates - Seasonal storage - Scalable	- Costly investment - Large amount of unrecoverable gas due to aquifer's heterogeneity and unfavourable sweep efficiency - Required gas treatment processes	- No data available for pure H2 in aquifers - Many existing aquifers with NG and town gas - Bio-degradation of H_2

Type of Storage facilities		Definition	Features	Conversion into NG storage	Ability to inject H_2
	Salt Caverns	Artificially created cavities built in salt deposits	- Large geometrical volumes - High storage pressures - Long term stability - Gas tightness - Very low specific construction costs - High withdrawal and injection rates - Short, mid-term and also seasonal applications	- Only one single well bore - Rock salts dissolved by water - Required cushion gas with 1/3 of the gas inventory - Required gas drying, not gas cleaning	- Feasible for H_2 storage - No issues on biological or chemical degradation - Required hydrogen-safe cemented bonding, steels and plastic materials
Above ground	**LNG and CNG storage**	Liquefied natural gas (LNG) or compressed natural gas (CNG)	- Used to meet periods of extreme or peak demand - Built in areas where the geology does not provide for underground storage - Mobile storage	- Built for containing NG	- Feasible for H_2 storage - Required H_2-safe compressor - Required use of steels comparable with H_2
	NG pipe storage	Pipelines buried a few meters below ground level	- For short-term peak demands - Very small storage capacity - Not big enough for seasonal applications - Coatings applied for corrosion protection - The most expensive storage option regarding CAPEX per working gas	- Built for peak shaving of NG on a weekly or daily basis - Surface facilities comprised of a compressor, venting valves and gas meters	- Feasible for H_2 storage - Required H_2-safe compressor and gas metering system - Required use of steels and materials comparable with H_2

Salt caverns being used for storing natural gas could be suitable for much higher hydrogen concentrations in natural gas or even pure hydrogen, but require modification of equipment such as injection wells or compressors at gas storage facilities. However, since these major storage assets are linked to the existing natural gas grid, their practical capacity for hydrogen would be limited by existing pipeline standards / specification, so around to 5 vol.%. Other underground gas storage facilities such as deep aquifers or depleted gas fields do not offer the same qualities of hydrogen storage [30].

Figure 10 shows the Salt Cavern-based hydrogen storage facility built within the Clemens salt dome in Texas for Gulf Coast hydrogen infrastructure. The cavern consists of injection compressor with ancillary equipment, hydrogen product dryer and associated metering and control equipment. The commercialization of cavern storage enables safe injection/withdrawal of hydrogen, real-time operation adding value for supply-system optimization and peak demand, and steady state operations improving pipeline operability [50].



Design Basis	
Storage Capacity	2.5 Billion CF
Working Capacity	1.4 Billion CF
Max Storage Pressure	2200 psig
Working Pressure	800 - 2200 psig
Fill Rate	~ 75 MMCFD
Withdrawal Rate	pressure dependent
Commissioned	Q4 2007

Figure 10: Praxair's salt cavern-based hydrogen storage facility built in Texas [50]

Natural gas is also stored above ground as liquefied natural gas (LNG) or compressed natural gas (CNG). Like salt caverns, LNG storage units are used to meet periods of extreme or peak demand. LNG and CNG can also be transported to locations beyond the existing pipeline system. In some cases, this mobile storage can be used to overcome situations where piped-in natural gas is unavailable or has been interrupted [47].

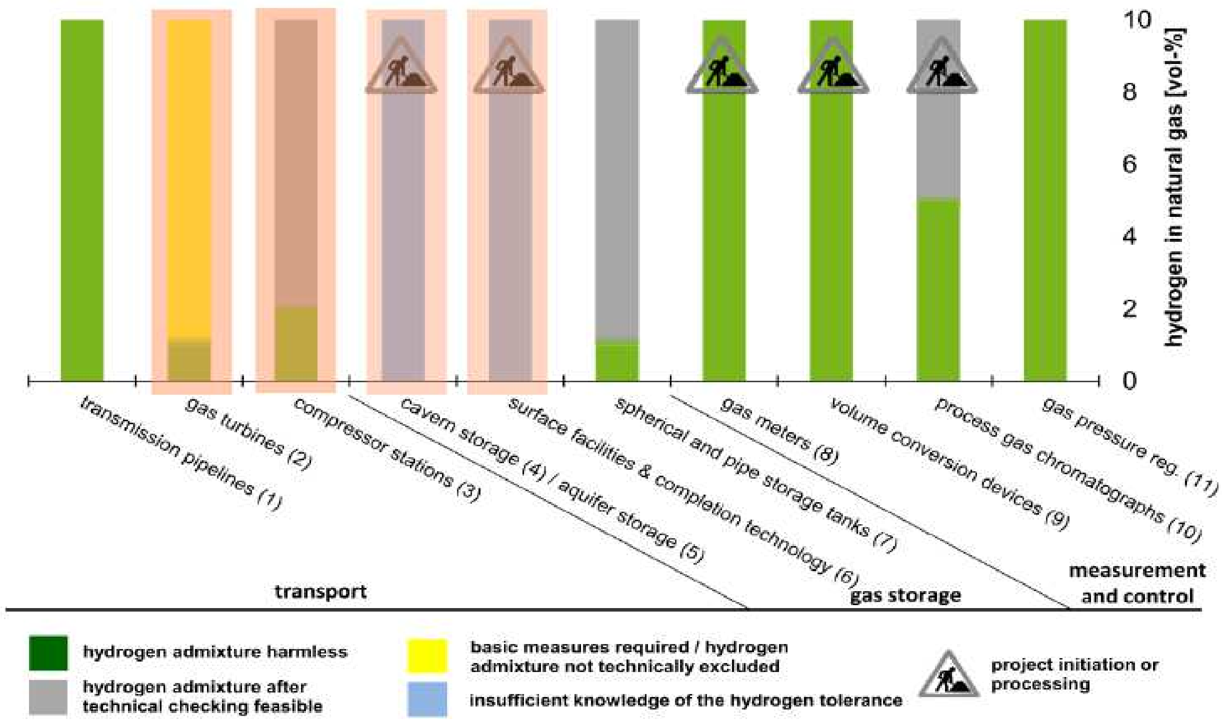
Pipe storages are not generally categorized as geological storages because they are only buried a few meters below ground level. Pipe storages are used to store NG and smooth out short-term demand peaks at larger facilities or cities with limited connectivity to the gas grid. The stability and pressure range of pipe storages are determined by the strength and thickness of pipes [49]. The compatibility of pipeline materials with hydrogen should be verified to build safe pipe storages for blending hydrogen with natural gas.

