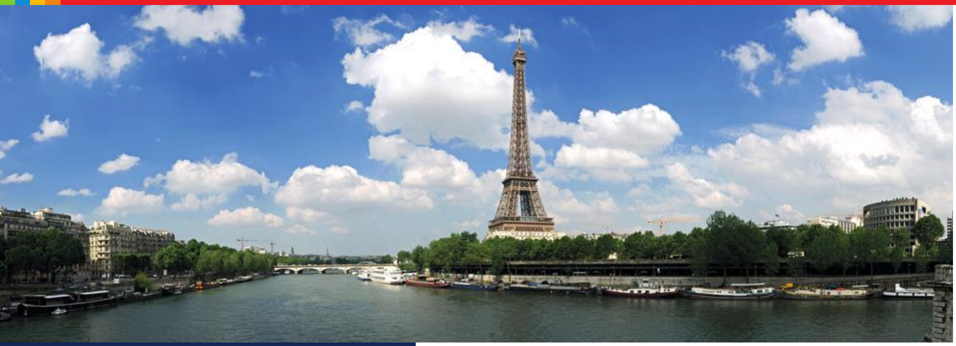
2012-2015 Triennium Work Reports



WOC 5.4/TT1 - Committee report

Renewables: Technological and economic aspects of power to gas and upgrading of biogas to natural gas quality.

Aksel Hauge Pedersen, DONG Energy A/S, Denmark and
Koen G. Wiersma, Gasunie, The Netherlands

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2012-2015 Triennium Work Report
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Renewables: Technology and economic aspects of power to gas and upgrading of biogas to natural gas quality

Executive Summary

This report gives a global overview of the technology status for the production of renewable gas that can be injected in the existing natural gas system. The report contains four separated chapters covering:

1. Global status for upgrading of biogas (2013)
2. Electrolyzing technologies (2013)
3. Injection of Hydrogen into the Natural Gas System (2014)
4. Economic aspect of Power to Gas (2015)

The overall conclusion is that commercial technologies for the upgrading of biogas to biomethane are available in the market, and economic feasible under certain conditions . For power to gas economic operation is not possible today. The main reasons for that are the high capital costs, the limited efficiency of the process and low prices for CO_2 emissions. However commercial technologies are available today, and a future with an massive increase in fluctuating renewable energy, associated with increased need of energy storage and a realistic price of CO_2 emissions could change this situation. Feasible economics for power to gas therefore seems possible in 10 - 15 years time.

Introduction

The following four chapters gives an economic and technical overview for;

- Global status for upgrading of biogas (2013)
- Electrolyzing technologies (2013)
- Injection of Hydrogen into the Natural Gas System (2014)
- Economy of Power to Gas (2015)

The information has been collected by the IGU WOC 5.4/TT1 working group. The motivation for this working group is that there are growing efforts of using the existing natural gas network as storage and transport medium for renewable energy. A special focus is on the storage of power in a gaseous form (power togas).

Global status for upgrading of biogas (2013)

Biogas is produced when bacteria in an oxygen free atmosphere convert organic matter to methane gas. This process often is named anaerobic digestion, or anaerobic fermentation. For this process the following components are needed; organic materials, bacteria, anaerobic conditions and heat.

Biogas contains moisture and hydrogen sulphide, so before it is used in an engine the moisture must be condensed out, and the hydrogen sulphide removed to avoid engine problems. Biogas can be used directly to produce thermal energy, or to power a gas or diesel engine that in turn can drive a generator to produce electricity. Biogas also can be upgraded to natural gas quality before being injected into the natural gas network. For the last 10 - 20 years a number of upgrading technologies has been commercial available. Technologies which remove CO_2 from biogas, leaving a CH_4 rich gas that can be injected directly into the natural gas system. The upgrading process increase the heating value and Wobbe-index for the gas, dries the gas and removes trace substances like oxygen, nitrogen, hydrogen sulphide, ammonia or siloxanes.

The European Biogas Association, which covers 27 European countries, reported that in 2011 approximately 190 upgrading plants had produced roughly 4000 GWh of upgraded biogas.

Electrolyzing technologies (2013)

Electrolyzers and electrolyzing technologies becomes more and more interesting due to several potential benefits of using electrolysis as an integral part of operations in the electric power industry. An industry that in the future will be highly depended and influenced by fluctuating renewable power (like wind and solar power) and needs storage of power in periods with excess power production (as example - high wind combined with low consumption).

If wholesale electricity prices are low (or even negative), energy storage can be a valuable technology. Producing and storing hydrogen during off-peak periods can add load to the off-peak periods and create storage of energy to be used later. The benefits of using off-peak electricity to produce hydrogen improves the load factor of electric power distribution and transmission facilities and increase the efficiencies of intermediate generation by allowing plants to run at their optimal level. One of the biggest drawbacks to using hydrogen is the round-trip efficiency. Since current technologies for electrolyzers have relatively low efficiencies, the total power to gas and storage process loses a lot of energy, unless the excess heat can be utilized.

This report gives the technological background for the electrolyzing process, and a description of the three most common technologies: Alkaline, PEM and SOEC. The experiences with electrolyzers are mainly due to the Alkaline electrolyzer that has been used for approximately 100 years, while PEM still is in the demonstrating phase and SOEC has not left the laboratories yet.

It is expected that SOEC and PEM will be the technology of the future due to high process temperature, with system efficiencies in the range of 3,2 kWh/Nm3 for SOEC and 3,75 kWh/Nm3 for PEM, while the Alkaline electrolyzer hardly will be lower than 4,3 kWh/Nm3 hydrogen. The cost of hydrogen production through electrolyzers is not comparable with hydrogen produced from fossil fuels (natural gas).

Injection of Hydrogen into the Natural Gas System (2014)

In many countries with renewable energy (wind and solar) it seems obvious to use the existing natural gas transport network for storage (and transport) of the fluctuating form of renewable energy. Therefore power to gas will become more and more common due to a future energy world with a majority of fluctuating renewable power. In some periods power will be in surplus and in shortage in other periods, in contrast to the present situation with more manageable power production mainly based on fossil fuels like nuclear, coal, oil and natural gas plus hydropower.
The main questions analyzed in this report are:

- What is the share of hydrogen that can be injected into the existing natural gas network?
- What is the related power balancing possibility? and
- Where in the natural gas system should the hydrogen be injected?

Natural gas must comply with certain quality requirements and must have a certain calorific- or heating value, Wobbe-index, methane number etc. The addition of hydrogen to natural gas will not be without consequences for the existing gas infrastructure. Hydrogen has a lower calorific value than natural gas. The LHV (Lower heating value) for hydrogen is 3 kWh/Nm^3 when natural gas has LHV of app 11 kWh/m^3, so one volume of natural gas (mostly methane) contain 3 - 4 times the energy of the same volume of hydrogen. In order to maintain the same energy output a much higher volume of natural gas must be transported if it contains hydrogen.

It is very unlikely that the step to a hydrogen-based economy will take place overnight. Such fundamental change will certainly take several years, or even decades. And this very important, even critical, transition period is too often overlooked when the possibility of a hydrogen economy is considered.

Clearly, the technical aspects of the natural gas pipeline infrastructure and the different end use applications will play an important role as far as the feasibility of this approach is concerned. A transition towards a hydrogen economy by means of hydrogen-natural gas mixtures, transported and distributed through the existing natural-gas grid, seems to be possible - but with limitations.
Recommendation for injection of hydrogen in natural gas pipelines indicates that underground storage in porous rock should be avoided. Further a maximum hydrogen content injected into natural gas pipelines could be in the range 2- to 10%.

- Max. 2 % - if connected to CNG filling station
- Max. 5 % - if not connected to CNG filling station, gas turbines and gas engines with a hydrogen specification < 5 %
- Max. 10 % - if not connected to filling station, gas turbines and gas engines with a given hydrogen specification < 10 % .

Finally, developments in separation techniques might become available, and then the hydrogen can be extracted from the mixture with natural gas - and used for other purpose - like fuel vehicles (electric vehicle equipped with fuel cells instead of batteries). Research is also initiated to find ways for industrial use of the O_2, produced in parallel with hydrogen during the electrolyser process.

Economic aspect of Power to Gas (2015)

The concept of power-to-gas is still at an early stage of development. There are a lot of questions to be answered, but the concept is very promising. The power to gas concept distinguishes itself from other energy storage options because, in addition to energy storage, it has other functions such as transportation of electricity in a gaseous form, or the provision of a raw renewable material to the industry or mobility. This makes the business case for P2G divers.

With the present knowledge of hydrogen production from electrolysers, production cost calculations are made based on a 10MW electrolyser plant with 4,000 running hours, using different power prices. The three cases for the period 2015-2030 indicate an expected development for the electrolyser technology starting with the present mature Alkaline electrolyser moving ahead of the PEM electrolyser, ending up with the very efficient SOEC. It is clear that the power price is an essential parameter for hydrogen production and that its influence will grow as the capital cost will be reduced in the course of time.

A second step in the power to gas chain could be methanation. Methanation is the conversion of hydrogen and carbon dioxide into methane. The methanation process can be executed either chemically or biologically. Chemical methanation is a mature technology that is currently commercially available. It has been widely applied in different industrial applications. In this process, the reaction takes place by use of a catalyst. Biological methanation is an alternative to chemical methanation. The main difference lies in the temperature ranges used for the reaction and the response time. The biological methanation process is still in the research and demonstration phases. From a cost perspective, it seems that the biological process, if developed according to the plans, has the potential to be the most economic way to produce synthetic methane in the future. After 2030 the calculated methane production costs are in the range of 7,4 - 12,4 cent/kWh.

Energy storage as a way to store renewable electricity via electrolysis in underground and above ground storages is economically very challenging. There are also significant costs involved with the compression or liquefaction of hydrogen.

Power-to-gas is not considered a cost-effective option in the short to medium term. Yet it is not unthinkable that a positive business case is possible in specific situations with favourable (local) conditions. The development of new efficient and low-cost technologies is important for the success of power-to-gas. The biological methanation and the direct conversion of CO2 and H2 in the SOEC process seems to be the most challenging aspect.

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The IGU WOC 5.4/TT1 working group consist of:

Aksel Hauge Pedersen, DONG Energy, Denmark and
Koen G. Wiersma, Gasunie, The Netherlands

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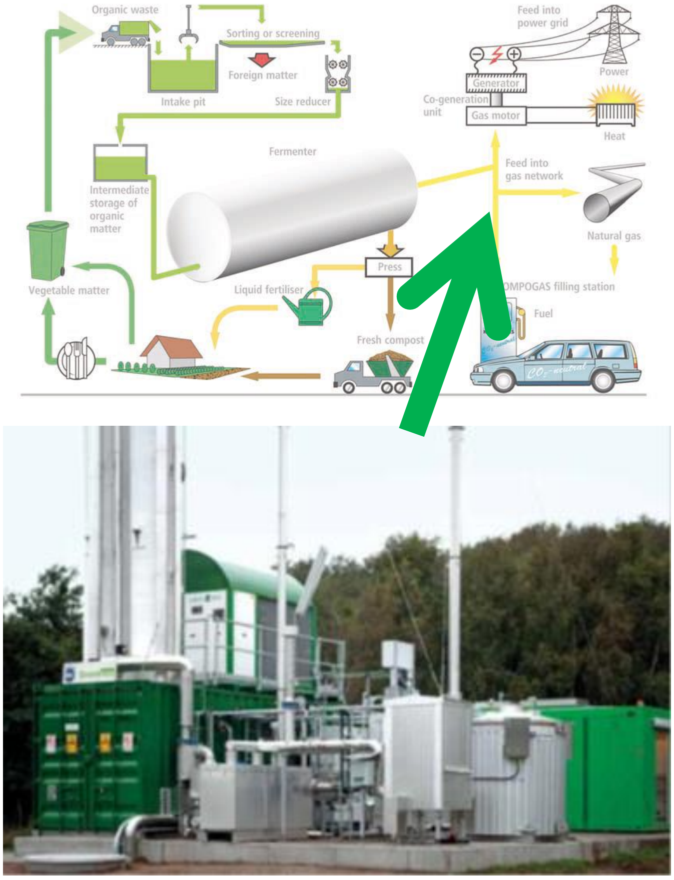
Sources of information, graphs, labelling are pointed out on/in the specific pages and chapters.

IGU WOC 5.4/TT1

Global status for upgrading of biogas - 2013

Prepared by Aksel Hauge Pedersen, DONG Energy A/S, Denmark



Content

Integration of Renewable Gas (biogas) and fossil natural gas

Country status, upgrading and integration of renewable gas in the natural gas grid

1. Background and summary

Biogas production

Biogas is produced when bacteria in an oxygen free atmosphere convert organic matter to methane gas. This process often is named anaerobic digestion, or anaerobic fermenting. The needed components are;

1. Organic Materials
2. Bacteria
3. Anaerobic Conditions
4. Heat

Organic matter is the food source for the methane producing bacteria. As feedstock might be used garbage, sewage, manure from cattle's, industrial waste, feedstock from food waste etc. The primary future biogas production will be farm-based biogas coming from manure mixed with different kind of organic waste. Only organic source might be manure, but the gas production can be greatly increased by adding certain types of food wastes with the manure. Energy crops such as corn silage can also be added to increase gas production. The second necessary ingredient is bacteria. Bacteria are necessary to convert the fats, carbohydrates and proteins in the organic matter to simple acids. Then, a second type of bacteria transform the acids to methane and carbon dioxide. This process takes place simultaneously. The bacteria are commonly present in manure, and under the right conditions they thrive and multiply.

Two conditions that are necessary for the bacteria growth are an anaerobic atmosphere (no oxygen) and the right temperature. Most digesters operate in the mesophylic range of 35-40 deg. C, but others are designed to operate in the thermophylic range of 50-60 deg. C.

Biogas contains moisture and hydrogen sulphide, so before it is used in an engine the moisture must be condensed out, and the hydrogen sulphide removed to reduce maintenance problems. Biogas can be used directly to produce thermal energy, or it can be used to power a gas or diesel engine to run a generator to produce electricity. Biogas also can be upgraded to natural gas quality and feed into the natural gas network.

Upgrading of biogas

For the last 10 - 20 years a number of upgrading technologies has been commercially available. Technologies which remove CO_2 from biogas, leaving a CH_4 rich gas that directly can be injected into the natural gas system. The upgrading process increase the heating value and Wobbe-Index for the gas, is drying the gas, removes trace substances like oxygen, nitrogen, hydrogen sulphide, ammonia or siloxanes. Further compression to a pressure needed for the following gas utilisation/injection into the natural gas network, and odorisation and adjustment of the heating value by propane if this might be might be needed.

Country status for upgrading technologies

The /1/ IEA Bioenergy task 37 (www.iea-biogas.net/) created an overview with global numbers for biogas plants - with upgrading facilities (2012). In attachment 1 a more detailed overview is shown for upgrading plants and manufacturers for the involved technologies.

	Water scr.	Chem. Scrubbing/amine scubbing	Organic physical Scrubbing	PSA	Membrane	Cryogenic
Austria	1	1		2	2	
DK	1					
Finland	2					
France	2					
Germany	12	19	6	15	1	
Iceland	1					
Japan	2					
Norway		2		1		
Holland	3	1		2	3	
South Korea	1					
Spain	1	1				
Sweden	40	8		7		2
Switzerland		6	2	10		
US	1	4		4	4	
UK				1 (4)		
Sum	67	42	8	42(45)	10	2
% distribution	39%	25%	5%	25%	6%	1%

Table 1: Upgrading technologies according to /1/

The European Biogas Association/4/, which covers 27 European countries, reported that in 2011 app. 190 upgrading plants produced roughly 4000 GWh upgraded biogas.

The numbers from /4/ are given in table 2:

Country	Upgrading plants	Upgrading capacity Nm³ (CH_4)/h	Production of upgraded biogas GWh/year
Austria	10	2000	50
Denmark	1	180	3
Finland	2	445	2
France	3	1400	
Germany	87	55930	3400
Hungary	1	25	
Luxemburg	3	610	26
Netherlands	16	7031	208
Spain	1	2400	
Sweden	47		170
Switzerland	15		81
UK	2	200	
Total	188	70041	3937

Table 2: Upgrading capacity for European upgrading plants /4/

The background behind some of these numbers is shortly summarized in the "country reports - page 8 - 16 - with information from some non-European countries - Austria, Canada, Denmark, Finland, France, Germany, The Netherlands, Japan, Italy, Norway, Portugal, Spain, Sweden, UK and US.

2. Upgrading technologies

Biogas is a mix of methane (CH_4) and carbon dioxide (CO_2) plus some minor content of hydrogen, nitrogen, oxygen, hydrogen sulphide, ammonia.

Gas component	Biogas	Landfill gas	Natural Gas (Danish quality)
Methane - vol%	60 - 70	35-65	89
Other hydrocarbons - vol%	0	0	9,4
Hydrogen - vol%	0	0-3	0
Carbon dioxide - vol%	30-40	15-50	0,67
Nitrogen - vol%	< 1	5-40	0,28
Oxygen - vol%	< 0,5	0-5	0
Hydrogen Sulphide - ppmv	0-4000	0-100	2,9
Ammonia - ppmv	< 100	< 5	0
LHV - kWh/m³ (STP)	6,5	4,4	11,0

Table 3: Biogas quality. From biogas to biomethane - Technology Review, TU Vienna, 2012

Today a number of different technologies are in commercial use for the production of biomethane. Technologies that can meet the quality requirements for injection into the natural gas grid. No technology is the optimal solution to each and every biogas upgrading situation. The right choice of the economically optimal technology is strongly depending on the quality and quantity of the raw biogas to be upgraded and the desired quality for the biomethane. Biogas upgrading is a gas separation task ending up with a methane-rich product gas stream with a certain specification. Depending on the raw biogas composition this separation task comprises the separation of carbon dioxide (and thus increasing the heating value and Wobbe-Index), the drying of the gas, the removal of trace substances like oxygen, nitrogen, hydrogen sulphide, ammonia or siloxanes as well as the compression to a pressure needed for the further gas utilisation. Furthermore odorisation and adjustment of the heating value by propane might be needed.

First of all the removal of the sulphur is necessary. Hydrogen sulphide is a very corrosive gas that has to be removed before any other use or treatment of the biogas. This process might be handled through sulphide precipitation (use of various metal salts), biological scrubbing, chemical - oxidative scrubbing, adsorption on active carbon etc.

For the upgrading (or CO_2 removal) process a mix of commercial processes are available. As mentioned before this might be: Water scrubbing, Organic- or chemical scrubbing, PSA, Membranes or even use of a cryogenic technology. In below table is shown the latest commercial figures (2012) for the technologies in question:

Parameter	Water Scrubbing	Organic scrubbing	Chemical Scrubbing (Amine)	PSA	Membrane	Cryogenic
Methane cont. - vol%	95,0-99,0	95,0-99,0	> 99,0	95,0-99,0	95,0-99,0	
Methane recovery - %	98	96	99,96	98	80 - 99,5	
Methane slip -%	2,0	4,0	0,04	2,0	20-0,5	0,037
Delivery pressure - bar	4-8	4-8	0	4-7	4-7	
Power cons. - kWh/m^3 biomethane	0,46	0,49 - 0,67	0,27	0,46	0,25 - 0,43	0,5 - 1,12
Number of ref. plants	High	Low	Medium	High	Low	Low
Capex - - €/(m^3/h) biomethane						
100 m^3/h	10100	9500	9500	10400	7300-7600	
250 m^3/h	5500	5000	5000	5400	4700-4900	
500 m^3/h	3500	3500	3500	3500	3500-3700	13000
OPEX - ct/m^3 biomethane						
100 m^3/h	14,0	13,8	14,4	12,8	10,8-15,8	
250 m^3/h	10,3	10,2	12,0	10,1	7,7-11,6	
500 m^3/h	9,1	9,0	11,2	9,2	6,5-10,1	

Table 4: Commercial figures for different upgrading technologies (from Biogas to Biomethane tech. review, TU, Vienna 2012) and Biogas upgrading - review of commercial technologies, SGC rapport 2013:270

The dominating upgrading technologies are water scrubbing followed by PSA and amine scrubbing. Membrane separation is a technology trying to get established in the field of biogas upgrading.. Cryogenic upgrading technologies, are still struggling with operational problems, but is a technology of increasing interest. The Capex for the presented upgrading technologies are almost the same (with the exception of the Cryogenic process that still is quite expensive), in the level of 3500 €/Nm^3 (biomethane)/h for upgrading units with gas capacities larger than 500 Nm^3 (biomethane)/h. For smaller units, the specific investment costs increase significantly. The energy demand of the technologies are also alike with an electricity demand in the range of 0.4-0,6 kWh/Nm^3 biomethane, except for the amine scrubber which has an electric power demand of about half. However the regeneration process for amine is not included in these numbers, and if it was - the energy demand would be almost the same as for other upgrading technologies. Biogas production is increasing globally, and the interest for biogas upgrading to utilize the gas as vehicle fuel or in other traditional natural gas applications increases as well. The mature technologies will receive competition from upcoming technologies like membrane separation, cryogenic separation etc. with one single purpose - to reduce cost.

Today (2013) the overall upgrading cost for a biogas plant of 500 - 1000 biomass/day might be in the range of 10 - 13 cent/m^3 biomethane and maybe 13 - 15 cent/m^3 biomethane if injection cost is included (pressurizing cost). However cost reduction down to 7 cent/m^3 biomethane seems reachable in a few years.

Upgrading through electrolyzing

Some new technologies lately have appeared into the upgrading market. These technologies use the electrolysers that partly convert water or steam to H_2 (Alkaline electrolyser) and in a following Sabatier process combines this hydrogen with CO_2 from the biogas - to build methane CO_2. Further if the Alkaline electrolyser is replaced with an SOE (Solid Oxide Electrolyser) a much more efficient process can be made for the conversion of the CO_2 into methane.

Both technologies still are under demonstration in Germany and Denmark, but with the "green" perspectives (re-use of CO_2) and promising results obtained so far this seems to be one of the most interesting upgrading technologies.

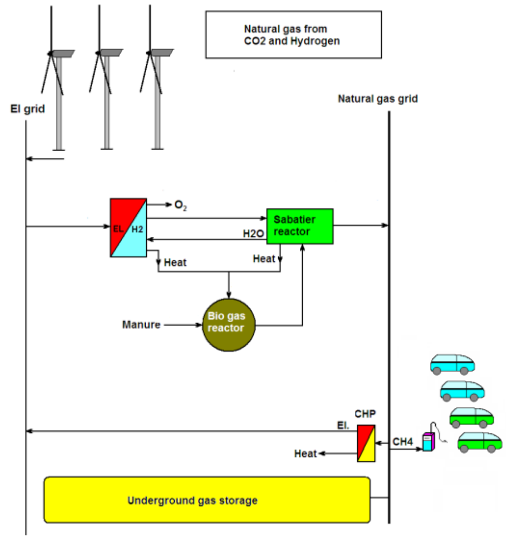


Figure. 1: Upgrading through Alkaline Electrolyser and the Sabatier process

3. Country reports

3.1 Austria

In 2011 there were 360 biogas plants running in Austria. The total capacity was about 103 MW. The produced biogas is mostly used in CHP units for combined heat and power production. Most of the plants are farm-based. At the moment there are 7 plants which feed in the biogas into the gas network and 3 plants which offer biogas as a fuel - with a total of 10 upgrading plants. The techniques applied at upgrading projects are membrane separation technology, absorption technology and water/ chemical scrubbing. The first Austrian biogas feed in plant is located in Pucking and operating since 2005 (6 Nm3/h).

