MSc Program
Renewable Energy Systems

Evaluation of Power to Gas Technology in Europe

A Master's Thesis submitted for the degree of
“Master of Science”

supervised by
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Vienna, 13.11.2019

Affidavit

I, **DI FIRAS DRISS**, hereby declare

1. that I am the sole author of the present Master's Thesis, "EVALUATION OF POWER TO GAS TECHNOLOGY IN EUROPE", 86 pages, bound, and that I have not used any source or tool other than those referenced or any other illicit aid or tool, and
2. that I have not prior to this date submitted the topic of this Master's Thesis or parts of it in any form for assessment as an examination paper, either in Austria or abroad.

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Abstract

In the era where climate change matters the life of billions of people around the globe, greenhouse gas and CO_2 emissions exceptional rates increasing in the recent years are making this change going in the wrong direction and escalating more critically, and this is manifested in many aspects of the human being life style like the recent storms invading the globe in most of the continents and the floods and the temperature raising etc..

To cope with this, the European Union urged all member states and the extension states to push further the integration of renewable energies which resulted in a gigantic electricity generation from renewable all over the continent, this introduced another challenge in efficiency to recover the surplus production especially from photovoltaic and wind.

Power to Gas got introduced to boost the area of energy storage and optimizing better efficiency of existing renewable energy utilities, as well capturing CO_2 in the methanation process for example.

In this work of evaluating the power to gas deployment and implementation, an overview is given of the technology of power to gas itself along with introducing the economic variant within power to gas and its specificities.

Later, an assessment is performed to the pilot researches and projects that have been deployed/done in most of the european countries leading in this technology, in a regional to national scale and distributed scale to emphasis on the wide portfolio and application that could be done with this technology.

Afterwards, a demonstration of the executed projects is displayed along with the dashboard of the continent in this area.

Finally, an overview is given on the trends and the future opportunities within this technology to open the perspective and project the business in the reality of the future technological context.

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1 INTRODUCTION

In its Renewable Energy Roadmap 21, the European Commission has proposed a target of 20% renewable energy in the EU's overall energy mix by 2020 (Zervos et al. 2011: 24) Thus, wind and solar energy play an important role. In 2013, wind power had already included a high portion of the electricity supply. In Denmark (34%) and Spain (21%), wind energy has become the widest source of electricity; also, Portugal (>20%), Ireland (>16%), and Germany (9%) have attained high shares (WWEC2014. 2015). The total world installed wind capacity increased from 17,400 MW in 2000 to 318,105 MW in 2013 (GWEC. 2014). However, wind and solar energy are fluctuating and intermittent and must be balanced for electric grid stability purposes. Thereby, long term and wide capacity electricity storage is required, as well reserve production capability. In Germany, e.g., the residual power capacity is estimated to be 30 to 60 GW.

The Power to Gas (PtG) technology has a potential role to play to tackle this issue, The PtG process interface the power grid with the gas grid by converting the excess power into a grid compatible gas via two-step: the first step is the H_2 production by water electrolysis and the second step is the conversion of the produced H_2 with an exterior CO or CO_2 source to CH_4 through methanation (Fig.1)

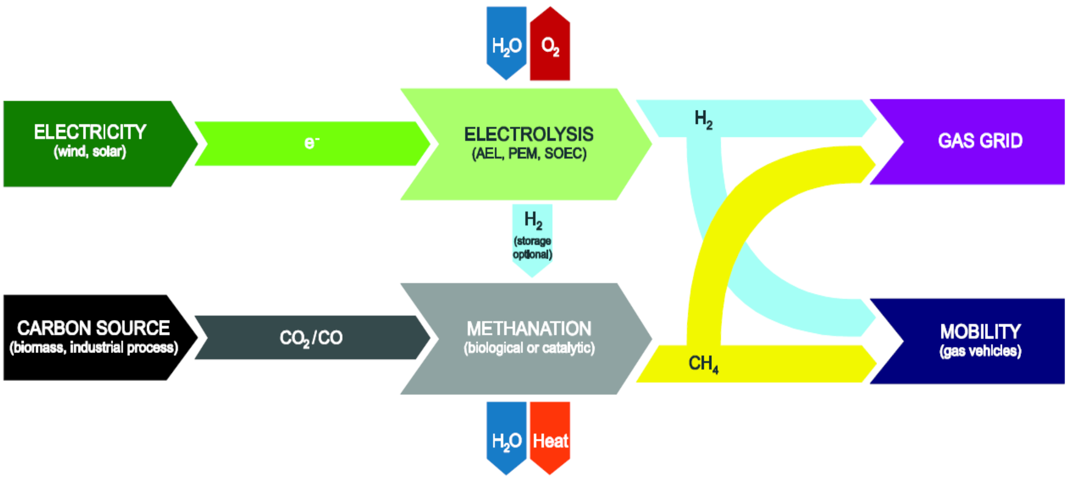

Fig.1 Exemplary Power to Gas process chain.

The resulting CH_4 also known as substitute natural gas (SNG), can be used in multiple applications, for instance, it can be injected into the existing gas grid, used as CNG motor fuel, or it can be utilized in the established natural gas facilities.

2 METHOD OF APPROACH

In the topic of evaluating a certain technology in a territory or in a continent or at any geographical scale, it is very important to define a framework of this evaluation.

The idea behind is to go in each part of this framework through a deep illustration of PtG technology in EU countries as well as showing differences in the processes, in the context, economic and technologic reality and feasibility etc.

In this work, it has been chosen to go through a clear framework which is composed of

- Introduction to Power to Gas
- Driven researches and studies around Power to Gas in Europe
- Demonstrated Power to gas projects in Europe
- Researches trends and future opportunities of Power to Gas in Europe

In the intro to Power to Gas in Europe, the fundamentals of PtG technologies starting by Electrolysis, hydrogen storage, methanation etc. is tackled then an economic overview of the different stages of the PtG process is shown, along with showcasing examples and results of driven projects in Europe.

Then, the driven researches and studies around PtG and the discussed/investigated approaches and applications within this area in most of the European countries is discussed, those who are focusing on PtG in their energy policy and capitalising on its polyvalence product and application wise as well as product end uses and integration possibilities within vital energy sectors.

An evaluation of the driven pilot researches is conducted on two cluster classification, first regional to national scale and second the distributed scale, along with emphasising here on the multiple and wide application of PtG and how far it could be a potential key player in the energy sector in the future by highlighting the related advantages and boundaries.

Afterwards, a demonstration of all the PtG projects existing in Europe and their statistics is shown by going through the statistics and discuss the efficiency of the projects and their added value in the energy mix of most of the European countries.

Finally, some research trends and future opportunities based on the existing current obstacles is showcased.

3 INTRODUCTION TO POWER TO GAS

3.1 General Technological Overview of Power to Gas

3.1.1 Hydrogen Supply

3.1.1.1 Fundamentals

Water electrolysis to yield H_2 and O_2 (Eq. 1) is an electrochemical reaction done in two steps. At the negative cathode the reduction reaction takes place (Eq. 2), while the oxidation reaction happens at the positive anode (Eq. 3). Depending on the technology, the charge carrier can be OH^-, H_3O^+, or O_2^{2-}.

$$H_2O(l) \rightarrow H_2(g) + ½O_2(g) \quad \Delta H_r^0 = +285.8 \text{ kJ/mol} \qquad \text{Eq. 1}$$

$$H_2O + 2e^- \rightarrow H_2 + O^{2-} \qquad \text{Eq. 2}$$

$$O^{2-} \rightarrow ½O_2 + 2e^- \qquad \text{Eq. 3}$$

For calculating equilibria (Fig. 2), the Gibbs free energy of water electrolysis delta G_r^0 is expressed by the equilibrium cell voltage (Eq. 4), where n is the number of moved electrons counted in moles and F is the Faraday constant, converting electric characteristics into thermodynamic and vice versa:

$$\Delta G_r^0 = nFE_V^0 \quad \Delta G_r^0 = +237.1 \text{ kJ/mol} \qquad \text{Eq. 4}$$

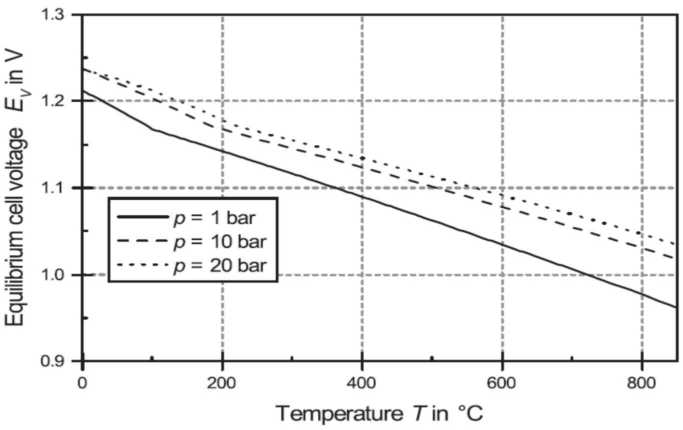

Fig.2: Equilibrium cell voltage as function of temperature for different pressure levels. Source: Renewable Power to Gas: A technological and economic review.

3.1.1.2 Water Electrolysis

Excess electrical energy might be used to produce hydrogen via water electrolysis. H_2 can be converted into methane with an appropriate carbon source or it can be directly transferred into the gas grid or used for fuel cell vehicles.

Water electrolysis is a well understood technology. Hence, improvements in fuel cell technology also helped to enhance water electrolysis technologies. There are three electrolysis technologies for PtG process chains: alkaline electrolysis (AEL), polymer electrolyte membranes (PEM), and solid oxide electrolysis (SOEC).

3.1.1.2.1 Alkaline Electrolysis (AEL)

It is the most spread technology. In AEL, an alkaline solution (KOH or NaOH) is used as the electrolyte. AEL works both atmospherically or in high pressure. Pressurized alkaline electrolysers have less efficiency and produce less purity product than atmospheric AEL (Smolinka et al. 2011).

The advantage of pressurized AEL with comparison to atmospheric AEL is that it generates compressed hydrogen (either for grid injection or other use) with less energy input (Bhandari et al. 2014: 85).

This the result of decrease in electric efficiency of the electrolysis with increased pressure (see Fig. 2 above) is less than the energy needed to compress the produced hydrogen. The inconvenience of AEL is that the used electrolytes (alkaline solution, e. g. 20 to 30 % potassium hydroxide solution) are very corrosive, which means the need for high maintenance costs. A general overhaul of the system is necessary every 7 to 12 years (Smolinka et al. 2011).

3.1.1.2.2 Polymer Electrolyte Membrane (PEM) electrolysis

The technology is based on solid polymer membranes (Carmo et al. 2013: 38), the main advantages of PEM include faster cold start, higher flexibility, and better coupling with dynamic and intermittent systems (Gahleitner 2013: 38).

Furthermore, the purity of the produced H_2 is very high (Hacker et al. 2015: 65). However, this technology is currently more expensive than AEL systems (due to the costs for the membrane and the use of a noble metal catalyst).

3.1.1.2.3 Solid Oxide Electrolysis (SOEC)

Solid Oxide Electrolysis (also known as high temperature electrolysis) is the latest developed electrolysis technology and is still at the development stage. In SOEC, ZrO_2 doped with 8 mol % Y_2O_3 is used as the electrolyte, which at high temperatures is highly conductive for oxygen ions (charge carrier) and has good thermal and chemical stability (Brisse et al. 2008: 33).

The high temperature reduces the equilibrium cell voltage and therefore the electricity demand (Laguna Bercero. 2011: 203), However the heat demand increases with increasing temperature.

The biggest challenge for SOEC systems is the fast material degradation due to the high temperature operation. As well, the high temperature level means that the product stream from the electrolyser is a mixture of hydrogen and steam which requires additional processing and by the way higher capital cost. Moreover, SOEC systems are not stable against fluctuating and intermittent power sources (Ursua et al. 2012: 100).

3.1.1.2.4 Cost Analysis of water electrolysis technologies

At the time being, the capital expenditure for AEL is significantly lower than for PEM, Fig.3 shows the difference in the specific investment cost for hydrogen production for each technology based on the current selling prices of the leader integrators in the market (Siemens, Mougin).

Currently, the investment for PEM is approximately two times of that of AEL systems which its investment cost is in the order of 1000 Eur/KW for 70% electrical efficiency (Müller-Syring & Henel 2013: 7-10).

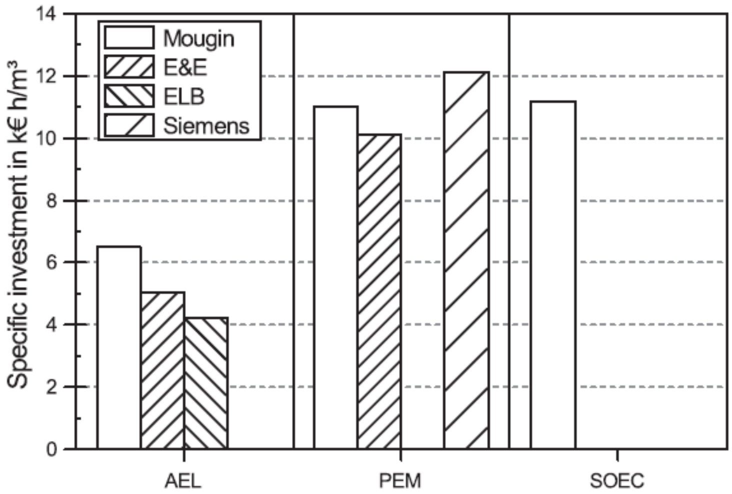

Fig.3: Comparison of the current selling prices of AEL, PEM, and SOEC systems. Source: Renewable Power to Gas: A technological and economic review.

For SOEC, there is no much available information, Mougin et al. estimated the price for manufacturing and selling a SOEC system producing 46.4 m^3/h (100 Kg/day) of H_2, the calculation made for the scenario of an annual production of 100 systems, the price is approximately 11,200 Eur.h/(m^3 H_2) (Reytier et al. 2014).

3.1.1.3 Hydrogen Storage

One of the challenges for PtG systems is the temporary storage imposed by the fluctuating power and the intermittent operation of the electrolyser. For the hydrogen storage, the size and necessary equipment vary and depends on the configuration and the operating parameters of the system (Gahleitner 2013: 38).

Many methods exist for hydrogen storage: compressed gas tanks, cryogenic compressed liquid hydrogen tanks, metal hybrid storage etc. Storage of hydrogen as a cryogenic liquid is a technical challenge as well as energetically inefficient (Scamman & Newborough 2016: 41).

The unstable pressure, continuous leakage of gas, and expensive insulation make cryogenic liquid hydrogen storage a poor choice for PtG applications (Roses & Patel 2011: 19).

The non-stable pressure, leakage of gas, and the high cost of insulation make cryogenic liquid hydrogen storage an unattractive choice for PtG applications.

The two best options for the temporary hydrogen storage are high pressure gas tanks (350 to 700 bar) or metallic hydride tanks.

According to Gahleitner (Gahleitner 2013: 38), hydrogen storage within PtG systems (both planned and realized in 2012) in high pressure gas cylinders is the current and future method of choice. As an alternative, metal hydride tanks were installed in 12% of the PtG plants included in the study. However, they are more expensive.

3.1.2 Methanation

3.1.2.1 Fundamentals

Methanation can be done in biological and catalytic methanation reactors (see Fig.4). those could be compared according to the following parameters:

- Reached gas quality of the produced gas.
- Reactor volume aimed to meet the required gas quality and volumetric flow.
- Complexity of the process setup.