The storage of hydrogen within the same type of facilities, currently used for natural gas may add new operational challenges to the existing cavern storage industry, such as the loss of hydrogen through chemical reactions and the occurrence of hydrogen embrittlement. However, it has been shown that if the underground storage of hydrogen is operated at pressures below 1200 psi and at temperatures below 500°F, there may be little need for concern. It is recommended that all steel used in the storage and operation of a site be free of defects and possess low-yield-strength [51].

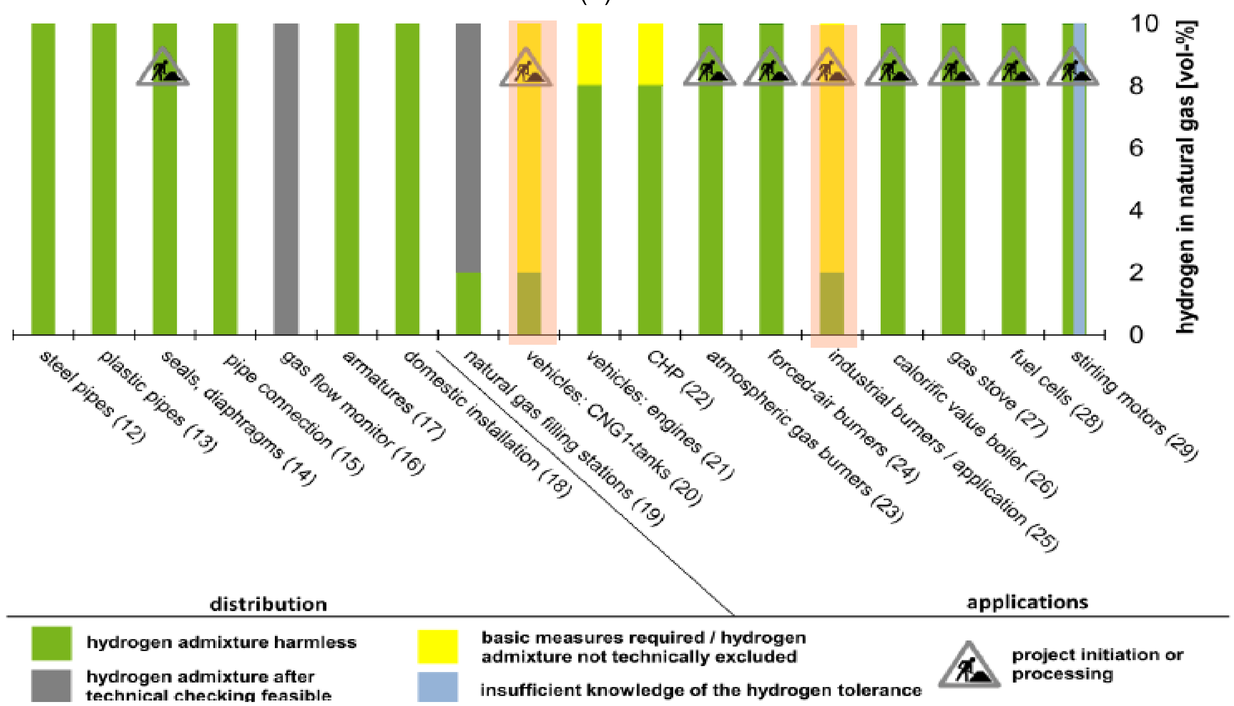
5.3 Hydrogen tolerance in Canadian natural gas infrastructure and end-use appliances

According to the current consensus of international projects and studies investigated for hydrogen injection into NG pipelines, it seems that most parts of the natural gas system can be tolerant of the gas mixtures of up to 10% by volume of hydrogen [52]. Figure 11 shows preliminary H_2-tolerance information resulted from DVGW project, including the H_2-tolerance of 29 components belonging to 5 categories of transport, gas storage, measurement and control, distribution, and applications [53]. The hydrogen tolerance of some components such as cavern storage, surface facilities, storage tanks, gas flow monitors and gas analysis instruments should be investigated further [52].

The requirements for blending hydrogen into the natural gas grid network and supplying blended gas mixtures to end-users should be determined based on system perspectives. The minimum threshold for requiring no or limited actions would be around 2% of hydrogen by volume in natural gas. It’s also possible to mix up to 5% of H_2 by volume with NG, but this tolerance should be investigated further and could be a driver for innovation of end-use appliances. It’s expected to be challenging to increase the allowable hydrogen concentration up to 20 vol.% without the generation of extensive performance and safety information for end-use appliances and gas analysis methods. Further research is needed to address end-user concerns regarding process control, emissions and safety. Public acceptance relies on the appropriate identification and assessment of risks [52]. In general, the natural gas grid would be tolerant for 1%-5% hydrogen blending by volume at any point of the network, and up to 20% in distribution pipelines with no critical downstream appliances [54].