Figure 2: Pucking; The first biogas feed in plant in Austria

3.2 Canada

Canada has a lot of natural energy resources. Both for fossil fuel (Oil, tar sand, Coal and gas) and renewable energy from hydro power. However some attention is given to biomethane as well. Still it's up to the different province how to support the development of biomethane. The provincial leaders here are: British Columbia, Alberta, Ontario and Quebec with Ontario as the far leading province (app. with app 40 plants and 16 MW biogas power installed in 2012).

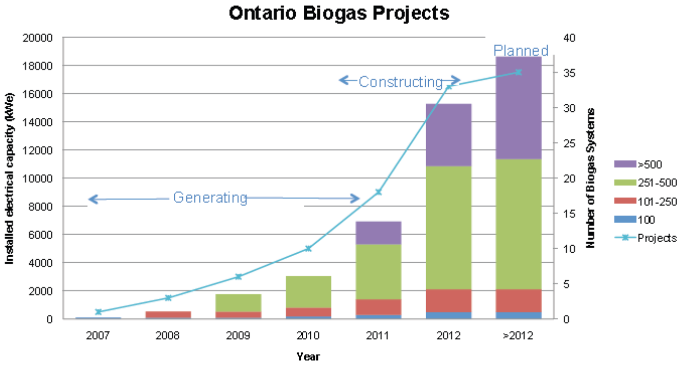


Figure 3 : Biogas power installed in Ontario

3.3 Denmark

In Denmark the biogas production is app 40 PJ (or app 100 million m^3 methane - 1100 GWh) which is equal to app 4% of the present Danish gas consumption. The expectations are massive market introduction until 2020 with a doubling of the existing capacity. So far Denmark has only one upgrading plant, a water scrubbing plant.

Figure 4 : The only Danish upgrading plant in Fredericia (Water Scrubbing)

3.4 Finland

The Finnish biogas market consist of 75 biogas plants (2011) with at total production of 659 GWh/year. However a rapid build-out is expected. One of the world's first upgrading plants was established in Finland in 2002 at the Kalmari farm. Here excess electricity is sold to the grid, and biogas upgraded to vehicle fuel quality is sold to customers. The biogas plant was built and heat production started in 1998. CHP production began shortly after that. Biogas has been upgraded to vehicle fuel since 2002. Today this farm has a new biogas reactor of 1000 m^3/h capacity. The farm has the capacity to produce bio-methane to fuel about 200 gas vehicles. Cow manure, industrial bio-waste and energy crops are digested in the biogas plant. At the moment grass silage is cultivated at the farm for the digester. The first upgrading plant to inject methane into the natural gas grid started in Finland in 2011 with a capacity of 7 GWh/year of biomethane - to be used into the transportation sector.

Figure 5: Kalmari Farm - a pioneer inside upgrading of biogas

3.5 France

In 2007, in France there were 200 biogas plants. These plants produced more 2500 GWh biogas, with half coming from waste processing and the other half from water treatment plants. Only a dozen plants for agricultural biogas were operational in 2008. In 2011 new legislations was introduced that promotes upgrading of biogas for injection into the natural gas grid. Secondly, the feed-in tariff for electricity produced by biogas was re-evaluated in 2011 so that it is now comparable to the German feed-in tariff of 20 euro cents/kWh in the best case.

Figure 6: Buses in Lille are running on upgraded biogas

3.6 Germany

3.6.1 Biogas

Germany is worldwide the leading country for biogas production. At the end of 2011 there were 7,215 biogas plants running. Most of the plants are directly connected to a CHP and produces electricity, approximately 3 GW electrical power is installed. Energy crops and agricultural manure or slurry are the substrates primarily used to generate biogas in Germany.

Currently 107 biogas plants are feeding in into the natural gas grid. The feed-in capacity of these plants amounts to 67.000 m3/h biogas. 36 biogas plants are currently under construction, 26 biogas plants are planned. If the plants under construction are realized there will be 143 units in Germany with a capacity of around 89.000 m3/h. Together with the plants being planned the number of projects will be 169 with a capacity of 104.000 m3 per hour. Only a little part of the biogas is used for the direct usage in a filling station.

The largest upgrading plant in Germany is the Biogas park Gustrow about 40 kilometres from Rostock. This upgrading plant was established in June 2009 and is since then the largest biogas feed in project in Germany. Since the completion of the plant 46 million cubic meters of biogas is feed in annually. Maize silage, grain and crop silage is digested in the biogas plant. To provide the required substrates an agricultural area of about 10,000 ha is required. If the plant produces at full capacity approximately 5,000 m3/h can be feed in to the grid.

Figure 7: Biogas park Gustrow; The largest upgrading plant in Germany

3.6.2 Power-to-gas

In Germany the Power-to-gas (PtG) concept is seen as a promising development for the integration of renewable energy sources like wind and solar in the energy system. The PtG concept is considered as the only large scale storage solution that can store energy for a longer period. Electricity generated from renewable sources can be stored in the natural gas infrastructure via hydrogen or methane. This system is being tested in various pilot and demonstration projects. One of the main advantages of the PtG concept is that it can add more flexibility to the energy system. Also the necessary investments in the power grid can be avoided by investing in PtG solutions.

Electrolysis and methanation are the key technologies to produce hydrogen and methane. Electrolysis is the conversion of electricity to hydrogen. Water separating in hydrogen and oxygen is not new, the coupling between the natural gas grid and the power grid is. The electrolysis of water is the core component for the PtG concept. Besides the alkaline electrolysis the PEM electrolysis is a promising technology. The efficiency of electrolysis ranges between 60% and 80% dependent on the technology and scale. The produced hydrogen can be feed-in to the natural gas system to a limited extend.

Methanation is the synthesis of hydrogen and carbon dioxide (CO2) to methane (CH4). The gas produced via methanation has the same quality as the gas in the system and can be fed in without restrictions to the gas network and its associated underground storage facilities . The efficiency of methanation is about 80%. The total chain efficiency (from electricity to methane) is about 55%.

In Germany there are several PtG pilot projects in development. There are projects focusing on the production and injection of hydrogen into the natural gas grid and projects with the additional methanation step. One of the projects is started up in Falkenhagen. Wind energy is converted into hydrogen which can be stored in the natural gas grid en be used as normal (renewable) natural gas. The plant will produce approximately 360 m3/ of hydrogen per hour.

Figure 8: Falkenhagen; The design of one of the first Power-to-gas pilot projects

3.7 The Netherlands

In the Netherlands the yearly production of biogas in 2009 was app 3000 GWh. Figure 9 shows one of the first Dutch upgrading plants. Pentair Haffmans designed a compact solution, housed in two pre-assembled 40-foot containers, consisting of the following components:

- Gas washer to scrub the biogas with water for optimal ammonia removal
- Activated carbon filter to remove of H2S and other impurities
- Biogas compressor to pressurize the biogas
- Membrane unit for separation of biogas into CH4-rich and CO2-rich gases
- CO2 compressor to pressurize the CO2 gas to 17.5 bar
- Activated carbon filter/dryer to clean the CO2 gas
- Refrigeration for liquefaction of the CO_2 gas through cooling to a temperature of -24 °C (-11 °F) and removal of the remaining H2S that is fed back to the membrane unit.

Figure 9: One of the first Dutch upgrading plants

3.8 Italy

In Italy there are more than 800 biogas plants. The yearly biogas production is more than 4700 GWh. The number of upgrading plants in Italy is not known for the time being, but Italy is the European leading country for NGV's (Natural Gas Vehicles). And especially this customer segment can benefit from upgraded biogas. Some demonstration of Power2gas will be demonstrated in Italy through the 1 MW electrolyzer (INGRID):

Puglia, Italy

INGRID (24Mio€ FCH JU project, 7 partners)

OBJECTIVES

- Allow increased penetration of highly fluctuating RE into the grid using electrolysis and supply-demand balancing.
- Improvement of distribution operation through active/reactive power control for optimal voltage regulation and power quality.
- Use H_2 for transport, industry, grid balancing and injection into the gas network.

SOLUTION:

- 1MW HySTAT® electrolyser 40Ft. outdoor solution with all peripherals to produce 200Nm³/h H_2.
- 60kW Fuel Cell backup system.
- 39 MWh, 1'000kg solid hydrogen storage system.

Figure 10: 1 MW electrolyzer (200 m^3 hydrogen). Use of H2 for injection, transport and industry

3.9 Japan

Based upon data from 2009 - 624 biogas plants was in operation in Japan. The total production in 2009 was 313 million m^3 biogas. 30% was used for heating of digestion tanks, 45% for direct utilization and 25% for upgrading to natural gas quality, and injection into the natural gas grid (personnel interview of Kazuka Sakata for Kobelco - Eco solutions). Per 2012 five plants were upgrading biogas to natural gas quality (3 plants in Kobe City, Hitachi city and one plant in Tokyo). For all plants the biogas was coming from waste water treatment plants. The purpose is to produce methane for use in vehicles, to inject upgraded biogas into the natural gas system and for power production. The price for power generated from biogas is quite high (39 Yen/kWh - or 32 €cent/kWh), which is much higher than the feed-in tariff for wind power (22 Yen/kWh or 18 Ecent/kWh). This also means that power production is preferred instead of upgrading of injection into the natural gas grid. Osaka Gas, the Kobe Municipal Government, and Kobelco Eco-Solutions co-operates about this injection of upgraded biogas from the sewage plant in Kobe to the pipeline network of Osaka Gas. Since 2004, the Kobe Municipal Government and Kobelco Eco-Solutions have operated the Kobe Biogas project, purifying biogas produced at the Higashinada Sewage Treatment Plant in Kobe for use as fuel for vehicles.

Figure 11: The Kobe Biogas Station for production and upgrading of biogas (from Sewage)

3.10 Norway

In Norway the present biogas production is app. 200 GWh at app. 20 plants. In a couple of plants have been installed upgrading facilities of the producer Purac CApure. In Stavanger in 2009 a 500 Nm3/h plant - for injection in the local natural gas grid, and in 2010 in Oslo a 750 m^3/h plant for vehicle fuel.

Figure 12: Chemical Scrubbing (Purac CApure)

3.11 Portugal

Biogas arise in Portugal as a useful energy source by its direct conversion into heat and electricity or by injection into a natural gas network. In 2008 the total biogas production was app 270 GWh. In Portugal, over the last decade there has been a large growth of the biogas produced from anaerobic digestion, both in electricity production (97 GWh in 2010) and installed power. However, the current installed capacity and energy produced from this renewable source does not reflect its huge potential.

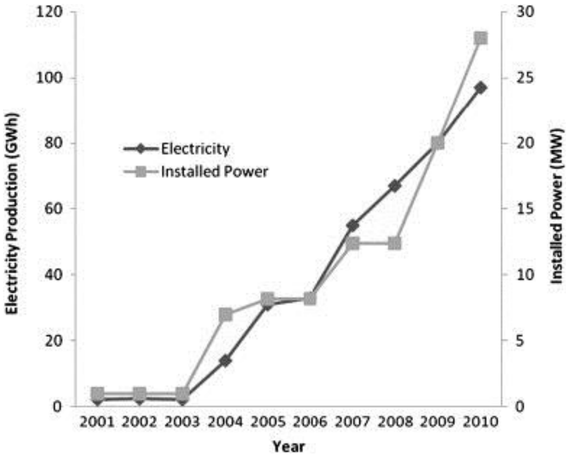


Figure 13: Power capacity and - production - from biogas in Portugal

3.12 Spain

In 2008, Spain's production of primary energy from biogas was 2400 GWh. which was a position as no 6 in the EU. The most important sources are landfills (77%). As far as electricity is concerned, Spain produced 584 GW h from biogas in 2008. In /1/ is registrated two upgrading plants for biogas in Spain. The picture shows the Valdemingómez Technology Plant, that is the most advanced waste treatment facility in Spain. The plant produce annually about 34 million m3 of biogas. 295,000 tons of organic waste (70 percent of the organic material from urban waste) will be treated and turned into 240,000 tons of biomass.

Figure 14: The Valdemingómez biogas plant

3.13 Sweden

Beside Germany - Sweden in one of the two globally dominant countries for biogas - and biogas upgrading. The biogas production in 2012 was in the order of app 1500 GWh, but separated upon 233 biogas plants. Impressing 50 % of the produced biogas is upgraded to natural gas and injected into the natural gas grid, mainly for the purpose as vehicle fuel. The total number of upgrading plants were 57, with a majority of 70% as water scrubber plants. Next to that chemical scrubbers and PSA plants had 14% each, while the reaming upgrading plants were based upon Cryogenic separation.

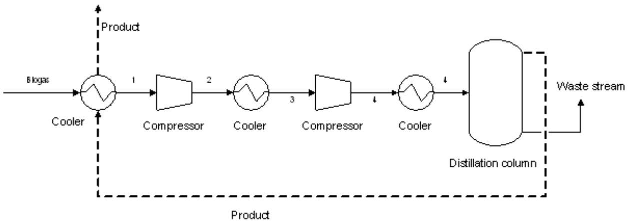


Figure 15: Cryogenic separation - a new technology introduced in field operation in two Swedish plants

3.14 UK

In 2012 the British biogas production was coming from 233 plants. 36 based upon Farm Waste, 51 upon Food Waste and 146 Sewage plants. In total 8270 GWh biogas was produced in 2012. The installed power capacity combined with the biogas plants was 188 MW. So far four upgrading plants have been built in UK. but more is to come. The plants in question are one plant equipped with the selective membrane technology from Carborex MS, and the remaining plants with the Chesterfield water scrubbing system.

Figure 15: Chesterfield BioGas (CBG) supplied the UK's first biogas upgrading plant to produce clean biomethane for direct injection into the national gas grid. The project was successfully completed and gas injected into the national grid at the wastewater treatment site of Thames Water site at Didcot, Oxfordshire in October 2010.

3.15 US

In US there are more than 2200 biogas producing sites, of which app 1500 is anaerobic digesters at wastewater treatment plants (for comparison Europe has over 10.000 operating digesters). 12 upgrading plants were reported in 2011.

Figure 17: Upgraded landfill gas from Meadow Branch Landfill in McMinn County, Tennessee, is piped to Spectra Energy's East Tennessee Natural Gas

4. List of references

/1/ IEA energy, task 37 (www. iea-biogas.net), Country reports etc.

/2/ "Biogas in Portugal. Status and public policies in a European Context", M. Ferreira, Isabel Marques, Isabel Malico, jan 2012.

/3/ Deutsche Energie-Agentur GmbH (dena); Biogasapartner, Branchebaromenter Biomethan 2/2012

/4/ "European Biogas report 2012", European Biogas Association

5. Appendix - Global status for upgrading plants and manufacturers of upgrading plants.

Manufacturers of Upgrading technologies (from Biogas upgrading - review of commercial technologies, SGC report 2013, 270)

Company	Homepage
Acrona-systems	www.acrona-systems.com
CarboTech	www.carbotech.de
Cirmac	www.cirmac.com
ETW Energietechnik	www.etw-energy.com
Guild	www.moleculargate.com
Strabag	www.strabag-umweltanlagen.com
Xebec	www.xebecinc.com
Mahler	www.mahler-ags.com

Table 5 : Manufacturers of PSA units

Company	Homepage
DMT	www.dmt-et.nl
Econet	www.econetgroup.se
Greenlane Biogas	www.greenlanebiogas.com
Malmberg Water	www.malmberg.se
RosRoca	www.rosroca.com

Table 6: Manufacturers of water scrubbing units

Company	Homepage
BIS E.M.S. GmbH	www.ems-clp.de
Cirmac	www.cirmac.com
Hera	www.heracleantech.com
MT-Biomethan	www.mt-biomethan.com
Purac Puregas	www.lackebywater.se
Strabag	www.strabag-umweltanlagen

Table 7: Manufacturers of Chemical scrubbing units

Company	Homepage
HAASE Energietechnik	www.haase.de

Table 8: Manufacturers of organic physical scrubbing units

Company	Company
Air Liquide	www.airliquide.com
BebraBiogas	www.bebra-biogas.com
Biogast	www.biogast.nl
Cirmac	www.cirmac.com
DMT	www.dmt-et.nl
Eisenmann	www.eisenmann.com
EnviTec Biogas	www.envitec-biogas.com
Haffmans	www.haffmans.nl
Gastechnik Himmel	www.gt-himmel.com
Mainsite Technologies	www.mainsite-technologies.de
Memfoact	www.memfoact.no
MT-Biomethan	www.mt-biomethan.com

Table 9: Manufacturers of membrane units

Company	Homepage
Gas treatment Services	www.gastreatmentservices.com
Acrion Technologies	www.acrion.com
Terracastus Technologies	www.terracastus.com
FirmGreen	www.firmgreen.com
Prometheus Energy	www.prometheusenergy.com
Cryostar	www.cryostar.com
Hamworthy	www.hamworthy.com
Gasrec	www.gasrec.co.uk
Air Liquide	www.airliquideadvancedtechnologies.com

Table 11: Manufacturers of cryogenic units

6. Appendix - County reports from IEA task 37

COUNTRY	PLACE	SUBSTRATE	UTILISATION	CH4(%)	TECHNOLOGY	PLANT CAPACITY (Nm3/h Raw gas)	IN OPERATION SINCE
Austria	Pucking	Manure	Gas grid	97	PSA	10	2005
Austria	Bruck/Leitha	Biowaste	Gas grid	97	Membrane	180	2007
Austria	Margarethen am Moos	Energy crops & Manure	Vehicle fuel	>95	Membrane	70	2007
Austria	Linz	Sewage	Gas grid	97	Water scrubber	800	2008
Austria	Reitbach / Eugendorf	Energy crops	Gas grid, vehicle fuel	97	PSA	150	2008
Austria	Loeben	Sewage sludge, biowaste	Gas grid	97	Chemical Scrubber	140	2009
Austria	Wiener/Neustadt		Gas grid	97	Membrane	260	2010
Austria	Engerwitzdorf				Chemical Scrubber	300	2010
Austria	Rechnitz		Vehicle fuel		PSA		2010
Austria	Steindorf				PSA	300	2012
Canada	Berthierville, (QC)	Landfill gas	Gas grid		Membrane		2003
Denmark	Fredericia	Sewage sludge	Gas grid		Water scrubber	300	2011
Finland	Kalmari farm, Laukaa	cow manure, confectionary by-products, fat	Vehicle fuel	>95	Water scrubber	50	2002
Finland	Mäkikylä biogas plant, Kouvola	sewage sludge, biowaste, sludge, energy crops	Gas grid	>95	Water scrubber		2011
France	Lille	Biowaste	Vehicle fuel	97	Waterscrubber	2*600	2007
France	Lille Marquette				Waterscrubber	100	2009
France	Forbach	Biowaste, green waste, energy crops	Gas grid, vehicle fuel		Membrane	100	2012
Germany	Jameln	manure, energy crops	vehicle fuel		Genosorb scrubber	140	2006
Germany	Straelen	manure, energy crops	gas grid		PSA	1000	2006
Germany	Bottrop	sewage sludge	vehicle fuel		PSA	1250	2007
Germany	Könnern 1	manure, energy crops	gas grid		water scrubber	1250	2007
Germany	Mühlacker	manure, energy crops	gas grid		PSA	1100	2007
Germany	Neuss	manure, energy crops	gas grid		chemical scrubber	600	2007
Germany	Werlte	manure, biowaste	gas grid		PSA	500	2007

Germany	Burgrieden / Laupheim	energy crops	gas grid	PSA	600	2008
Germany	Darmstadt Wixhausen	manure, energy crops	gas grid	water scrubber	900	2008
Germany	Graben - Lechfeld	energy crops	gas grid	PSA	1000	2008
Germany	Ketzin	energy crops	gas grid	PSA	380	2008
Germany	Maihingen	energy crops	gas grid	water scrubber	1250	2008
Germany	Pliening	energy crops	gas grid	PSA	1000	2008
Germany	Ronnenberg	energy crops	gas grid	Genosorb scrubber	680	2008
Germany	Schwandorf	energy crops	gas grid	PSA	2.000	2008
Germany	Aiterhofen	energy crops	gas grid	PSA	2.100	2009
Germany	Altenstadt / Schongau	biowaste	gas grid	water scrubber	1250	2009
Germany	Angermünde / Schmargendorf	manure, energy crops	gas grid	water scrubber	1200	2009
Germany	Einbeck	energy crops	gas grid	chemical scrubber	1140	2009
Germany	Godenstedt / Rockstedt	energy crops	gas grid	chemical scrubber	600	2009
Germany	Güstrow	energy crops	gas grid	water scrubber	10.000	2009
Germany	Güterglück	manure, energy crops	gas grid	PSA	1200	2009
Germany	Hardegsen	manure, energy crops	gas grid	chemical scrubber	1075	2009
Germany	Horn / Bad Meinberg	energy crops	gas grid	chemical scrubber	2.000	2009
Germany	Kerpen / Sindorf	manure, energy crops	gas grid	PSA	1000	2009
Germany	Könnern 2	energy crops	gas grid	chemical scrubber	3.300	2009
Germany	Lanken / Wotersen	energy crops	gas grid	chemical scrubber	750	2009
Germany	Lüchow	manure, energy crops	gas grid	water scrubber	1250	2009
Germany	Niederndodeleben	energy crops	gas grid	water scrubber	1400	2009
Germany	Pohlsche Heide / Hille	biowaste	gas grid	PSA	500	2009
Germany	Rathenow-Heidefeld	manure, energy crops	gas grid	Genosorb scrubber	1150	2009
Germany	Wetschen - Diepholz	manure, energy crops	gas grid	water scrubber	1250	2009
Germany	Wüsting	manure, energy crops	gas grid	PSA	1200	2009
Germany	Zeven	energy crops	gas grid	chemical scrubber	250	2009
Germany	Arnschwang	manure, energy crops	gas grid	water scrubber	1400	2010

Germany	Blaufelden / Emmertsbühl	manure, energy crops	gas grid	PSA	500	2010
Germany	Dannenberg	manure, energy crops	gas grid	chemical scrubber	375	2010
Germany	Drögennindorf / Betzendorf	energy crops	gas grid	chemical scrubber	500	2010
Germany	Eggertshofen	energy crops	gas grid	chemical scrubber	400	2010
Germany	Forchheim / Breisgau	energy crops	gas grid	Genosorb scrubber	900	2010
Germany	Grabsleben	manure, energy crops	gas grid	chemical scrubber	700	2010
Germany	Homberg / Efze	manure, energy crops	gas grid	water scrubber	650	2010
Germany	Kißlegg / Rahmhaus	biowaste	gas grid	membrane	500	2010
Germany	Rhede	manure, biowaste	gas grid	chemical scrubber	800	2010
Germany	Schwedt / Oder I	biowaste	gas grid	chemical scrubber	10.000	2010
Germany	Semd / Groß Umstadt	energy crops	gas grid	water scrubber	400	2010
Germany	Tuningen	manure, energy crops	gas grid	chemical scrubber	410	2010
Germany	Unsleben	energy crops	gas grid	chemical scrubber	700	2010
Germany	Willingshausen / Ransbach	manure, energy crops	gas grid	water scrubber	700	2010
Germany	Zörbig	biowaste	gas grid	chemical scrubber	10.000	2010
Germany	Altena / Bahrdorf	energy crops	gas grid	chemical scrubber	680	2011
Germany	Barsikow	manure, energy crops	gas grid	chemical scrubber	1000	2011
Germany	Blankenhain	energy crops	gas grid	PSA	700	2011
Germany	Bruchhausen - Vilsen	manure, energy crops	gas grid	chemical scrubber	700	2011
Germany	Börger	manure, energy crops	gas grid	water scrubber	800	2011
Germany	Dargun	energy crops	gas grid	water scrubber	2.500	2011
Germany	Eich / Kallmünz	energy crops	gas grid	PSA		2011
Germany	Gollhofen	energy crops	gas grid	water scrubber	1400	2011
Germany	Groß Kelle	manure, energy crops	gas grid	chemical scrubber	500	2011
Germany	Hamburg / Köhlbrandhöft	sewage sludge, biowaste	gas grid	chemical scrubber	500	2011
Germany	Hankensbüttel - Emmen	energy crops	gas grid	chemical scrubber	700	2011
Germany	Hollleben II	manure, energy crops	gas grid	water scrubber	1400	2011
Germany	Industriepark Höchst / Frankfurt a. M.	sewage sludge, biowaste	gas grid	chemical scrubber	1500	2011
Germany	Karft	manure, biowaste	gas grid	chemical scrubber	1000	2011