One possible approach to compare reactor performance is to compare the gas Hourly Space Velocity (GHSV) of different reactor concepts (Eq.5)

$$GHSV = \frac{F_{V,G,in}}{V_R} \qquad \text{Eq. 5}$$

$F_{V,G,in}$: Volumetric flow rate (STP: standard temperature pressure, 0 °C, 101 Pa) of the feed gas without any inert gases and with stoichiometric H_2/CO_2 ratio

V_R : Reactor volume

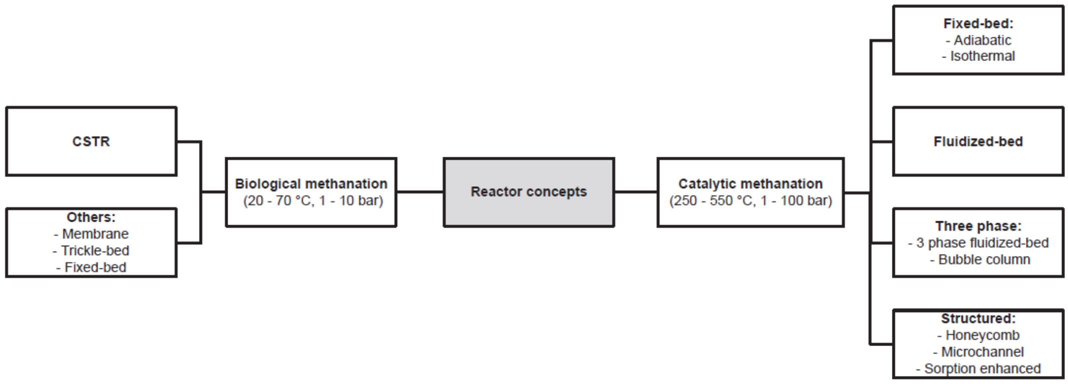

Fig.4: Reactor concepts to produce SNG. Source: Renewable Power to Gas: A technological and economic review

The properties of the synthetic natural gas (SNG) produced in a PtG chain must be like the properties of natural gas distributed in the gas grid. Typically, natural gas contains more than 80% CH_4 (Günter 2008: 7).

Further important components are higher hydrocarbons, e. g. ethane, propane, and butane which rise the calorific value comparison to pure methane. Furthermore, inert components such as CO_2 or N_2 can be explored in natural gas and have an identical lowering effect on the calorific value.

Fig. 5 shows that a CO_2 conversion of almost 98% is required to achieve a methane content of more than 90%, whereas a CO_2 conversion of 99% correlates with a methane content of 95%. Inert gases or hyper stoichiometric H_2/CO_2 ratios make it impossible to achieve high methane contents. Therefore, the requirements for the methanation reactor are very high.

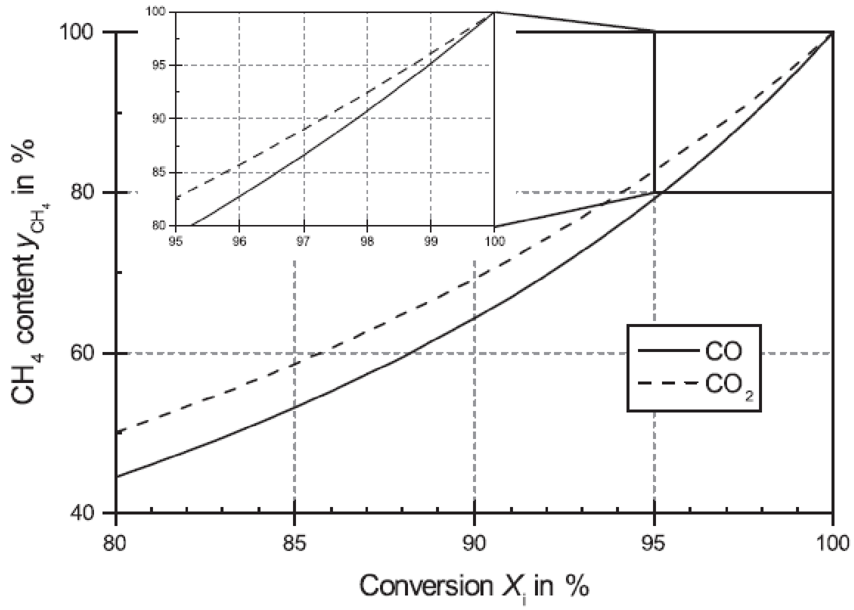

Fig.5: Relationship between CO or CO_2 conversion and methane content in the dry SNG (no inert gas: H_2/CO =3 and H_2/CO_2 = 4, respectively; 100% selectivity: selective methanation of CO over its preferential oxidation). Source: Renewable Power to Gas: A technological and economic review.

3.1.2.2 Thermodynamics

Many reactions take part in the methanation process: the CO (Eq. 7) and the CO_2 hydrogenation (Eq. 6) are followed by other reactions like the reverse water gas shift reaction (Eq. 8) and the Boudouard reaction (Eq. 9). The CO_2 hydrogenation be the combination of CO hydrogenation and reverse water gas shift.

$$CO_2(g) + 4\ H_2(g) \rightleftharpoons CH_4(g) + 2\ H_2O(g) \quad \Delta H_r^0 = -165.1\ \mathrm{kJ/mol} \qquad \text{Eq. 6}$$

$$CO(g) + 3\ H_2(g) \rightleftharpoons CH_4(g) + H_2O(g) \quad \Delta H_r^0 = -206.3\ \mathrm{kJ/mol} \qquad \text{Eq. 7}$$

$$CO_2(g) + H_2(g) \rightleftharpoons CO(g) + H_2O(g) \quad \Delta H_r^0 = +41.2\ \mathrm{kJ/mol} \qquad \text{Eq. 8}$$

$$2\ CO(g) \rightleftharpoons C(s) + CO_2(g) \quad \Delta H_r^0 = -172.5\ \mathrm{kJ/mol} \qquad \text{Eq. 9}$$

CO and CO_2 hydrogenation are highly exothermic reactions with the consequence that high temperatures limit the CO and especially the CO_2 conversion. As illustrated in Fig. 6, a temperature below 225 °C (1 bar) or 300 °C (20 bar) is mandatory to reach a CO_2 conversion of minimum 98%. As well, the positive effect of pressure, as previously described, is apparent from the results displayed in Fig. 6. Thus, an elevated pressure must be used for the methanation.

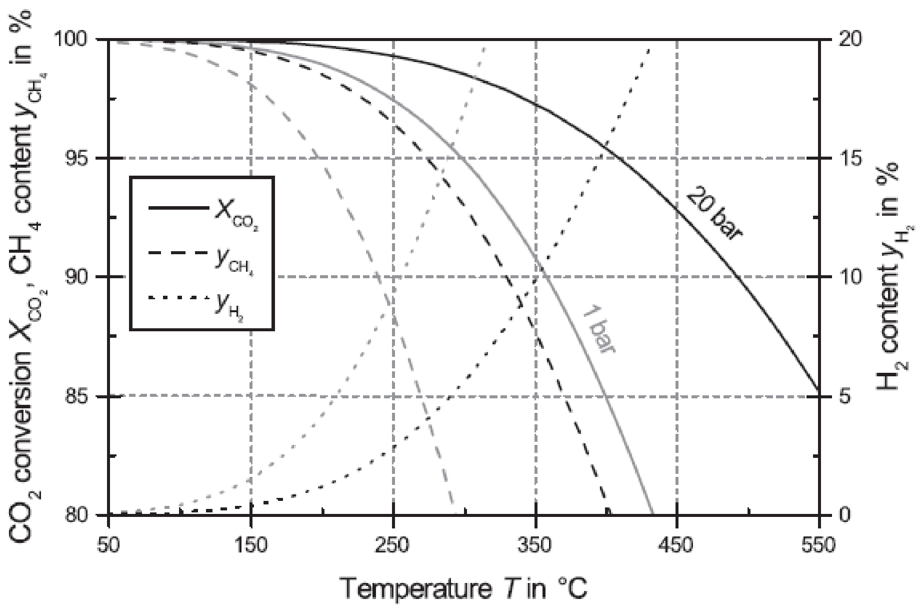

Fig.6: Equilibrium conversion as well as H_2 and CH_4 content for CO_2 methanation ((H_2/CO_2) in =4, no inert gases). Source: Renewable Power to Gas: A technological and economic review.

3.1.2.3 Catalytic Methanation

Catalytic methanation reactors are usually operated at temperatures between 200°C and 550 °C and at pressures from 1 to 100 bar. Many metals such as Ni, Ru, Rh, and Co might be used as the catalyst for the methanation reaction. In the other hand, often Ni is the optimum catalyst choice due to its relatively high activity, good CH_4 selectivity, and low raw material price (Mills & Steffgen 1974: 159-210).

The methanation reaction is highly exothermic. Assuming a GHSV of 5000 h-1 and a full CO_2 conversion, approx. 2 MW heat per m^3 catalyst bed must be taken (methanol synthesis: approx. 0.6 MW/m^3).

Therefore, a significant issue in a methanation reactor is to realize good temperature control in the reactor to prevent thermodynamic limitation and catalyst sintering. To reach this mandatory objective, many steady state reactor concepts have been introduced, like fixed-bed, fluidized-bed, three-phase and structured reactors. Fluidized-bed reactors same as fixed-bed reactors are live technologies, while the other reactor concepts are still in the development phase.

3.1.2.4 Biological Methanation

Biological methanation (BM) is anadditional option for the PtG process chain. Thus, methanogenic microorganisms play the role of biocatalysts. In a standard biogas plant, the first action is the hydrolysis of an organic substrate (biomass) to simple monomers (monosaccharide, amino acids, and fatty acids). Then, theses monomers are transformed to acetate, carbon dioxide, and hydrogen (acidogenesis, acetogenesis). finally, the methane is produced by acetolactic methanogenesis (depletion of acetate) and hydrogenotrophic methanogenesis (CO_2 reduction with H_2) (Pavlostathis & Giraldo-Gomez 1991: 411- 490)

The production of methane directly from CO_2 and H_2 is done by microorganisms (cell type: archaea), which obtain the energy for growth by anaerobically metabolizing hydrogen and carbon dioxide.

This biological reaction has been known since 1906 and the metabolic pathways are shown by (Thauer et al. 2008: 579-591).

In BM, methane is generated via hydrogenotrophic methanogenesis from CO_2 and H_2.

3.2 General Economic Overview of PtG

3.2.1 Capital Expenditure (CAPEX)

Three main axes which are considered in the examination of the capital expenditure:

- Electrolysis
- Hydrogen storage and compression if existed

- Methanation

The most significant contributor to the total CAPEX is the electrolysis (Table.1), as discussed in section 3.1.1.2 the water electrolysis is approximately in the range of 800 to 3000 Eur/KW electricity.

Table.1: Investment for different parts of a Power to Gas plant (36 MW electrolysis, pressure in H_2 storage: 30-200 bar, methanation pressure: 20 bar), (Aicher et al. 2014: 51-55).

Investment in M€	Electrolysis	Compressor	H_2 storage	Methanation	Total
Case 1	28.8	1	8.3	0.7	38.8
Case 2	28.8	1	4.8	1.2	35.8

In the other hand, the availability of literature regarding methanation investment is very less but there are some reported investment estimations in Europe that have been done by companies and consultants that will follow below:

- Outotec Gmbh show an investment cost of 400 Eur/KW SNG for a 5 MW plant and 130 Eur/KW SNG for a 110 MW plant (both data sets are for 2014 and 20 bar operating pressure), (Graf et al. 2014: g3-01-12).
- Gassner and Maréchal investigated the Biomass-to-Gas process chain with a 14.8 MW CO methanation (15 bar) in 2009, the investment cost was set at 175 Eur/KW which is correlating with the data from Outotec Gmbh (Gassner & Maréchal 2009: 1587-1604).
- Lehner et al. has gone through the comparison of three different reports and identified a range of 300 to 500 Eur/KW (Lehner et al. 2014: 836)
- Ausfelder et al. presumed an investment cost of 600 Eur/KW in 2050 (Ausfelder et al. 2015: 17-89).
- E&E Consultant has given an estimation of the investment const for methanation in the amount of 500 Eur/KW in 2030 while currently in the amount of 1500 Eur/KW (E&E Consultant 2014).

- Ueckerdt et al. assume 1000 Eur/KW SNG (Ueckerdt et al. 2013: g8-01-11).

All the previous data regarding methanation reflect the uncertainty of the evaluation of the investment cost currently and the inability to foresee/predict a standard reliable investment costs in the future, but in the mean time we can qualify the data coming from Outotec Gmbh as the most reliable since it is coming from a plant engineering company, which make us conclude the overestimations of methanation costs data coming from the other players in the sector.

Another evaluation that has to be considered when tackling the costs topic is the hydrogen storage, which is still a considerable extend linked to the electrolysis and methanation, actually electrolysis is operated in most of the scenarios more dynamically than the methanation from a process point of view, this imply the necessity to have a hydrogen storage that vary in sizing depending on the dynamicity of the process, meaning that a less dynamic methanation results in larger hydrogen storage and higher cost by the way. But from another point of view, a smaller hydrogen storage means a larger methanation plant.

Here below we will showcase a study from (Aicher et al. 2014: 51-55) which aims to investigate the dependency in cost between methanation and hydrogen storage that was discussed above, the following two cases/scenarios were compared as seen in Table.1:

1. Case 1: The methanation operates in steady state mode and produces 311 m^3/h CH_4. The needed hydrogen storage volume is 1700 m^3.

2. Case 2: The methanation can be operated within a load range of 40 to 100 %. The total capacity of the methanation is 591 m^3/h CH_4; however, the annual methane production is like case 1. The hydrogen has a volume of 850 m^3.

As seen in Table.1, the hydrogen storage is the second most significant contributor to the investment of a PtG plant. In this example, the total investment of the PtG chain can be reduced by 8% by operating the methanation dynamically compared with a steady state operation (although the investment for the methanation increases).

3.2.2 Operational Expenditure (OPEX)

The main important aspects influencing the OPEX are the electricity price, CO_2 costs as well as heat and oxygen utilization.

Heat and oxygen can be used in other processes, for instance using oxygen from the electrolysis process in the primary biogas desulphurization, which its cost is expected at approximately 32,000 Eur/a for a 1000 m^3/h biogas plant (Aicher et al. 2014: 51-55).

Some companies investigated the reduction in SNG cost by capitalizing on selling the oxygen production from the electrolysis process, for instance Vendiwalle et al. studied the effect of two different oxygen prices (10 and 70 Eur/t O_2) on the SNG costs if all the oxygen produced can be sold. According to this scenario a reduction of 2 ct/KWh (5000 h/a operation) in the SNG costs is feasible (Vandewalle et al. 2015: 28-39).

Little information is available for CO_2 costs. Usually is always regarded as being freely available, however Ausfelder expected an increase of 2 ct/KWH SNG for CO_2 costs of 100 Eur/t (Ausfelder et al. 2015: 17-89).

Biological vs. catalytic methanation. Furthermore, it is interesting to compare the costs for biological methanation versus catalytic methanation. According to (Graf et al. 2014: g3-01-12), for a small plant size (5 MW) the production costs for biological methanation are slightly higher than for catalytic methanation. For larger plants (110 MW), the methanation production process costs for biological methanation are approximately 2.5 times that of catalytic methanation. In contrast, higher costs for catalytic methanation compared with biological methanation are reported from E&E Consultant (E&E Consultant 2014), however, it was shown above that the catalytic methanation costs assumed by E&E Consultant are probably too high.