(a)



Source: DVGW (2013) (b)

Figure 11: Preliminary H_2-tolerance information resulted from DVGW project, including the H_2-tolerance of 29 components belonging to 5 categories of (a) transport, gas storage, measurement and control, (b) distribution, and applications [53]

In case of underground porous rock storage, hydrogen blending with natural gas may induce bacterial growth forming hydrogen sulfide and consuming hydrogen. Steel tanks in natural gas vehicles have a limit value for hydrogen of 2%. Most of currently installed gas turbines were specified for a hydrogen fraction in natural gas of 1 vol.% or even lower and 5-15 vol.% may be attainable by using new or modified types of gas turbines. It is recommended to restrict the hydrogen concentration to 2 vol.% for gas engines, but higher concentrations up to 10 vol.% may be possible for dedicated gas engines with sophisticated control systems [55].

If blending hydrogen into the existing natural gas pipeline network is implemented with relatively low concentrations, less than 5%-15% hydrogen by volume, this strategy of storing and delivering renewable energy to markets appears to be viable without significantly increasing risks associated with utilization of the gas blend in most end-use devices such as household appliances, overall public safety, or the durability and integrity of the existing natural gas pipeline network. However, the appropriate blend concentration may vary significantly between pipeline network systems and natural gas compositions and must therefore be assessed on a case-by-case basis. Any introduction of a hydrogen blend concentration would require extensive study, testing, and modifications to existing pipeline monitoring and maintenance practices (e.g., integrity management systems) [56].

6. P2G opportunities based on P2G demo cases

6.1 P2G demo cases in Europe and USA

The European Commission has set a target for producing 20% of its final energy consumption through renewables by 2020 [57]. Germany has a goal to generate 80% of electricity from renewables such as biomass, hydro, solar and wind energy by 2050, indicating that high level of renewable electricity would be fed to power grids. This will lead to an increased demand for balancing power. That's the reason why Germany is currently emphasizing so called Power-to-Gas technology [58].

Fifty-seven recent P2G demo projects with key features were well-documented and reported in a Master's thesis prepared by Vesa Vartiainen and submitted to Lappeenranta University of Technology in 2016 as shown in Table 12 [57]. The end products from over 70% and 25% of all the reviewed projects were hydrogen and methane, respectively for power generation, mobility, natural gas grid injection, and chemicals. The addition of methanation in P2G results in increasing the overall cost and complexity and decreasing efficiencies. Product gases of almost one third of the projects (18 out of 57) were injected into the NG grid for the integration of electric and gas grids. Most of these projects (12 out of 18) injected hydrogen into the natural gas grid. There were no major problems reported from the cases. Biological methanation seems to be very efficient when coupling with waste water treatment [57].

Table 12: P2G research, pilot and demo projects worldwide [57]

Project name	Country	Product	Electrolysis method	Methanation method	Input power [kW_e]	Application	Schedule
Hebei	China	Hydrogen	Alkaline	N/A	4,000	-	Planned
Tohoku	Japan	Methane	Alkaline	Catalytic	-	Research, electric power generation	Built in 1995
HyFLEET:CUTE, CUTE	Germany	Hydrogen	-	N/A	390	Mobility	2003 - 2011
Reussenköge	Germany	Hydrogen	PEM	N/A	200	Electric power generation	Active
Schnackenbur-gallee	Germany	Hydrogen	PEM	N/A	-	Mobility	2015 -
HafenCity	Germany	Hydrogen	-	N/A	-	Mobility	2012 -
Prenzlau	Germany	Hydrogen	Alkaline	N/A	500	Electric power generation, natural gas grid injection	2011 -
Werite	Germany	Methane	-	Catalytic	6,300	Natural gas grid injection	2013 -
Ibbenbüren	Germany	Hydrogen	PEM	N/A	150[1]	Natural gas grid injection	2015 -
H2Herten	Germany	Hydrogen	-	N/A	-	Electric power generation, Mobility	Active
CO2RRECT	Germany	Methane, methanol	PEM	Catalytic	100	Chemical industry	2009 -2014
BioPower2Gas	Germany	Methane	PEM	Biological	400	Natural gas grid injection	2013 - 2016
Frankfurt am Main	Germany	Hydrogen	PEM	N/A	325[2]	Natural gas grid injection	2014 - 2016
Energiepark Mainz	Germany	Hydrogen	PEM	N/A	3,900[1]	Natural gas grid injection, various	In commission
Stuttgart	Germany	Methane	Alkaline	-	250	-	2012 -
H2Move	Germany	Hydrogen	PEM	N/A	-	Mobility	2013 -
Scwandorf	Germany	Methane	-	Biological	-	-	2014 -
MicroPyros	Germany	Methane	-	Biological	-	-	2014 - 2017
Hassfurt	Germany	Hydrogen	PEM	N/A	2,100	Electric power generation, natural gas grid injection	Planned
HYPOS	Germany	Hydrogen	-	N/A	-	Chemical industry, mobility	Planned