Germany	Lehma / Altenburg	energy crops	gas grid	Genosorb scrubber	1100	2011
Germany	Malstedt	energy crops	gas grid	chemical scrubber	680	2011
Germany	Merzig	manure, energy crops	gas grid	Genosorb scrubber	1100	2011
Germany	Neukammer 2 / Nauen	manure, energy crops	gas grid	water scrubber	1250	2011
Germany	Oschatz	energy crops	gas grid	PSA	1400	2011
Germany	Osterby	manure, energy crops	gas grid	water scrubber	700	2011
Germany	Palmersheim-Euskirchen	energy crops	gas grid	Genosorb scrubber	700	2011
Germany	Roßwein/Haßlau	energy crops	vehicle fuel	water scrubber	1350	2011
Germany	Rostock	manure, biowaste	gas grid	PSA	850	2011
Germany	Satuelle	manure, energy crops	gas grid	water scrubber	600	2011
Germany	Schuby	energy crops	gas grid	water scrubber		2011
Germany	Schwarme	energy crops	gas grid	PSA	1200	2011
Germany	Schwedt / Oder II	energy crops	gas grid	chemical scrubber	1400	2011
Germany	Schöpstal	energy crops	gas grid	Genosorb scrubber	1400	2011
Germany	Seelow / Sachsendorf	energy crops	gas grid	water scrubber	700	2011
Germany	Stresow	manure, energy crops	gas grid	water scrubber	1200	2011
Germany	Uchte	energy crops	gas grid	water scrubber	1100	2011
Germany	Wriezen	manure, energy crops	gas grid	PSA	1200	2011
Germany	Altenstadt / Hessen	biowaste	gas grid	chemical scrubber	700	2012
Germany	Berlin-Ruhleben	energy crops	gas grid	water scrubber	700	2012
Germany	Bützberg	energy crops	gas grid	Genosorb scrubber	1200	2012
Germany	Dresden	n/s	n/s	n/s	n/s	2012
Germany	Eschbach	n/s	gas grid	PSA	550	2012
Germany	Hahnennest	n/s	gas grid	Genosorb scrubber	700	2012
Germany	Jürgenshagen	n/s	gas grid	PSA	1400	2012
Germany	Müden-Aller	n/s	gas grid	chemical scrubber	1346	2012
Germany	Oberriexingen	n/s	gas grid	chemical scrubber	700	2012
Germany	Ostrach / Hahnennest	energy crops	gas grid	chemical scrubber	1000	2012
Germany	Ramstein-Miesenbach	energy crops	gas grid	water scrubber	1600	2012

Germany	Sagard	n/s	gas grid		n/s	1400	2012
Iceland	Reykjavik	Landfill gas	Vehicle fuel		Water scrubber	700	2005
Japan	Kobe	Sewage sludge	Vehicle fuel	97	Water scrubber	100	2004
Japan	Kobe	Sewage sludge	Vehicle fuel	97	Water scrubber	2*225	2007
Norway	Fredrikstad		Vehicle fuel		PSA		2001
Norway	Oslo	Sewage sludge	Vehicle fuel		Chemical scrubber	750	2009
Norway	Stavanger	Sewage sludge, biowaste	Gas grid		Chemical scrubber	500	2009
South Korea	Seoul				Water scrubber	150	2008
Spain	Vacarisses (Barcelona)	Landfill gas	Vehicle fuel	>85	Chemical scrubber	100	2005
Spain	Madrid	Biowaste	Vehicle fuel	96.5	Water scrubber	4000	2008
Sweden	Linköping	Sewage sludge, biowaste	Vehicle fuel	97	Water scrubber	2*330	1997
Sweden	Eslöv	Biowaste, sewage sludge	Vehicle fuel	97	Water scrubber	80	1999
Sweden	Kristianstad	Biowaste, manure, sewage sludge	Vehicle fuel	97	Water scrubber	280	1999
Sweden	Jönköping	Biowaste, sewage sludge	Vehicle fuel	97	Water scrubber	300	2000
Sweden	Laholm	Biowaste, manure	Gas grid	97	Water scrubber	500	2000
Sweden	Helsingborg	Biowaste, manure	Vehicle fuel, gas grid	97	PSA	350	2001
Sweden	Trollhättan	Biowaste, sewage sludge	Vehicle fuel	97	Water scrubber	400	2001
Sweden	Uppsala	Sewage sludge	Vehicle fuel	97	Water scrubber	400	2001
Sweden	Borås	Biowaste, sewage sludge	Vehicle fuel	97	Chemical scrubber	450	2002
Sweden	Bromma, Stockholm	Sewage sludge	Vehicle fuel	97	PSA	250	2002
Sweden	Linköping	Sewage sludge, biowaste	Vehicle fuel	97	Water scrubber	1400	2002
Sweden	Skövde	Sewage sludge, slaughter house waste	Vehicle fuel	97	PSA	140	2002
Sweden	Bromma, Stockholm	Sewage sludge	Vehicle fuel	97	PSA	250	2003
Sweden	Eskiltuna	Biowaste, sewage sludge	Vehicle fuel	97	Water scrubber	330	2003
Sweden	Nynäs gård	Manure	Vehicle fuel	97	Water scrubber	10	2003
Sweden	Ulricehamn	Sewage sludge	Vehicle fuel	97	PSA	20	2003
Sweden	Henriksdal, Stockholm	Sewage sludge	Vehicle fuel	97	Water scrubber	600	2004
Sweden	Norrköping	Sewage sludge	Vehicle fuel	97	Water scrubber	250	2004

Sweden	Västerås	Biowaste, sewage sludge	Vehicle fuel	97	Water scrubber	650	2004
Sweden	Lilla Edet			97	PSA	25	2005
Sweden	Skellefteå	Sewage sludge	Vehicle fuel	97	Water scrubber	250	2005
Sweden	Henriksdal, Stockholm	Sewage sludge	Vehicle fuel	97	Water scrubber	800	2006
Sweden	Kristianstad	Biowaste, manure, sewage sludge	Vehicle fuel	97	Water scrubber	600	2006
Sweden	Norrköping	Distiller's waste, energy crops	Vehicle fuel	97	Water scrubber	240	2006
Sweden	Östersund	Sewage sludge	Vehicle fuel	97	Water scrubber	200	2006
Sweden	Bjuv	Biowaste, manure	Gas grid	97	PSA	500	2007
Sweden	Boden	Sewage sludge, manure	Vehicle fuel	97	Water scrubber	360	2007
Sweden	Falköping	Sewage sludge	Vehicle fuel	97	Water scrubber	200	2007
Sweden	Göteborg	Biowaste, sewage sludge	Gas grid	97	Chemical scrubber	1600	2007
Sweden	Helsingborg	Biowaste, manure	Vehicle fuel, gas grid	97	Water scrubber	650	2007
Sweden	Helsingborg	Sewage sludge	Gas grid	97	Water scrubber	250	2007
Sweden	Örebro	Sewage sludge	Vehicle fuel	97	Water scrubber	450	2007
Sweden	Kalmar	Sewage sludge, manure	Vehicle fuel	97	Chemical scrubber	200	2008
Sweden	Malmö	Sewage sludge	Gas grid	97	PSA	500	2008
Sweden	Plönninge	Manure	Vehicle fuel	97	Water scrubber	20	2008
Sweden	Falkenberg	Biowaste, sewage sludge, energy crops	Gas grid	97	Chemical scrubber	750	2009
Sweden	Himmerfjärden, Stockholm	Sewage sludge	Vehicle fuel	97	Chemical scrubber	800	2009
Sweden	Katrineholm	Sewage sludge	Vehicle fuel	97	Water scrubber	80	2009
Sweden	Motala	Sewage sludge	Vehicle fuel	97	Water scrubber	80	2009
Sweden	Västervik	Sewage sludge	Vehicle fuel	97	Water scrubber	130	2009
Sweden	Örebro	Sewage sludge	Vehicle fuel	97	Water scrubber	2000	2009
Sweden	Jönköping	Biowaste, sewage sludge	Vehicle fuel	97	Water scrubber	600	2010
Sweden	Karlstad		Vehicle fuel	97	Chemical scrubber	120/500	2010
Sweden	Katrineholm	Manure, co-digestion	Vehicle fuel	97	Water scrubber	800	2010
Sweden	Käppala (Stockholm)	Sewage sludge	Vehicle fuel	97	Water scrubber	1000	2010

Sweden	Lund	Sewage sludge	Gas grid	97	Water scrubber	200	2010
Sweden	Norrköping	Sewage sludge Distiller's waste	Vehicle fuel	97	Water scrubber	400/800	2010
Sweden	Sundsvall		Vehicle fuel	97	Cryogenic separation	100	2010
Sweden	Visby	Energy crops	Vehicle fuel	97	Water scrubber	550	2010
Sweden	Lidköping		LBG	LBG	Water scrubber	2000	2011
Sweden	Loudden (Stockholm)		LBG	LBG	Cryogenic separation	200	2011
Sweden	Sävsjö			97	Chemical scrubber	700	2011
Sweden	Brålanda	Manure, biowaste	Vehicle fuel	97	Water scrubber	300	2012
Sweden	Gävle		Vehicle fuel	97	Water scrubber	300	2012
Sweden	Mörrum	Biowaste	Vehicle fuel	97	Water scrubber	300	2012
Sweden	Skövde		Vehicle fuel	97	Water scrubber	800	2012
Sweden	Växjö	Sewage sludge, food waste	Vehicle fuel	97	Chemical scrubber	350	2012
Sweden	Borås		Vehicle fuel	97	Water scrubber	300	
Switzerland	Rümlang	Biowaste	Vehicle fuel	96	PSA	30	1995
Switzerland	Otelfingen	Biowaste	Vehicle gas	96	PSA	50	1998
Switzerland	Samstagern	Biowaste	Gas grid	96	PSA	50	1998
Switzerland	Emmenbrücke	Sewage sludge	Gas grid	96	PSA	90	2005
Switzerland	Pratteln	Biowaste	Gas grid	96	Genosorb scrubber	300	2006
Switzerland	Berne	Sewage sludge	Gas grid	96	PSA	300	2007
Switzerland	Romanshorn	Sewage sludge	Gas grid	96	Genosorb scrubber	100	2007
Switzerland	Widnau	Agricultural, co-digestion	Gas grid	96	PSA	100	2007
Switzerland	Obermeilen	Sewage sludge	Gas grid	96	Chemical scrubber	100	2008
Switzerland	Roche	Sewage sludge	Gas grid	96	PSA	250	2008
Switzerland	Inwil	Biowaste, manure	Gas grid	96	Chemical Scrubber	225	2009
Switzerland	Lavigny	Biowaste	Gas grid	96	PSA	150	2009
Switzerland	Utzensdorf	Biowaste	Gas grid	96	PSA	100	2009
Switzerland	Volketswil	Biowaste	Gas grid	96	Chemical Scrubber	100	2010

Switzerland	Münchwilen	Animal by-products	Gas grid	96	Chemical scrubber	280	2011
The Netherlands	Tilburg-De Spinder	Landfill gas	Gas grid	88	Water scrubber	600	1987
The Netherlands	Wijster	Landfill gas	Gas grid	88	PSA	1000	1989
The Netherlands	Nuenen	Landfill gas	Gas grid	88	PSA	1500	1990
The Netherlands	Collendoorn	Landfill gas	Gas grid	88	Membrane	50	1993
The Netherlands	Beverwijk	Sewage sludge	Gas grid	88	Membrane	130	2006
The Netherlands	Groningen	Biowaste	Gas grid	88	Chemical scrubber	1200	2009
The Netherlands	Mijdrecht	Sewage sludge	Gas grid	88		70	2009
The Netherlands	Bunschoten- Spakenburg	Biowaste	Gas grid	88	Water scrubber	1200	2010
The Netherlands	Witteveen	Biowaste, manure	Gas grid	88	Membrane	300	2010
The Netherlands	Zwolle	Biowaste	Gas grid	88	Water scrubber	700	2010
The Netherlands	Dinteloord	Organic waste	Gas grid	88		1100	2011
The Netherlands	Meerlanden	Biowaste	Gas grid	88		400	2011
The Netherlands	Well	Biowaste	Gas grid	88	Membrane	600	2011
The Netherlands	Haarlem	Landfill gas	Gas grid, LBG		Cryogenic separation	280	2012
United Kingdom	Albury	Landfill gas	Vehicle gas		PSA/Membrane		2008
United Kingdom	Poundbury				Membrane	650	2012
USA	Staten Island (NY)	Landfill gas	Gas grid		Selexol	13000	1981
USA	Cincinatti (OH)	Landfill gas	Gas grid		PSA	10000	1986
USA	Houston (TX)	Landfill gas	Gas grid		Selexol	9400	1986
USA	Los Angeles (CA)	Landfill gas	Vehicle gas		Membrane	2600	1993
USA	Dallas (TX)	Landfill gas	Gas grid		PSA	10000	2000
USA	Shasnee (KS)	Landfill gas	Gas grid		Organic scrubber	5500	2001
USA	Dayton (OH)	Landfill gas	Gas grid		Krysol (methanol)	6000	2003
USA	Pittsburg - Monroeville (PA)	Landfill gas	Gas grid		Membrane	5600	2004
USA	Pittsburg - Valley (PA)	Landfill gas	Gas grid		Membrane	5600	2004
USA	Antonio, TX		Gas grid		PSA	~1000	2011
USA	San Diego, CA	Sewage sludge	Gas grid		Membrane	~1000	2012
USA	Renton (WA)	Sewage sludge	Gas grid	98	Water scrubber	4000	1984/1998 +

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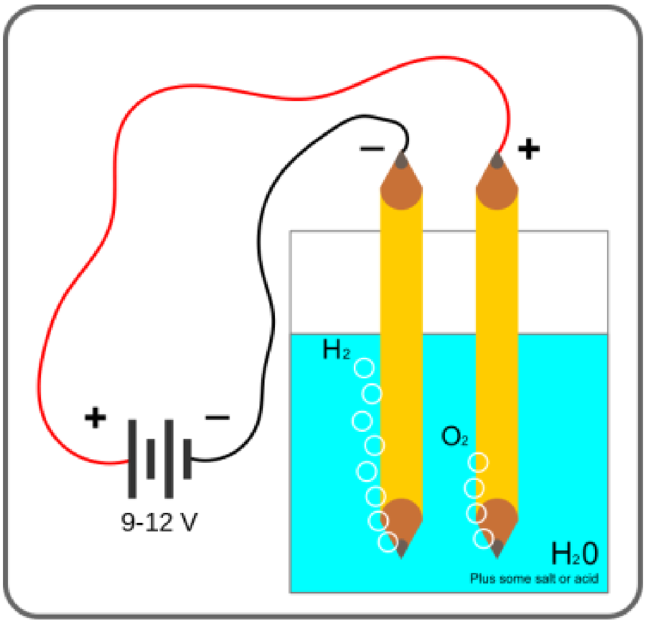
Status for electrolyzing technologies (2013)

Prepared by Aksel Hauge Pedersen, DONG Energy A/S, Denmark



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1. Background and summary

Background

Electrolyzers and electrolyzing technologies becomes more and more interesting due to several potential benefits of using electrolysis as an integral part of operations in the electric power industry. An industry that in the future will be highly depended and influenced by fluctuating renewable power (like wind and solar power) and needs storage of power in periods with excess power production (as example - high wind combined with low consumption).

If wholesale electricity prices are low (or even negative), energy storage can be a valuable technology. Producing and storing hydrogen during off-peak periods can add load to the off-peak periods and create storage of energy to be used later. The benefits of using off-peak electricity to produce hydrogen improves the load factor of electric power distribution and transmission facilities and increase the efficiencies of intermediate generation by allowing plants to run at their optimal level. One of the biggest drawbacks to using hydrogen is the round-trip efficiency. Since current technologies for electrolyzers have relatively low efficiencies, the total power to gas and storage process loses a lot of energy, unless the excess heat can be utilized.

Summary

This report gives the technological background for the electrolyzing process, and a description of the three most common technologies: Alkaline, PEM and SOEC. The experiences with electrolyzers are mainly due to the Alkaline electrolyzer that has been used for approximately 100 years, while PEM still is in the demonstrating phase and SOEC has not left the laboratories yet.

It is expected that SOEC and PEM will be the technology of the future due to high process temperature, with system efficiencies in the range of 3,2 kWh/Nm3 for SOEC and 3,75 kWh/Nm3 for PEM, while the Alkaline electrolyzer hardly will be lower than 4,3 kWh/Nm3 hydrogen. The cost of hydrogen production through electrolyzers is not comparable with hydrogen produced from fossil fuels (natural gas).

2. What is electrolyzing?

Electrolysis of water is the decomposition of water (H_2O) into oxygen (O_2) and hydrogen gas (H_2) due to an electric current being passed through the water. An electrical power source is connected to two electrodes, or two plates typically made from some inert metal (such as platinum, stainless steel or iridium) which are placed in the water. Hydrogen will appear at the cathode (the negatively charged electrode, where electrons enter the water), and oxygen will appear at the anode (the positively charged electrode). Assuming an ideal process the amount of hydrogen generated is twice the number of moles of oxygen, and both are proportional to the total electrical charge conducted by the solution. However, in many cells competing side reactions dominate, resulting in different products and less than the ideal efficiency.

Electrolysis of pure water requires excess energy in the form of overpotential to overcome various activation barriers. Pure water has an electrical conductivity about one millionth that of seawater. The efficiency of electrolysis is increased through the addition of an electrolyte (such as a salt, an acid or a base) and the use of electro catalysts.

Currently the electrolytic process is rarely used in industrial applications since hydrogen can currently be produced more economic from fossil fuels (mostly natural gas). The inventor of the electrolysis process was more then one person, but most known is Alessandro Volta that in year 1800 invented the voltaic pile, and a few weeks later William Nicholson and Anthony Carlisle used it for the electrolysis of water. From 1870 electrolysis of water became a common method for the production of hydrogen.

In figure 1 (see /1/) a schematic overview of an electrochemical cell is presented. The core is an electrochemical cell, which is filled with a water solution and has two electrodes connected with an external power supply. At a certain voltage, which is called critical voltage (theoretical > 1,23 V at 25 °C, or 296 kJ/mol (15,9 MJ/kg) - equal to 2,96 kWh/Nm^3 H_2) between both electrodes, the electrodes start to produce hydrogen gas at the negative electrode and oxygen gas at the positive electrode.

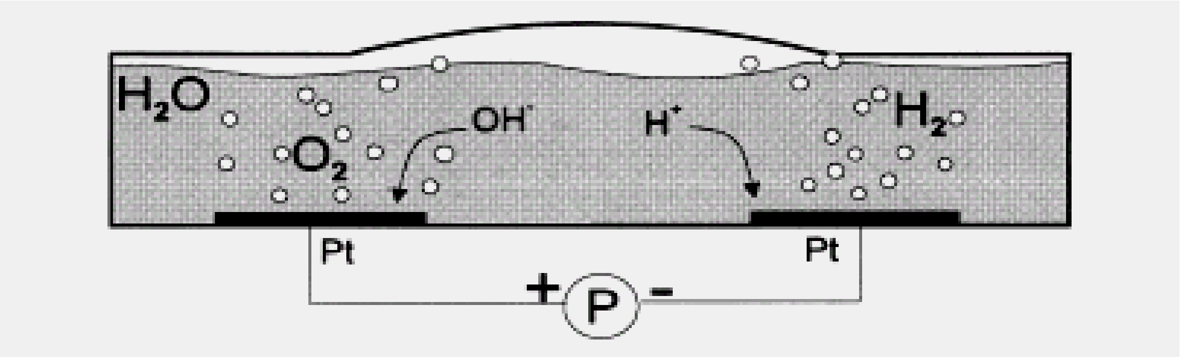


Figure 1: The fundamental Electrolyzing proces

When a current is passed through water, the molecules accept electrons from the cathode, where their hydrogen's are reduced to H_2 gas. The half-cell reaction is:

$$4H_2O(l) + 4e^- \rightarrow 2H_2(g) + 4OH^-(aq)$$

Other water molecules donate electrons to the anode, where oxygen gas is produced:

$$2H_2O(l) \rightarrow O_2(g) + 4H^+(aq) + 4e^-$$

The OH- ions and H+ ions produced by the electrolysis combine to produce water again:

$$4OH^-(aq) + 4H^+(aq) \rightarrow 4H_2O(l)$$

and the net result is the breakdown of water to hydrogen gas and oxygen gas, with no net change in the concentrations of H+ and OH-:

$$\begin{gathered} 4H_2O(l) + 4e^- \rightarrow 2H_2(g) + 4OH^-(aq) \\ 2H_2O(l) \rightarrow O_2(g) + H^+(aq) + 4e^- \\ \underline{4OH^-(aq) + 4H^+(aq) \rightarrow 4H_2O(l)} \\ 2H_2O(l) \rightarrow 2H_2(g) + O_2(g) \end{gathered}$$

The hydrogen molecules accumulate on the surface of the electrode until a bubble forms, breaks away, and rises to the surface of the electrolyte. At the oxygen electrode, a similar process occurs. The oxygen molecules also accumulate into gas bubbles and rise to the surface. Both of these electrode reactions require some intermediate catalytic reaction with a metal surface. A basic electrolyzer cell consists of an electrolyte plus the former mentioned two metal plates. The electrolyte is a water solution made conductive by mixing a salt or compound with water. Selection of the electrolyte is important because it must;

- exhibit high ionic conductivity;
- not be chemically decomposed;
- not be volatile enough to be removed with the evolved gas; and
- the electrolyte should have a strong resistance to pH changes

For the most practical applications, these criteria can be met by the use of a strong acid, such as sulphuric acid, or a strong alkali, such as potassium hydroxide (KOH). Maximum conductivity occurs in KOH solutions at about a 30% concentration, and this is the concentration usually selected. There is one notable exception to this use of alkaline electrolytes, the use of a solid polymeric ion-exchange material that also has good ionic conductivity.

In the following parts of this report the focus is on three electrolyzing technologies;

- Alkaline electrolyses (AEC)
- Proton Exchange electrolyses (PEM)
- Solid Oxide Electrolyses (SOFC)

See also /2/ and /3/.