Final point to tackle in the OPEX topic is the generation cost, all the data will be in Eurocent/KWh SNG,

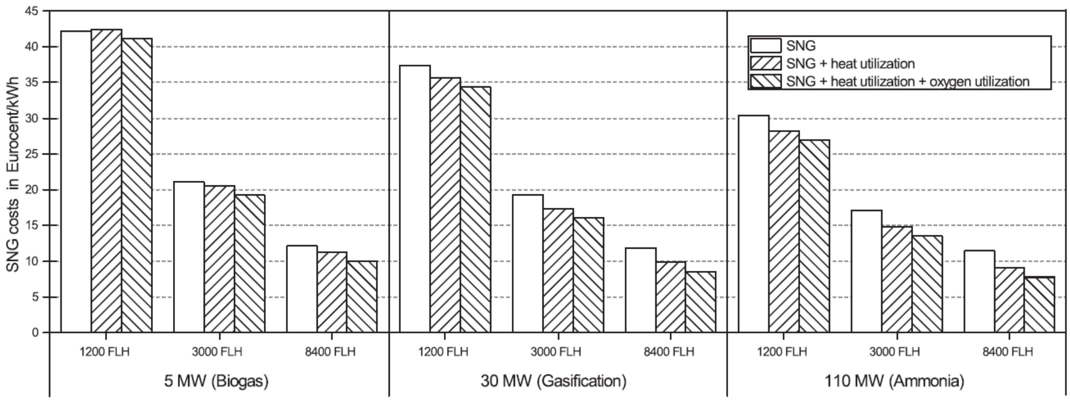

Fig.7: SNG generation costs for the coupling of PtG with different CO_2 sources (electricity price 5 ct/KWh, heat price 4 ct/KWh, oxygen price 7 ct/KWh), (Graf et al. 2014: g3-01-12).

FLH: Full Load Hours

As shown in Fig.7, The coupling with a biomethane plant (5MW SNG generation capacity), with a biomass gasification (30 MW SNG generation capacity), and with an ammonia plant (110 MW SNG generation capacity) is illustrated for different annual operation times

A rise in full load hours (FLH) from 1200 to 3000 FLH lowers the SNG costs by about 50%. An extra increase has less impact on the SNG costs.

Buchholz et al. (Buchholz et al. 2014: 7993-8009) accomplished a PtG design study with CO_2 from a lignite power plant. The yearly operation time is approximately between 800 and 1200 h/a. With SNG generation costs of about 60 to 90 ct/kWh, the produced SNG is much more expensive than natural gas. Non the less, the authors perceive economic benefits in the rised flexibility in operating of the lignite power plant.

A study from E&E Consultant (E&E Consultant 2014) reports SNG costs from 16.5 to 39.2 ct/kWh for today and 7.2 to 10.2 ct/kWh for 2050 including heat and O2 utilization.

Summarizing, the generation costs for H_2 and for SNG strongly depend on the annual operational time and the electricity price.

Compared with natural gas (approximately 2 to 3 ct/kWh), the costs are much higher.

The CAPEX for the electrolysis is predominant, for wider full load hours, the electricity price is the major parameter influencing the economics.

The microeconomic evaluation shows that SNG from PtG processes is not competitive with natural gas or even biomethane (approx. 7 ct/kWh). For economic feasibility, different business cases such as mobility, balancing services, and CO_2 certificates must be combined. With respect to a macroeconomic consideration, it must be considered that PtG can contribute to minimize the expansion of the electricity grid infrastructure (Baumann et al. 2014: 65) and to increase the share of renewables in the transport/heating sectors. Therefore, PtG can play a major role in the realization of the ambitious transition of the energy system.

4 EVALUATION OF DRIVEN PILOT RESEARCHES AND PROJECTS AROUND PTG IN EUROPE

PtG is a technology that is perceived as a non-competitive technology economically keeping in mind the generation cost of natural gas and even further the biogas generation cost which are way cheaper than PtG gas.

From another hand it is considered as a technology of a high efficiency in CO_2 reduction keeping in mind the different business models that could be established based on this technology, for instance the usage of CO_2 in the methanation process, and by the way its greatness in boosting the key performance indicators of saving the climate like reduction of CO_2 emissions as well as generating clean energy and helping in the energy transition and decentralization.

Departing from the two above points we can conclude that to perform a competitive and efficient PtG project, it could not be without taking into consideration each application aside, and here we talk about the availability of surplus from green generated electricity such as photovoltaic, wind turbines' as well the availability of CO_2, gas grid, the business need etc.

Apart from supporting high levels of intermittent renewable energy penetration, PtX technologies could contribute to reduce the expansion of the electricity network (Götz et al. 2016: 1371) and reduce energy transmission losses, which are approximately four times lower for gas pipelines than power lines (Zakeri & Syri 2015: 569).

Furthermore, the variety of potential transformation pathways and products can enable a more sustainable use of resources by connecting the electricity, heating/cooling, district, industrial and transport sectors in smart energy systems (Conolli et al. 2006: 1634).

To this extend, PtX may ease the operation of isolated energy systems (that supply electricity, heating/cooling and transport fuels) in topographically difficult and/or remote regions.

As a part of my study which is the evaluation of PtG in Europe, I have chosen to go through different pilot/demonstrated projects in this area to emphasize on the different business models implemented within depending on the respective business conditions like country of execution, technical context, technical conditions as well as profitability and the added value to meet a given energy system demand portfolio, in Fig.8 an overview of PtG possible conversion routes.

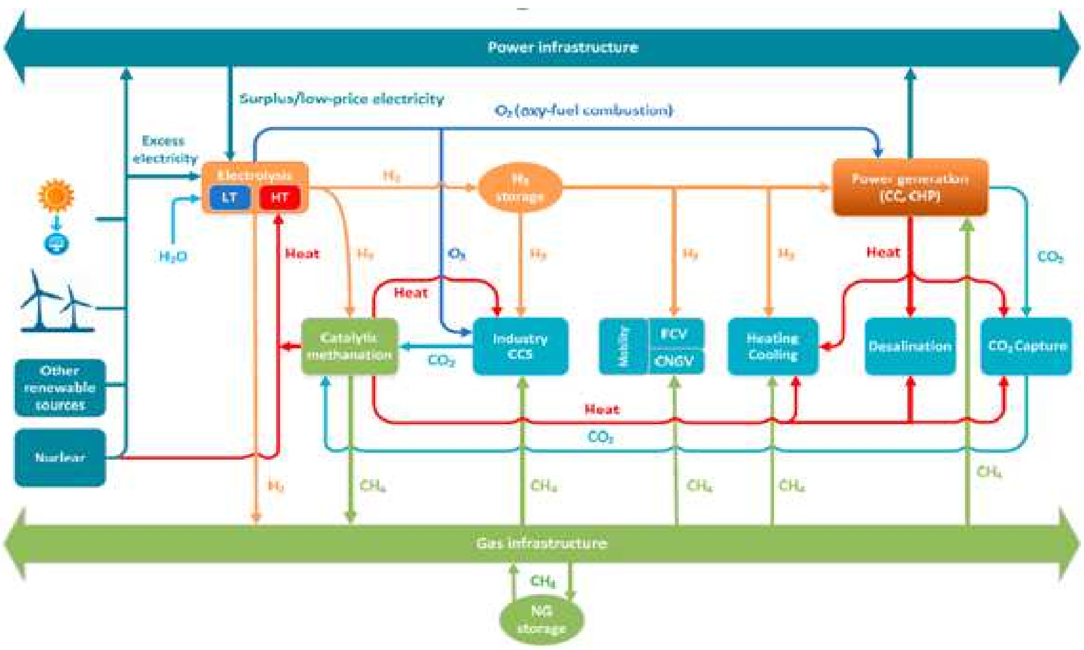

Fig.8: Schematic diagram of PtG conversion routes, product end-uses, and integration options with electricity / gas infrastructures and other sectors. CC = combined cycle, CCS = carbon capture and storage, CHP = combined heat and power, CNGV = compressed natural gas vehicle, FCV = fuel cell vehicle, HT = high temperature, LT = low temperature, NG = natural gas

Depending upon the PtG conversion route and economic context, the use of PtG by-products (O_2, heat etc.) and heat/material integration between PtG and external processes, may be required to enhance profitability. In this regard, Fig.8 also highlights possible heat and material (like H_2, O_2, CO_2) flows within the PtG plant and between the PtG plant and industrial, power, transport, district and water systems.

High-temperature electrolysis can get as an input the thermal energy from either methanation or external heat-rejecting processes (additionally to an electricity input).

Depending on its amount and grade, PtG heat rejection could be used externally, for example, for the desorption of amine-based CO_2 capture processes, district heating, water treatment/desalination and other heat-driven applications. The PtG oxygen by-product could be implemented in oxygen-fed processes such as chemicals and metals manufacturing, and oxyfuel combustion.

PtG deployment scenarios may be classified according to two broad types, with the objectives of maximizing the use of electricity generation and corresponding resources and decreasing environmental emissions. In the first scenario, PtG is deployed into a specific regional or nation-wide energy system with the additional objective to enhance stabilizing the grid to avoid the effects of surplus electricity caused by an essential share of oscillating sources (generally, renewables), and ameliorate the security of energy supplies. In the second scenario, PtG is incorporated in the energy value chain of industrial or small-scale power facilities, or other distributed installations, for increased profitability.

4.1 Regional to National Scale Research and Projects around PtG in Europe

4.1.1 GERMANY

Germany aims to increase electricity generation from renewables to 50% by 2030 and 80% by 2050 from approximately 32% in 2015 with emphasis on wind power as the largest single share of renewable electricity.

Many studies, scenarios analysis and researches were performed in Germany in PtG, the main criteria for the performed projects were about economic feasibility and optimality, spatial deployment, availability of electricity and electrical and gas grids and decentralization of energy mix, and finally some researches were tackling the topic of coupling power and transport sectors.

Here below we will showcase some pilot projects done by different companies, institutions and bodies to assess the technology of PtG in Germany:

4.1.1.1 The Path of Economic Optimality of PtG in Germany

Jentsch et al. (Jentsch et al. 2014: 254) performed a scenario-based analysis to determine both the economically optimum PtG capacity and spatial deployment technology option in Germany's energy mix, assuming 85% renewable intervention (i.e., wind, solar photovoltaic, biogas, run-of-river hydro-electricity), with no timeframe specified.

PtG, power to hydrogen (PtH) and short-term energy storage systems were assessed in terms of their effectiveness in storing the surplus of electricity. PtH end-use was modelled as electric heaters and served to improve flexibility over CHP units. Based on a unit commitment framework of the German transmission grid, the economically optimal PtG capacity that reduced the difference between PtG benefits and the fluctuating costs of power/heat production, for an assumed power to SNG efficiency of 62% and PtG investment cost of 750 Eur/kW, was found to be in the range of 6 to 12 GW. PtG was perceived to provide an economic added value, but a mix of PtG and PtH was optimal. For the optimal PtG capacity specified, the most economical location of the PtG plant was perceived to be near the region from which excess electricity is exploited (i.e., Northern Germany), to reduce transmission losses. However, it was emphasised that the local availability and cost of the CO_2 feedstock, and internal heat recycling between methanation and electrolysis, could lead to different optimum locations.

4.1.1.2 The perspective of injecting SNG in Saxony-Anhalt

Moskalenko et al. (Moskalenko et al. 2014: 27) identified optimum PtG installation locations in Saxony-Anhalt, depending on the availabilities of renewable energy resources (i.e., wind and solar PV), gas network, and CO_2 sources,

using a genetic algorithm (GA) based optimization. Saxony-Anhalt is the largest electricity exporting region in Germany, and the largest importer of natural gas. As of 2011, the region had already reached 40% share of renewable energy, including over 50% share of wind power (i.e., 3.8 GW) and 1.3 GW of PV installations. Due to a large regional gas distribution and storage infrastructure, SNG was selected as PtG product.

Existing biogas (60% of CH_4 and 35% of CO_2) plants (currently in a total of 397) would provide the CO_2 requirement for PtG biological methanation. The optimization objective was to reduce the CAPEX and the OPEX of PtG related to electrolysis (i.e., electricity consumption) as well for methanation (i.e., feedstock), according to the locations of PtG units.

The best PtG units' locations were close a SNG injection point, or near by a gas storage point.

The results proposed that by incorporating PtG technology for SNG production, Saxony-Anhalt could secure its total natural gas demand without gas importation.

Assuming 80% renewable energy electricity in Germany's future energy system, short-term (5 h) and long-term storage (17 days) capacity requirements of 70 GWh for and 7.5 TWh have been predicted, which could be provided using synthetic gas. However, PtG transformation and/or utilization pathways can significantly affect the overall efficiency and economics of the process (Schiebahn et al. 2015: 4285).

Schiebahn et al. (Schiebahn et al. 2015: 4285) compared three alternative PtG options technically and economically, namely direct injection of either hydrogen or SNG into the natural gas grid, or utilization of hydrogen in a targeted hydrogen infrastructure in fuel cell cars for transport and industrial processes in Germany. These options were primarily for storing excess wind electricity for total on-shore and off-shore generation capacities of 169 GW and 70 GW, respectively. 84 GW electrolyser capacity, in conjunction with 70% and 80% electrolysis and methanation efficiencies, respectively, were considered. For the mobility option, a park of 9800 vehicle refuelling stations was envisaged, with a new 51,000 km long pipeline distribution network, and 27–90 TWh H_2 storage salt caverns.

The above three scenarios PtG end-uses were assessed in terms of the levelized production costs of the SNG. The price of the surplus electricity converted was figured out to have a critical impact.

Injection of either H_2 or SNG into the natural gas grid was found to be uneconomical due to their production costs being several times higher than that of conventional natural gas. The use of both hydrogen or SNG for industry is not of an advantage.

The economically most attractive PtG conversion pathway and end-use was found to be hydrogen for fuel cell vehicles, due to both vehicle efficiency and gasoline prices (Schiebahn et al. 2015: 4285).

4.1.1.3 PtG to Mitigate the Effects of Wind Power Forecast Errors in Brandenburg, Germany

Grueger et al. (Grueger et al. 2017: 551) quantified the potential of alkaline electrolysers and fuel cells for re-electrification in mitigating the effects of wind power forecast errors, and in supplying secondary reserve power, for a 100 MW wind power plant in Brandenburg, Germany.

The electrolytic hydrogen was used to supply fuel cells that assured reserve power. The wind plant operator was accounted to take part in a day-ahead electricity market by using a wind power forecasted data.

Forecast errors were modelled using a mixed weighted normal Laplace probability distribution function. Measured wind plant generation and market tendering data from year 2013 were used.

Fixed electrolyser ranges of 300–1500 kW and fuel cell power outputs of 150–700 kW was deemed.

Ideal electrolyser and fuel cell dynamic operation, and constant, load-independent efficiencies were assumed.

The H_2 consumption expenses, H_2 production income, and income from lowered forecast errors and secondary reserve expectation were calculated over a yearly period to get the net equivalent yearly cost and specific H_2 production/consumption costs.

H_2 storage capacity barriers, and hydrogen storage/compression expenses and taxes were not considered. A 200-kW fuel cell and a 700-kW electrolyser could avoid 17% of forecast errors for a 100 MW wind installation.

However, the electrolyser operational hydrogen production costs were estimated to be up to 2.4 times higher than the hydrogen price required for economically feasible fuel cell operation (i.e., 1.25 Eur/kg).

It was suggested to market electrolytic hydrogen in refuelling stations, for which higher hydrogen prices would be viable.

Fuel cells were not assumed to be viable for secondary reserve power saving.

Similar analysis could be followed in future work to further H_2 uses, PtG products, and a wider geographical base, using more developed electricity generation/consumption and economic insights considering a greater range of influencing variables, as discussed in (Grueger et al. 2017: 551).

4.1.2 SPAIN

The Spanish scenario is quite different from the German for many reasons, first, because of the gap between the two countries in term on infrastructure and here we talk mainly about electrical and gas grid interconnectivity , second the macroeconomic parameter, while we find an agriculture and service provider Spain, we find in the other hand a gigantic industrial German economy, so necessarily a different approach of business models (i.e., national scale projects, distributed scale projects).

As a result, the researches and the demonstrated pilot projects that have been performed in Spain were focusing much on the P-t-H meaning the hydrogen production. And its implementation in the transportation sector via the bias of cell fuel vehicles.