Project name	Country	Product	Electrolysis method	Methanation method	Input power [kW_e]	Application	Schedule
Power-to-Liquids	Germany	Various	SOEC	N/A	-	Chemical industry, electric power generation	Active
Cottbus	Germany	Hydrogen	Alkaline, PEM	N/A	-	Research, electric power generation	2010 - 2013
WindGas Falkenhagen	Germany	Hydrogen	Alkaline	N/A	2,000	Natural gas grid injection	2013 -
WindGas Hamburg	Germany	Hydrogen	PEM	N/A	1,500	Natural gas grid injection	2012 - 2016
H2BER	Germany	Hydrogen	Alkaline	N/A	500	Mobility, electric power generation, natural gas grid injection	2014 -
RH2-WKA	Germany	Hydrogen	-	N/A	1,000	Electric power generation, natural gas grid injection	2009 - 2015
Stralsund	Germany	Hydrogen	Alkaline	N/A	20	Research, electric power generation	Active
Foulum	Denmark	Methane	N/A	Biological	N/A	Pre-commercial test	2011 - 2013
BioCat	Denmark	Methane	Alkaline	Biological	1,000	Natural gas grid injection	In commission
Vestenkov	Denmark	Hydrogen	-	N/A	104	Local CHP production	2007 - 2014
MeGa-stoRE	Denmark	Methane	Alkaline	Catalytic	-	Biogas upgrading	2013 - 2015
GRHYD	France	Hydrogen	-	N/A	-	Natural gas grid injection, mobility	2013 - 2020
MYRTE	France	Hydrogen	-	N/A	-	Isolated power network	2013 -
Minerve	France	Various	N/A	N/A	-	Various	2014 - 2015
DEMETER	France	Methane	SOEC	-	-	Natural gas grid injection	2011 -2014
Jupiter 1000	France	Hydrogen, methane	Alkaline, PEM	-	1,000	Natural gas grid injection	2012 - 2020
ECTOS	Iceland	Hydrogen	-	N/A	-	Mobility	2001 - 2005
George Olah	Iceland	Methanol	-	N/A	-	Mobility	2011 -
INGRID	Italy	Hydrogen	-	N/A	1,152	Electric power generation, various	2012 - 2016
Utsira	Norway	Hydrogen	-	N/A	48	Isolated power network	2004 -

Project name	Country	Product	Electrolysis method	Methanation method	Input power [kW$_e$]	Application	Schedule
Sotavento	Spain	Hydrogen	Alkaline	N/A	-	Electric power generation	2009 - 2011
ITHER	Spain	Hydrogen	Alkaline	N/A	-	Mobility	2010 -
Hidrólica	Spain	Hydrogen	PEM	N/A	60	Electric power generation	2007 -
El Tubo	Spain	Hydrogen	PEM	N/A	2.65	Electric power generation	Active
HyFLEET:CUTE	Spain	Hydrogen	Alkaline	N/A	400	Mobility	2006 - 2009
CUTE	Sweden	Hydrogen	Alkaline	N/A	400	Mobility	2003 - 2006
Rapperswil	Switzer-land	Methane	-	-	-	Mobility	2015 -
Ameland	The Nether-lands	Hydrogen	-	N/A	-	Natural gas grid injection	2009 - 2012
Delfzijl	The Nether-lands	Hydrogen	-	N/A	12,000	Chemical industry	2014 - 2016
Rozenburg	The Nether-lands	Methane	PEM	Catalytic	7	Natural gas grid injection	2013 - 2018
HyFLEET:CUTE	The Nether-lands	Hydrogen	Alkaline	N/A	400	Mobility	2003 - 2009
HARI	United Kingdom	Hydrogen	Alkaline	N/A	36	Isolated power network	2001 - 2007
Hydrogen Mini Grid System	United Kingdom	Hydrogen	-	N/A	-	Mobility, electric power generation, natural gas grid injection	Active
Schatz Solar Hydrogen Project	USA	Hydrogen	-	N/A	6	Electric power generation	1991 - 2012
Wind2H2	USA	Hydrogen	Alkaline, PEM	N/A	113	Electric power generation, mobility	2003 - 2014
Chubut	Argentina	Hydrogen	-	N/A	650	Electric power generation	2008 -
HyLink	New Zealand	Hydrogen	PEM	N/A	0.4	Isolated power network	2001 - 2005

[1] nominal capacity
[2] peak capacity
N/A = not applicable
- = information unavailable

Owing to the political strategy in Germany for transitioning to complete renewable energy production in the future, almost half of reviewed projects were located in Germany involving federal, state or local government in the list of project participants. Only 6 projects out of the reviewed 57 projects were located outside of Europe [57]. The combination of alkaline electrolysis for hydrogen production and catalytic methanation would be the most matured and established approach in P2G technology, but as advanced processing technologies, both of PEM electrolysis and biological methanation have ability to operate dynamically [57].

Gerda Gahleitner also reported an international review of 48 P2G pilot plants for stationary applications, including Germany (7), the USA (6), Canada (5), Spain (4) and the United Kingdom (4), Argentina (3) etc. [58]. 53% of the projects that were integrated with renewables utilized battery banks between renewable power source and the electrolyzer. Batteries are primarily employed in stand-alone power-to-gas pilot plants as short-term storage to minimize the cycling of the electrolyzer and compensate for transient peak power. Batteries can play an important role in control strategies of power-to-gas systems, since the state of charge (SOC) of the battery is used as the main control variable in many pilot plants. In comparison to alkaline electrolyzers, PEM electrolyzers are applied in a lower power range and not yet suitable for large plants [58]. The design and sizing of the components of power-to-gas plants considerably influences their efficiency, reliability and economics. The overall efficiency of power-to-gas plants strongly depends on the control strategy and can be improved by higher efficient components, improved heat management and optimal system integration [58].

Table 13: Overview of profitability of different business cases in 2015, 2030 and 2050 [41]

	2015	2030	2050
Power-to-Industry - small Scale			
Power-to-Industry - large Scale			
Power-to-Gas - direct Injection			
Power-to-Gas - Synthetic Natural Gas (methanation)			
Power-to-Fuel - Methanol			
Power-to-Mobility - HRS for cars			
Power-to-Mobility - HRS for buses			
Power-to-Power - small scale			
NB: This table refers to the analysis of the different business cases in a 'business as-usual' scenario assuming no fundamental policy changes.			