3. Alkaline electrolyzers

Alkaline electrolysers (AEC) is a very mature technology that is the current standard for large scale electrolysis. The anode and cathode materials in these systems are made of nickel and nickel plated steel. Electrocatalysts are often added to the electrodes and might be noble metals like platinum, rhodium or iridium. The electrolyte in these systems is a highly caustic KOH aqueous solution. The electrodes and the evolved gasses are separated by a diaphragm with very fine pores made of NiO or other materials stable in KOH. Key advantages of this technology are:

- Simple technology,
- Proven maturity
- Demonstrated durability.

The electrode reactions in an AEC are:

$$\text{Cathode: } 4H_2O(l) + 4e^- \rightarrow 2H_2(g) + 4OH^-(aq)$$
$$\underline{\text{Anode: } 4OH(aq) \rightarrow O_2(g) + 2H_2O(l) + 4e^-}$$
$$\text{In total: } 2H_2O(l) \rightarrow 2H_2(g) + O_2(g)$$

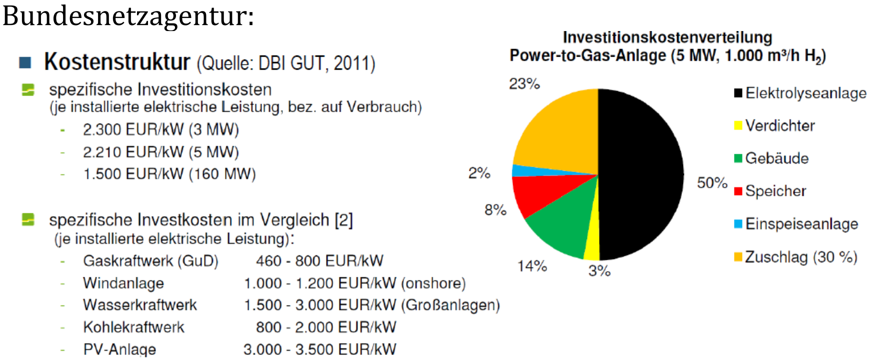
Most commercial AECs are operated at 70-80 °C. Increasing the AEC operation temperature above 200 °C may significantly increase the performance and the electricity-to-hydrogen efficiency. A known obstacle for operating at elevated temperature is the lower stability of the materials. State-of-the-art figures and theoretical potentials for AEC are listed in table 1.

AEC - state of the art - 2013		
Parameter	State of the art	Potential
Capacity (Nm^3/h)	1 - 1000	Up to 3000
System Price €/Nm^3/h (€/kW @ 5 kWh/Nm^3)	7000 - 8500 (1400 - 1800)	2000
Power consumption kWh/Nm^3	4,8 - 5,5	3,9 - 4,6
Increase in power cons. due to degradation	2-4% per year	2 - 4%
Outlet pressure	32 bar	Up to 100 bar
Lifetime for stack (hours)	40.000	40.000
System lifetime (years)	10	10

Table 1 : Alkaline Electrolyzer - State of the Art - 2013

Economy

A comprehensive cost study was made by DBI Gas and environment technology - Müller- Syring, DBI og Peter Franke, Bundesnetzagentur:



Kostenstruktur (Quelle: DBI GUT, 2011)

- spezifische Investitionskosten
  (je installierte elektrische Leistung, bez. auf Verbrauch)
  - 2.300 EUR/kW (3 MW)
  - 2.210 EUR/kW (5 MW)
  - 1.500 EUR/kW (160 MW)
- spezifische Investkosten im Vergleich [2]
  (je installierte elektrische Leistung):
  - Gaskraftwerk (GuD) 460 - 800 EUR/kW
  - Windanlage 1.000 - 1.200 EUR/kW (onshore)
  - Wasserkraftwerk 1.500 - 3.000 EUR/kW (Großanlagen)
  - Kohlekraftwerk 800 - 2.000 EUR/kW
  - PV-Anlage 3.000 - 3.500 EUR/kW

Figure 2: AFC investments (from DBI Gas and environment technology - Müller- Syring, DBI og Peter Franke, Bundesnetzagentur)

From the calculations in Figure 2 the conclusion can be drawn that the AEC accounts for 50% of the system cost.

The electric consumption of AEC systems is expected to decrease from present 5 - 5.2 kWh/Nm^3 Hydrogen to 3.9 kWh/Nm^3, if the cell-temperature in AEC systems can be increased to app. 200 °C and the pressure increased to app. 100 bar. However is the most important economic figure that is influencing electrolyzers is the power price. As a "thump rule" the power price counts for app. 75% of the cost for the production of 1 m^3 of hydrogen. The alkaline technology is currently used commercially almost exclusively to produce hydrogen for industrial purposes that require very pure hydrogen.

More and more demonstration plants with hydrogen (or methane) production for the storage of wind or solar power are showing up. In 2013 more than 10 plants will be built in Germany for this purpose. All based upon the AFC technology.

Figure 2: Large scale Alkaline electrolyzers

An overview of manufacturers is shown in table 2.

Manufactures of alkaline electrolyzers

Manufacturer	**Country**	**Capacity range m^3 H_2/h**	**Pressure bar**	**kWh/Nm^3 H_2**
Hydrogenics	CA/US/EU	1 - 60	10 - 25	4,2
Teledyne	US	2,8 - 150	4,2 - 16	5,6 - 6,1
NEL/Norks Hydro	N	0 - 485	0 - 12	4,1 - 4,8
IHT (Lurgi/Barmag syst))	CH	3 - 760	0 - 32	3,9 - 4,6
Accagen	CH	1 - 100	10 - 200	4,4 - 6,3
Idroenergy	IT	0,4 - 64	1,8 - 3,9	5 - 6

Table 2: Manufactures of Alkaline Electrolysers

In addition to table 2 several manufactures exist in Japan, India, Denmark, US, etc.

4. PEM electrolyzers

Polymer electrolysers, known as proton exchange membrane electrolysers (PEMEC), are built around a proton conductive polymer electrolyte. The membrane consists of a solid fluoropolymer. This has been chemically altered to contain sulphonic acid groups, SO3H, which easily release their protons and thus is an ion exchange resin (Nafion). The electrodes are typically made of a support with catalysts made of IrO2 and Pt in the anode and cathode respectively.

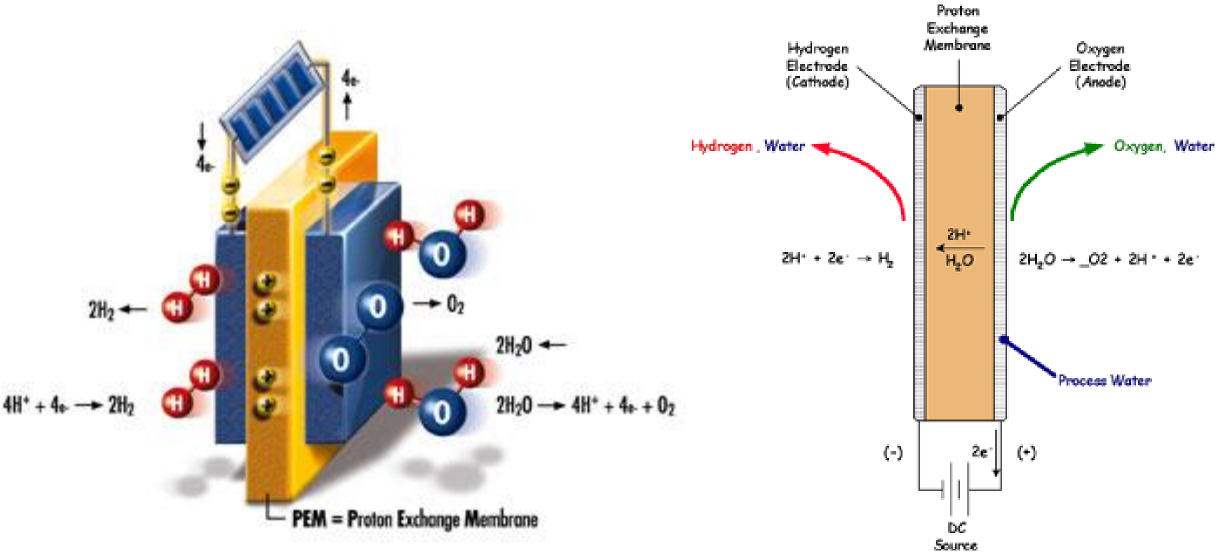


Figure 3:. Functionallity of PEMEC (PEM electrolyzer)

The key advantages of PEMEC are the high production rates at low temperature and compact design. The solid electrolyte allows for operation at high pressure.

Further claimed advantages over classical (Alkaline) technology, are:

- no corrosive electrolytes
- good chemical and mechanical stability
- high protonic conductivity
- high gas impermeability
- excellent gas separator
- high current density at higher efficiency
- reduced number of moving parts
- easy maintenance
- excellent partial-load range and rapid response to fluctuating power inputs
- compact stack design allowing high pressure operation

The disadvantage of the PEMEC is the high cost of the electrolyte and catalyst.

The electrode reactions in a PEMEC are:

$$\text{Anode}: 2H_2O \rightarrow 4H^+ + O_2 + 4e^-$$
$$\underline{\text{Cathode}: 4H^+ + 4e^- \rightarrow 2H_2}$$
$$\text{Cell}: 2H_2O \rightarrow 2H_2 + O_2$$

The PEMEC is usually cooled by circulating water through the cavity between the metal separator and the electrode plate. Hydrogen or oxygen evolved into this cavity is swept out by the coolant stream and is separated from the water outside the cell. PEMECs have fast response time and start-up/shut-down characteristics.

State of art figures and theoretical potentials for PEMEC are listed in table 3.

PEM electrolyzer - state of the art - 2013		
Parameter	**State of art**	**Potential (in 5 - 10 years)**
Capacity (Nm^3/h)	1 - 30	1-3000
System Price €/Nm^3/h (€/kW @ 5 kWh/Nm^3)	15000€/Nm^3/h (3000 €/kW)	2700 €/Nm^3/h (540 €/kW)
Power consumption kWh/Nm^3	6-6,5	3,6 - 4,4 (at elevated temperature - up 200 gr. C)
Degradation (increase in power consumption/year)	2 - 4%	2 - 4%
Outlet pressure	30 bar	200 bar
Lifetime stacks (hours)	5000	50.000

Table 3: PEM Electrolyzer - State of the art 2013

Existing PEMEC demonstrates already a part of the potential of the PEM technology in the form of compact, simple and secure installations producing pressurized hydrogen. There is a development potential that may lead to an overall reduction in manufacturing costs and increase the efficiency. Lower material costs can be achieved using new electrolyte membranes and new non-noble metal-containing catalyst materials.
Such components are under development for low temperature PEMEC. Increased efficiency is expected when the operating temperature is increased, although it is not expected in the short term that high temperature PEMEC (200 °C) will be operated at thermoneutral potential as is possible with SOEC.

Manufactures

Manufactures of PEMFC				
Manufacturer	Country	Capacity range m^3 H_2/h	Pressure bar	kWh/Nm^3 H_2
Proton	US	0,2 - 30	1,5 - 4	6,8 - 7,3
Siemens	D			
CETH2	GB	5 - 160	14	5 - 5,2
Syslatech	D	0,09 - 2	?	?
Hydrogenics	US/CA/EU	1 - 2	0 - 8	6,7
ITM Power	GB	1 - 2	15	4,8 - 5

Table 4: Manufactures of PEMFC

Further a lot of smaller companies are involved in the development of stacks and the sale of PEMEC units.

5. Solid Oxide Electrolyzer

See /4/.

An SOEC is in principle the same cell as a solid oxide fuel cell (SOFC). The SOEC consists of two porous electrodes on either side of a thin oxygen-ion conducting electrolyte. The electrolyte is usually made of yttria-stabilized zirconia (YSZ). The cathode and anode can be made of Nickel/YSZ and YSZ/LSM (Lanthanum Strontium Manganate).

The preferred operation temperature is in the range of 700 - 900 °C. A key advantage of SOECs is the capability of a high production rate at a high efficiency. Other advantages are low material costs and a possibility for co-electrolysis of H_2O and CO_2. A disadvantage of SOECs is the demand for material stability at high temperature. The electrode reactions in a SOEC are:

$$\begin{gathered}\text{Cathode : } 2H_2O \rightarrow 2H_2 + 2O{-}{-} + 4e{-} \\ \underline{\text{Anode : } 2O{-}{-} + 4e{-} \rightarrow O_2} \\ \text{Cell : } 2H_2O \rightarrow 2H_2 + O_2\end{gathered}$$

Various designs of SOECs have been produced and tested, but the planar design is widely acknowledged as the optimum since it offers the shortest current paths and thus the lowest internal resistance.

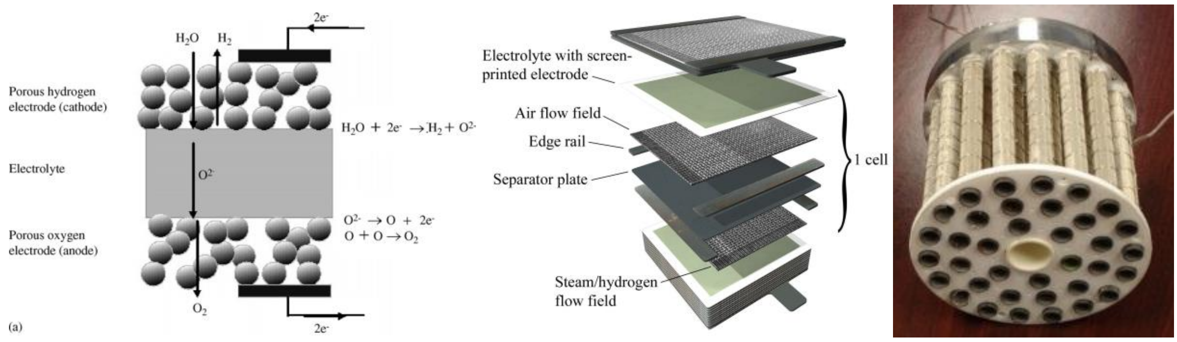


Figure 4: Operating mechanisms of solid oxide cells (left). Ceramatec's solid oxide cell/stack construction - planar design (middle). Turbulaf EC (left).

The steel support is more mechanical robust than the Ni/YSZ support which allows a reduction of the thickness of the support layer. The cathode and the electrolyte are spray painted on the support tape. Half-cells are stamped and subsequently sintered at high temperature. The anode is spray painted on the sintered half-cell and the full cell is sintered again. Finally current collectors are applied to both sides of the cell. In order to produce a usable voltage, the SOECs are serially connected by means of interconnect layers. These are typically made of ferritic stainless steel when the operation temperature is below 800 ^{0}C.

SOEC - state of the art - 2013		
Parameter	State of art	Potential (in 5 - 10 years)
Capacity (Nm^3/h)	3	3000
System Price €/Nm^3/h (€/kW @ 5 kWh/Nm^3)	4000€/Nm^3/h (800 €/kW)	700 €/Nm^3/h (150 €/kW)
Power consumption kWh/Nm^3	3,3 - 3,7	3,2
Degradation (increase in power consumption/year)	8%	2%
Outlet pressure	8 bar	50 bar
Lifetime stacks (hours)	8000	40.000

Table 5: Solid Oxide electrolyzer - sate of the art 2013

Economy

No public information exist about the cost level for SOFC. For the future the manufacture predict cost for a 5 kW SOFC modules to be 200€/kW at a production rate of 500 MW/year (jvf. DOE). The system price is estimated to be 2.5 to 3 times higher than the stack cost.

Performance

The heat formed may be used to supply the necessary heat to the cell as electrolysis is particularly endothermic at high temperature. This enables a very high system electrical efficiency.

One of the specific benefits of SOEC compared with conventional electrolysis technology is its ability to make combined H_2O and CO_2 electrolysis and thus the ability to make cheap synthetic (non-fossil) fuel to e.g. the transport sector. The electrolysis process is endothermic, which means it consumes heat. Combined with the high operating temperature this means that almost no waste heat is produced and this gives a very high efficiency - considerably higher than for low-temperature electrolysis. The high operating temperature also enable relatively cheap electrode- and electrolyte materials can be used (no precious metals). Further efficiency and improvement of the economy can be achieved by pressurized operation of the SOEC. The pressure can be achieved by evaporation of high pressure feed water (liquid) using low grade heat and is therefore expected to be inexpensive compared with other pressurization methods. The high operating temperature and high pressure makes it possible to integrate further catalysis of the synthesis gas to synthetic fuel in one system.

The electric energy requirement for the electrolysis process decreases with increasing temperature and this also makes SOEC's advantageous compared with AEC's and PEMEC's. Steam electrolysis (i.e. SOEC electrolysis) requires app. 3.1 kWh/Nm3 H_2 whereas water electrolysis requires app. 3.5 App. kWh/Nm3 H_2. The difference in energy requirement (0.4 kWh/Nm^3) is the energy needed for steam generation. Low grade heat for steam generation is normally cheaper than electricity. For this reason, SOEC operation may be cheaper than AEC or PEMEC operation. In the table "State-of-the-art SOEC + theoretical potential" the low grade heat for steam generation is not included.

In short, the thermodynamic and the kinetic of all three electrolysis technologies may benefit from increased pressure and temperature operation. However, serious stability issues of the electrodes and the electrolyte must be addressed before high pressure and temperature AECs and PEMECs can be widely commercialized. The efficiency is given as 1.5 V divided with the cell voltage. This corresponds to the energy contained in the produced hydrogen (HHV) divided with the electricity consumption of the cell. If the cell is operated below 1.5 V, the energy must be supplied as heat instead. Hence, at low current density it is possible to operate both AECs and PEMECs with efficiencies close to 100%. However, such an operation is not commercially optimized since the hydrogen production rate is proportional to the current density. In other words, both AECs and PEMECs will be operated with efficiencies significantly lower than 100%. In contrast to this, the SOEC can be operated with a high current density and a high efficiency at the same time.

Potential future manufacturers (not a commercial product in 2013)

Manufacturers of SOEC				
Manufacturer	**Country**	**Capacity range m^3 H_2/h (kW)**	**Pressure bar**	**kWh/Nm^3 H_2**
Ceramatec	US (Idaho) - 2008	17 kW	?	?
Haldor Topsoe/DTU	DK - 2014	20 kW	?	?
Kier/HERC	Korea	? turbular stack	?	?
Kyocera	Japan	?	?	?
Acumentrics	US	?	?	?
Versa Power systems	Canada/US	2 - 10 kW	?	?
Delphi/PNNL	US	?	?	?
Sunfire	US	200 kW	30	

Table 6: Existing laboratories for testing of SOEC / coming manufacturers of SOFC.

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IGU WOC 5.4/TT1

Injection of Hydrogen into the Natural Gas System (2014)

Prepared by Aksel Hauge Pedersen, DONG Energy A/S, Denmark

E.ON Falkenhagen 2 MW Alkaline electrolyzer (Hydrogenics). Start-up

List of content

1. Background and Summary

1.1 Background

Storage and transport of hydrogen in a gas pipeline is not a new technology. In the "town gas"- (or "coal gas") age from 1850 half of the volume of the "coal gas" was hydrogen. The composition of "coal gas" varied according to the type of coal and the temperature of carbonization. Typical figures were: hydrogen 50%, methane 35%, carbon monoxide 10%, ethylene 5%. Furthermore several pipelines transporting pure hydrogen is functioning to day in US and Europe (see picture below for Air Liquid transport system for chemical gases in Europe).

Figure 1: Air Liquide's European network for pipeline transport of chemical gases.

However the philosophy about use of the natural gas system for storage (and transport) of hydrogen produced through surplus of fluctuating renewable energy, is relatively new. Nevertheless it seems obvious to use the existing natural gas transport network for storage (and transport) of future surplus of renewable energy from wind- and solar power (and biogas). Power to Gas will become more and more common due to a future energy world with a majority of fluctuating renewable power. In some periods power will be in surplus and in shortage in other periods, in contrast to the present situation with more manageable power production mainly based upon fossil fuels like nuclear, coal, oil and natural gas plus hydropower.

The main questions analysed in this report are:

- How much hydrogen is reasonable to inject into the existing natural gas network?
- What is the related power balancing possibility? and
- Where in the natural gas system should the hydrogen be injected?

1.2 Summary & conclusion

Natural gas must comply with certain quality requirements and must have a certain calorific- or heating value, Wobbe index, methane number etc. The addition of hydrogen to natural gas will not be without consequences for the existing gas infrastructure. Hydrogen has a lower calorific value than natural gas. The LHV (Lower heating value) for hydrogen is 3 kWh/Nm^3 when natural gas has LHV of app 11 kWh/m^3, so one volume of natural gas (mostly methane) contain 3 - 4 times the energy of the same volume of hydrogen. In order to maintain the same energy output a much higher volume of natural gas must be transported if it contains hydrogen.

An interesting question is where the hydrogen physically will be injected into the network with the given limitations for the maximum concentration of hydrogen today. Another challenge is whether consumers will be able to use the natural gas/hydrogen mix to fuel a central heating boiler or an industrial process? Would industry be better off without the natural gas/hydrogen mix, or would the disadvantages outweigh the benefits? One thing seems clear, if hydrogen is injected into the gas network, every household and every company should be able to use it.

Another possible application for the mixture is automotive fuel. A 80/20 mixture of hydrogen and natural gas (market under the name 'Hythane') has extremely good combustion properties, see /13/. Used in vehicles with internal combustion engine it has lower emissions of CO_2 and NO_x compared with use of pure natural gas, whereby environmental gains can be made.

It is very unlikely that the step to a hydrogen-based economy will take place from one day to the next. Such fundamental change will certainly take several years, or even decades. And this very important, even critical, transition period is too often overlooked when the possibility of a hydrogen economy is considered.

Clearly, the technical aspects of the natural-gas pipeline infrastructure and the different end-use applications will play an important role as far as the feasibility of this approach is concerned. A transition towards a hydrogen-economy by means of hydrogen-natural gas mixtures, transported and distributed through the existing natural-gas grid, seems to be possible - but with limitations.

1.2.1 How much hydrogen is reasonable to inject into the existing natural gas network?

Recommendation for injection of hydrogen in natural gas pipelines from /8/ and /9/ indicates that underground storage in porous rock should be avoided. Further a maximum hydrogen content injected into natural gas pipelines could be in the range 2- to 10%.

- Max. 2 % - if connected to CNG filling station
- Max. 5 % - if not connected to CNG filling station, gas turbines and gas engines with a hydrogen specification < 5 %
- Max. 10 % - if not connected to filling station, gas turbines and gas engines with a given hydrogen specification < 10 %.

Injection of hydrogen should be carefully controlled to avoid sudden increases of the hydrogen concentration in the natural gas systems.

Finally, developments in separation techniques might become available, and then the hydrogen can be extracted from the mixture with natural gas - and used for other purpose - like fuel vehicles (electric vehicle equipped with fuel cells instead of batteries). Research is also initiated to find ways for industrial use of the O2, produced in parallel with hydrogen during the electrolyser process.

1.2.2 What is the related power balancing possibility - example form the Danish Gas System?

If only 2% hydrogen is allowed it's argued in chapter 2.2.1 that the max energy storage into the Danish natural gas network will be 0,2 TWh/year, If the hydrogen production is spread over a whole year (will require a certain amount of hydrogen storage). This is equal to a power capacity of 24 MW in in

8448 hours/year (24 hoursx352 days). If only produced in 50% of time the similar possible power capacity doubles to 48 MW. These capacities seems quite low, combined with real need in the few hours per year with a situation of high wind power production and low power demand. Storage of hydrogen, and/or methane production might be the answer to that challenge.