From approximately 37% renewable share of gross power generation in 2016 (mostly wind, hydro, solar PV and thermal), Spain intends to reach 90–100% by 2050, and in the meantime 27% renewables in overall energy consumption by 2030 (EEA 2018 Report N° 23).

The Spanish power generation system is characterized by a high penetration of renewables, but limited grid interconnections (Gutiérrez-Martín & Guerrero-Hernández 2012: 1151).

The significant amount of surplus electricity generated currently results in low power installation capacity factors, which are mitigated by converting surplus electricity via hydro storage or exporting it abroad.

Gutiérrez-Martín and Guerrero-Hernández (Gutiérrez-Martín & Guerrero-Hernández 2012: 1151) investigated the balancing of the Spanish electrical grid by large-scale integration of hydrogen production using polymer electrolyte membrane (PEM) electrolysis, in an energy system with 42% renewable penetration (i.e., wind, solar thermal, PV, hydro, nuclear).

Hydrogen was either transformed back to electricity for peak shearing or exploited in fuel cell vehicles.

The electricity demand and structure of power generation were expected using a daily average analysis until 2020, using 2009 data from the power operator.

Many future hydrogen production possibilities were assessed for different power supply against the demand gap profiles, to specify the optimal capacity and operation of alkaline electrolysers, taking into consideration the utilization factor, basing on a dynamic electrolyser model.

An important generation-demand factor parameter was found to determine the power generation requirement to reach the forecasted daily demand profiles.

The transformation of hydrogen back to power was perceived to result in extra energy losses.

However, the PtG system may convert surplus electricity generated from renewables (i.e., wind and hydro) to hydrogen, to supply over three million of fuel cell vehicles, with a net yearly decreasing of over 4 Gton of CO_2 emissions (relatively to 2009 levels).

Using 53 nos. 50 MW electrolyser units, the scheme could become profitable after three years.

Here below we will showcase some pilot projects done by different companies, institutions and bodies to assess the technology of PtG in Spain.

4.1.2.1 Power to Hydrogen Potential on a National Scale

Gutiérrez-Martín et al. (Gutiérrez-Martín et al. 2015: 5544) refined the electricity and generation profiles and electrolysis physical model employed in (Gutiérrez-Martín &

Guerrero-Hernández 2012: 1151) to predict the current-voltage characteristics and hydrogen production cost of advanced alkaline electrolysers.

This permitted electrolyser current density to be adjusted in relation to its utilization factor in each time.

Several base-load and fluctuating electricity production scenarios were analysed in conjunction with the power demand to determine the number and capacity of electrolysers to store excess electricity at national-scale, for non-specified hydrogen end-uses heat, power, SNG fuel production and grid penetration.

It was found that 300 nos. 50 MW electrolyser units could be deployed in the country, at locations that could potentially correspond to decommissioned conventional power plants, wind farms and/or end-user sites.

Gutierrez-Martin and Rodriguez-Anton (Gutiérrez-Martín & Rodriguez-Anton 2015: 19239) extended previous work to include catalytic SNG production from alkaline hydrogen, to absorb 90% of excess electricity generation in the 2050 Spanish energy sector.

SNG was assumed to be injected into the gas grid and re-converted to power.

Assuming free-of-charge excess electricity, the levelized costs of hydrogen, SNG and power were estimated at 0.52 Eur/kgH_2, 0.26 Eur/Nm^3 SNG and 51.4 Eur/MWhe, respectively.

In the case of surplus electricity priced at 25 Eur/MWhe, the cost of power was estimated to rise to 132.5 Eur/MWhe.

However, at wholesale electricity prices, the cost of hydrogen would range from 2.6 to 5.9 Eur /kgH_2, with the upper bound cost applicable to industrial users.

The environmental emissions of the power to SNG-to-power conversion chain were evaluated at 34.9 gCO_2/kWhe, most of which was contributed by materials manufacturing, and CO_2 capture and storage losses.

Despite the synthetic gas cost estimates obtained, PtG was anticipated to become likely unavoidable to enable the integration of large renewable power shares in the future.

4.1.2.2 Assessment of PtG Capacity in the Different Energy Scenarios in Spain

Bailera and Lisbona (Bailera & Lisbona 2018: 900) presented predictions of excess electricity and PtG capacity requirements in 2020–2050 in Spain for four different energy scenarios, involving different fuel mixes (i.e., wind, hydro, solar CSP/PV, natural gas, coal, nuclear, biomass, with some marine and geothermal), and different average annual electricity demand growths (1.36–1.80%).

Two energy scenarios from four permitted to restrict the global mean ambient air temperature rise to 2 °C by 2100.

Nuclear plants handed base load power, whereas biomass, coal and natural gas played as backup power to overcome production and demand ratio.

The daily variability of wind generation was accounted for, while solar and hydro-electricity generations were modeled assuming monthly-average daily patterns.

The 2050 annual surplus electricity was forecasted to be between 1.4 to 13.5 TWh based on the energy scenario expected and wind power variability and was mainly produced between March and June.

The correlated PtG capacity expects to absorb 90% of annual surplus electricity spanned 7.0 to 19.5 GW.

It was suggested to place PtG facilities near renewable installations to reduce network transmission losses and congestion.

Hydrogen was assumed to supply part of transportation, and the peak load power generation was proposed as a possible synthetic natural gas end-use.

Analyses of SNG material requirements, PtG facility sizing and spatial distribution, and an optimization approach were recommended as future work.

4.1.3 DENMARK

Denmark is another unique example within the European union, it is unique in the mass implementation of wind turbine technology among the power mix share achieving 432 GW capacity.

It has a specific economical and geographical reality, as a Scandinavian country, its economy is based on a large extent on maritime/land transportation and energy transition, hence, many researches were made to couple the renewable energy sector along with the transportation sector, where PtG play an important role and present an outstanding concept to consider.

Denmark has actively driven the implementation of wind power, achieving 432 GW capacity and 42% wind share in its electricity generation in 2015 (Hou et al. 2017: 359).

The country aims at zero fossil energy by 2050, which will be achieved in steps including 50% wind share in power generation by 2020, 100% renewables in power and heating by 2030, and phasing out coal power (Heinisch & Tuan 2015).

Here below we will expose some pilot projects and projected pilot projects in Denmark, we will showcase their parameters, context efficiency and profitability:

4.1.3.1 Economic Viability of PtG in Long Distance Transport in Denmark Transport Sector

Ridjan et al. (Ridjan et al. 2014: 104) evaluated the production costs of PtG-SNG and PtL-methanol in comparison with first/second generation biodiesel, second generation bioethanol, and biogas in a 100% renewable 2050 Danish energy system with emphasis on wind.

Their focus was not on planning aspects such as PtG/PtL capacities and spatial distributions, but on evaluating the potential economic viability of the PtG/PtL products for heavy load and long-distance transport compared to other transport fuels.

Differently to the majority of PtG works, which have taken low temperature electrolysis processes, solid oxide steam electrolysis and steam/CO_2 co-electrolysis-based production pathways were assessed.

Although a developing technology, co-electrolysis is highly efficient, can recycle substantial amounts of CO_2, and can process biogas directly with no CO_2 separation, to produce quasi carbon-neutral synthetic fuels. In addition, co-electrolysis could enable the flexible production of different synthetic liquid fuels (e.g., DME, jet fuel, methanol) by adjusting the hydrogen-to-carbon ratio of the co-electrolytic syngas product.

Furthermore, solid oxide electrolysis cells can operate in reversed, fuel cell mode to produce electricity and thermal power from hydrogen and other fuels.

In (Ridjan et al. 2014: 104), the CO_2 for either hydrogenation after steam electrolysis to produce SNG, or for co-electrolysis to produce syngas (and subsequently methanol via a catalytic process), was captured from biomass plant combustion products.

The electrolytic processes were driven by surplus off-shore wind electricity and are meant for methanol and DME synthesis.

An EnergyPLAN software model of the Danish energy system, focusing on the portion of the transport sector that cannot be fulfilled electrically, was used to minimize fossil fuel (i.e., natural gas) consumption.

The model balanced surplus electricity production and gas supply and demand.

PtG/PtL capital costs included wind power, electrolysis and SNG and methanol chemical synthesis plants.

The PtG-SNG and PtL-methanol fuels were found to incur higher specific (i.e., per unit chemical energy) production costs than first generation biodiesel (which involves a simple and efficient process), but lower than the cost of second-generation bioethanol.

PtG-SNG specific cost was found to be lower than that of PtL-methanol, due to a lower hydrogen and thus input electricity requirement.

For both PtG-SNG and PtL-methanol, the costs consisted essentially of electricity, followed by fuel handling/CO_2 emissions, then (co) electrolyze, chemical synthesis and carbon capture costs.

Both SNG and methanol had higher production costs via PtG/PtL than via biomass hydrogenation, due to a higher electricity requirement, and despite lower biomass consumption.

But, when combining CO_2 emission costs, the production costs of PtG-SNG and PtL-methanol were close to that petrol, suggesting their potential to replace this transport fuel, thus addressing climate change, energy security, and limited biomass availability in a 100% renewable energy system.

Ridjan et al. (Ridjan et al. 2013: 76) showed that co-electrolysis and steam electrolysis to produce PtL-methanol or PtL-DME enabled the lowest consumption of biomass in the Danish 2050 transport sector, compared with biodiesel and biomass hydrogenation.

In addition, co- and steam electrolysis, with total electrolyser capacity requirements of ~22 and ~18 MW, respectively, used more wind electricity than the other above two transport fuel production pathways.

For a given installed wind power capacity, co-electrolysis followed by steam electrolysis also permitted the largest reduction in surplus electricity.

However, steam- and co-electrolysis were anticipated to take over higher yearly transport fuel costs taking into consideration the lower development of these technologies.

4.1.3.2 PtG the Path of Challenging Power Grid Stability and Volatile Electricity Prices

Temporal variations in wind power generation affect grid stability, require backup power and its cycling, and implies volatile electricity prices.

Hou et al. (Hou et al. 2017: 359) evaluated, from an economic investment perspective, the integration of either an alkaline or PEM-based 10–100MW power to hydrogen plant with a 72MW off-shore wind farm.

Electrolytic hydrogen was produced from excess/low-cost wind electricity to stabilize the electricity network and electricity prices, fuel mobility/industry, and/or re-generate electricity using a 0.2–0.7 kWe PEM fuel cell.

An optimization methodology of the simplified power sector (i.e., twenty nos wind turbines, electrolysers, hydrogen storage tanks, compressors, fuel cells) was developed.

This methodology combined sequential quadratic programming for the optimization of equipment operation (including the amount of electricity to be converted or re-generated) and an adaptive particle swarm algorithm for power to hydrogen and fuel cell equipment selection and sizing. That was based of the Danish 2015 hourly electricity prices data.

The return on investment (i.e., net present value) associated with several scenarios (i.e., power to hydrogen-to-power for electricity market arbitrage, or power to hydrogen for product sale to mobility/industry), were compared.

For the considered hydrogen and electricity prices, selling electrolytic hydrogen straight as a fuel was found to be of good profits, but not its retransformation to power.

It was recommended to consider as well in future work the impacts of hydrogen distribution possibilities, rather than just hydrogen production, the same for ancillary grid services, government support, and the progress of hydrogen demand markets, on the (ROI) return on investment.

4.1.3.3 PtG to Defy Coal Usage in Generating Electricity and Heat

Zeng et al. (Zeng et al. 2017: 192) optimized the projected joint expansions of the Western Danish gas distribution and electricity sectors in 2016–2024.

Wind and natural gas power plants were widened to gradually lower the current coal power capacity.

The electricity sector and gas grid were related by-directionally via gas power and power to methane installations.

Three scenarios were simulated, differentiated by their assumed annual wind power growth rates (2–5%).

The network topology (i.e., locations of new gas power and power to methane plants among assumed two and three possible locations, respectively, gas storage, compressors, pipelines, CO_2 transportation pipelines from power to PtG installations), power generation capacity and introduction time of new equipment, as well as electricity and synthetic gas dispatch, were optimized.

The objective was to minimize the sum of investment and operational costs, using a modified binary particle swarm algorithm combined with an interior point method.

PtG was expected to lower operational expenses by reduced wind limitation, gas consuming and environmental emissions.

4.1.4 UNITED KINGDOM

The United Kingdom has perceived different pathways in its PtG projected plans and projects, as it has different reality from the above investigated countries.

First, it is at a lower renewable energy share in electricity generation, Second, it is investigating the PtG for hydrogen production using clean energies like clean coal, renewable surplus and nuclear as shown in Fig 4.

Here we will explain the coupling of PtG with nuclear for multipurpose outcome.

The PtG literature has focused on the conversion of excess, fluctuating renewable electricity primarily using electrolysis, with less attention to other low-carbon power sources and other hydrogen synthesis options.

Nuclear power generation is a low-emission technology which can contribute to support the transition to renewable-based energy systems.

Total excess electricity may be produced from a combination of fossil and renewable sources, with the time-varying portion of electricity that causes grid instability either generated by fluctuating renewables, or in for example the French power sector, by advanced reactor controls to follow power demand profiles (Scamman & Newborough 2018: 10080).

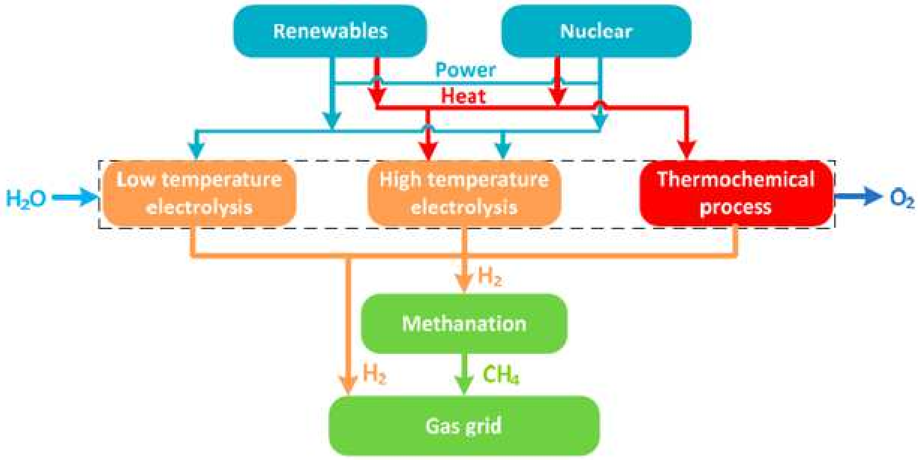

Fig.9: Conceptual hybrid renewable and nuclear power-based hydrogen and SNG production.

Retrieving again the UK case, the main mission in most of the researches and studies that have been projected was about achieving the reduction of CO_2 emissions and meet the global goals for climate change.

Another sector that was pretty much investigated is the coupling of PtG with the transportation sector.

The UK has committed to increase its renewables penetration in total energy consumption to 15% by 2020 and 27% by 2030, to enable 80% reduction in CO_2 emissions by 2050, relative to 1990 level (Qadrdan et al. 2015: 5763).

Towards these targets, on- and off-shore wind power capacities of 21 GW and up to 37.5 GW, respectively, are anticipated by 2035 (Qadrdan et al. 2017: 181).

4.1.4.1 Assessing Pathways for Hydrogen Production

Barton and Gammon (Barton & Gammon 2010: 8222) investigated three potential UK energy supply pathways for hydrogen production, with emphasis on either clean coal, fluctuating renewable energy and nuclear power, for annual periods between 2007 and 2050.

Every energy provision scenario was obliged to lower greenhouse gas emissions by 80% by 2050, lower hydrocarbon importation and allow stable electrical grid operation.

The renewable energy sources included on and off-shore wind, solar PV, solar thermal, tidal and wave energy, biomass, waste, and hydropower.