Green: Profitable
Orange: Not profitable, but turning profitable in case of a 25% change to one of the main cost drivers (CAPEX, electricity price, value of the end product and, if applicable, CO_2 capture and filtration cost)
Red: Not profitable at all, requiring major and unrealistic changes to one or more cost drivers to turn profitable

As shown in Figure 5, power-to-gas valorisation pathways include power-to-power, power-to-gas, power-to-mobility, power-to-fuels, and power-to-industry. Their economic feasibility was analyzed and summarized in Table 13 [41]. None of the pathways is profitable at this moment, but the small scale industrial pathway where hydrogen is generated locally to replace externally sourced hydrogen, will be the first to turn positive before 2030. Also two of the mobility pathways, Power-to-Methanol and Power-to-Hydrogen for cars are expected to turn profitable before 2050 [41].

6.2 Canadian P2G demo cases

Table 14 shows the recent large-scale P2G demonstration projects [59]. Two Canadian P2G cases with 2MW PEM electrolyzer for Power-to-Gas and 350kW alkaline electrolyzer for Power-to-Power were demonstrated in Ontario and Quebec, respectively.

Table 14: Recent large-scale P2G demonstration projects [59]

Country	Project	Size	Year	Electrolyser technology	Power	Gas	Industry	Mobility	Fuel
Thailand	EGAT	1.2 MW + 500 kW FC	2017	PEM	•				
Canada	Embridge P2G	2 MW	2017	PEM		•			
Germany	MefCO2	1 MW	2017	PEM					•
Denmark	HyBalance	1.2 MW	2017	PEM			•	•	
UK	Levenmouth	370 kW + 100 kW FC	2016	Alkaline + PEM	•			•	
Denmark	BioCat	1 MW	2016	Alkaline		•			
Italy	Ingrid	1 MW	2016	Alkaline	•	•	•		
UK	Aberdeen	1 MW	2016	Alkaline				•	
Germany	WindGas Reitbrook	1.5 MW	2015	PEM		•			
Canada	Raglan Nickel mine	350 kW + 200 kW FC	2015	Alkaline	•				
Belgium	DonQuichote	150 kW	2015	Alkaline + PEM	•			•	
Germany	WindGas Falkenhagen	2 MW	2014	Alkaline		•			

Ontario's Independent Electricity System Operator (IESO) launched a game changer hydrogen energy storage project with a supplier of an advanced electrolysis system, Hydrogenics Corp. in 2014, coupling the electrolysis system with a fuel cell for storing power effectively for any length of time and dispatching power as needed in Toronto [60].

TUGLIQ's Glencore RAGLAN Mine Renewable Electricity Smart-Grid Pilot Demonstration project deployed an Artic-rated 3MW wind turbine generator coupled with innovative storage systems in 2015, including a 200 kW/1.5kWh flywheel, a 200kW/250kWh Li-ion battery storage, and a Hydrogenics 200kW/1MWh electrolyzer coupled with a fuel cell to minimize the loss of wind energy over longer time periods [61].

7. ES TDM Framework for P2G technology

Section Outline:

- Overview of master TDM working spreadsheet
- Approach: framework, functionality, then data
- Inputs: Location, ES Tech Attributes (Performance, Cost, Lifetime), Specific Applications or Target Goal(s)
- Outputs: Graphical comparisons of individual ES being studies to one or more of State of The Art (SOTA), Specific Application(s), Target Goal(s)
- Specific P2G TDM working spreadsheet

<u>Overview of master TDM working spreadsheet</u>

- Approach: framework, functionality, then data

  The P2G TDM is part of a larger TDM working spreadsheet. The larger TDM is designed for all ES technologies studied in the ES Program. There are two key points to this TDM framework: first is a system level approach to a breadth and depth of ES technology comparisons, and second is an ability to link the TDM to Techno Economic Analysis (TEA) of the ES technologies.

  Regarding the first point, having a top down or system level approach allows apples to apples comparisons across the full breadth of ES technologies, and the expandability to add different ES technologies in future projects. Also sub types can be added for comparisons within a single ES technology. Next, a depth of comparisons within one type of ES technology is accomplished by adding ES technology specific sub system details. Again, the TDM can be expanded beyond the system level to include those ES technology specific sub systems down to the right level of granularity.

  Regarding the second point, the same system level approach for the TDM can be reflected in the corresponding TEA. This allows feedback between the two to both cross check and continuously update R&D priority areas. The TDM becomes part of the "T" in TEA.

Currently the TDM includes electricity to electricity (E2E) ES technologies within the scope of the ES Program. However if that scope expands, then other ES technologies such as heat to electricity (H2E), electricity to heat (E2H), and heat to heat (H2H) could be added.

- Inputs: Location, ES Tech Attributes (Performance, Cost, Lifetime), Specific Application(s) or Target Goal(s)

  A description of those three main TDM sections is as follows.

  - The first section, Location, is identifying the location of the ES System on the electric grid by power rating.
    - Within that first section there are three sub segments by power rating [62]. In descending order roughly they are generation, transmission and distribution. Then each power rating segment determines the respective ES technology sub types. A fourth sub section, Customer (including Behind the Meter or BTM), could be added for future TDM versions. Currently BTM is out of scope.
    - Still within Location, an application or Grid Service is chosen. Those Grid Services are in three respective areas: System, Transmission, and Distribution [63]. Once the Grid Service area is selected, then the specific Grid Service can be chosen for that area (IE: System, and then System Electric Supply Capacity).
    - The last item in the first section is Commercialization. Here both the Technology Readiness Level (TRL) and Manufacturing Readiness Level (MRL) gauge where the technology is on the path to commercialization, and where the supply chain is on manufacturing that technology. TRL's progress on a scale of one to nine, while MRL's progress on a scale of one to ten.
  - Moving on to the second section, the ES Tech Attributes are performance, cost and lifetime. They show the respective technical, financial and durability factors that influence commercialization. These attributes cut across a specific or individual ES System being studied and the state of the art (SOTA) for that ES Tech. This is to evaluate the ES technology studied from the point of view of what the industry considers "best in class" or SOTA.
  - Finally the third section consists of Specific Applications and or Target Goals for that ES Tech using the same attributes of cost, performance and lifetime, but now from the point of view of the desired market (end user) or long term goal (set by an industry organization, like the DOE or CSA). In the current TDM version a Specific Application includes a Grid Service. Future versions of the TDM will separate Specific Applications from Target Goals such as long term R&D objectives, for example DOE stretch goals for 2025, 2030, etc. Those Specific Applications and or Target Goals then benchmark where the ES technology