The DGC made some estimates for hydrogen injection possibilities as well, see /11/. Here 10% of hydrogen was used as a maximum injection percentage. One of the conclusions was that: with storages for hydrogen, the natural gas grid could receive during the year for regulating purposes an amount of energy in the order of 1 % of the annual electricity consumption. In 2012 the Danish power consumption was app 31.000 GWh. Converted to power capacity over a whole year this equalize to app. 40MW. There seems to be obvious similarities between the two different ways for estimation of power balancing possibilities.

1.2.3 Where in the natural gas system should the hydrogen be injected?

Hydrogen should only be injected at a point with reasonable gas flow. For the Danish Natural Gas System this might be in Nybro where the Natural gas is coming in from the gas fields in the North Sea. On the other hand, to avoid energy loss through compression, injection should take place in the medium- or low pressure system. So it's a question about cost for compression, energy loss through transport of power - and mixing possibilities between natural gas and hydrogen. In a minor scale might be used spots after a M/R station. At this place the hydrogen/natural gas mix only can flow in one direction, but the injection rate might be limited and always depending of gas consumption at the downstream side of the distribution network in question.

Some preliminary estimates for a single point hydrogen injection at Nybro (max. gasflow up to 1 million m^3/h) and an injection rate of 2% (20.000 m^3/h) of hydrogen would require an electrical input of app. 100 MW for the electrolysis reaction. That would be the max. possible power storage for the Danish gas-system - but only for the limited amount of hours with max. gas flow.

2. Consequences of hydrogen into the natural gas system?

2.1 Hydrogen/natural mix - a transition to pure hydrogen?

Hydrogen as an energy carrier will only be a realistic option if and when it becomes economically favourable. Here, “economic” has to be interpreted in a broad sense, meaning that the external costs for all energy options also have to be included in the overall comparison. When these conditions are met, the question can be raised how the transition from natural gas to hydrogen will take place. The considerations are that although it could be a first step towards the widespread use of hydrogen, the use of hydrogen-natural gas mixtures containing over 10 - 15 vol% of hydrogen, is not self-evident, unless certain standards are enforced by governments by means of taxes or subsidies. Therefore, it should be investigated whether the immediate use of pure hydrogen, instead of a transition period with mixtures, might perhaps prove to be a more realistic scenario.

Technically seen, this drastic changeover should be possible. As mentioned before most European countries have switched from town gas (a mixture which contained up till 50% H_2) to natural gas literally overnight. Hereby, the grid was divided into different sectors and during one night, the replacement of town gas by natural gas was carried out in one particular sector. In the subsequent week, all end-use applications were modified or replaced and natural gas became the new energy carrier. It seems very unlikely that this scenario can be repeated for the transition from natural gas to hydrogen. Several reasons are the logic background for this statement:

- the distribution network today is almost three times larger than it was 40 years ago. This would make such a changeover very time-consuming.
- the absence of a high-pressure transport grid in the days of town gas made such transition far less complicated than it would be now.
- the number of end-users have increased considerably so the necessary replacement of all end-use applications will be very cost-intensive.

Another option, the installation of a parallel pipeline network for hydrogen, could theoretically also be considered as one possible solution for the introduction of hydrogen. This approach might be quite difficult due to lack of space. Thus, since an immediate and entire switch from natural gas to hydrogen does not seem to be a realistic scenario, both for the distribution and the transmission a transition period with mixtures, certainly has to be considered as a serious option.

For technical reasons, any injection of hydrogen into the natural-gas pipeline should take place at the medium or low-pressure grid, immediately after the pressure-reduction stations. On the one hand, backflow from the medium or low-pressure grid to the high-pressure transport grid is effectively impossible, which allows to carry out the transition process on both levels strictly separated. On the other hand, no compressors are used in the medium or low-pressure distribution grid, which facilitates the use of the pipeline infrastructure for hydrogen transport.

2.2 Pipeline considerations

Very little experience exists for hydrogen in modern natural gas pipelines made of steel and plastics (Polyethylene). For that reason DGC (Danish Gastechnology Center) app 10 years ago began to test used natural gas tubes in PE and steel for transport of hydrogen. The test are ongoing today. In the following is referred to the reporting from test results obtained in the period from 2006 - 2009 (/1/).

The conclusions for the transport of hydrogen in distribution pipelines in plastics (PE 80 and PE 100):

- No visible interaction observed between hydrogen and pipe material over the investigated period of four years.
- The structure analysis of the PE tubes also indicates no interaction between hydrogen and the Polymer.
- For the mechanical analysis the tensile tests, elongation at break and the elastic modulus as well as the slow crack growth show that no deterioration occurred due to the exposure to pressurised hydrogen during the four years of exposure.

Strong indications were found for polyethylene gas pipes PE80 and PE100 to be usable for transportation of hydrogen without adverse long-term effects on polymer structure or the mechanical performance of the polymer pipes. The same indications have been found for both new pipes – and old pipes used in the Danish natural gas distribution network for more than 20 years.

For the steel pipes used for transmission of high pressure natural gas was examined all weldings. The conclusions were: The dynamic testing equivalent of 80 years with two times the maximal pressure variations found in the Danish gas transmission system showed no defect growth. The overall conclusion from these tests at DGC therefore indicates no safety problems. However the gas distribution network consists of many other components and connections. The conclusion only applies to the tested types of pipe material, and not to other components and connections in the natural gas network.

2.2.1 The energetic transport of hydrogen amounts to 80% of natural gas - for the same pressure drop

To meet the energy demand, the flow rate of natural gas has to be sufficiently high. This flow rate, in turn, is controlled by the pressure drop in the pipeline. The energy flow through a pipeline is described by /4/

$$Q = C \times e \times D^{2.5} \times \sqrt{\frac{(p_1^2 - p_2^2)}{d \times Z \times T \times L \times f}}$$

whereby Q = normal flow rate (Nm^3/h)
d = relative density compared to air [-]

C = proportionality constant = 0.000129 [-]
Z = compressibility [-]

D = inner diameter [mm]
T = gas temperature [K]

e = pipeline efficiency [-]
L = length [km]

p_1 = inlet pressure [kPa]
f = friction factor [-]

p_2 = outlet pressure
Nm^3/h = Normal cubic metre/hour

The Higher Heating Value (HHV) of hydrogen amounts to 3,5 kWh/Nm^3 (LHV = 3 kWh/Nm^3) whereas the HHV of natural gas equals approximately 12 kWh/Nm^3 (LHV = 11 kWh/m^3). For the same energy demand, the volume of hydrogen to be transported has to be three times that of natural gas, but the density of hydrogen is nine times smaller than that of natural gas. From equation above, it can be seen that a flow rate of hydrogen, three times larger than that of natural gas, results in approximately the same pressure drop. Pressure drop is a critical parameter for the pipeline network.

However, also other parameters such as Z and f can vary with pressure or flow rate. The final result is that the energy carrying capacity of hydrogen is less for a pipeline of the same pipe diameter and pressure drop than for natural gas and /5/ and /11/, but the much lower volumetric energy density of hydrogen partly is offset by a much higher flow rate. This means that the hydrogen energy transmission capacity at an unchanged pressure drop is approximately 20% lower than the similar energy transport by pure natural gas. However gas demand is expected gradually to diminish in the future so whether it's a question about 2, 10- or 100% hydrogen seems without practical importance concerning delivery of energy.

For peak gas demands the pipe network currently is used as a short-term storage reservoir. The volume of gas maintained in a pipeline network during normal operation is commonly called the linepack. The linepack capacity of the network for hydrogen is more than four times smaller than for natural gas as it only depends on the relative volumetric energy density of the two fuels.

Network operators are uncertain about operating practice for hydrogen. Should they follow current natural gas operating practices also for hydrogen? Will additional storage be required? Answers have to found in the future, but one option to increase hydrogen linepack capacity would be to use higher operating pressures than at present.

2.2.2 Temperature goes up - when reducing pressure of Hydrogen

Due to the Joule-Thomson effect temperature drops with 0,5 degrees C/bar when reducing pressure of natural gas, whereas the temperature goes up with 0.035 degrees C/bar when the pressure of 100% hydrogen is reduced. So, throttling hydrogen from 80 bar to 15 bar, results in a temperature rise of 2 degrees C. A pressure reduction of a hydrogen/natural gas mix therefore will not cause any problems, that is not already foreseen with natural gas.

Due to molecule size of hydrogen versus methane the volumetric loos of hydrogen through permeability through pipe walls always will be larger than for natural gas, but the energetic loos due to difference in heating value is in favour of hydrogen. Furthermore, the quantitative amount of loos strongly depends on the material of the pipeline. Diffusion of hydrogen through PE pipelines is five times higher than diffusion of natural gas, but still negligible. Calculations have shown that the yearly loos of hydrogen by leakage amounts to approximately 0.0005% - 0.001% of the totally transported volume /1/, /6/ and /7/.

2.2.3 Practical recommendations for hydrogen injection (Conclusions from /8/)

In general, a case by case analyse is necessary before injecting hydrogen in the natural gas network. First of all most gas chromatographs will require modification. It is recommended that manufacturers' specifications should always be followed, particularly when gas turbines or gas engines are connected to the network. However, on the basis that most of the natural gas systems can accepts admixture of up to 10 % by volume of hydrogen, the following maximum hydrogen concentrations based upon safety by use of natural gas are recommended:

- 2 % - if a CNG filling station is connected;
- 5 % - if no filling station, no gas turbines and no gas engines with a hydrogen specification < 5 % are
connected;
- 10 % - if no filling station, no gas turbines and no gas engines with a hydrogen specification < 10 % are connected.

2.3 Gas quality considerations.

2.3.1 How much Power might be balanced - example with the Danish Natural Gas System?

As mentioned before the volume of hydrogen that might be added to natural gas is limited. However hydrogen also might be used directly to produce methane, the main constituent of natural gas, but the process will involve further capital expenditure and energy losses.

The "easy" way is just to mix natural gas and hydrogen. If hydrogen is injected into the natural gas network, the transportation capacity and the storage capacity of the existing natural gas infrastructure including underground storage facilities can be used directly. The Danish network consist of app 4.000 km steel pipes (incl 860 km high pressure transmission line) plus 15.000 km plast pipes (distribution). At the given pressure (from 4 to 80 bar) this gives a storage of 50 - 100 million m^3, but taking into account the gas storage at Ll. Torup and Stenlille one may add further 1,5 - 2 bill m^3 of possible gas storage facilities. This might add important contribution to the storage of renewable electricity and might as a consequence avoid the construction of new electricity transportation capacity. However one important remark must be added - hydrogen storage in salt caverns (like Ll. Torup) is well known technology, but no experience is available for hydrogen storage in aquifair layers like the second Danish gas storage in Stenlille.

Example:
How much power might be balanced - if max hydrogen content is 2% (in the Danish natural gas network)?
The max transport capacity in the existing Danish Natural Gas system is 8 bill m^3/year. The expectations for the future is some lower natural gas consumption than to day, so the yearly transport capacity might drop to the order of 4 billion m^3/year - or app 50 TWh of energy. This is almost twice as much energy as the electricity consumed in 2012 (app 30 TWh).

If 10% of hydrogen is injected into the natural gas network it would correspond to an energy quantity of approx. 1,2 TWh. If only 2% hydrogen is allowed this magnitude would be app 0,24 TWh, but even that will be a quite ideal situation. The max injection will only be possible at a certain percentage of time, when the flow and quality of natural gas at the injection point is good. Therefore the injection with 2% hydrogen only will be possible maybe less than 50% of time. If this is truth - and the assumption of an efficiency of 60% through the hydrogen production (electrolyzer efficiency) - the possible amount of power stored into hydrogen will be 0,24x0,5/0,6 = 0,2 TWh If the hydrogen production is spread over a whole year (will require a certain amount of storage) this gives a possible power storage capacity of 24 MW in 8448 hours/year (24x352). If only produced in 50% of time (when injection of 2% hydrogen is possible) the similar power capacity stored in hydrogen will be 48 MW for 4224 hours/year (24x176). These capacities seems quite low - in relation to the real need for power storage the few hours per year with high wind and low power consumption. Storage of hydrogen - and/or methane production might be the answer to that challenge.

DGC also made some estimates for hydrogen injection possibilities, see /11/. Here 10% of hydrogen was used as max injection. One of the conclusions was that with storages for hydrogen, the NG-grid could receive during the year for regulating purposes an amount of energy in the order of 1 % of the annual electricity consumption. In 2012 the Danish power consumption was app 31000 GWh. Converted to power capacity over a whole year this equalize to app 40MW (352 days of 24 hours) so it seems to be a kind of similarity between the ways of calculations.

For a single point of hydrogen injection one might select the main gastransmission line from the gas-treatment plant - Nybroe, which is the "key point" for the gasflow from the North Sea. Max gas flow here might be up to 1 million m^3/h. At this point an injection rate of 2% hydrogen (20000 m^3/h) would require an electrical input of app. 100 MW for the electrolysis reaction. That would be the max possible power storage - but only for periods with max. gas flow.

2.3.2 How much hydrogen is possible to inject?

Natural gas qualities in Europe in the future will show more variations in combustion characteristics than seen before. The most important combustion characteristics are Wobbe index, relative density, calorific value and methane number.

In table 1 (page 12) is shown gas qualities and combustion characteristics for most common European natural gas qualities. Table 2 (page 12) shows the characteristics after adding of 10% hydrogen.

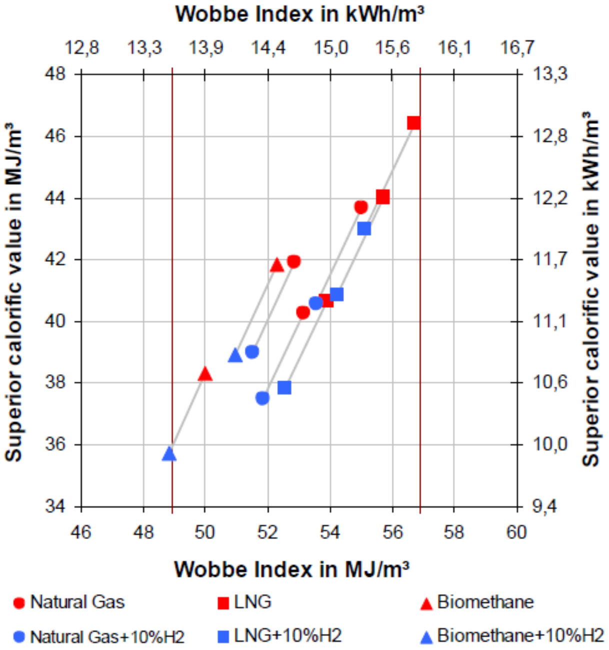

Figure 2: HHV as function of Wobbe index for different gases with or without 10 % hydrogen.

Figure 2 shows the HHV (high Heating Value) as a function of Wobbe index including the EASEE-gas (European Association for the Streamlining of Energy Exchange – gas) recommendations /10/ for the Wobbe index range (49/57 MJ/m^3) (red lines). The blue symbols stand for the gases mixed with hydrogen.

Figure 2 confirms that, prior to hydrogen admixture, all gases listed comply with the EASEE-gas recommendations.

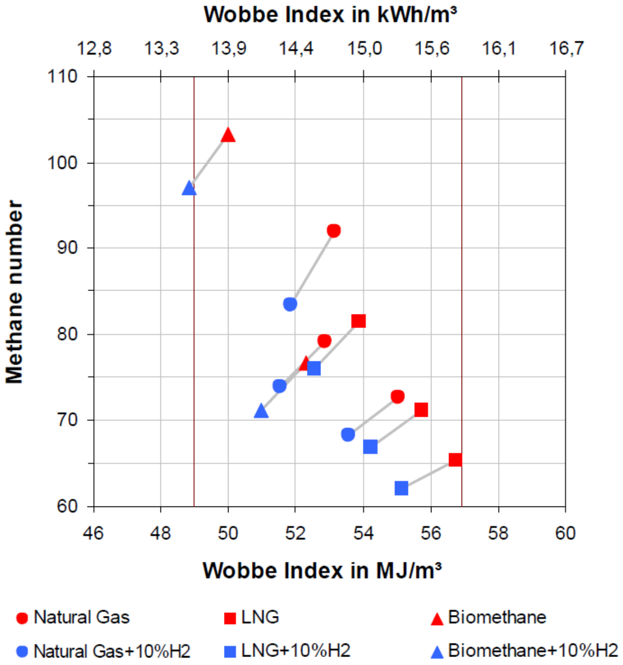

Figure 3: Methane number as a function of Wobbe index for different gases - with or without 10% Hydrogen

The very high Wobbe indexes of rich LNG (56,7 MJ/m^3) are not acceptable in most European countries for safety reasons. Adding 10% of hydrogen reduce Wobbe index for all gases. In the case of gases with very high methane content relative densities may be slightly lower than the minimum value recommended by EASEE-gas (0.555), but according to practical experience it is not problematic with respect to combustion behaviour in residential gas appliances. Figure 3 shows methane number as a function of Wobbe index calculated by DGC (Danish Gas technology Centre).

The wide "methane number" range, with values from 62 to 83 (with 10% hydrogen) is remarkable. Without hydrogen admixture, some LNG qualities and pipeline gases are in the range from 65 to 91. This must be taken into account when designing gas engines for packaged cogeneration plants and vehicles. Using gas as a motor fuel has become increasingly important over the past few years, methane number as a fuel property should be included in international gas quality specifications and will also be an important parameter in European gas quality standardisation. Except for rich LNG qualities, natural gases expected to come to the market and biomethane will not pose any utilisation problems in most European countries. With certain restrictions this also applies up till 10% hydrogen admixed - except for the three well known exception - CNG tanks, gas turbines and underground storage facilities in porous rocks.

Gas composition	Symbol	Unit	Russian Gas (H)	North Sea (H)	Danish (H)	Lybia LNG (rich)	Egypt (Lean)
Methane	CH_4	Mol%	96,96	88,71	90,07	81,57	97,7
Nitrogen	N_2	Mol%	0,86	0,82	0,28	0,69	0,08
Carbon Dioxide	CO_2	Mol%	0,18	1,94	0,60		
ethane	C_2H_6	Mol%	1,37	6,93	5,68	13,38	1,8
propane	C_3H_8	Mol%	0,45	1,25	2,19	3,67	0,22
butane	C_4H_{10}	Mol%	0,18	0,35	0,18	0,69	0,2
Sum		Mol%	100	100	100	100	100
Heat. value - upper	H_s	kWh/m^3	11,2	11,6	12,1	12,9	11,3
Rel. density	d	-	0,574	0,629	0,630	0,669	0,569
Wobbe ind. - upper	W_s	kWh/m^3	14,8	14,7	15,3	15,8	15,0
Methane number	MZ	-	91	79	73	65	82

Table 1: Common gases from the European Gassystem

Gas compo-sition	Symbol	Unit	Russian Gas (H)	North Sea (H)	Danish (H)	Lybia LNG (rich)	Egypt (Lean)
Methane	CH_4	Mol%	87,26	79,84	81,06	73,41	87,93
Nitrogen	N_2	Mol%	0,77	0,74	0,25	0,62	0,07
Carbon Dioxide	CO_2	Mol%	0,16	1,75	0,54		
ethane	C_2H_6	Mol%	1,23	6,24	5,11	12,04	1,62
propane	C_3H_8	Mol%	0,41	1,13	1,97	3,30	0,20
butane	C_4H_{10}	Mol%	0,17	0,30	1,07	0,63	0,08
Hydrogen	**H_2**	**Mol%**	**10,00**	**10,00**	**10,00**	**10,00**	**10,00**
Sum		Mol%	100	100	100	100	100
Heat. value - upper	Hs	kWh/m^3	10,4	10,8	11,3	12,0	10,5
Rel. density	d	-	0,523	0,573	0,574	0,809	0,519
Wobbe ind. - upper	Ws	kWh/m^3	14,4	14,3	14,9	15,3	14,6
Methane number	MZ	-	83	74	68	62	76

Table 2: Gases from table 1 - incl 10% Hydrogen

2.4 Influence upon Consumer appliances

2.4.1 Gas engines.

See /8/.

Physics of combustion, supported by experimental evidence from real engines, shows that the increase in flame speed and reactivity caused by hydrogen addition to natural gas typically increases in-cylinder peak pressures. Further the addition of hydrogen to a natural gas will decrease the methane number.
All this can result in:

- increased combustion- and exhaust gas temperature, which might lead to enhanced sensitivity for
engine knock and increased NOx emissions;
- improved engine efficiency, but with increased engine wear and increased) NO_x emissions;
- reduced power output or tripping, for engines with knock control;
- an adverse effect on lambda sensors which can cause an inaccurate (low) measurement of oxygen in the exhaust gas.

Even low fractions of hydrogen can generate engine knock, compared to the "pure" natural gas. This implies directly one major limitation on hydrogen fraction. In case of a knock resistance of the fuel is at the lowest acceptable value no adaption of engine operation with just a small amount of hydrogen is possible. On the opposite side natural gases with a relatively high knock resistance, contains naturally a certain knock margin. In any case are engines normally not expected to have controls to adapt engine conditions for fluctuating fractions of hydrogen addition. One performance issue of major interest regards the NO_x emission; many engines are running at the permitting limit for NO_x and is therefore not able to receive hydrogen as a part of the fuel-mix. The consequences of the of the higher cylinder pressure for engine/component lifetime is more difficult to quantify. However the same challenge exist in case of LPG as substitute for Natural Gas.

Recommendations are that 2 - 5 % hydrogen addition should be the aimed interval for engines. However, given the large and unknown variation in operating conditions of the installed base of engines, and the dependence of both knock and NOx emissions, it is strongly recommended that a case by case approach to be used to determine the desirable maximum hydrogen fraction content. The physical effects are the same for engines used in the transportation sector.

2.4.2 CNG steel tanks, metallic and elastomer seals

With regard to steel CNG vehicle tanks. The potential for harmful interaction between hydrogen and steel
has been known for many years and severe restrictions have long been in place. According to UNECE3 Regulation 110 for CNG vehicles, the H2 content in CNG is limited to 2 vol %, if the tank cylinders are manufactured from steel. This limit stems from the risk of hydrogen embrittlement.

A key aspect here is that, under UNECE rules (United Nations Economic Commission for Europe) /14/, car manufacturers are held responsible for the suitability of car components, including CNG tanks. This means that CNG vehicles will only be fuelled with natural gases containing more than 2% hydrogen when substantial tests have proved that it's safe. Further concerns focus upon leak tightness of seals, both metallic and polymer. All gas carrying components inside the vehicle are currently designed and tested for a maximum 2 % H_2. As a result, all such components are potentially critical and their ability to cope with higher H_2 fractions remains to be tested.

2.4.3 Gas turbines

Current fuel specifications for many gas turbines place a 5% limit on hydrogen. However exceptions are that dedicated (syngas) gas turbines can accept very high hydrogen content(> 50 %). In /8/ the conclusion is that fuel composition variation can have an adverse impact on gas turbine operation, despite being within the range allowed in the grid and manufacturers' specifications. The general recommendation for installed base gas turbines therefore is 1 % Hydrogen as the general limit for hydrogen admixture to natural gas in a first step. Clearly, further work will be necessary to modify this situation.

2.4.4 Specific gas burners in the domestic sector

When mixing hydrogen with natural gas the risk depends on the combination of two factors: the primary
air excess and the initial Wobbe index. Due to that, atmospheric burners gas are more sensitive to H_2, if they have been adjusted with G20 (methane). Hydrogen has a direct and indirect effect on the flame speed in burners used in domestic appliances:

- it slightly increases the flame speed,
- it increases the air ratio if rich premix burners are considered (unless there is a systems that controls it) and so indirectly changes the flame speed.