Hydrogen potential end-uses include industrial, transport, and power usage, gas network injection and transformation to other fuels.

Using a future energy scenario assessment (FESA) software model, which is a software concept assessing scenarios of future energy scenarios within an entity considering how much energy this entity might need and where it could come from, by looking as well to the forecasted changes and the energy supply/demand on a total system basis, it was found that regardless of the energy scenario considered, by including mobility as a possible hydrogen end-use, lower CO_2 emissions and primary energy consumption would be achieved than if this end-use was not considered.

This suggested the use of hydrogen for transport as an alternative to energy-intensive and costly carbon capture and storage (CCS) for reducing CO_2 emissions.

4.1.4.2 Investigation of PtG Impact on Electrical and Gas Networks

To evaluate the operational impact of PtG on the electrical and gas transmission networks, Clegg and Mancarella (Clegg & Mancarella 2015: 1234) developed an integrated electricity-gas grid model for the simulation of electricity and gas grids operational interdependencies.

The model included a two-stage optimal power flow dispatch model coupled with a transient gas network model.

The UK's electrical transmission network, with a predicted installed generation capacity including 48% of wind energy in 2030, was considered for evaluating the technical, economic and environmental aspects of deploying PtG.

PtG facilities having 1 GWH_2 and 1 GWSNG production capacities, and 1 GWH_2 storage, for product injection into the gas network, were assumed in one of three location types, namely gas stations, closed gas nodes or closed electrical nodes.

The efficiencies of hydrogen and SNG production were taken as 73% and 64%, respectively (including gas compression at 80 bar for distribution).

The electrical and gas networks interacted through gas-fired power plants as well as PtG installations, with the latter accounting for limitations of the gas network to absorb the produced synthetic gas.

The model quantified the avoided wind curtailment, gas consumption, and CO_2 emissions (through both avoided gas combustion and CO_2 consumption for methanation), and the de-confectioning of the electrical and gas grids, through PtG.

Many case-studies were aiming at different objectives, corresponding to minimizing PtG operational expenses, increasing the bypassed greenhouse gases emissions, and electrical or gas network burden relief.

The results suggested that PtG deployment near gas network terminals could avoid wind power curtailment by producing hydrogen for direct gas network injection or SNG production, without disrupting the operation of the gas network.

In addition, the strategic placement of PtG SNG facilities was found to reduce the gas compression requirement to overcome gas distribution pressure drops (Clegg & Mancarella 2015: 1234).

Qadrdan et al. (Qadrdan et al. 2015: 5763) optimized the operation of the UK's gas and electricity networks in a high wind electricity generation scenario in year 2020.

Without adequate demand-supply matching measures, fluctuations in wind electricity production would impose frequent transient operation of gas power plants and increase the variabilities of gas flow and demand.

A combined gas and electricity network model were employed to minimize the total operating expenditure of both integrated networks in fulfilling the gas and electricity demands.

The cost components included gas feedstock and storage, electricity generation costs (i.e., fuel and varying operation), gas supply/distribution cost and unserved energy cost. Gas-fueled power plants, electrically-powered gas compressors and 70% efficient-electrolysers acted as links between the electricity and gas grids.

The electrolysers served to convert excess wind power to hydrogen injected into the gas network, hence to avoid electricity curtailment, improve the gas grid integrity and lifetime, and decrease the dependence on natural gas importation and their price vulnerability.

To reduce computational expenses, the model iteratively performed separate calculations for the power and gas networks, rather than through a simultaneous, coupled network optimization.

When restricting the maximum hydrogen content to 5% (volume %) in the gas grid, PtG could reduce wind curtailment by 27% and 62% for typical high and low demand days, respectively.

When getting rid of hydrogen concentration, all limitations could be excluded.

PtG activity was primarily needed in morning periods of less demand and high wind power generation.

For the low-demand day, the maximum aggregated hourly PtG capacity reached 4.4 and 12 GW when restricting and unrestricting maximum hydrogen concentration to 5% in the gas grid, respectively.

PtG units were mostly required in the Northern part of the country (i.e., Scotland, North England and Wales), due to significant wind generation and gas network capacities.

By substituting part of the gas demand, electrolytic hydrogen contributed to decrease gas flow and compression work at gas terminals.

PtG was found to reduce the combined network operating expenditure by 7–8% depending on demand and whether hydrogen concentration in the gas grid was constrained.

The upper bound hydrogen concentration that minimized the combined gas and electricity network operating expenditure was found to be 3%, leading to a recommendation that the maximum allowable 0.1% hydrogen ratio in the gas grid must be re-considered.

Qadrdan et al. (Qadrdan et al. 2017: 181) enhanced their combined gas and electricity network model (Clegg & Mancarella 2015: 1234) using a rolling methodology to simultaneously optimize the coupled power and gas networks, to more realistically model the time-dependent operation of energy storage systems and improve computational efficiency.

The effectiveness of three alternative options (i.e., gas-fired plants with improved flexibility, pumped hydroelectricity storage, and PtG) to tackle electrical grid balancing issues arising from the incorporation of large-capacity wind generation in the UK in 2030 was compared.

An electrolysis capacity of 6 GW with an efficiency of 70% was taken into consideration to produce hydrogen to be injected in the the gas grid.

The electrolysers were assumed to be located at any potential busbar and corresponding gas node of the electricity and gas network, respectively.

The amount of hydrogen produced by electrolysis was optimized as part of the cost minimization procedure.

PtG was found to enable the largest avoidance in wind curtailment in winter, closely followed by hydro storage, but the opposite trend was observed in summer due to a lower hydrogen demand than in winter.

At an overall 42% PtG efficiency (including reconversion of hydrogen to power in combined cycle gas turbines), higher energy losses and consequently higher operational costs were incurred than for hydro storage;

PtG's cost in the other hand stayed less than for the flexible gas fired power plants option, partially because of their low capacity factor.

On a grid scale hydro-electricity storage could allow the widest reduction in OPEX (up to 3 and 12 million USD in a standard summer and winter week).

While, it was shown that PtG would present the advantage of distributing hydrogen rather than electricity, which decrease grid limitations.

Ameli et al. (Ameli et al. 2017: 841) also applied the combined gas and electricity network model of Qadrdan et al. (Qadrdan et al. 2017: 181) to explore the relative potentials of electrochemical and power to hydrogen storage to improve the flexibility of the UK's 2030 energy system with substantial wind and solar fluctuating power.

At every fixed installed storage capacity for every technology, PtG was found to eliminate a significantly greater amount of wind cut than batteries, particularly in a typical winter week, where curtailment could be eliminated, not like the batteries option.

But, for the same presumed specific CAPEX, electro-chemical storage was expected to take to a greater decrease in the OPEX of the mixed electricity and gas grids than PtG.

This was obvious in winter and was referred to the decreased participation of high peak power facilities.

The PtG stimulated cost decreasing was stronger in summer than in winter because of a combination of less demand and avoid more limitations.

4.1.5 FRANCE

According to 2013, France is at a 40 GW renewable electricity generation capacity (25 GW hydro, 8 GW wind, 5 GW solar), and 63 GW nuclear electricity capacity with a yearly utilization factor of 73%.

To decrease surplus electricity generation and follow the routine demand profile, high reactor control techniques are used, with many nuclear installations regularly shut down.

This reduces the return on nuclear CAPEX and can elevate the volume of effluent nuclear waste generated.

Other measures include curtailment and electricity exports (i.e., 52 TWh of the total 402 TWh nuclear generation), but the latter will no longer be enough with higher renewable shares in the future (Kouchachvili & Entchev 2018: 456).

France targets 40% and 32% of renewables in electricity generation and final energy consumption, respectively, by 2030, with 30% reduction in fossil fuel consumption by 2030 relative to 2012 level.

Nuclear electricity will be taken down to 63 GW, that represent 50% of total electricity share, with comparison to 80% in 2013.

To absorb large future shares of excess renewable and nuclear electricity, Scamman and Newborough (Scamman & Newborough 2018: 10080) evaluated the potential deployment of PtG in the French energy system.

The feasibility of transforming surplus nuclear generated electricity to hydrogen or SNG via PtG for mobility applications, injection in the network, or underground storage to help decarbonizing the French energy mix, was discussed based on the amount of excess nuclear electricity generated over the period 2011–1013, rather than attempting to predict future renewable and nuclear capacities (Scamman & Newborough 2018: 10080).

Nuclear load profiles corresponding to the data sets of the years 2011, 2012 and 2013 were considered for this analysis.

The proportions of transport fuels, gas and electricity demands were the same, but the gas consumption profile had the widest seasonal fluctuations.

It was found that to meet the complete hydrogen demand for mobility, plus a 5% hydrogen concentration in the gas grid, a 2050 PtG strategy would require less than half of the currently generated excess nuclear electricity.

It was suggested that up to 6GW of electrolysis capacity would meet 2030's mobility fuel and gas grid injection demands, while "valley filling" low-production periods of the weekly 2013 nuclear generation profile.

On the other hand, 20 GW electrolysis capacity would be required to valley-fill the annual 2013 nuclear load profile—this would comfortably meet both the mobility and 5% gas grid injection demands.

Most of the hydrogen produced could be transformed to SNG, which would decrease natural gas consumption by 7%.

4.1.6 SWITZERLAND

With approximately 56% hydroelectricity and 40% nuclear power in 2014, the Swiss electricity sector is close to being decarbonized (Kannan, R.; Turton 2016: 211).

However, hydroelectricity causes seasonal fluctuations in electricity generation, where a solution is mandatory to replace nuclear installations after their suspension.

For the 2015–2030 Swiss energy system, Parra et al. (Parra et al. 2016: 3748) compared the techno-economic performance (i.e., life cycle efficiency, capacity factor, levelized cost and value, and internal rate of return) of PtG systems utilizing alkaline or PEM electrolysers and chemical methanation, for capacities of 25 kW to 1 MW.

The systems produced either hydrogen or SNG for gas grid injection at up to 75 bar.

Furthermore, electrolysis and methanation heat were presumed to be supplied to district heating, and oxygen to the industry sector.

The provision of grid stability in the primary frequency control market was also a source of revenue.

The levelized cost of electricity supply was found to be 5% to 15% lower for AEL-based than PEM-based power to hydrogen, at MW- and kW-scale, respectively.

Even though PEM electrolysis had larger efficiency than AEL, the best durability of AEL systems resulted in wider gas production and as a consequence a higher levelized value than for PEM based power to hydrogen.

SNG production resulted in 15% to 30% higher levelized costs at MW and kW-scale, respectively, compared with hydrogen production, suggesting that SNG production may be more economically justifiable at MW-scale.

Nevertheless, hydrogen injection into gas transmission grids would be affected by its maximum 3–10% allowable concentration based on location.

4.1.7 ITALY

In 2015, the Italian power generation sector (i.e., 120 GW capacity) had in its annual generation (i.e., 317 GWh) 58% thermal power, 14% hydro-electricity, 7% solar, 4% on-shore wind, and 2% geothermal, with the rest of the need through electricity importation (Guandalini et al. 2017: 13389).

The geographical conditions of the country restrict the implementation of a blended electricity grid in central geographical locations and would affect the perspective of energy storage technologies.

4.1.7.1 Assessment of Power to Hydrogen Potential in the Italian 2050 Energy System

Guandalini et al. (Guandalini et al. 2017: 13389) assessed the power to hydrogen potential from on-shore wind and solar PV in the Italian 2050 energy system.

Wind and solar photovoltaic capacities of 9 to 49 GW and 19 to 98 GW, respectively, coupled with the yearly demands of 290 or 350 TWh, were taken in five different future energy scenarios. The PtG prospect assessment was considered on the forecasted residual load.

A positive backward load is the part of the electric load that has to be met by conventional or controllable renewable power plants after varaying renewables, which are in priority.

A negative residual load from excess variable renewable generation refers to surplus electricity, and implies the must for storage, in this instance via PtG. Presuming no grid balancing, annual surplus electricity was concluded to range from 2 GWh (0.7% annual demand) to 51 GWh (17.6%) depending on the different energy scenarios.

Wider amounts of surplus electricity generation were seen at high wind to photovoltaic ratios than at the same photovoltaic to wind ratio, because of wind power being more desynchronized by daily demand.

At 51 GWh surplus electricity, it was concluded that either ~5% of Italy's current natural gas need for heating, or 7% of its actual transportation fuel consumption, could be phased out by electrolytic hydrogen utilized in fuel cell vehicles.

The eliminated transportation fuel would show the yearly consumption of 6.5 million cars or 95,000 buses.

It was also found that saturation of the transmission lines could result in up to 50% higher synthetic gas production.

4.1.7.2 Power to Hydrogen Potential in Italy

Nastasi and Lo Basso (Nastasi and Lo Basso 2016: 5) presented generic, combined electricity and heat generation strategies at national, district and building level that implemented the involvement of electrolytic hydrogen utilization technologies.

PtG aspects concentrated on hydrogen applications, rather than the planning of PtG implementation details in a defined regional/geographic energy system.

Four hydrogen end-uses were recommended to support renewable electricity generation portions of 25–50% in modeled generic energy system structures illustrating national-scale (e.g., Italian) power and heating sectors in the next two decades.

Due to the lack of either a hydrogen grid, or hydrogen vehicles and related legislation, hydrogen was not taken into consideration for use as a pure fuel, and the transportation sector was suspended from the energy systems' models.

While, hydrogen played in four possible roles as: a natural gas blending fuel (i.e., 20% hydrogen by volume) for gas grid distribution and combustion, either in combined heat production for electricity and heat production, or in gas engine driven heat pumps for heating; a working fluid in metal hydride adsorption heat pumps driven by electrolyser heat and used in heating applications; a feedstock for catalytic synthetic natural gas production.

The share of hydrogen energy use (relative to the energy demand) attributed to each hydrogen application was optimized as a function of renewable share by reducing primary energy consumption.

SNG synthesis required the largest hydrogen use of all four types of hydrogen applications.

However, larger primary energy savings were obtained for the other hydrogen applications.

This was allocated to the use of hydrogen for heating in gas driven heat pumps, and the positive effect of hydrogen blending on combined heat production efficiency.

4.1.8 BELGIUM

4.1.8.1 Hypothetical Interactions between Large Scale Electricity, Gas and CO_2 Infrastructure

Vandewalle et al. (Vandewalle et al. 2015: 28) analyzed the interactions between hypothetical large-scale electricity, gas and CO_2 infrastructures using a mixed-integer linear programming model of a simplified energy system with a high share of fluctuating renewable power.

This system composed of the electricity, gas and CO_2 infrastructures, PtG installations, and backup gas generators with CCS. Equal solar photovoltaics and wind electricity generations were presumed.

Power to methane was chosen to store surplus solar/wind electricity, with SNG injected into the gas grid for re-electrification and other domestic applications, and to supply captured CO_2 for hydrogenation.

Current demand, power generation and gas demand data from the Belgian energy system were used.

The total yearly investment and operating/maintenance expenses of the energy system was decreased under constraints including operating characteristics of the power generators.

Renewable power production costs, curtailment, surplus electricity price and CO_2 costs were dropped.

The renewable power portion of the minimum cost energy system was forecasted at 69% and 76% without and with PtG, respectively, when assuming the residual load covered by SNG/natural gas fired power installations.

At the minimum OPEX identified, PtG could not fully get rid of curtailment.

Renewable generation and PtG implementation were concluded to result in increased temporal fluctuating of the gas demand and imports, needing increased flexibility of the gas grid.

It was found that by reducing the gas demand, renewable power could take to a lower import gas prices that could be widely influenced by SNG cost.

PtG also decreased the need for CO_2 storage through CO_2 sinking for SNG synthesis but was forecasted to require a developed CO_2 transmission/storage network.

In general, this work showed the increased extent and complexity of the interactions between the electricity, gas and CO_2 domains, in the presence of wide renewable portions and PtG.