needs to be in order to achieve commercialisation from the perspective of the market, or an industry organization, respectively.

A hypothetical example of the second and third sections above is shown in Table 15. To summarize, all of the inputs above combine to answer the questions:

1. What is the status of the ES technology today?
2. How does it compare to others in its' field?
3. Where does the ES technology need to go to get to a specific market?

- Outputs: Graphical comparisons of individual ES being studied to State of The Art (SOTA), Specific Application(s), Target Goal(s).

  To answer these questions, the TDM's main outputs plot the data from the input sections above into graphs to visualize system level comparisons among the individual ES System both to SOTA, and to Specific Application(s) or Target Goal(s). Currently for the same "Target" attribute/parameter, the ES System and SOTA can be compared to a Specific Application, like a Grid Service, or a Target Goal, like a DOE future target. In each case the application serves as an end goal, and both ES System and SOTA are benchmarked as relative percentages at, above or below that Application for the given Attribute. Each Attribute becomes a single axis on the radar chart, and so multiple attributes can be visualized simultaneously. The outcome is to help prioritize resource allocation to go from R&D to commercial deployment. An example output based on the hypothetical values in Table 15 is shown in Figure 12.

  From the hypothetical radar chart in Figure 12, some key takeaways are apparent. Neither the System being studied, nor the SOTA are ready for commercialization in the Target Application. The System is ahead of SOTA in three attributes and the same as SOTA in a fourth. However, the System is behind SOTA in two attributes. Putting this together, if the System has exceeded both SOTA and Target Application in Performance Attribute 1, then those excess resources can be re-allocated to higher priority areas such as Cost Attribute A (where the System is well below both SOTA and Target application), or Performance Attribute 2 (where it is below both SOTA then Target).

Table 15: Summary of hypothetical ES Technology Performance, Cost and Lifetime attributes for the ES System, SOTA and a Target Application

Performance	Units	System	SOTA	Target
Perf Att 1		6	3	5
Perf Att 2		2	4	3
Perf Att 3		4	5	8
Perf Att 4		5	4	4
Perf Att 5		3	7	9
Cost	**Units**	**System**	**SOTA**	**Target**
Cost Att A		2	5	5
Cost Att B		4	3	5
Cost Att C		5	8	4
Cost Att D		4	4	5
Cost Att E		7	9	3
Lifetime	**Units**	**System**	**SOTA**	**Target**
Life Att i		5	5	7
Life Att ii		3	2	4
Life Att iii		8	4	5
Life Att iv		4	5	4
Life Att v		9	3	7

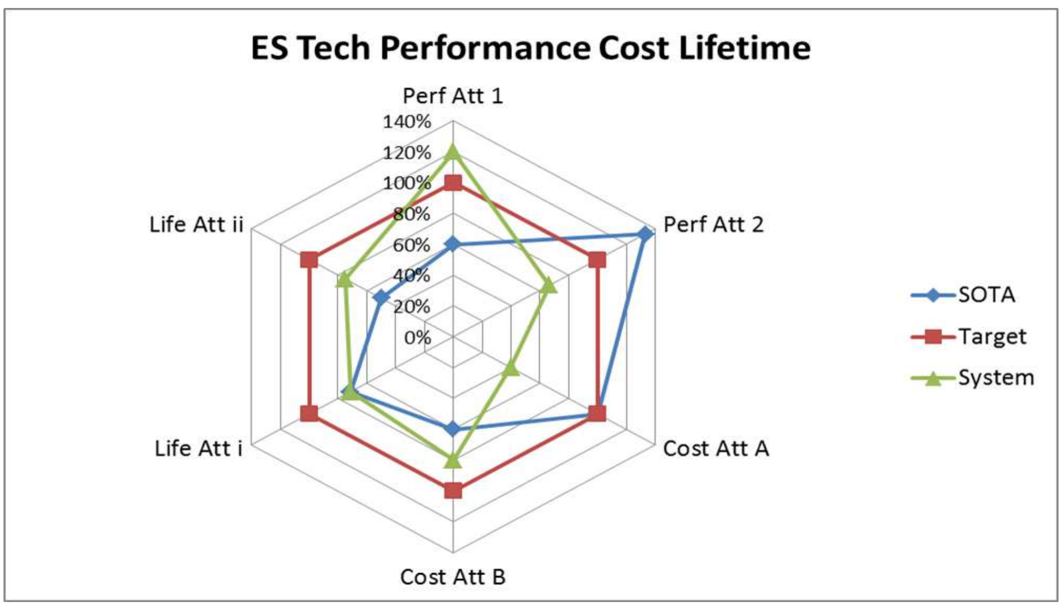


Figure 12: Radar chart of hypothetical ES Technology Performance, Cost and Lifetime attributes for the ES System and SOTA relative to the Target Application