For rich premixed combustion, the addition of H_2 will result in both direct and indirect increase of the flame speed. Many appliances have routinely been tested with test gas G222, which is a mixture of 23 % H_2/77 % CH_4, and this gives a strong indication that such a high H_2 content in natural gas is acceptable, at least in the short-term.

The conclusion amongst the experts from GERG /8/ are that injection of 10 % of H_2 in natural gas grids (H gas) seems to be a reasonable future prospect for the domestic and commercial appliances considered. A "safety margin" should be taken into account. However, the uncertainties need to be clarified, and in that regard, it would be beneficial to initiate some additional tests to acquire more data.

3. Underground storage

Experts have been reluctant to suggest a limit value for hydrogen addition because of the difficulty of identifying and quantifying the relevant processes among all possible reactions in underground storage facilities. The most serious issue, or potential issue identified, particularly in aquifers and oil/gas depleted fields, is the potential for bacterial growth. The associated issues are principally loss of gas volume and disappearance of injected hydrogen, whether partial or total. There is also potential for damage to the cavity itself, and production of H_2S. No problems has been identified with salt cavern storage, so they could possibly be used for storage of hydrogen and natural gas mixtures, if necessary. In conclusion, it's not possible at the moment to define a limit value for the maximum acceptable hydrogen admixture for natural gas stored underground - if it's a question of using aquifer storage - but hydrogen storage in salt caverns is well known and seems rather unproblematic (see also remarks for storage under 2.3.1).

4. Practical examples with Hydrogen Injection

4.1 The first PEM electrolyzer in operation Dec. 2013

The very first plants for mixing of hydrogen into the natural gas system was introduced in Germany during 2013. ITM Power, with its partners Mainova Aktiengesellschaft and NRM Netzdienste Rhein-Main GmbH, started injection of hydrogen into the German gas distribution network in December 2013. During the commissioning phase of the Thüga Group's power-to-gas demonstration plant, the system injected the first generated hydrogen into the Frankfurt am Main gas distribution network. The core of the system is an ITM Power proton exchange membrane (PEM) electrolyser. The electrolyser converts electrical energy into chemical energy, which in turn facilitates the storage of electricity.

Figure 4: ITM - 315 kW PEM electrolyzer (60 m^3 Hydrogen/hour)

A gas mixing plant ensures that the proportion of hydrogen in the natural gas stream does not exceed 2% by volume, the technically permissible maximum value when a natural gas filling station is situated in the local distribution network. The electrolyser supplies the hydrogen-methane mixture at the same pressure as the gas distribution network (3.5 bar), thus a costly compressor plant is avoided. The plant is located on the premises of Mainova AG in Frankfurt am Main. The project partners decided to install a PEM system, as this technology, in comparison with Alkaline systems, uses water rather than a potassium hydroxide solution, and is therefore more environmentally friendly. In addition, the system can respond more quickly to changes in the electrical load. A further advantage is the unit's compact design (2.45m high, 6m long, 3.30m wide, weighing 10 tons). The power consumption of the electrolyser is 315 kilowatts. It produces about 60 cubic meters per hour of hydrogen (⍰⍰= 57%, LHV) and thus in one hour can feed 3,000 cubic meters of hydrogen-enriched natural gas into the natural gas system. The gas mixing plant ensures that the proportion of hydrogen in the natural gas stream does not exceed 2 vol%, the technically permissible maximum value for a natural gas filling station in the local distribution network. The total investment for this project is 1.5 million €. Following the first phase of this project, the partners will consider a second project, in which hydrogen will be generated and combined with CO_2 to form synthetic methane to be directly injected and stored in the natural gas grid.

4.2 Falkenhagen. 2 MW alcaline electrolyser began operation mid 2013.

This E.ON project will be followed by another E.ON project mid 2014 with MW sized PEM electrolyzer unit at Hamburg.

In August 2013 E.ON began to inject hydrogen into the German natural Gas network in Falkenhagen. This unit, which has a capacity of two megawatts, can produce 360 cubic meters of hydrogen per hour (⍰ = 54%, LHV). The plant uses wind power and Hydrogenics alcaline electrolysis equipment to transform water into hydrogen, which is then injected into the existing regional natural gas transmission system at a pressure of 55 bar. Swissgas is a partner in the project with a 20 percent capital stake and an agreement to purchase a portion of the gas produced. The delivery contained a turnkey -to-Gas project from Hydrogenics
which included supply, installation, connection and commissioning of the hydrogen production facility including gas compression, master controls, as well as a five year service and maintenance agreement. Construction price app. 2,2 mill. €.

Figure 5: E.ON Falkenhagen, 2 MW alcaline electrolyzer plant.

Another E.On plant is under construction in Hamburg (Reitbrook) but this time E.On will test a MW sized PEM electrolyzing technology. The construction price for the Hamburg plant is estimated to be more than 13 mill €.

4.3 1 MW Power-to-Gas System from Hydrogenics to store power from 140 MW wind park

In September 2013, a 140MW wind farm in Germany was put into operation with a 1MW electrolysis system from Hydrogenics. The 140 Megawatt wind farm, is located in the municipality of Grapzow (Mecklenburg-Vorpommern District) and is connected to the local 50 Hertz 380 kilovolt high voltage grid, and will save 250,000 CO_2 per year. Hydrogenics installed a 1MW Power-to-Gas system inside a newly constructed building. The unit produces 210Nm^3 of H_2 per hour (⍰ = 63%, LHV). The plant's owners have the option to use the hydrogen in an internal combustion engine to produce electricity or be injected directly into the local natural gas grid depending on operational needs. The hydrogen compression and storage system stores up to 27MW/hour of energy and dramatically increases the overall efficiency of the wind park by tapping wind energy which otherwise would be wasted. The wind farm with 28 wind turbines can provide electricity for 125,000 households, 15% of the Mecklenburg-Vorpommern region. The storage project is funded by the Germany Federal Government with funds from the National Innovation Programme for Hydrogen and Fuel Cell Technology.

Figure. 6: Grapzow, Germany. 1 MW electrolyzing system (Hydrogenics) - 210 Nm2 hydrogen/hour. Taking power from 140 MW wind farm.

4.4 Audi's 6 MW power to methane plant in Wertle

With its synthetically-produced e-gas, e-diesel, and e-methane, the German car manufacturer hopes to use excess CO_2 in the process of creating fuels, producing a gas that gives off just as much carbon as is used to create it. In June 2013 Audi took the first major step in this ambitious project with the opening of power-to-gas facility in Wertle, Germany. This industrial-sized e-gas plant takes excess carbon dioxide harvested from landfills and biogas plants and combines it with hydrogen electrolyzed from water (using power generated from windmills or solar panels) to create a synthetic, carbon-neutral compressed natural gas. Overall the e-gas plant will reuse up to 2800 metric tons of CO_2 /year. The plant will produce app. 1300 Nm^3 hydrogen/h
(□ = 65%, LHV) and 300 m^3 SNG/h.

Figure 7: 6 MW Alcaline electrolyzer. 1300 Nm3 hydrogen/hour (+ 300 Nm3 SNG when methanization plant is established)

4.5 Other Projects

4.5.1 Hamburg/Reitbrook

A second E.ON power to gas project is started in Hamburg/Reitbrook district expected to open during 2014. In this project E.ON want to test a 1 MW PEM electrolyzer. This is claimed to be the largest in the world. The plant will feed hydrogen into the local gas grid of Hamburg. The hydrogen rate will be 265 m^3/h (▯ = 80%, LHV). This advanced technology used in comparison to conventionel electrolyzers of this size much more compact and considerably more efficient. Additionally this technology offers better dynamics and overload capabilities.

4.5.2 The GRHYD project with hydrogen for "hythane" and mix with natural gas

The GRHYD project (2013-2020) from GDF SUEZ and Areva in France started in 2013 for injecting hydrogen into the natural gas network of 200 houses. The project, launched at the end of the first quarter of 2013, includes a two-year preliminary study phase followed by a five-year phase to demonstrate the two uses of hydrogen injection: NGV and injection into the natural gas network. The industrial scale Hythane® fuel project. A NGV bus fueling station will be adapted to handle the hydrogen/natural gas blend, which will begin with a 6% hydrogen content that will be increased over time to 20%. A fleet of around 50 buses will be operated using this hydrogen-natural gas blend. A new residential neighborhood of around 200 homes in the Capelle la Grande district of the Dunkerque Urban Community will be supplied with a blend of hydrogen and natural gas using a variable hydrogen content of below 20%. Production will be based on energy from renewable sources (wind power) injected into the power distribution network. Surplus power will be used to produce hydrogen for storage (MacPhy solid state hydrogen storage - see picture below) and subsequent distribution to meet demand.

Figure 8: Storage container and McPhy composite (based on magnesium hydride), central to the McPhy storage system

4.5.3 INGRID - a high capacity hydrogen-base green-energy storage solution for grid balancing

The INGRID project started in 2013 in Puglia, Italy. A four year project with separate energy storage and 1.2 MW electrolyser for smart grid monitoring and control.

The relevance of this project is threefold:

- To balance the power grid by making it possible to store surplus electricity and use it to provide additional energy as required,
- to supply the hydrogen market by delivering green solid hydrogen storage to customers, and to test mobility by providing the electricity generated from hydrogen to the electric vehicle charging station.
- This energy storage capacity of 39 MWh will include a new fast-response 1.2 MW hydrogen generator and solid hydrogen storage with capacity to store more than 1 ton of hydrogen safely using McPhy technology (metal hydrates at low temperature).

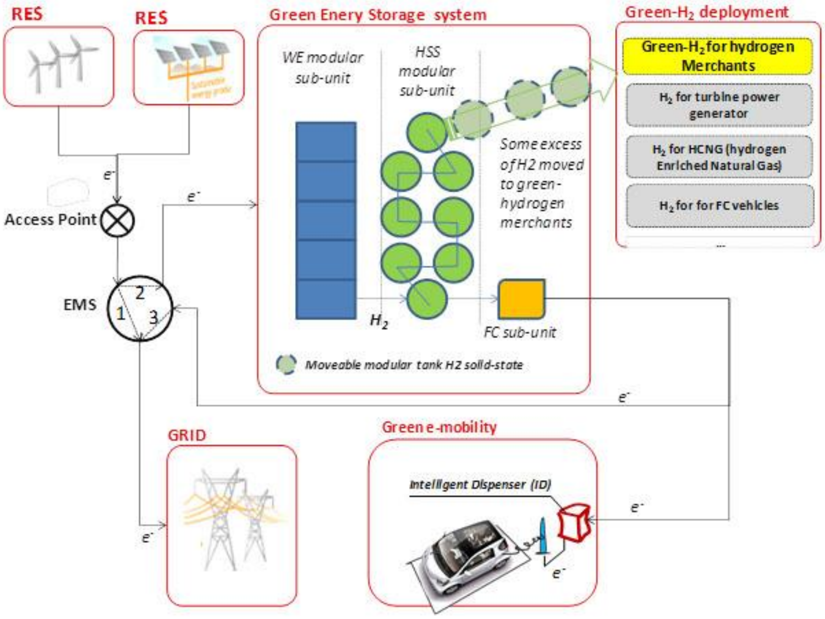

Figure 9: System principle for the INGRID project, Italy.

5. References

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/2/ Hazards and risks associated with Hydrogen and natural gas mixtures . Hydrocarbon world 2012.

/3/ Future gas profiles in the EU / Denmark, By Jean Schweitzer, DGC, 2012

/4/ "Grundlagen der Gastechnik", Carl Hansen Verlag München, Wien 1999

/5/ The use of the Natural-Gas Pipeline Infrastructure for Hydrogen Transport in A changing market structure, WP EN 2008-008.

/6/ Naturalhy - project

/7/ "Hydrogen diffusion through plastic pipes", Sholten and Wolters, 2002

/8/"Admissible Hydrogen Concentrations in Natural Gas Systems" GERG report from Klaus Altfeld and Dave Pinchbeck

/9/ Power to gas, gas quality and the GERG hydrogen project, Dave Pinchbeck and Klaus Altfeld, Marcogas, 2012

/10/ EASEE-gas Common Business Practice Nr. 2005-001/02, Harmonisation of gas quality. EASEE - gas (European Association for the Streamlining of Energy Exchange - gas.

/11/ Hydrogen in the Danish Natural Gas System. Could it balance wind power?
Niels Bjarne K. Rasmussen, DGC Note 336-55-420 version 2, 2013.

/12/ Conversion oft he UK gas system to transport Hydrogen. Paul E. Dodds, Stephanie Demoullin, University College, London, 2013

/13/ Malmö Hydrogen and CNG/Hydrogen filling station and Hythane bus project, WHEC 16 / 13-16 June 2006 – Lyon France. Bengt Ridell Carl Bro Energikonsult AB, Sweden.

/14/ Regulation No 110 of the Economic Commission for Europe of the United Nations (UN/ECE), 2011

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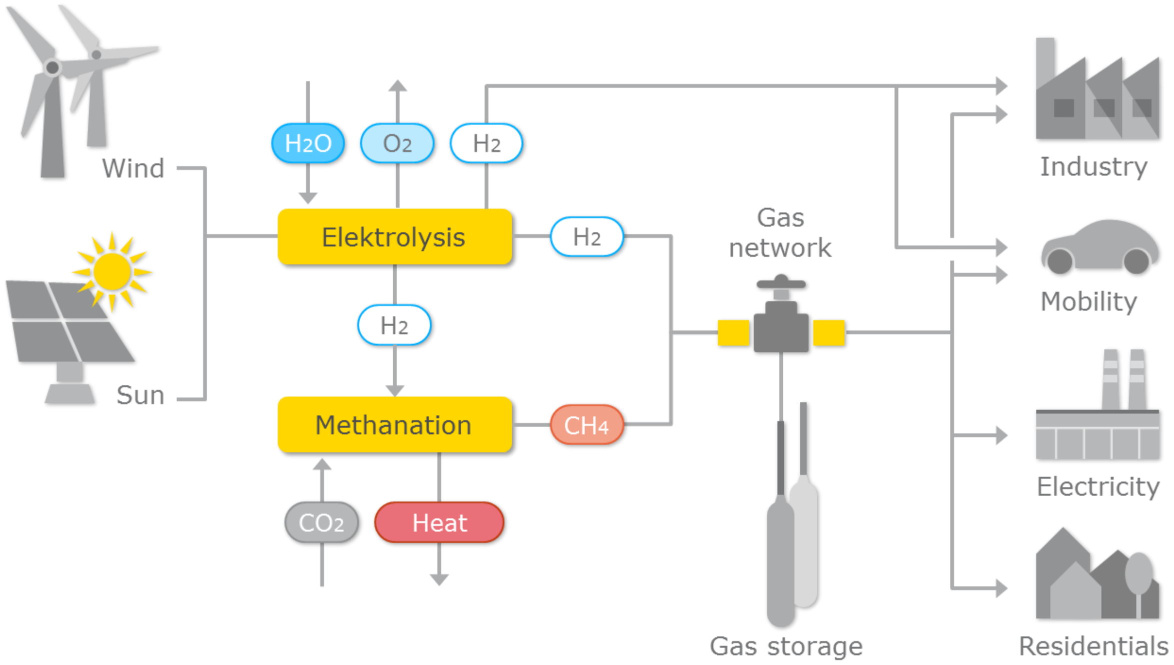
Economic aspects of power to gas

Prepared by Koen G. Wiersma, Gasunie, The Netherlands



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1. Introduction

The role of renewable energy is expected to increase significantly in the coming decades. Renewable energy technologies are an important part of the mix of options required to achieve a secure and sustainable energy mix, together with energy efficiency and other low carbon options. To stimulate the growth of renewables governments have put supportive policies in place. As a result, renewable sources have been the driver of much of the growth in the global clean energy sector. The European Union has for example set targets to increase the share of energy consumption produced from renewable resources to 20% in 2020 and 27% in 2030.

The current energy system is not designed to cope with a large share of intermittent sources. As the share of intermittent sources, mainly wind and solar, is growing the need for flexibility in the system will also increase. The production pattern from wind and solar power does not necessarily follow the demand pattern. Periods with an excess of electricity will occur, as will periods with a shortage of electricity, if the system is not prepared for this situation. It will require a mix of solutions to provide flexibility to the system. Generally considered solutions are demand-side management, flexible fossil-based generation, grid expansion, energy storage, electrification of heat demand and curtailment of surplus intermittent generation capacity.

2. Energy storage technologies

The field of energy storage covers a wide range of technologies, each with specific technical characteristics (Figure 1). These characteristics determine the functions this specific storage technology has to offer for the energy system. Storage technologies should be assessed at the application level, taking into account storage duration, frequency of charge and discharge, efficiency, response time and site constraints.

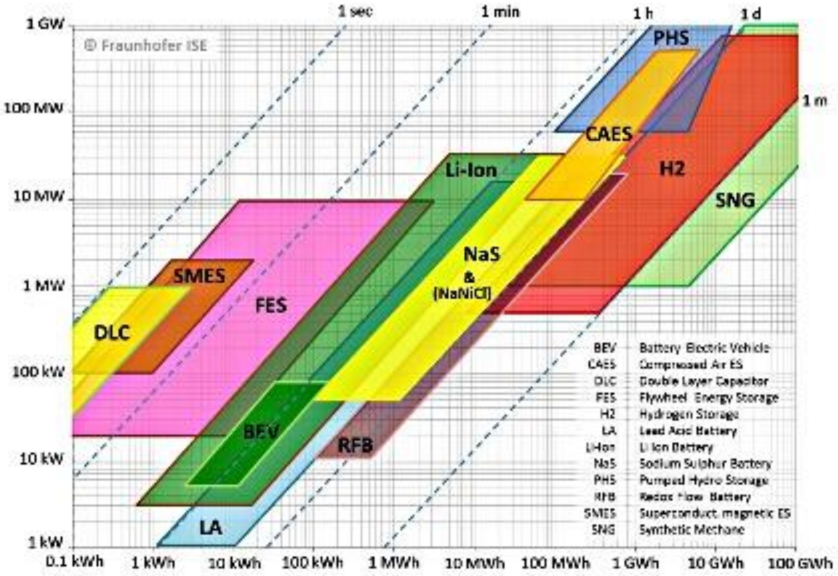

Figure 1: Comparison of energy storage technologies[1]

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[1] Electrical Energy Storage, IEC Market Strategy Board Fraunhofer ISE

Ultra capacitor's and flywheels offer very rapid power transfer, which can smooth out power fluctuations of less than a second. For longer-term storage, in the order of minutes, hours or days, a variety of battery types can be used. Compressed air energy storage (CAES), pumped hydro storage (PHS), and methane and hydrogen storage systems (through P2G) are useful for long-term storage. Energy storage systems can be classified as mechanical, chemical, electrochemical, electric field, magnetic and thermal, as shown in Table 1.

Electrical energy storage		
Mechanical	**Electrochemical**	**Electric Field**
Pumped Hydro (PHS) Compressed Air (CAES) Fly wheel	*Conventional batteries* Lead Acid (PbA) Nickel Cadmium (NiCad) Lithium - Ion (Li-Ion)	Capacitor **Magnetic** Magnetic Coil (SMES)
Chemical	*High temperature batteries* Sodium Sulphuer (NaS) Zebra (NiCl)	**Thermal**
Hydrogen Synthetic natural gas (SNG) Other chemical compounds	*Flow batteries* Vanadium Redoz (VBR) Zinc-Bromine (ZnBr)	Molten Salt Hot water storage

Table 1: Classification of energy storage systems[2],[3]

2.1 State of energy storage technologies

The SBC Energy Institute analysed the current state and future developments of electricity storage technologies. At the end of 2012, the installed power capacity of electricity storage plants amounted to more than 128 GW. This development was limited to mostly one technology: pumped hydro storage. Development of pumped hydro storage started in the 1960s, and the technology accounts for 99% of global installed capacity.

The first CEAS plant, a 290 MW facility in Germany, was commissioned in 1978. The second, a 110 MW plant in the US, was not built until 1991. Two large plants, with capacities of 300 MW and 150 MW, are under construction in the US. Large batteries are also being developed, with installed capacity amounting to almost 750 MW. Driven by developments in Japan, sodium-sulphur batteries became the dominant technology in the 2000s and now account for nearly 60% of stationary batteries installed (441 MW of a total of 747 MW).

In recent years, lithium-ion batteries have become more popular and account for the majority of planned battery projects. Although at a very early phase of deployment, with few projects announced, flow batteries could be a game changer in the medium term. With the exception of thermal storage, developed in recent years in conjunction with concentrating solar power plants, all other electricity-storage technologies remain marginal in terms of installed capacity. Despite the recent commissioning of a 20 MW plant in the US, flywheels struggle to find a sustainable value proposition; electrical storage technologies, either super capacitors or superconducting magnetic energy storage, remain at an early phase of demonstration. The interest in chemical storage is high in Europe, with several large-scale demonstration projects in Germany, Denmark and the UK [4]. Figure 2 shows the maturity of the energy storage technologies.

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[2] Utility Scale Energy Storage Systems, June 2013

[3] Electricity Storage factbook, SBC Energy Institute, 2013

[4] Electricity Storage factbook, SBC Energy Institute, 2013

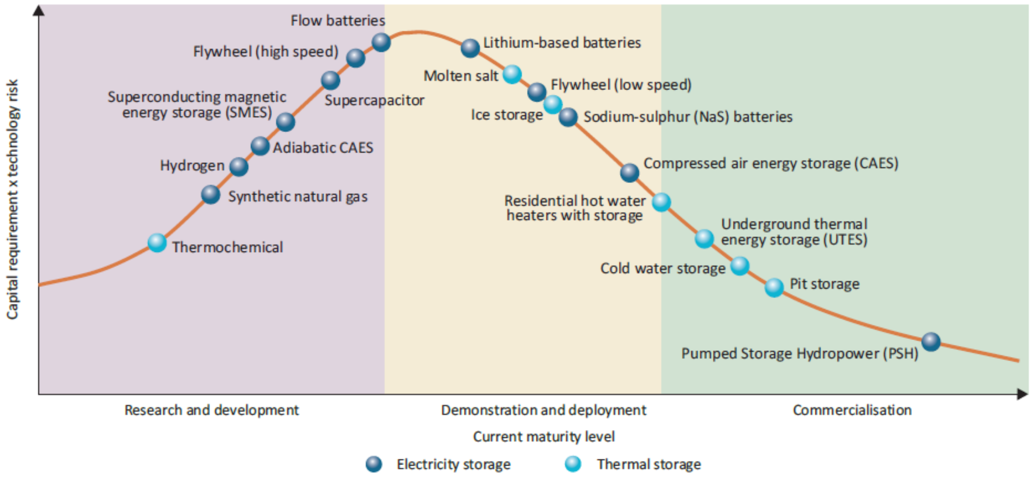

Figure 2: Maturity energy storage technologies[5]

2.2 Technical features of energy storage technologies

The technical features of energy storage technologies have been researched extensively. The Hanze University summarised the key operating characteristics of energy storage systems[6];

1. **Discharge power** refers to the rate at which energy can be removed from storage per unit of time.
2. **Charge power** refers to the rate at which energy can be placed into storage per unit of time.
3. **Energy storage capacity** refers to the total amount of energy which can be placed in storage.
4. **Discharge time** is the amount of time during which a storage system can provide energy at the maximum power level.
5. **Charge time** is the amount of time it takes to completely refill the storage system at maximum charge power.
6. **Operational time** is the amount of time for which a storage system can be expected to provide a reasonable (i.e. average) discharge power.
7. **Energy density** refers to the physical space required to store a given amount of energy.
8. **Discharge response time** refers to the amount of time required between the request for energy from the storage system and the actual delivery of energy from the storage system.
9. **Charge response time** refers to the amount of time required between the request to deliver energy into storage and the actual delivery of energy into the storage system.
10. The **energy carrier** is the form which energy takes when it is extracted from storage.
11. **Costs** are generally evaluated in terms of the cost per unit of power as well as the cost per unit of stored energy capacity.
12. **Ramp up / Ramp down** speed is the capability of a storage system to change its power output over a given amount of time.
13. **Self-discharge rate** is the amount of stored energy lost per unit of time.
14. **Roundtrip efficiency** is the percentage of energy lost when inserting and later extracting energy from storage.
15. **Lifetime** is the number of years or cycles a technology is designed to function for.
16. **Storage time** is the amount of time energy is typically stored for..