Future modeling enhancements include extending the analysis to a broader range of electricity generation technologies at different shares in alternative scenarios, inclusion of other (non-power) sectors of the energy system, analysis of PtG capacity sizing and distribution, a wider range of candidate PtG applications, long term instead of spot market pricing for imported gas, and the effects of uncertitudes.

The results could help in improving the operation and regulation of the power, gas and CO_2 systems, and linked policy making.

4.1.8.2 Effects of the Fluctuating Electricity Remaining Demand on Storage Capacity Requirements

Belderbos et al. (Belderbos et al. 2017: 137) assessed the impacts of the fluctuating electricity remaining demand on storage capacity requirements.

The residual demand was specified as the difference between demand and production at a given time, in a system characterized by an optimized renewable power and storage capabilities.

Desultory technologies had charging/discharging power and energy storage capacities that may be optimized independently, such as PtG SNG synthesis (charging and storage) and SNG fired power generation (discharging).

Batteries were an integrated charging/storage and discharging technology.

The optimal combination of the two types of storage technologies to take care of a given remaining load was characterized by minimizing storage and renewable electricity generation investment expenditures, on account of technical storage technology constraints, for renewable power portions of up to 100%.

This optimization was taken by using as input actual demand and on/off-shore wind and solar photovoltaics generation data from the Belgian power sector.

Desultory storage was concluded to be mandatory for remaining demands requiring large energy to power storage capacity shares (monthly/seasonal demand production mismatch styles, that normally occur at wide renewable shares, for instance more than 50%).

By contrasting, integrated storage was concluded to be mandatory for remaining demands with wide power to energy storage capacity ratios (daily/weekly mismatch styles that would occur at least renewable shares).

Such an analysis, particularly if taken to the actual, total energy system and storage deployment details may assist in the optimization of storage investments.

4.1.9 FINLAND

Finland has reached an overall renewable energy consumption of 32% including 40% share in power generation, and targets 38% overall renewable share by 2020 to meet its committed 80–95% GHG emissions reduction compared to 1990 levels, resulting in zero GHG emissions (Child & Breyer 2016: 517).

Finland has several electricity grid interconnections with neighboring countries, enabling electricity imports primarily and exports.

4.1.9.1 PtG as a key player in the future energy system of Finland

Child and Breyer (Child & Breyer 2016: 517) examined Finland’s integrated future energy system in 2050 with power, heating/cooling, and mobility as interacting components.

They defined eight re-carbonized energy system scenarios for Finland, aimed at both eliminating or reducing overall CO_2 emissions, and replacing fossil carbon-based fuels with either synthetic ones or with fuels derived from biogenic sources.

Analyzed at hourly resolution, the scenarios combined varying capacities (i.e., low to high) of nuclear, biomass and other renewables, collectively representing up to 100% share of the installed power generation capacity.

Up to 42.5 GW wind power, 35 GW solar photovoltaic, 3.5 GW hydro-power, and 9 GW biomass-based CHP capacities were taken into consideration, with up to 4.3 GW nuclear power capacity.

The flexibility of the energy system in handling high portions of variable renewable energy generation, with varying levels of nuclear power and forest biomass-based CHP, was assessed using EnergyPlan software, concentrating on the role of PtG (with H_2 and SNG as products), PtL, and other energy storage technologies. An efficiency of 73% for electrolysis was presumed.

CO_2 for methanation was taken from air, and methanation heat was used for district heating.

PtG capacities of up to 32.3 GW and 0.6 GW for SNG and H_2 production were considered, respectively.

It was found that 100% renewable energy scenario would be feasible and would result in a system having the lowest Finnish energy system overall annual cost at 24.1 b Eur /annum, while increased shares of nuclear power would take cost upwards.

PtG (up to 15 GW) and PtL (up to 10 TWhth) could offer robust and flexible storage solutions for excess power generated from intermittent renewable resources.

The Finnish energy system would reach a high degree of independence, with natural gas imports phased out.

4.1.10 Alpine Region Including Austria

Mesfun et al. (Mesfun et al. 2017) have gone through the economic feasibilities of power to gas and power to liquid processes to transform excess renewable electricity to SNG (as a fuel substitution for district heating), methanol (as substitution for gasoline in transportation) in the Alpine region, including Austria, France, Germany, Italy, Slovenia, and Switzerland.

The renewable share consisted of biomass (transformed to heat, power, and biofuels, implementing biomass steam turbines, CHP, and incorporated gasification combined cycles), constant hydro-electric power, solar photovoltaic and wind.

Coal-fired plants and natural gas provided back-up power, respectively.

The obstacles imposed by the Alpine topology and protected areas were considered to find out the possible locations of future power installations.

Solid-oxide co-electrolysis of water and CO_2 was taken to produce syngas, with was further transformed to SNG and methanol at a forecasted total 70% efficiency.

Available pre-determined power to gas and power to liquid installation locations were assumed to be close to CO_2 supply sources (like the centralized and distributed thermal power generation installations) to get rid of CO_2 transportation.

Instead of assuming a fixed renewable power portion, the generation of renewable electricity, as well SNG and methanol, was assumed to reduce the total cost of the energy supply grid using a combined integer linear programming model.

This assumption was taken in function of carbon prices (0–200 €/ton) and fossil fuel prices (0–100% more than market prices), using 2010 electricity demand data and a large energy demand and supply network spatial resolution.

Surplus electricity generation was assumed to range from 0.85 to 65 GW (0–93 TWh) for a total yearly demand of 530 TWh.

Instable renewable electricity share (i.e., solar PV, wind) and synthetic fuel generation were concluded to increase at high carbon and fossil fuel prices, however low carbon prices led to larger natural gas and hydroelectricity generation, and power curtailment.

Because of the respective applications of methanol (like transport) and SNG (like heating), thus corresponding displaced fossil fuel prices, methanol generation was preferred over SNG production.

Almost 11% of the gasoline need could be swapped by methanol, over the range of carbon and fossil fuel prices taken in consideration, In addition, almost 15 million tons of CO_2 could be avoided annually by power to gas and power to liquid, while fossil fuel swap by renewables for transportation, heating and power generation could lower CO_2 emissions by 22 to 103 million tons on an annual basis.

4.2 Distributed Scale Projects and Perspectives in Europe

4.2.1 PtG and Coal Power Plant Integration

The need for surplus electricity storage in Germany arises because of the increasing renewable shares and the consequent decrease in the operational load of lignite-fired power installations (LPPs), which lead to higher electricity cost.

Buchholz et al. (Buchholz et al. 2014: 7993) assessed the coupling of an 80 MW alkaline-based PtG-SNG installation and standard 800 MW lignite power plant to store surplus energy and improve LPP economic profitability.

Since the PtG plant absorbs the surplus of LPP loads, the LPP can works at fixed load and avoid the extra operating expenses related to load-following.

Additionally, the LPP lifetime is ameliorated.

Three candidate methanation thermal setups (isothermal, adiabatic and combined) were in comparison in terms of capital and operating expenses, operability, controllability, technology development, safety and flexibility.

The former was chosen because of its less capital equipment requirement.

The heat thrown by the methanation reactor was taken for steam production, either as supply to the LPP or to the amine based LPP fuel gas CO_2 capture.

The number of heat exchangers and heating/cooling facilities were reduced using a heat incorporation pinch analysis.

The cooling water to control the temperature of the methanation process was taken from the LPP pre-boiler supply water stream.

In time of using SNG to produce electricity to decrease the LPP boiler heat duty, the general power to power efficiency was assumed at 29%.

The corresponding decrease in LPP lignite consumption was concluded to be negligible (less than 1% by mass).

Dynamic operation wise, the CO_2 capture was found to be the obstacle process. Based on SNG prices compared to natural gas prices, the PtG-LPP hybridization was only concluded to be profitable when accounting for the decrease in LPP operating costs because of its operation at fixed load when connected with PtG, instead of load-following when functionning as stand-alone.

The future decrease in electrolysis cost and increasing renewable potion were forecasted to ameliorate the value of this hybridization.

4.2.2 PtG and Kraft Pulp Mill/Biodiesel Production Plant Integrations

Together CO_2 capture and oxygen consumption have huge importance for pulp mill energy efficiency.

Breyer et al. (Breyer et al. 2015: 182) have taken an integrated value chain approach for assessing the economic benefits that could be reached by integrating a PtG installation with either a current pulp mill or a biodiesel production installation in Finland.

The PtG installation fed oxygen to the kraft and paper mill, and it was also suggested to utilize methanation heat for a CO_2 capture.

The kraft pulp mill generated wood-derived CO_2 for methanation and deionized make-up water used for electrolysis.

The utilization of electrolytic hydrogen for methanation or bio-diesel generation (to raise the value of bio-diesel) from pulp and paper mill by-products were assessed.

Additionally, it was proposed to use the electrolyser for network frequency containment regulation.

Finding a standardized viable business case for PtG was concluded to be difficult, but, with progress in PtG technology, it was assumed that viable business models could be achieved by 2020.

It was suggested that all possible sources of revenue should be used, including the generated PtG gases in markets where they would attain the top possible value (like mobility), the power to gas oxygen by-product, power to gas grid services, and that the power to gas plant should be driven by low-cost electricity and function at a high load utilization factor.

4.2.3 PtG and Biomass Combined Heat and Power Plant Integrations

Tsupari et al. (Tsupari et al. 2016: 62) presented a detailed analysis of a PtG process incorporating a 10 MW electrolyser integrated with an existing 300MWfuel biomass co-fired (i.e., peat and forest residues) CHP plant in Finland.

The CHP plant integrated a boiler to co-fire peat and forest residues and could flexibly support moist feedstocks and mixed feedstocks.

The CHP facility provided electricity and CO_2 for the electrolysis and methanation processes, respectively.

In return, the PtG process fed part of the oxygen enrichment to the CHP installation combustion process.

Oxygen enrichment allowed increased fuel processing capacity, which was applied to generate additional electricity in a steam cycle and heat for district heating application.

This thermal energy partly swapped the heat traditionally generated by district boilers.

The PtG plant was presumed to operate only during low-cost electricity periods and could help in frequency control to the grid.

When used, this service, together with SNG generation, were the most important income generator.

But, at actual renewable integration levels in the country, the size of the frequency control market was found to be too limited.

The revenues from electrolysis oxygen utilization in the CHP installation were concluded to be highly dependent on the price of the additional heat generated by the CHP plant for district heating.

Additionally, high CO_2 prices were concluded to improve profitability, but lowered the value of oxygen because of an increase in peat-fueled CHP operating cost, when electricity prices did not get high.

The installation capital cost and electricity price were found to be the most significant expenses.

This CHP-PtG incorporation could only be profitable in less than ten years for the larger electrolysis efficiency value (70% versus 62% base case) or higher SNG price in Finland, considering local electricity prices.

Analyzing many market scenarios, it was concluded that the same PtG concept could lead to profitable business cases in Germany, where electricity cost is lower than in Finland (Tsupari et al. 2016: 62).

In parallel, the same authors (Kärki et al. 2016) pre-screened and discussed the techno-economic feasibility of several conceptual industrial PtX integrations schemes, including PtG, in the short term and on a location-generic rather than location-specific basis, in sectors including pulp and paper, CHP, water purification, oil refining and iron/steel (Kärki et al. 2016).

The utilization of at least three PtG products (heat, steam and oxygen), as well as avoidance of electricity distribution and CO_2 supply costs, were recommended for the amelioration of economic viability.

Several options for heat, steam and oxygen utilization were assessed.

Although transport fuels were assumed to be the most profitable PtX products, it was found that PtG schemes were near to also becoming economically viable projects, subject to the promotion of carbon-neutral CO_2 via supporting measures, like increasing CO_2 prices.

4.2.4 PtG and District/Building Integrations

Nastasi and Lo Basso (Nastasi and Lo Basso 2016: 5) suggested many electrolytic hydrogens uses in generic national energy systems same in generic district and building environments for application in the next two decades.

Hydrogen was mixed with natural gas for combustion in CHP units for heat and electricity production, and in gas engines to conduct adsorption heat pumps for heating.

Hydrogen also played as a working fluid in metal hydride adsorption heat pumps conducted by electrolyser heat and employed in heating applications, and for catalytic SNG generation.

Low-temperature electrolysis heat losses were utilized to regenerate the regeneration hydride of the metal hydride heat pumps, by thermal integration between the power to hydrogen system as well for heating application.

Following this approach, the electrolyser co-generates hydrogen and thermal energy, thereby improving its efficiency above unity.

CO_2 for SNG synthesis was taken from combustion processes, thus reaching a closed-loop (quasi of fully)-neutral carbon cycle.

De Santoli et al. (De Santoli et al. 2017: 424) assessed applications of natural gas-blended electrolytic hydrogen in existing European buildings instead of new constructions, to lead to primary energy savings.

The mixed hydrogen was used as a combustion fuel to drive CHP and adsorption gas-driven heat pumps, while building-incorporated solar PV and hybrid PV-thermal collector (PVT) modules was not able be fitted on roof surfaces.

These electrolytic hydrogen utilizations lowered the need for additional renewable power installations.

Nastasi and Lo Basso (Nastasi and Lo Basso 2016: 5) went further with their heat provision strategies to different temperature levels in existing building mixes in Rome, Berlin, and Copenhagen, for renewable electricity production shares of 25–50% representative of the following two decades.

The building energy models were specified by different power to heat ratios and heat consumptions at every temperature level. The natural gas-mixed hydrogen was combusted in CHP to supply high temperature heat (70–120 °C) and in gas engines to provide medium temperature heat (60–65 °C), as a substitution of traditional boilers.

The highest renewable heat share was obtained for the Copenhagen urban model, although the high share it has of low-temperature heat consumption.

This was allocated to the fuel switching directly affecting all medium and high-temperature heat supplies, and indirectly network electricity savings.

4.2.5 PtG and Winery Integration

The energy needs of the wine industry for irrigation, farming, processing, and transportation reflect significant seasonal and daily variations, and are currently supplied by fossil fuels.

Winey yards and wineries are generally present in remote areas.

Carroquino et al. (Carroquino et al. 2018: 251) suggested the use of solar PV electricity to supply the energy demand of a Spanish vineyard irrigation pumping system and the waste water treatment installation of a winery.

To help in stabilizing the micro-grid, surplus solar electricity was stored using a combination of a 129-kWh battery and alkaline-based power to hydrogen installation, for short-term and longer-term storage, respectively.

Reverse osmosis was used to purify the electrolytic water feedstock.

The generated hydrogen was compressed at 200 bar (109 m^3 storage capacity), stored in a refueling station and utilized on-site in hybrid battery electric-PEM fuel cell vehicles.

The efficiency of the solar PV-to-vehicle wheels conversion chain was considered at 24.6% to 30.5%.

72 MWh of solar PV electricity was produced annually, of which 6.4 MWh was transformed to 1214 m^3 of hydrogen.

Solar PV electricity generation was concluded to both be economically viable and save 1010 L of diesel consumption and 2.7 annual tons of CO_2 emissions, compared with the actual use of grid power and diesel generators.

4.2.6 Pilot PtG Plant and Compressed Natural Gas Vehicle Refueling Network Integration

Finally, in terms of industrial pilot PtG installations, it is worth noting that among the number of European-based PtG demonstration projects listed in (European Power to gas demonstrations: 2018), the largest operational one (6.3 MW capacity), Audi's CO_2-neutral e-gas mobility system , is an industrial initiative.

This PtG facility produces SNG from hydrogen synthesized by alkaline electrolysis from a standalone wind power plant, and CO_2 from an organic waste-fueled biogas plant.

5 DEMONSTRATED PROJECTS AND STATISTICS

Overall in Europe 128 demo-projects concerning PtX have been, are or will be in operation (as per the end of 2017; including dismantled and planned projects) to get experience with systems integration of PtX components.