Specific P2G TDM working spreadsheet

- P2G System Level Data
    - Current focus is on Electrolyzer technologies including PEM and Alkaline. Future TDM versions could include other technologies, like Solid Oxide Electrolyzers.
- P2G Sub System Data
    - Future TDM versions could incorporate key P2G subsystems like compression, storage, mixing and injection. The overall system level parameters would be totals of the corresponding Sub Systems.
- Application Data
    - This TDM focussed on electric Grid Services, including arbitrage, electric supply capacity, and frequency response / regulation. Future versions could include other P2G applications:
        - Natural Gas Grid Injection (for heat and or power)
        - Underground Hydrogen Storage (for power)
        - Clean Transportation
        - Industrial Hydrogen as a feedstock for chemical processes

8. Conclusions

P2G technology enables hydrogen produced from electrolysis and renewable natural gas produced by methanation to be injected into national gas grids. This permits large scale storage of green energy. If economically feasible, methane injection in the grid could represent considerable volumes, since RNG complies with grid specifications. The amount of hydrogen in the gas grid is limited by country specific standards and regulations. In the European Union, the maximum is 0-12 vol.% or 0-2 wt.%. In Germany, up to now, the content of hydrogen in the distributed natural gas is limited to max. 5 vol.% according to the DVGW standard G 262. A detailed investigation of codes, standards and regulations (CSR) on the injection of renewable hydrogen and RNG into NG pipelines has clarified current constraints and safety considerations in terms of gas injection, transport and end-use systems.

Even at low levels, hydrogen blends can be a problem for appliances that are not properly maintained. High blend levels can be safe in transmission lines, but additional risks are posed from the city gate through distribution lines. Most pipeline materials are not subject to hydrogen-induced failures. In order to accelerate the implementation of hydrogen injection into natural gas pipelines in North America, harmonized standards specifying gas quality and composition (including hydrogen tolerance) for NG transmission and distribution will be required. Energy regulators and policy makers will need to identify ways to encourage the pipeline industry’s adoption of gas quality standards for initial levels of hydrogen blending.

According to current understanding, a hydrogen concentration limit up to 20% poses some challenges with regard to end-use appliances and gas analysis methods. Further research is needed to address end-user concerns regarding process control, emissions and safety. Public acceptance relies on the proper identification and assessment of risks. Standardization needs to ensure the safety of hydrogen compressed natural gas (HCNG) use by considering the specific properties of hydrogen and NG blends and address all associated risks.

Much work has been done to address the need for codes and standards for renewable hydrogen technologies, but standards need further development to enable wide-scale transmission and distribution of renewable fuels.

Canada is a world leader in the production and use of energy from renewable resources, which currently provide about 18.9 per cent of Canada's total primary energy supply. Wind and solar photovoltaic energy are the fastest growing sources of electricity in Canada. However, wind and solar-based energy production is intermittent and fluctuating, which requires long term scalable energy storage to enhance grid stability and reliability. In late 2016, the Government of Canada announced its intention and plans to develop a national Clean Fuel Standard. This initiative aims to reduce up to 30 million tonnes of GHG emissions annually by 2030 with this proposed policy and, notably, planning to extend the clean fuel standard beyond transportation fuels to include fuels used in homes and buildings as well as in industry.

The power-to-gas valorisation pathways include power-to-power, power-to-gas, power-to-mobility, power-to-fuels, and power-to-industry. The total energy capacity of Canada's natural gas grid is much larger than that of its electrical generating capacity, indicating the significance of the gas grid for domestic energy supply. While the power-to-gas pathway allows the connection of electric and gas grids, there are challenging techno-economic aspects and regulation issues for the implementation and commercialization of P2G technology in Canada. The developing national LCFS regulation may accelerate the deployment of P2G technology by providing incentives to use renewable hydrogen and renewable natural gas in Canada.

Renewable hydrogen blending into natural gas grid networks is a low-cost, early stage solution for monetizing electricity surpluses in countries with highly developed natural gas infrastructure. In general, the entire gas grid should tolerate 5 vol.% blending anywhere, and up to 20% in distribution or regional transmission pipelines with no critical downstream appliances. More research and development work to quantify safe and practical upper limits of hydrogen blending is needed to support regulatory reform and harmonize HCNG standards.

Canada has one of the world's largest pipeline networks delivering natural gas from producing areas in western and eastern Canada to markets across North America. The blending ratio of H_2/NG is technically limited to 17-25 vol.% in some parts of the distribution grid and not above 5 vol.% in the transport grid. The H_2 blending limit is uncertain and very system specific, limited by grid integrity, safety, energy transport capacity, and by the specifications of end-use applications. The transmission pipelines with medium to high pressures are made of carbon steel with protective coating, where hydrogen-induced embrittlement can accelerate the growth of micro cracks and compromise pipeline safety. It is estimated that existing, unmodified steel pipes could sustain 20 vol.% of hydrogen and potentially up to 50 vol.% of hydrogen, depending on the quality of the steel used. The distribution pipelines made of plastic for low pressures are not suffering from embrittlement and may accommodate 17-25 vol.% of hydrogen without the need for case-by-case testing. It is also estimated that the hydrogen blending over 20 vol.% into NG pipelines may result in too much negative effects on energy transport capacity and grid energy efficiency.

In June 2013, the German electric and gas utility E.ON injected hydrogen into the natural gas pipeline for the first time as a full system test and the plant operations commenced in August 2013. The company stated that their regulations allowed up to 5% hydrogen in the natural gas pipeline [46]. In Canada, Alberta-based TransCanada Pipeline's (TCPL) natural gas quality specifications do not directly limit the amount of hydrogen that can be injected into TCPL pipeline; however, the lower limit on the heating value of 36 MJ/m^3 implicitly limits hydrogen content to around 5 vol.% in a TCPL pipeline at any point.