Table 2 shows a selection of characteristics for the most important storage technologies today.

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[5] Energy storage Technology roadmap, IEA, 2014

[6] Energy Storage Label, Hanze University of applied sciences, 2015

Storage technology	**PHS**	**CAES**	**Hydrogen**	**Flywheels**	**NaS batteries**	**Li-Ion batteries**	**Lead Acid battery**	**Flow batteries**
Power range (MW)	X MW-3 GW	5-300	kW- x MW	100 kW-x MW	Up to 50	Up to 50	X MW	X MW
Energy range	1– 100 GWh	100 MWh – 10 GWh	10 kWh-several TWh	3 KWh-100 KWh	300 MWh	24 MWh	250 MWh	5-250 MWh
Discharge time (h)	Minutes - Days	Several hours	Hours-weeks	Minutes-hours	Several hours	Several hours	Several hours	Several hours
Lifetime (years)	50-100	25-40	5-15	>15	<15	15-20	5-15	10-20
Discharge response time	s-min	5-15 min	s-min	s	ms	ms	ms	ms
Roundtrip efficiency(%)	70-85	45-55	25-35	>90	75-85	85-98	75-85	70-75
Energy density (W/kg)	0,5-3	100	200-500	>100	100-120	120-180	25-35	10-25
Power costs (€/kW)	400-1500	400-1200	2000-5000	500-2000	150-1000	150-1000	100-500	500-1300
Energy costs (€/kWh)	40-150	50-150	1-10	2000-8000	350-700	700-1300	100-500	100-400

Table 2: Summary of data for storage technologies as seen in different literature[7],[8],[9]

Seen from a point of view of roundtrip efficiency point, hydrogen production clearly is lacking in the competition with other storage technologies, but if size and duration are required hydrogen storage has the best characteristics. Hydrogen production facilities have a competitive advantage over compressed air energy storage and pumped hydro because they can be placed anywhere nearby a gas pipeline and a power network and are not bound to special geographical conditions. Power to gas seems to have potential for large-scale energy storage in areas where the gas infrastructure is well developed and pumped hydro storage or large-scale compressed air energy storage is not available or difficult to realise.

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[7] DG Energy Working Paper, The future role and challenges of Energy Storage, European Commission ,2013

[8] System analyses Power to Gas: A technology review, DNVKEMA, 2013

[9] Utility Scale Energy Storage Systems, June 2013

3. Power to gas technologies

6.1 Electrolysers

The balancing effect of the electrolyser depends on the technology. Currently, there are only two technologies on the commercial market: the Alkaline and PEM electrolysers. The high temperature Solid Oxide Electrolyser (SOEC) is a premature electrolyser technology which, according to the Aalborg University, is still is under development and expected to become available in 10 years' time[10].

The current Alkaline and PEM electrolysers do have a relatively long start-up time from cold condition, but then on standby position the ramp-up time to maximum capacity is a few seconds. The Alkaline electrolyser by NEL is stated to have a ramp-up time of less than 3 seconds to maximum capacity, and response time to dynamic load of less than one second[11]. The PEM electrolyser is claimed to have even faster response time and possibilities for load variations. The future SOEC technology also seems applicable for power regulation, however, the start-up time from cold conditions might be several hours[12].

6.2 Methanation

The concentration of pure hydrogen that can be injected into the natural gas network depends on many factors. In general, a case by case analysis is necessary before injecting hydrogen in the natural gas network[13]. A second step in the power to gas chain, if case the injection of hydrogen is limited by the effect on the natural gas properties, could be methanation, the synthesis of hydrogen and carbon dioxide to methane.

The methanation process is based upon the Sabatier reaction discovered by Paul Sabatier. Methanation became well known during the 1970s when the oil crisis resulted into high prices for oil, making the production of methane from coal and biomass became more popular. The opposite reaction, the production of hydrogen through steam reforming, is currently the most attractive technology for the production of hydrogen from methane. Methanation can be executed chemically or biologically. Both processes are based on the same chemical reaction, but are fundamentally different.

The necessary amounts of pure CO2 can come from the CO2 scrubbing of flue gas at fossil fuelled power plants, biogas plants, industry or from the atmospheric air. Sourcing CO2 from the atmospheric air decouples the plant from the source of CO2, but efficiency is low, as atmospheric air only contains approximately 390 parts per million (ppm) CO2.

6.3 Chemical methanation

Chemical methanation is a mature and commercially available technology. It has been widely applied in different industrial applications. In this process, the reaction takes place with the use of a catalyst. Nickel is often chosen as a catalyst because of the favourable costs compared to other more precious metals. The process takes place at two temperature ranges: low temperature methanation in the range of 200 – 550 °C and high temperature methanation between 550 – 750 °C. Table 3 gives a few of the process characteristics.[14]

Characteristic	Value	Reference
Process temperature	200 - 750 deg. C	DNV KEMA

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[10] Technology data for high temperature solid oxide electrolyser cells, alkali and PEM electrolysers, Aalborg University Aalborg numme 2, 2013

[11] NEL Hydrogen, 2012

[12] Technology data for high temperature solid oxide electrolyser cells, alkali and PEM electrolysers, Aalborg University , 2013

[13] Admissible Hydrogen Concentrations in Natural Gas Systems, Klaus Altfeld and Dave Pinchbeck; GERG 2013.

[14] System analyses Power to Gas: A technology review, DNVKEMA, 2013

Delivery pressure	4 - 80 bar	DNV KEMA
Maturity	Commercial (for large plants)	DNV KEMA
Lifetime catalyst	24000 hours	DOE_NETL 2008
Start up - from stand by stage	5 min	Solar Fuel 2013
Cold start up	Several hours	Muller-Syring 2012
Methanation efficiency	70 - 85%	Sterner (2009)

Table 3: Characteristics of chemical methanation

6.4 Biological methanation

In biological methanation, hydrogen is converted with CO2 to methane. The process consists of the same reaction as the chemical process; the difference lies in the process temperature. The biological metabolic processes of bacteria and archaea takes place in the temperature range of 20 - 60 °C. The bacteria involved can remain dormant for days, weeks or even months, but "wake up" very suddenly when called upon - as the reaction time is claimed to be a few seconds, even after a long time on "stand by".

Characteristic	Value	Reference
Delivery pressure (bar)	1-3	Krassowski (2012)
Maximum production capacity (MW $_{CH4}$)	15 MW CH_4	Krassowski (2012)/Electrochea (2012)
Maturity	Pre-commercial	Electrochea (2012)
Deployment time (from stand-by)	seconds	Electrochea (2012)
Cold start (from dormancy)	minutes	Electrochea (2012)
Annual availability	90%	Assumption (2012)
Methanation efficiency	95 - 100%	Electrochea (2012)
Thermodynamic efficiency	82%	Electrochea (2012)

Table 4: Technical characteristics of biological methanation[15]

Biological methanation is capable to respond in few seconds in its full power range, according to manufacturers. The process is claimed to be very efficient and doesn't require a nickel based (or precious metal) catalyst. Impurities with oxygen should be avoided, as it is a strictly anaerobic process. The only disavantage so far seems to be the energy requirement to maintain a constant temperature in the process. However, no large-scale plants exist today; the first MW-scale plants will begin to show results from 2015.

4. The role of power to gas

Power-to-gas could fulfill multiples roles in the future energy system. A power to gas technology review, by DNVKEMA described, a number key drivers for power to gas. When there are problems in the electricity sector (such as congestion, negative electricity prices) or with the availability of infrastructure, the electricity could be converted into hydrogen. The hydrogen can be injected in the gas grid, utilized in the chemical industry or mobility sector, stored in a hydrogen buffer in order to be re-converted to electricity at a later time, or converted into methane.

Power to gas can also overcome electricity transmission capacity constraints, avoid shutdown/startup costs at conventional power plants, and avoid transport of energy over long distances. DNVKEMA states that power to gas not seems to be suitable for frequency support and uninterruptable power

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[15] System analyses Power to Gas: A technology review, DNVKEMA, 2013

supply services, because these services require technologies that can instantly be deployed to deliver electrical power for short periods of time.

Power to gas can also play a role in the reduction of CO2 emission. In The Netherlands, the report “The role of power-to-gas in the future Dutch energy system” (by ECN and DNVGL) shows that drastic CO2 emission reductions are the main driver for a positive P2G business case. Of the many options needed to achieve significant CO2 emission reductions, the admixing of hydrogen in the gas system is relatively attractive because of the relatively limited distribution cost and the effect in terms of decarbonising (part of) the gas supply. The admixing of hydrogen could play a more significant role if current admixing restrictions can be successfully relieved or even removed. Figure 3 shows the relation between the amount of wind and solar-based electricity generation in The Netherlands per year, the ambition level for CO2 emission reductions (translated into CO2 shadow prices per ton), and the role of P2G (in relative volume of hydrogen produced through electrolysis)[16].

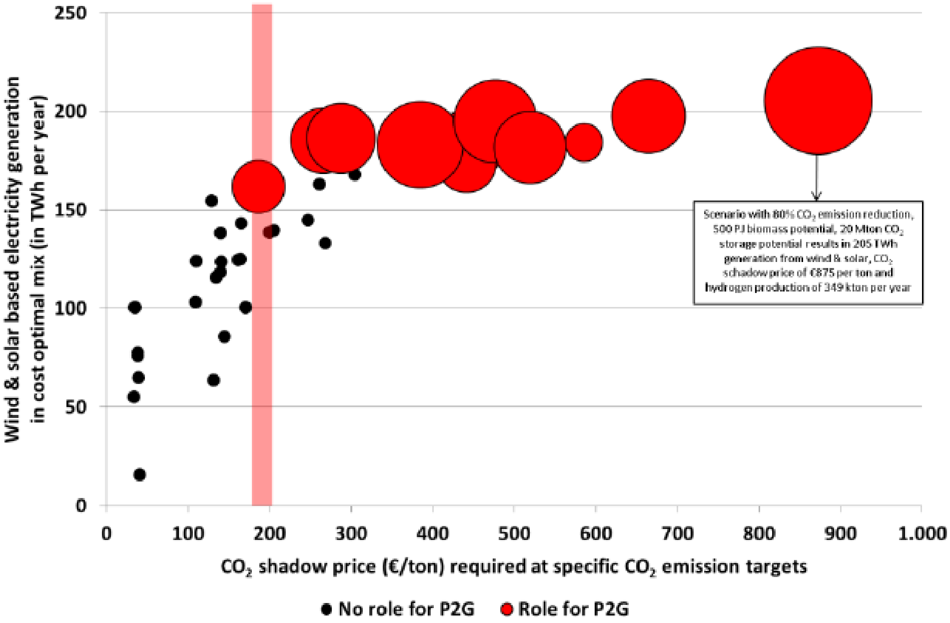

Figure 3: Relation between intermittent electricity generation,CO2 reduction ambition and P2G role

5. Power to gas potential

Because of its extensive infrastructure of efficient transmission and distribution networks, the natural gas network gas a large storage capacity. The capacity of existing natural gas storages that are connected to network are even larger. If hydrogen is injected into the network it directly make use of this storage capacity.

The potential of power to gas was analysed in several European countries. In Germany, a study by Agora Energiewende estimated the need for electrolysis (for power-to-gas, power-to-liquids and hydrogen mobility markets) to be up to 16 GW, 80 GW and 130 GW by 2023, 2033 and 2050[17]. The “Study of hydrogen and methanation as processes for capturing the value of excess electricity” (a report by ADEME GRTGaz and GRDF, France), estimates a need for 1.2-1.4GW of P2G plant in France

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[16] Exploring the role for power-to-gas in the future Dutch energy system, ECN, 2014
[17] Electricity Storage in the German Energy Transition,Agora Energiewende, 2014

by 2030 and up to 24GW by 2050[18]. As described in Chapter 4, a Dutch report on power-to-gas as a robust part of the mix of energy technology options required to achieve significant CO2 emission reduction targets in the energy system (-80% to -95% by 2050), indicates the need for up to 20 GW of installed P2G capacity[19]. Caution must be taken in comparing these figures because the reports use different assumptions for the input parameters.

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[18] Study on Hydrogen and methanation as means to give value to electricity surpluses, ADEMA, GRTGaz and GRDF, 2014

[19] Exploring the role for power-to-gas in the future Dutch energy system, ECN, 2014

6. Economics of hydrogen production

The costs of hydrogen from electrolysers depends on several factors. The main parameters are the costs of electricity, investment in electrolyser and other equipment and operational costs. Possible income parameters for hydrogen are the sale of hydrogen and payment for delivering ancillary services.

6.5 Electricity

An important component of the costs of power to gas is the cots of electricity. There are multiple scenarios which predict power, resulting in wide range of values. According to the Danish Energy Agency, the price of power will increase over time in the Nord Pool market area. Figure 4 shows a forecast price development. The Nord Pool market prices are approximately 4,5 cent/kWh until 2025, increasing to 7 cent/kWh in 2035[20].

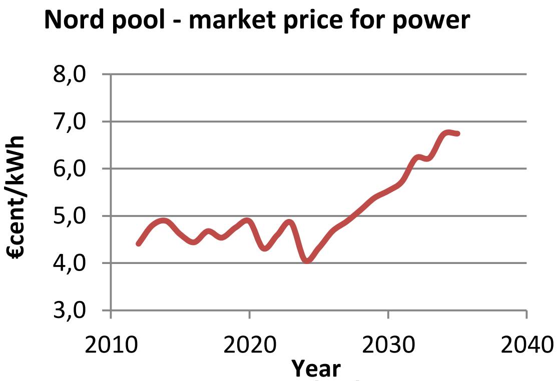

Figure 4: Forecast NordPool prices

6.6 Electrolyser

The electrolyser capital costs have been the subject of many projects and studies. Figure 5 shows that half of the cost of a power to gas plant consists is attributed to the electrolyser. Other cost factors are the buildings, compressor, storage and injection into the grid.

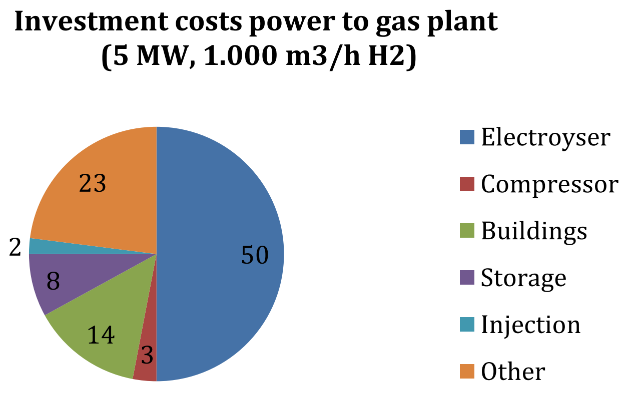

Figure 5: Capital costs of power to gas plant[21]

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[20] Danish Energy Agency

[21] DBI Gas and environment technology - Müller- Syring, DBI and Peter Franke, Bundesnetzagentur, 2011

In a German study, an estimate of cost development is given for electrolysers. The investment costs of an electrolyser are currently approximately 1 million Euros per MW, and are expected to decrease in the next few years[22].

		2013	2016	2020	2030
H_2 - Capacity	MWel	**2,4**	**2,4**	**2,3**	**2,0**
Power consumption	kWh/kWh $_{H2}$	1,73	1,70	1,67	1,43
Efficiency	% (LHV)	58	59	60	70
Investment	€/MWel	1,2 mill	1 mill	0,851 mill	0,706 mill
Depreciation time	Years	15	15	15	15
O&M	% /year of investment	4%	4%	4%	4%

Table 5: Cost parameters for electrolyse

The build-up of the costs of electrolyser technologies are not the same. In a US study, a rough cost breakdown is given for alkaline and PEM electrolysers. The share of stack, power electronics, gas conditioning and balance of the plant is shown in Figure 6 for the two types of equipment. The electrolyser stack dominates the costs of systems. The costs of power electronics are higher for the PEM electrolyser than for the alkaline. The balance of plant is a significant factor in both technologies, but it encompasses multiple smaller subsystems, each of which generally makes a small contribution. The conditioning of the hydrogen gas, which would include drying and purification processes, also amounts to a significant, but smaller percentage of the total cost[23].

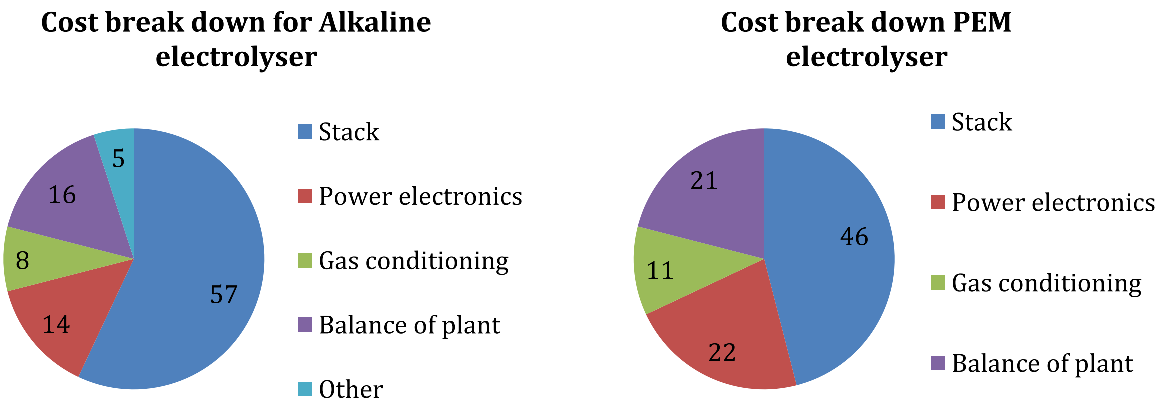

Figure 6: Cost break down for the Alkaline and PEM electrolyser (right)

At the end of 2013, the Danish Gas Centre published an update on the technological data for various electrolysing technologies . The data for the alkaline and PEM technologies were based on prices given by the commercial manufacturers. The data for SOEC technology (not commercially available) were based on data from several universities and manufacturer Haldor Topsoe. The results for a 10 MW electrolyser are shown in Table 6.

	Price turnkey (2014) - million €	Turnkey 2020 million €	Total Annual O&M including stack	Efficiency %

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[22] Analyse der Kosten erneubarer gas, Ludwig-Bolkow-Systemtechnik GmbH, 2013

[23] Electrolyser Capital Cost Study, NREL, 2008

	(€ per MW)	(€/MW)	exchange	
Alkaline				
NEL	9,3 (0,93)		1,1	61
Hydrogenics	17,2 (1,72)		1,2	55
PEM electrolysis				
Protone Onsite	11,9 (1,19)	8,5 (0,9)	0,3	49
SOEC				
HTAS etc.		9,3 (0,93)	0,3	76

Table 6: The costs of electrolysers

6.7 Calculation examples - Hydrogen production from electrolysers

To provide an insight into the expected costs of the production of hydrogen, three cases are described for the period 2015-2030, with an expected development in electrolyser technology. The first case is the commercial available alkaline electrolyser technology, followed by PEM electrolyser (case 2), ending with SOEC after 2030 (case 3). The calculations are given for a 10 MW electrolyser plant with 4,000 running hours with different power prices.

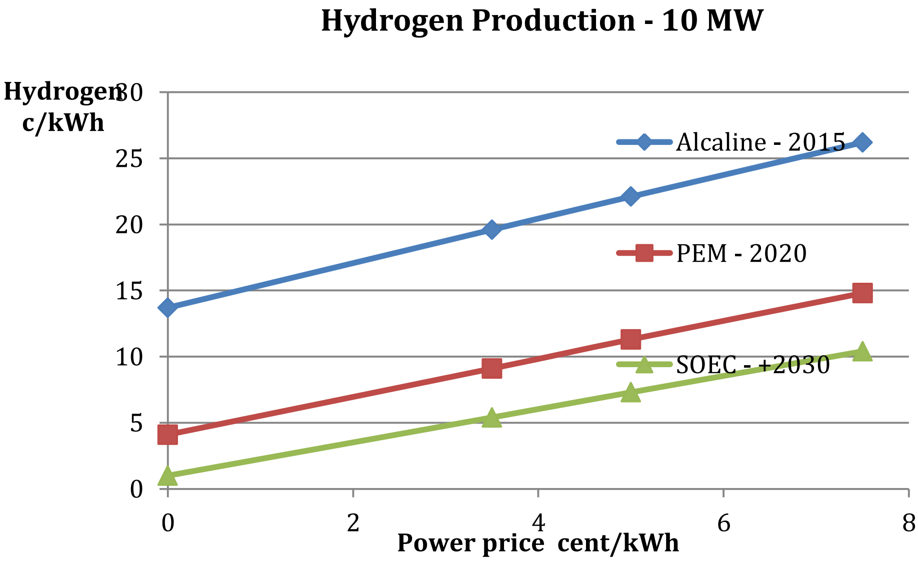

Figure 7: Hydrogen production economics

It is obvious that the price of power is an essential cost factor for the production of hydrogen, and that its influence will grow as the capital costs are reduced in coming years. For the cases given, the power expenses account for 33% of all expenses; with the low power price of 3.5 €c/kWh, this percentage could increase to 86% of all expenses after 2030 if power is being bought at 7.5 €c/kWh. On the other hand, the capital costs for the same cases will go down from 67% of total expenses now to 14% after 2030.

7. Economics of methanation

7.1 Chemical methanation

As described in Chapter 3, methanation could be a second step in the power to gas chain. Table 7 gives a rough indication of the capital and operational costs. The operational costs are expected to be 10% of the capital costs a year. This is excluding the costs of the hydrogen, but including the replacement of the catalyst[24].

Capacity kW	Capital costs/kW	Operational costs €/kW/year
500	2400	240
3000	1000	100
7000	700	70

Table 7: Capital and operational costs of chemical methanation

A German study estimated the cost development for methanation. On the basis of a 6.3 MW_{el} electrolyser plant, followed by the methanation step, indicative investment figures were calculated[25].

Plant: 6,3 MW_{el} - (electrolyser)		2013	2016	2020	2030
Efficiency of methanation process	%	83%	83%	83%	83%
Investment	€/kW_{CH4}	3,289	1,974	660	660
Depreciation time	Years	15	15	15	15
O&M	% /year of investment	2%	2%	2%	2%
Investment cost	Mill €	10,4	6,2	2,0	1,9

Table 8: Costs and technical parameters for the methanation plant

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[24] System analyses Power to Gas: A technology review, DNVKEMA, 2013

[25] Analyse der kosten erneubarer gas, Ludwig-Bolkow-Systemtechnik GmbH, 2013

7.2 Biological methanation

The economics for a biological methanation plant are shown in Table 9 and based on calculations made by Fraunhofer UMSICHT. Manufacturer Electrocheae expects a very fast development of biological methanation to the commercial market.