All projects and characteristic systems parameters are listed in Table 2.

The projects are regrouped by their field of application: blending of hydrogen or methane into the natural gas network, re-electrification with CHP, fuel generation or industry applications.

Some projects do not mention the usage of the generated gas because the focus of these projects lies on the system components.

Among 128 projects, 27 are already completed while 38 are not yet commissioned. Consequently, 63 projects were functional by end of May 2018.

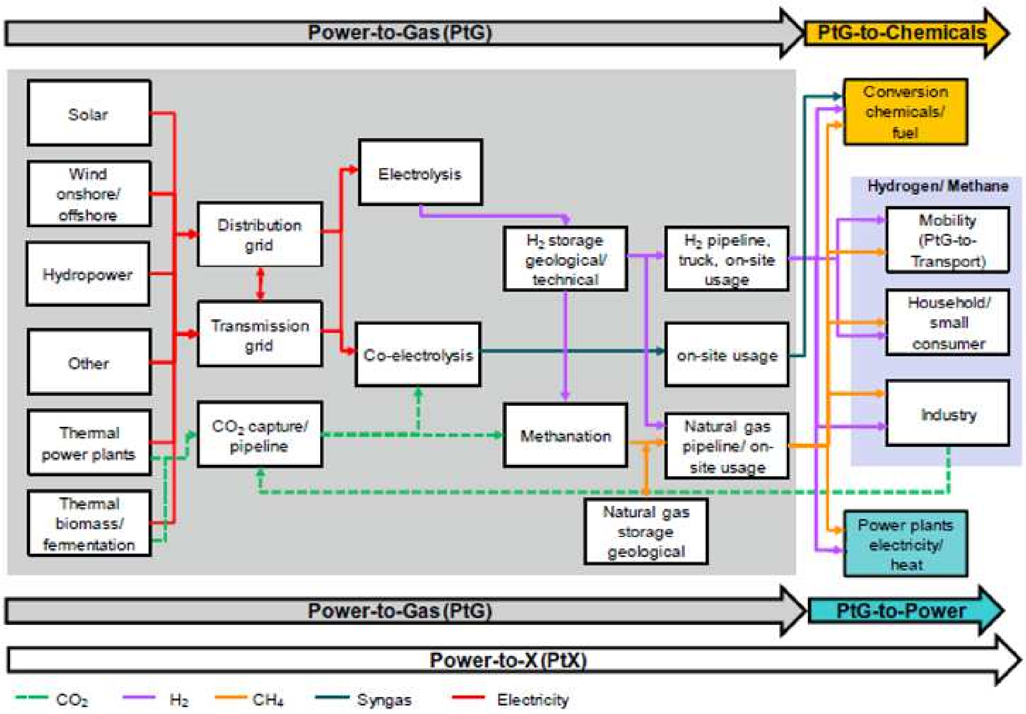

Fig.10: Overview of Power to X concepts. Source: Review of Power to Gas projects in Europe 12th International Renewable Energy Storage Conference, IRES 2018

Table 2: Demonstrated Power to X in Europe. Source: Review of Power to Gas projects in Europe 12th International Renewable Energy Storage Conference, IRES 2018

Acronym/ location/ name of the project	Type of Electrolyzer	Capacity kW	Commissioning	TRL	Processing H_2	Country
Hybrid power plant Prenzlau[a]	Alkaline	500	2011	7	-	Germany
Morbach	Alkaline	25	2011[f]	7	-	Germany
H2-Researchcentre BTU	Alkaline	145	2012	6	-	Germany
Methanation at Eichhof						
1st	n.s.	25	2012[f]	6	cat. Methanation	Germany
2nd	PEM	50	2018	6	cat. Methanation	Germany
Power to Gas at Eucolino	n.s.	108	2012[f]	6	cat. Methanation	Germany
Hybrid power plant Falkenhagen - STORE&GO Germany	Alkaline	2,000	2013	7	cat. Methanation	Germany
Audi e-gas	Alkaline	6,000	2013	7	cat. Methanation	Germany
Foulum	n.s.	250	2013[f]	6	bio. Methanation	Denmark
Viessmann microbial methanation	PEM	275	2013[f]	6	bio. Methanation	Germany
GRYHD[b]	PEM	n.s.	2014	6	-	France
Rozenburg	Alkaline	8.3	2014	6	cat. Methanation	The Netherlands
Thüga demonstration plant	PEM	300	2014	7	-	Germany
RWE demonstration plant	PEM	150	2015	7	-	Germany
WindGas Hamburg	PEM	1,000	2015	7	-	Germany
Energiepark Mainz[c]	PEM	6,000	2015	7	-	Germany
Energy Storage – Hydrogen Injected into the Gas Grid via Electrolysis Field Test	PEM	5.5	2015	7	-	Denmark
Biogas upgrading	SOEC	~50	2016	5	cat. Methanation	Denmark
DemoSNG	PEM	~60	2015	6	cat. Methanation	Sweden
BioPower2Gas	PEM	1,200	2015	6	bio. Methanation	Germany
Energy park Pirmasens-Winzeln	Alkaline	2500	2016	7	bio. Methanation	Germany
Hybrid power plant Aarmatt - STORE&GO Switzerland	PEM	700	2015	7	bio. Methanation	Switzerland
BioCat Project/POWERSTEP	Alkaline	1,000	2016	7	bio. Methanation	Denmark
bioCONNECT	PEM	n.s.	2016	5	bio. Methanation	Germany
Ingrid – STORE&GO Italy	PEM	1,000	2016	7	cat. Methanation	Italy
Renovagas	Alkaline SPE	15	2016	6	bio. Methanation	Spain
Integrated High-Temperature Electrolysis and Methanation for Effective Power to Gas Conversion	SOEC	15	2017	5	cat. Methanation	Germany
Minerve	SOEC	n.s.	2017	5	n.s. Methanation	France
CO2-SNG	n.s.	n.s.	2018	6	cat. Methanation	Poland
HyDeploy	PEM	500	2019	7	-	United Kingdom
Wind to Gas	PEM	2400	2019	7	-	Germany
Jupiter 1000	Alkaline/ PEM	500+ 500	2018	7	cat. Methanation	France
HyStock	n.s.	1,000	2018	7	-	The Netherlands
Swisspower Hybridkraftwerk	n.s.	2,000	2018	6	bio. Methanation	Switzerland
Symbio	n.s.	n.s.	~2018	6	bio. Methanation	Denmark
SYNFUEL	SOEC	n.s.	~2019	5	cat. Methanation	Denmark
Greenlab Skive	Alkaline	n.s.	~2020	6	cat. Methanation	Denmark
H2V Product						
1st	Alkaline	100,000	2020	8	-	France
2nd	Alkaline	600,000	2025	9	-	France
Power-to-Gas Hungary	n.s.	10,000	projected	7-8	bio. Methanation	Hungary
Heat and power generation						
HARI	Alkaline	36	2004[f]	6	-	United

Table 2: continued

Acronym/ location/ name of the project	Type of Electrolyzer	Capacity kW	Commissioning	TRL	Processing H_2	Country
						Kingdom
Utsira	Alkaline	50	2004[f]	6	-	Norway
Vestenskov	n.s.	n.s.	2006[f]	6	-	Denmark
RES2H2 Pozo Izquierdo	Alkaline	100	2007[f]	6	-	Spain
Hidrolica	PEM	30	2007[f]	6	-	Spain
HYRES	PEM	4.5	2008[f]	6	-	Greece
Abalone Energie	Alkaline	n.s.	2009[f]	6	-	France
H2KT	Alkaline	100	2010	6	-	Denmark
Myrthe	PEM	210	2013	6	-	France
RH2-WKA Grapzow	Alkaline	1,000	2013	7	-	Germany
La Croix Valmer	PEM	n.s.	2014	7	-	France
Spring Bank Farm[h]	Alkaline SPE	4.8	2014	6	-	United Kingdom
El Tubo	Alkaline SPE	2.4	2015	6	-	Spain
Exytron demonstration project	Alkaline	21	2015	7	cat. Methanation	Germany
Zero-Emission-Wohnpark	Alkaline	62.5	2017	7-8	cat. Methanation	Germany
Stromlückenfüller						
Test	PEM	20	2015	6		Germany
Pilot phase	PEM	200	projected	7		Germany
Hybrid plant	PEM	1,000	projected	7		Germany
Power-to-Gas Haßfurt	PEM	1,250	2016	7		Germany
Smart Grid Solar	PEM	75	2016	6		Germany
Power-to-Flex	Alkaline	n.s.	2018	6-7	bio. Methanation, Methanol	Germany/ The Netherlands
HYPOS LocalHy	Alkaline	250	2018	7	-	Germany
Haeolus[h]	PEM	2,000	2020	8	-	Norway
Fuels						
HyFLEET:CUTE Hamburg	Alkaline	400	2003[f]	6	-	Germany
HyFLEET:CUTE Amsterdam	Alkaline	400	2003[f]	6	-	The Netherlands
HyFLEET:CUTE Barcelona	Alkaline	400	2003[f]	6	-	Spain
HyFLEET:CUTE Stockholm	Alkaline	400	2003[f]	6	-	Sweden
ECTOS	Alkaline	300	2003[f]	6	-	Iceland
PURE	Alkaline	18	2005[f]	6	-	United Kingdom
RES2H2 Keratea	Alkaline	25	2005[f]	6	-	Greece
Chic Aargau	Alkaline	300	2011[f]	7	-	Switzerland
George Olah Plant						
1.	Alkaline	~1,700	2011	7	Methanol	Iceland
2.	Alkaline	~5,200	2014	7	Methanol	Iceland
Hydrogen refuelling station HafenCity	Alkaline	600	2012	7	-	Germany
Solar hydrogen filling station Freiburg	PEM	30	2012	7	-	Germany
Herten hydrogen centre of excellence	Alkaline	280	2013	7	-	Germany
Hydrogen filling station Stuttgart	Alkaline	400	2013	7	-	Germany
Sunfire Research project	SOEC	10	2014[f]	5	Fischer-Tropsch	Germany
Sunfire Power-to-Liquids	SOEC	150	2014	5	Fischer-Tropsch	Germany
Multi-energy fueling station H2BER[d]	Alkaline	500	2014	7	-	Germany
Power to Gas Biogasbooster[e]	n.s.	10	2014	6	bio. Methanation	Germany
M1 Wind Hydrogen Refuelling station	PEM	100	2015	7	-	United Kingdom
Wind2Hydrogen	PEM	100	2015	6	-	Austria
Power-2-Hydrogen-Tankstelle	PEM	185	2015	7	-	Germany
H2 Aberdeen: Hydrogen Bus Project	Alkaline	1,000	2015	7	-	United Kingdom
Rapperswil	Alkaline	25	2015	6	cat. Methanation	Switzerland
Levenmouth Community Energy Project[g]	Alkaline/ PEM	2x60 + 250	2016	7	-	United Kingdom
Don Quichote	PEM	~130	2016	6	-	Belgium
HyFive London 1	PEM	100	2016	7	-	United Kingdom
HyFive London 2	PEM	100	2016	7	-	United Kingdom

Table 2: continued

Acronym/ location/ name of the project	Type of Electrolyzer	Capacity kW	Commissioning	TRL	Processing H_2	Country
HyFive London 3	PEM	100	2017	7	-	United Kingdom
H2Mobility - Karlsruhe	SOEC	9.4	2017	5	-	Germany
FaHyance	Alkaline	57	2017	7	-	France
BIGH2IT	PEM	1,500	2018	7	-	United Kingdom
Flagship project: Power-to-Gas Baden-Württemberg	Alkaline	1,000 + 300	2018	7	-	Germany
MefCO2	PEM	1,000	2018	6	Methanol	Germany
HyBalance	PEM	1,200	2018	7	-	Denmark
H2energy	PEM	200	2018	7	-	Switzerland
Wasserstofftankstelle Kirchheim	n.s.	~30	2018	7	-	Germany
Infinity 1	PEM	n.s.	2020	7	bio. Methanation	Germany
Hydrogen for industry						
Sotavento	Alkaline	300	2007[f]	6	-	Spain
CO2RRECT	n.s.	300	2013[f]	7	-	Germany
Osshy Pushy	Alkaline	60	2013	6	-	France
Lashy Pushy	Alkaline	65	n.s.	6	-	France
Hanau	PEM	35	2015	7	-	Germany
H&R Ölwerke Schindler	PEM	5,000	2017	7	-	Germany
H2Orizon[a]	PEM	1,000	2018	7	-	Germany
GrInHy	SOEC	150	2018	6	-	Germany
Energy valley	PEM	12,000	2018	7	-	The Netherlands
HYPOS Megalyseur	PEM	2,000	2019	7	-	Germany
ALIGN-CCUS	Alkaline	~65	2019	6	DME	Germany
REFHYNE	PEM	1,000	2020	8	-	Germany
Fredericia	Alkaline	n.s.	~2020	8	-	Denmark
H2Future	PEM	6,000	2021	7	-	Austria
BASF/bse	n.s.	n.s.	projected	7	Methanol	Germany
PtG for the refining process Lingen	n.s.	6,000-15,000	projected	8	-	Germany
Usage of gas not specified						
ITHER	Alkaline/ PEM	63+7	2010[f]	6	-	Spain
SEE	PEM	6	2011[f]	6	-	Germany
PtG 250	Alkaline	250	2012	6	cat. Methanation	Germany
Hydrogen Centre	Alkaline/ PEM	55 + 12+-1	2012	6	-	United Kingdom
MeGa-stoRE						
1	Alkaline	6	2014[f]	6	bio. Methanation	Denmark
2	Alkaline	60	2016	6	bio. Methanation	Denmark
ESI Platform	PEM	100	2016	6	cat. Methanation	Switzerland
Underground Sun Storage[h]	Alkaline	600	2016	6	-	Austria
HPEM2Gas	PEM	180	2018	6	-	Germany
Demo4Grid	Alkaline	4,000	2019	7	-	Austria
HYPOS rSOC	SOEC	n.s.	projected	5	-	Germany

The number of countries investing in PtX demonstration is high.

Till now 16 countries have demonstration projects Fig.11 in Europe.

In 2003 the first projects initiated.

During this period the name PtG or PtX was not yet founded and the projects had their focus on the utilization of hydrogen instead of storing and using renewable electricity, e.g. HyFLEET:CUTE.

Since 2011, the number of projects has increased rapidly and found its maximum in 2015 with 16 projects Fig.11.

In the year 2017, just seven projects inaugurated their operation of plants, while for 2018 another 18 projects are planned to start.

However, this might reflect an increasing interest and on the other hand not all projects planned for commissioning in 2017 could meet their target and had to delay the date of commissioning (H2ORIZON 2016).

Most probably not all projects planned for 2018 and following years will start in time or even start at all as only a letter of intent exists and hold on approval of funding and/or operation license (Wirtz & Jörg 2017).

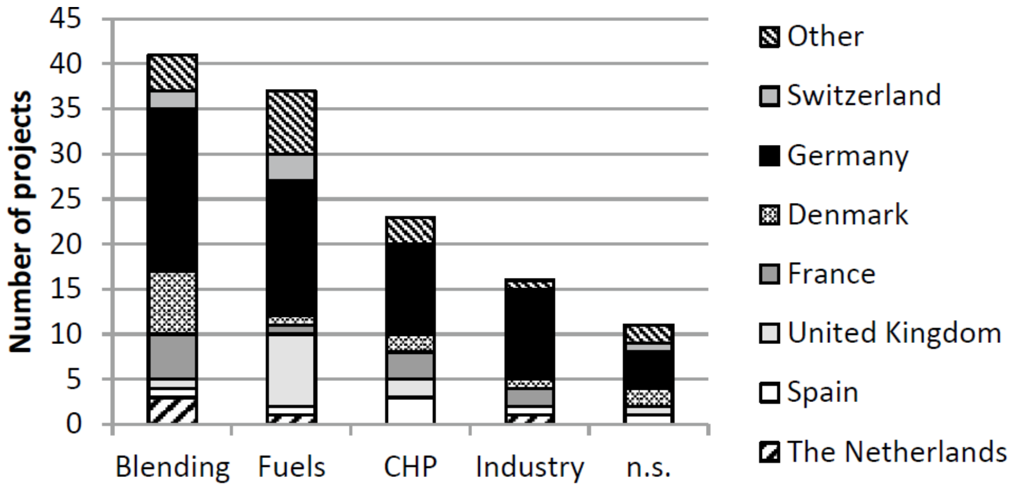

Fig.11: Spatial distribution of Power to X technologies regarding field of application (n.s: not specified). Source: Review of Power to Gas projects in Europe 12th International Renewable Energy Storage,Conference, IRES 2018

Germany has the largest share in realized demonstration projects Fig.11.