Natural gas can be stored in depleted oil or gas reservoirs, aquifers, salt caverns, LNG or CNG units, and pipeline network as line pack. In case of underground gas storage, a 2007 survey specified Canadian underground natural gas storage capacity as 583.8 billion cubic feet (Bcf), consisting of 44 depleted reservoirs, and 8 salt caverns. Salt caverns being used for storing natural gas could be suitable for much higher hydrogen concentrations in natural gas or even pure hydrogen, but require modification of equipment such as injection wells or compressors at gas storage facilities. However, since these major storage assets are linked to the existing natural gas grid, their practical capacity for hydrogen would be limited by existing pipeline standards / specification, so around to 5 vol.%.

According to the current consensus of international projects and studies investigated for hydrogen injection into NG pipelines, it seems that most parts of the natural gas system can be tolerant of the gas mixtures of up to 10% by volume of hydrogen. The requirements for blending hydrogen into the natural gas grid network and supplying blended gas mixtures to end-users should be determined based on system perspectives. The minimum threshold for requiring no or limited actions would be around 2% of hydrogen by volume in natural gas. It's also possible to mix up to 5% of H_2 by volume with NG, but this tolerance should be investigated further and could be a driver for innovation of end-use appliances. It's expected to be challenging to increase the allowable hydrogen concentration up to 20 vol.% without the generation of extensive performance and safety information for end-use appliances and gas analysis methods. In general, the natural gas grid would be tolerant for 1%-5% hydrogen blending by volume at any point of the network, and up to 20% in distribution pipelines with no critical downstream appliances. It is recommended to restrict the hydrogen concentration to 2 vol.% for gas engines, but higher concentrations up to 10 vol.% may be possible for dedicated gas engines with sophisticated control systems. If blending hydrogen into the existing natural gas pipeline network is implemented with relatively low concentrations, less than 5%-15% hydrogen by volume, this strategy of storing and delivering renewable energy to markets appears to be viable without significantly increasing risks associated with utilization of the gas blend in most end-use devices such as household appliances, overall public safety, or the durability and integrity of the existing natural gas pipeline network.

Fifty-seven recent P2G demo projects with key features were well-documented and reported in a Master's thesis prepared by Vesa Vartiainen and submitted to Lappeenranta University of Technology in 2016. The end products from over 70% and 25% of all the reviewed projects were hydrogen and methane, respectively for power generation, mobility, natural gas grid injection, and chemicals. The addition of methanation in P2G results in increasing the overall cost and complexity and decreasing efficiencies. Product gases of almost one third of the projects (18 out of 57) were injected into the NG grid for the integration of electric and gas grids. Most of these projects (12 out of 18) injected hydrogen into the natural gas grid.

Gerda Gahleitner also reported an international review of forty eight P2G pilot plants for stationary applications. 53% of the projects that were integrated with renewables utilized battery banks between renewable power source and the electrolyzer. Batteries are primarily employed in stand-alone power-to-gas pilot plants as short-term storage to minimize the cycling of the electrolyzer and compensate for transient peak power. Batteries can play an important role in control strategies of power-to-gas systems, since the state of charge (SOC) of the battery is used as the main control variable in many pilot plants. The design and sizing of the components of power-to-gas plants considerably influences their efficiency, reliability and economics. The overall efficiency of power-to-gas plants strongly depends on the control strategy and can be improved by higher efficient components, improved heat management and optimal system integration.

Among power-to-gas valorisation pathways including power-to-power, power-to-gas, power-to-mobility, power-to-fuels, and power-to-industry, none of the pathways is profitable at this moment, but the small scale industrial pathway where hydrogen is generated locally to replace externally sourced hydrogen, will be the first to turn positive before 2030. Also two of the mobility pathways, Power-to-Methanol and Power-to-Hydrogen for cars are expected to turn profitable before 2050.

Two Canadian P2G cases with 2MW PEM electrolyzer for Power-to-Gas and 350kW alkaline electrolyzer for Power-to-Power were demonstrated by Hydrogenics, Ontario in 2017 and TUGLIQ Energy Co., Quebec in 2015, respectively.

The NRC's TDM is a decision making tool that enables effective allocation of R&D resources to achieve commercialization in a desired market. The TDM accomplishes this by visualizing how an ES System compares to both SOTA and to a Specific Application or Target Goal based on metrics or Attributes essential to that market. There are three main aspects to the TDM. They are Approach, Inputs and Outputs. The most important is Approach. The TDM makes system level comparisons among several ES Technologies and as such is built on a top down approach starting with the framework, followed by functionality and finally data. That system level breadth allows comparisons both among different types of ES Technologies and within sub types of the same ES Technology. Within the same ES Technology a depth of comparisons is possible by breaking that system down into sub systems. Next the inputs classify ES Technologies into Location by power rating and commercial readiness, ES Technology Attributes of Performance, Cost and Lifetime, followed by a Specific Application or Target Goal. The outputs compare the ES System and SOTA to a Specific Application or Target Goal for a given Attribute, and display at least three Attributes in a radar chart or spider plot.

P2G is an evolving technology and data was limited at the time of this report. The authors therefore used a top down approach to include what system level P2G data could be found. With respect to P2G ES technologies, the current version of the TDM only focusses on commercial electrolyzer technologies: PEM and Alkaline. Similarly, with respect to technology attributes, like application and target goals, this study is bound by electric grid services over other applications (natural gas grid injection, underground hydrogen storage, clean transportation, industrial hydrogen as a chemical feedstock) for two reasons. First, the P2G TDM has to align with all other TDM ES technologies which provide electric grid services, and secondly, data for other applications was limited. With respect to electric grid services, P2G can perform up to three, depending on the regenerative PEM electrolyzer/fuel cell technology, including arbitrage, electric supply capacity, and frequency response / regulation.

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