In the early years, however, other countries were more involved in this concept Spain with 28 % of the projects (i.e. five projects).

As highlighted before 16 different countries were interested so far. However, in 2017 just three countries (Germany, France and United Kingdom) implemented new electrolysers.

Regarding the field of application of these projects, some countries concentrate on special fields. For instance, Denmark has a net focus on blending hydrogen or synthetic methane, into the natural gas grid. In the other hand, the United Kingdom concentrates on utilizing hydrogen as a transportation fuel.

Spain prioritize re-electrification with CHP, while Germany lead projects in all fields.

The share of projects blending the generated hydrogen or methane into the natural gas grid (32 % of all projects, Fig.11) is larger.

In the project category “blending of gas” all electrolyser technologies are used. Even electrolysers technologies with less TRL like solid oxide electrolysers (SOEC) and alkaline solid polymeric membrane (SPE) electrolysers (Acta "Powered by nature." 2017) are taking part of demonstration projects.

This type of application focuses on utilizing cheap or surplus renewable electricity.

PEM electrolysers are the most applied technology in this field of application, particularly, due to their dynamic behavior. The category “fuels” focuses more on steady feeding of fuels. That is why, alkaline electrolysers are more existent in this field of application.

Projects utilizing PEM and alkaline electrolysers are represented equally Fig.12

Industrial applications strive towards PEM electrolysers but actually the number of projects is too small to identify a viable outcome.

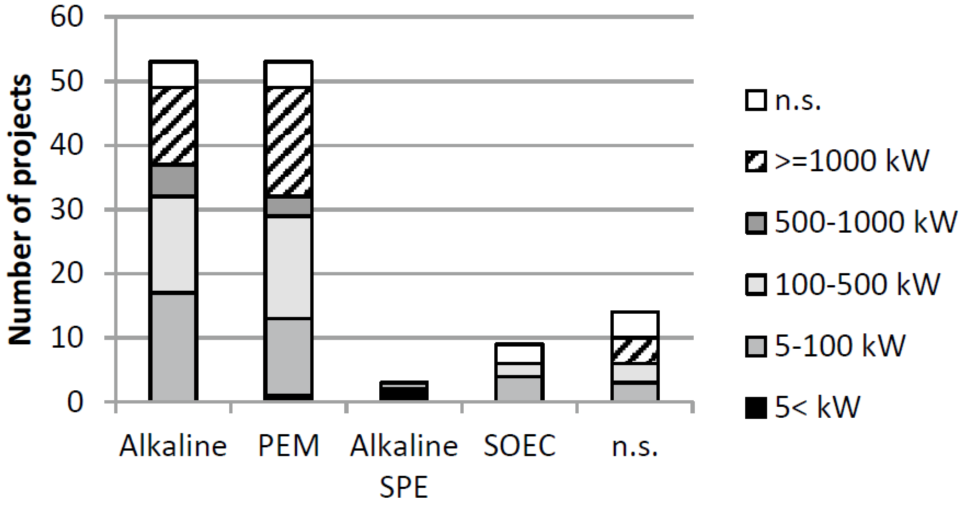

Fig.12: Electrolyser technologies in Power to X projects classified by their capacity (n.s: not specified) Source: Review of Power to Gas projects in Europe 12th International Renewable Energy Storage Conference, IRES 2018

The sequence of events of PtG demonstration projects shows that in the starting phase of all projects utilized alkaline electrolyser Fig.13. The first PEM electrolyser was put in place in 2007 and novel electrolyser technologies were not used before 2014. Since then, the PEM electrolyser became more widely spread. While, projects with alkaline electrolysers are still taking part of demonstration projects since it is a mature technology.

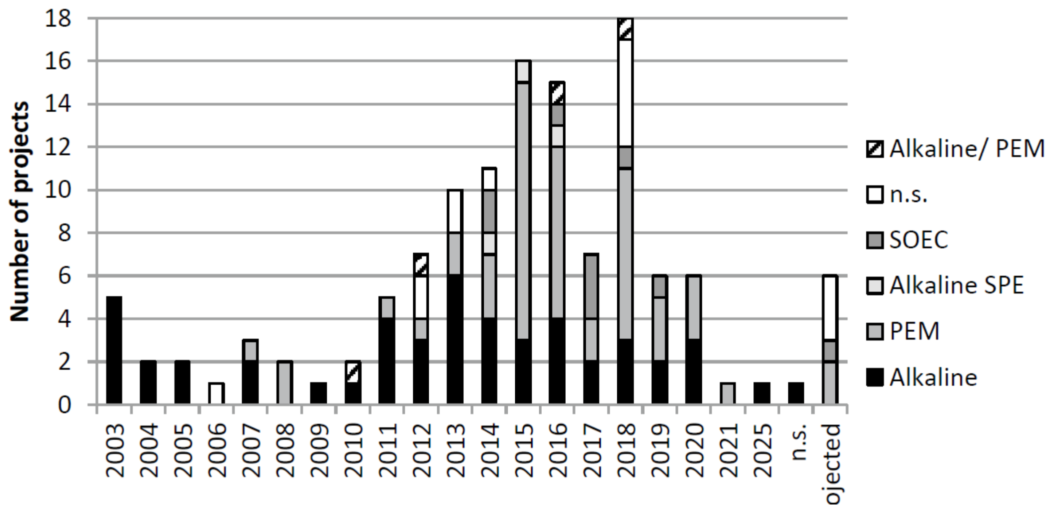

Fig.13: Temporal development of further processing of hydrogen in Power to X. Source: Review of Power to Gas projects in Europe 12th International Renewable Energy Storage Conference, IRES 2018

The trend (see Table.2) of projects for the category “Use in industry” demonstrates that refineries become more and more focused in PtG to generate green hydrogen for their processes.

In the next years, seven new projects are announced, however only five were commissioned over the last years. The historical trend demonstrates a net trend towards bigger electrolysers.

In 2018, already eight projects with an electrolysis capacity higher than 1 MW are declared. As Fig.12 already shows most of them will be with PEM electrolysers.

generally, PEM as well as alkaline electrolysers can cover the full range of capacity.

PEM electrolysers are more often utilized for higher capacities but alkaline for lower.

This is probably because of the chronology of projects with the trends towards PEM and larger hydrogen generation capacities.

Alkaline SPE electrolysers are mainly used in very small plants showing a very early stage of technical development. SOEC are still at lower TRL (Technology Readiness Level) levels and that is why they are far away from being commercialized.

however, those electrolysers, need a specified capacity (> 5 kW) to work on their full potential. As mentioned in the introduction, PtX also includes the transformation of hydrogen to other fuels and chemicals, like methanol, dimethyl ether (DME), long-chain hydrocarbons and most spreadly methane. For methanation, two different processes are used.

Since 2011 catalytic methanation is functional, see Fig.14 An additional path to generate methane is the biological process from hydrogen and carbon dioxide. The two processes will be ameliorated in several demonstration projects over the next years. There is no orientation for one technology yet.

Other fuel generation technologies are used seldomly.

Clustering the type of product by countries (Table.2) it becomes evident that Denmark has a strong choice for methanation based on biological processes.

As well, in Switzerland, some methanation is used in two-thirds of all PtX projects. Demonstration projects in the United Kingdom concentrate on hydrogen generation excluding any processing, but in Germany almost all possible PtX pathways are used.

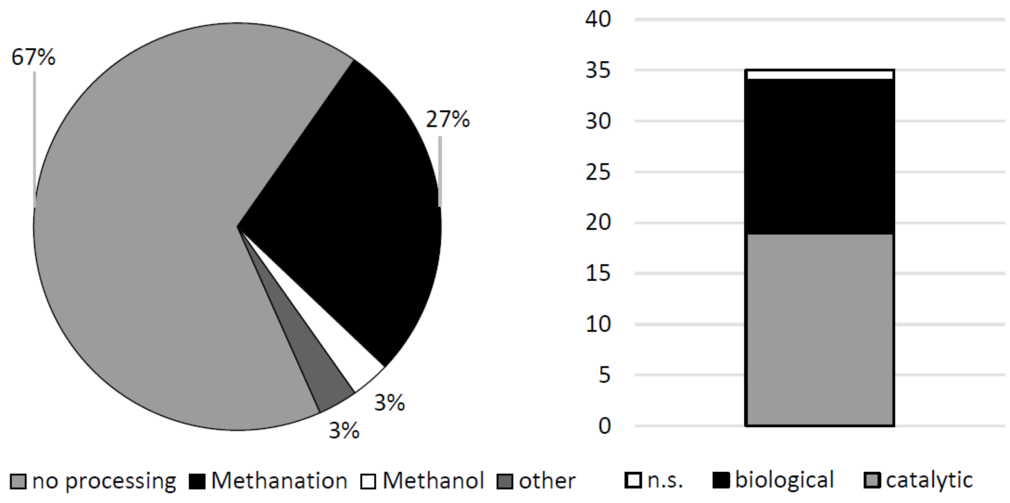

Fig.14: Share of further processing of hydrogen in Power to X. Source: Review of Power to Gas projects in Europe 12th International Renewable Energy Storage Conference, IRES 2018

6 RESEARCH TRENDS AND FUTURE OPPORTUNITIES

6.1 PtG Products

SNG was generated in the majority of suggested PtG scenarios, either as a standalone product or in jointly with hydrogen.

This shows the disponibility of a natural gas distribution, storage and end-use infrastructure, despite the additional thermodynamic losses and cost occured for the transformation of hydrogen to SNG.

Industrial PtG integrations have the unique advantage of allowing the use of hydrogen on-site in manufacturing processes and/or utilities, by the way getting rid of hydrogen transportation/distribution.

Generally, likely profitable outputs found in deployment researches include the use of hydrogen and synthetic PtL fuels in mobility (which will be boosted by leveraging fossil transport fuel prices), and power to heat in energy systems with large residential/district or industrial heat demands.

6.2 PtG Process

Given the highlights of projected PtG deployments on low-temperature electrolysis until now, future deployment researches involving solid oxide electrolysis and co-electrolysis could find new heat/pressure integration opportunities with external processes, operation in both electrolysis and fuel cell mode, and a larger range of PtX products (e.g., PtC/PtL/PtH).

Hybrid hydrogen generation processes could allow the flexible use of different power/heat sources, as well as PtG efficiency ameliorations, are subject to further development in water splitting technologies (low and high-temperature electrolysis, co-electrolysis andthermochemical splitting).

However, extensions of PtG processes to integrated electrolytic and thermochemical hydrogen generation, enabled by a mix of renewable and nuclear electricity/heat sources, deserve further assessement at both process- and deployment level via energy scenario-based analyses.

More focus could be given to the assessement of PtG product and by-product (oxygen) storage options (by type, sizing, spatial distribution and economics) in scenario-based deployment assessments.

The compatibility of a PtG product storage option (liquid/gas tanks, underground topology and hydrogen binding with other chemicals), depends on the specific PtG product end-use (steady versus mobile), safety and economics. Hydrogen mobility, low volumetric energy density as well reactivity implies challenges for storage.

Both hydrogen liquefaction and liquid hydrogen storage/conversion are energy-intensive and could serve space-constrained applications, like mobile/portable.

Salt caverns and depleted oil/gas fields are the most promising underground storage pathways, in the other hand uncertitudes exist regarding the compatibility of aquifers and porous rock formations, in terms of gas tightness and potential reactivity with the stored gas, further investigations need to be done.

6.3 PtG CO_2 Sources

Many CO_2 sourcing options for SNG generation has been considered to date.

These options have as well biogenic CO_2, showing a low-carbon approach, as well as capture from fossil and SNG-fueled power installations, industrial processes, atmospheric air and unspecified sources.

In the deployed distributed PTG, CO_2 was supplied from CHP and oxy-combustion boiler flue gases, kraft pulp mills, as well from other carbon-intensive industrial plants.

CO_2 supply assumptions consider important practical (transportation and storage-related) and cost uncertitudes.

The production of SNG and synthetic carbon-based PtL fuels, as well their transformation to power, heat and other uses, are forecasted to require a future CO_2 transmission grid that could be as complex as the gas grid.

Uncertainties in the economic and technical feasibility of CO_2 transportation and storage, need further technological progress to be done.

The design, operation and optimization assessment of future CO_2 transmission grids, interacting with the power, gas, industrial and other sectors may add value to PtG deployments.

7 CONCLUSION

The concept of PtX and its demonstration is increasingly developing over the last 15 years in Europe. 128 demonstration projects functional or planning are identified by May 2018

In 2018, additional 18 projects are planned to be commissioned. The leading country in this deployment is Germany with 56 projects.

Generally, the topic PtX is diversifying by different technologies, the sector is witnessing the involvement of more countries and more types of final products of the processes. Not only PEM and alkaline electrolysers are investigated but as well SOECs and new designs like alkaline SPE. Which reflects the importance and the strategic role of such a technology.

In addition to the development of biological and catalytical methanation also production of methanol, DME and long-chain hydrocarbons fuels are tested and demonstrated leading to a rich diversified package of the methanation process which will help to reach more flexibility within projects and business models and by the way more added value and positive change.

One of the spread applications for PtX is the injection of hydrogen or methane into the natural gas grid for storing renewable electricity. Producing fuels for transportation and leading to a more efficient carbon capture pathways

Power to Gas can play an important role in the future energy system. However, technical and economic barriers that have been addressed have to be solved before PtG can be commercially successful.

The electrolysis process requires according to the actual state an improvement in efficiency during transient operation as well more development to cope high cost, indeed, alkaline electrolysis is the cheapest currently but in the future PEM electrolysis (more expensive than alkaline) could be better choice for PTG plants because of its high efficiency for transient operation. In parallel solid oxide electrolysis should keep on the development pace it has at the moment to provide high potential coupling at steady state operation Catalytic.

The methanation process technologies are seeking a development boost as well by many groups investigating fixed bed and structured reactors, as well as fluidized bed reactors and three phase methanation. In the other hand, dynamic operation of methanation reactors are lagging behind in term of published results because latest researches show that dynamic methanation reactors is not that efficient in lowering the catalyst stability.

Whilst controlling the reactor temperature is not an easy process, thus, many investigations are led in the direction of cooled fixed bed reactors to cope with temperature control

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9 LIST OF ABBREVIATIONS

AEL: alkaline electrolysis

ASU: air separation unit

CC: combined cycle

CCS: carbon capture and storage

CHP: combined heat and power

CNGV: compressed natural gas vehicle

FCV: fuel cell vehicle

HT: high temperature

LHV: lower heating value

LT: low temperature

NG: natural gas

PEM: polymer electrolyte membrane

PtG: power to gas

PtH: power to heat

PtL: power to liquid fuel

PV: photovoltaic

RE: Renewable energy

SOE: solid oxide electrolysis

SNG: synthetic natural gas

STP Standard Temperature and Pressure: 0 °C, 101,325 Pa

10 LIST OF TABLES

11 LIST OF FIGURES