Parameter	»Small Plant" 0,25 MW_{el}	"Mean size plant" 2 MW_{el}	"Commercial size" 18 MW_{el}
Volume of H_2 m^3/h.	50,7	405,9	3.653,2
Volume of CO_2 m^3/h	12,7	101,5	913,3
Production of gas m^3/h (88 % CH_4, 10 % H_2, 2 % CO_2)	13,4	106,9	962,3
Production MW (in relation to calorific value of gases)	0,13	1,08	9,68
Size of biological reactor	2 x 3,9 m^3	2 x 31,3 m^3	2 x 281,8 m^3
Investment - biological methanisation €	150.000	250.000	950.000
Annual capital cost €/year	18.000	30.000	140.000
Cost Operation and maintenance ct/kWh -	0,5	0,4	0,3

Table 9: Economics for biological methanation

7.3 Biological or chemical process?

From an economic point of view it seems that the biological process, if developed according to the plans, will be the most economical way to produce synthetic methane in the future. The major cost difference between the chemical and biological process is the absence of a catalyst in the biological process. In a German study a comparison is made between the two different processes[26].

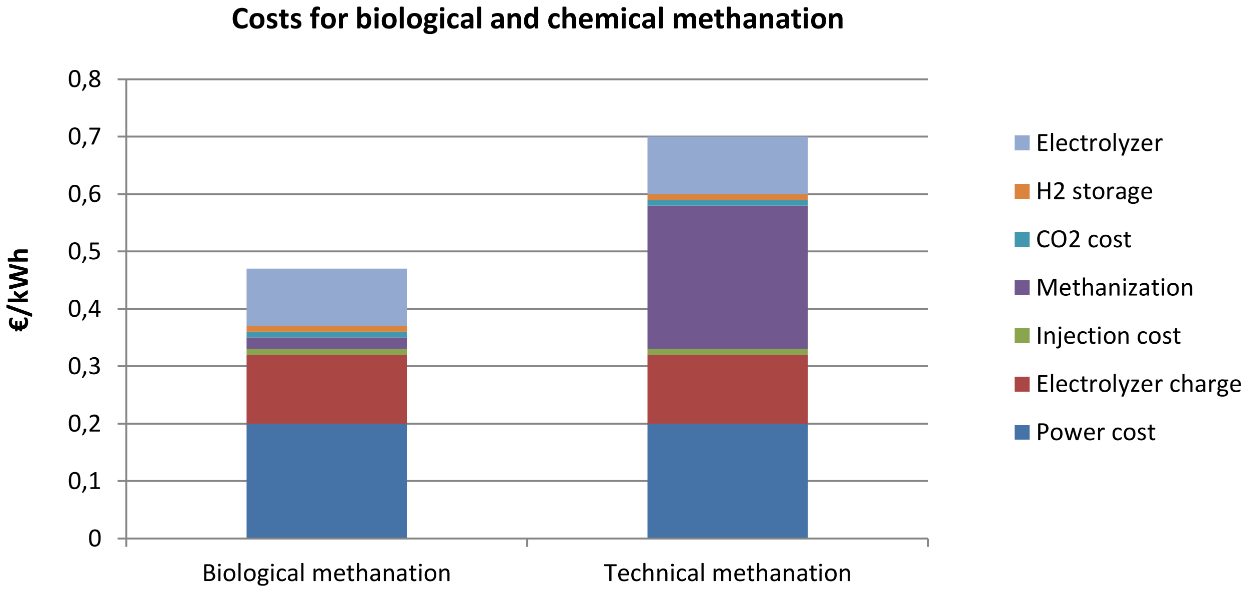

Figure 8: Costs of biological and chemical methanation

Figure 8 shows the data for the chemical proces, based on known data for methanation plants, and for the biological plant, based on expectations. The costs of power and of the electrolyser are the same for

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[26] Analyse der kosten erneubarer gas, Ludwig-Bolkow-Systemtechnik GmbH, 2013

both processes, which means that the biological process, if the technology development shows up to be successful, could be the preferred choice for methanation of hydrogen from renewable sources.

7.4 Calculation examples - Methanation (chemical reaction)

To provide an insight into the expected costs of methanation, calculations have been made for a 10 MW unit (size of the electrolyser) based on the results of the calculations in Chapter 6, Figure 9 shows the capital and operational costs of a methanation unit receiving hydrogen from a 10 MW electrolyser. The costs of hydrogen production with different power prices are also given.

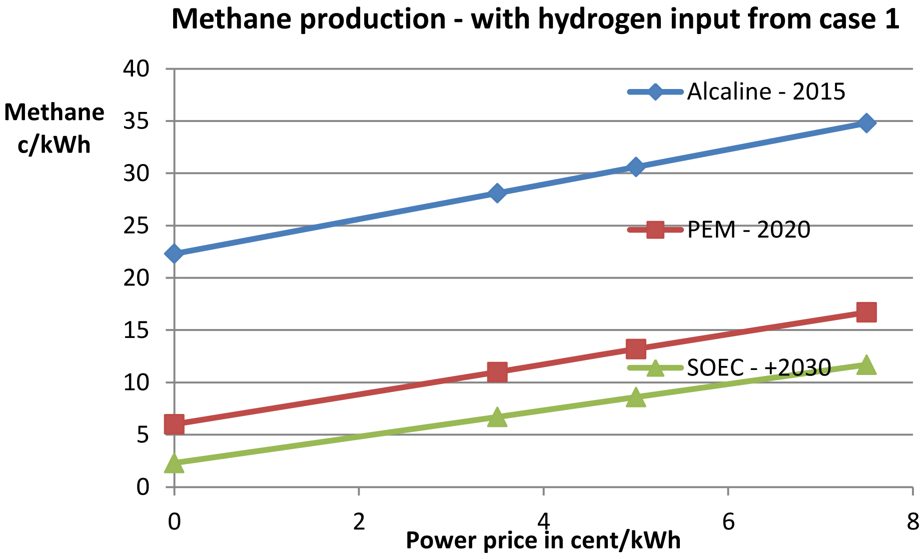

Figure 9: Methanation production economics

After 2030 the methane production costs will be in the range of 7,4 - 12,4 cent/kWh. The calculations are made on the assumption that the costs of the electrolyser and methanation unit will reduce significantly in the future. The costs for CO_2 are not included. If the CO2 cost are added this might be in the range of 20 to 40 cent/Nm³ CO2 . As 1 Nm³ methane comprises 0,77 Nm³ of CO2 (in theory), this will add between 15 - 30 cent/Nm³ methane - or 1,5 - 3 cent/kWh methane.

8. Costs of hydrogen storage

8.1 Underground hydrogen storage

Hydrogen can be stored underground in salt caverns. This is already practice in the United Kingdom and the United States of America. In general, the storage capacity of salt caverns is lower than that of (depleted) gas fields. The availability of suitable salt deposits is also limited. Gas field are widespread and have the potential to contain large volumes of hydrogen. However, the impact of hydrogen on rock composition of gas fields is mostly unknown. The growth of bacteria is considered to cause the most severe problems[27]. As part of the H2STORE project, basic research is performed to gain more insight into the behaviour of hydrogen in natural porous storages[28] .

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[27] Admissible hydrogen concentrations in natural gas systems, Klaus Altfeld and Dave Pinchbeck, 2013

[28] http://forschung-energiespeicher.info/en/projektschau/gesamtliste/projekteinzelansicht//Wasserstoff_unter_Tage_speichern/

Based on a study by Weinert, DNV KEMA compiled a comprehensive overview (Figure 10) of the capital costs of hydrogen storage[29].

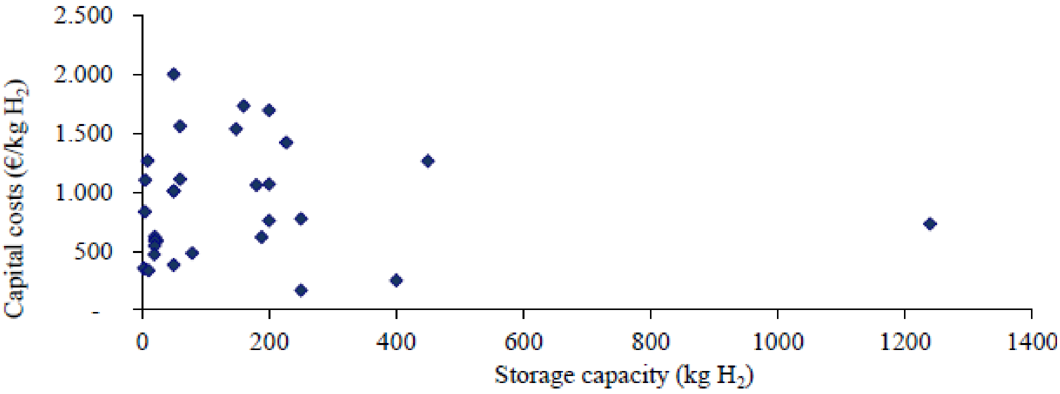

Figure 10: Capital costs of hydrogen storage

Figure 10 presents the different cost components for the production of hydrogen via electrolysis in 2030: capital expenditures, operational and maintenance costs (O&M), the cost of electricity (used as input in the process), and the indicative costs of hydrogen storage[30].

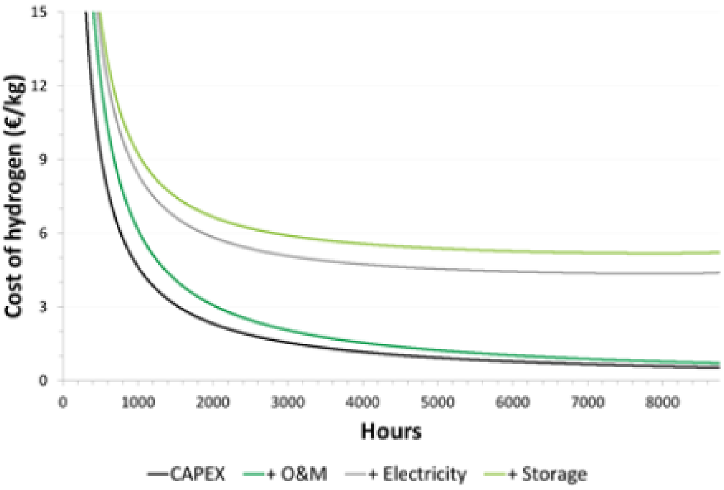

Figure 11: Cost components of hydrogen production and storage

The EU funded Hyunder study concluded that hydrogen energy storage as a way to store renewable electricity via electrolysis in underground storages is economically very challenging (Figure 12). In the short term, the transport sector seems to be the only market expected to allow a hydrogen sales price that may enable the commercial operation of an integrated hydrogen electrolysis and storage plant. Besides electrolyser CAPEX and electricity purchase prices, the costs of hydrogen from electrolysis strongly depends on the electrolyser utilisation[31].

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[29] System analyses Power to Gas: A technology review, DNVKEMA, 2013

[30] Exploring the role for power-to-gas in the future Dutch energy system, ECN, 2014

[31] Assessment of the potential, the Actors and Relevant Business Cases for Large scale and Long Term Storage of Renewable Electricity by Hydorgen Underground Storage in Europe, Hyunder, 2014

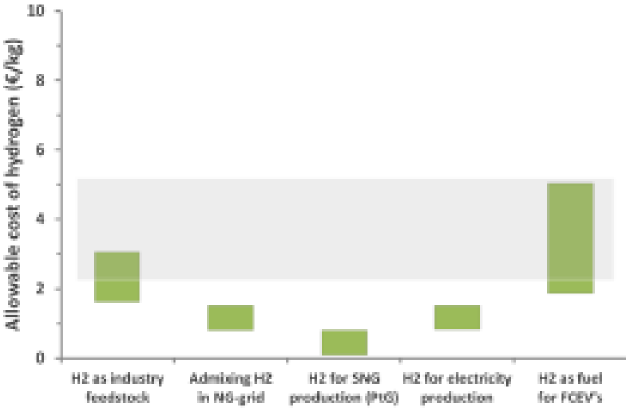

Figure 12. Allowable cost of hydrogen for various applications

8.2 Hydrogen storage above ground

Above ground storage is possible in bundles of pipelines, tanks or cylinders. Table 10 shows the investment costs for above-ground storage. The figures are based on analyses carried out by the Danish Gas Technology Centre[32].

Size of storage in million Nm³	0,7	1,9	10,5
Vertical bundle of pipes	43 €/Nm³ H_2	27 €/Nm³ H_2	20 €/Nm ³ H_2
Traditional pipe storage	54 €/Nm³ H_2	54 €/Nm³ H_2	54 €/Nm³ H_2
Gas cylinders	23 €/Nm³ H_2	20 €/Nm³ H_2	19 €/Nm³ H_2

Table 10: Investment cost for above ground storage of hydrogen

9. Compression of hydrogen

Because of its composition, hydrogen is difficult to compress. It is the lightest of all the gases and has a lower viscosity than natural gas. Hence, it is easier to migrate through small spaces. Special seals and/or tolerance standards need to be established to achieve the required high pressures. Compression is also an energy-intensive process.

In analyses by DNV KEMA, the costs for hydrogen compression were estimated. If hydrogen is compressed and directly injected and stored into the natural gas system at low pressure (8 bar), the energy requirement is 1.3 kWh/kg hydrogen and the operational costs are 0.008 €/nm3 hydrogen. To compress hydrogen from atmospheric pressure to 200 bar (for storage) require 3.6 kWh/kg hydrogen, which translates to 0.02 €/nm3 hydrogen.

The Institute for Energy analysed the relationship between the work of compression and the final (discharge) pressure. This relationship is not linear but parabolic. Therefore, the work required to compress hydrogen by a given pressure increase depends on the initial (suction) pressure: the higher the suction pressure, the less energy is required for compression. In other words, it requires significantly less energy to increase the pressure of hydrogen from 350 bar to 700 bar, compared to an increase from ambient pressure to 350 bar[33].

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[32] Evaluation of underground storage for CO2, O2 and H2, WP 1.3, Aksel Hauge Pedersen, 2013

[33] Hydrogen Storage: State of the art and future perspective, Institute for Energy, 2003

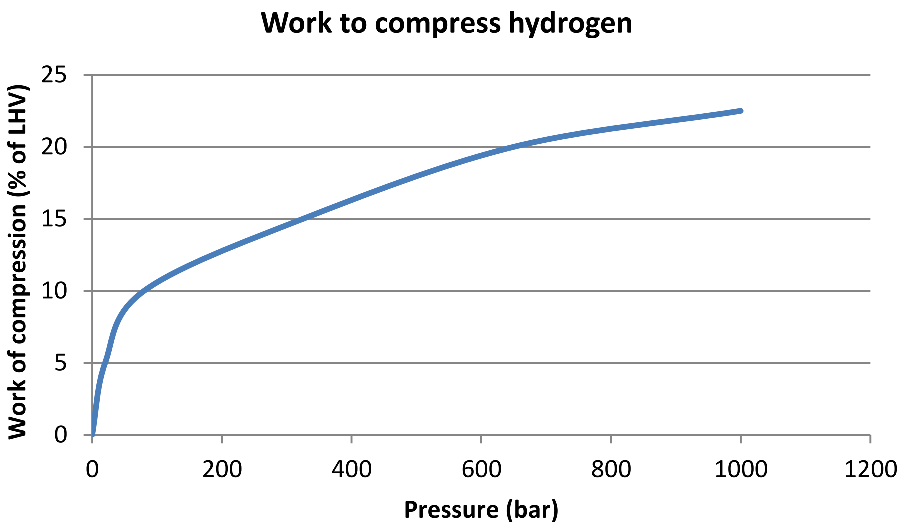

Figure 13: Work to compress hydrogen

In the same study, the investments costs for compressors are presented. Figure 14 shows the cost of hydrogen compression as reviewed in a number of publications [18, 19, 116].

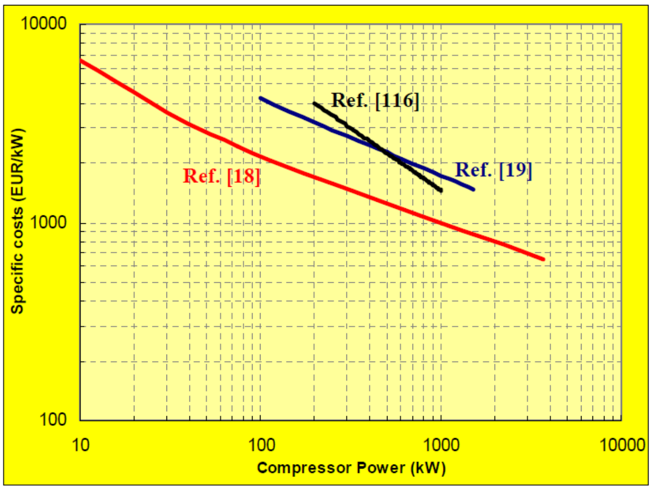

Figure 13: Cost of compressors

The investment costs of compressors are approximately 5000 €/kW for small size compressors (50 kW); for larger compressors, the price goes down to 1000 - 1500 €/kW for (100 kW). On top of these costs, the installation costs (approximately 35% of the bare cost of a compressor) and the costs of material and labour for its foundation, building, electrical, piping and other works (approximately equal to the bare cost of the compressor) should also be considered. The electricity consumption for the compressor depends on the efficiency of the compressor(70 - 85%) and the efficiency of the electric motor (90%).

10. Liquefaction of hydrogen

In the 1960’s, liquid hydrogen plants were built to support the Apollo program. There are 10 hydrogen liquefaction plants in North America ranging from 6 to 35 TPD (tonnes per day; i.e. 5,400 to 32,000 kg/day). Today, liquid hydrogen is used to reduce the cost of hydrogen distribution[34].

Storage of hydrogen in liquid form can be used to store large quantities of gas for longer times, however with high-energy penalties for liquefaction[35]. Depending on the size of the liquefaction plant, the energy required to liquefy hydrogen ranges from 27,8 kWh/kg hydrogen for a small liquefaction plant down to 11,1 kWh/kg hydrogen for a large-scale unit. The EU funded IDEALHY project gives estimates for the costs of a liquefaction plant. A 50 TPD requires an investment of approximately 105 million €[36] (table 11).

Parameter	50 TPD	40 TPD
Investment (million €)	105	90.5
Payback period	20	
Internal rate of return (%)	10	
Fixed annual costs of operation and maintenance (% of investment)	4	
Specific variable costs		
€/MWh$_{el}$	100	
€/m^3	1.25	
€/t H_2	2,000	

Table 11: Costs of liquefaction

As a part of the IDEALHY project a large scale liquefaction plant will be developed, with the goal to significantly reduce the required energy demand for liquefaction compared to state of the art plants[37].

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[34] Strategic Initiatives for Hydrogen Delivery Workshop,Praxair, 2003

[35] Hydrogen Storage: State of the art and future perspective, Institute for Energy, 2003

[36] Integrated Design for Demonstration of Efficient Liquefaction of Hydrogen (IDEALHY), Fuel Cells and Hydrogen Joint Undertaking (FCH JU), 2013

[37] http://www.idealhy.eu/

11. Power to gas efficiencies

Table 12 gives an overview of the efficiencies for the various conversion methods from power to compressed gas - to power[38].

Process	Efficiency	Conditions
"power to gas"	%	
Power to H_2	54 - 72	Compression to 200 bar
Power to CH_4	49 - 64	
Power to H_2	57 - 73	Compression to 80 bar
Power to CH_4	50 - 54	
Power to H_2	64 - 77	Without compression
Power to CH4	51 - 65	
"power to gas" to power		
Power to H_2 to power	34 - 44	Through repowering (60% efficiency) and compression at 80 bar
Power to CH_4 to power	30 - 38	
"power to gas" to CHP		
Power to H_2 to CHP	48 - 62%	40% power + 45% heat and compression to 80 bar
Power to CH_4 to CHP	43 - 54%	

Table 12: Efficiency power to gas processes

The efficiency for the production of hydrogen lies in the range of 64- 77%. If the hydrogen is methanised the efficiency is in the range of 51-65%. The efficiency for the power to power cycle is in the case of 34-44 % for hydrogen and 30-38% for methane. If a CHP is used, this percentage is even higher.

Some experts believe that the surplus of power can better be converted into chemicals than into hydrogen or methane. Storage of heat could also be a competitor for the power to gas concept. A Dutch study also indicates that power to gas is not considered to be a cost-effective option in the short to medium term from a public perspective. It is however not inconceivable that a positive business case is possible in specific situations with favourable local conditions, e.g. a combination of limited local capacity in the electricity network, the local / regional availability of a surplus of renewable electricity, and a sustainable, local demand for hydrogen (e.g. in industry or in local/regional public transport)[39].

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[38] Erneuerbares Gas fur eine nachhaltige Entwicklung, GWA, 2011

[39] Exploring the role for power-to-gas in the future Dutch energy system, ECN, 2014

12. Conclusion

The concept of power to gas is still in an early stage of development. There are a lot of questions to be answered, but the concept is very promising. The power to gas concept distinguishes itself from other energy storage options because, in addition to energy storage, it also has other functions such as transportation of electricity in a gaseous form, or the delivery of a raw renewable material to industry or transport sector. This makes the business case for power to gas divers.

With the current knowledge of hydrogen production using electrolysers, production cost are calculated based on a 10 MW electrolyser plant with 4,000 running hours, using different power prices. The three cases for the period 2015-2030 indicate an expected development for the electrolyser technology, starting with the currently mature Alkaline electrolyser, followed by the PEM electrolyser, and ending with the very efficient SOEC. It is clear that the price of power is an essential factor for hydrogen production and that its influence will grow as the capital costs are reduced in the course of time.

Methanation can be a second step in the power to gas chain. Methanation is the conversion of hydrogen and carbon dioxide into methane. The methanation process can be executed either chemically or biologically. Chemical methanation is a mature technology that is currently commercially available. It has been widely applied in various industrial applications. In this process, the reaction takes place with the use of a catalyst. Biological methanation is an alternative to chemical methanation. The main difference lies in the temperature ranges used for the reaction and the response time. The biological methanation process is still in the research and demonstration phases. From a cost perspective, it seems that the biological process, if developed according to the plans, has the potential to be the most economic way to produce synthetic methane in the future. After 2030 the calculated methane production costs are in the range of 7,4 - 12,4 cent/kWh.

Energy storage as a way to store renewable electricity by means of electrolysis in underground and above ground storages is economically very challenging. There are also significant costs involved with respect to the compression or liquefaction of hydrogen.

Power-to-gas is not considered a cost-effective option in the short to medium term. However, it is not unthinkable that a positive business case is possible in specific situations with favorable (local) conditions. The development of new efficient and low-cost technologies is important for the success of power-to-gas. Biological methanation and direct conversion of CO2 and H2 in the SOEC process seem to be the most challenging aspects.

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26. http://www.idealhy.eu/

1. Appendix

Hydrogen production (10 MW power capacity)	2015 (Alkaline)	2020 (PEM)	+ 2030 (SOEC)
Capital cost for electrolyser - million €/MW	1,3	0,85	0,3
Efficiency	60%	70%	80%
Operation & maintenance cost for electrolyser mill €/year	1,1	0,3	0,1
Capital & maintenance cost c/Nm^3 H_2 - calculated	41,2	12,3	3,1
Total cost (cent/kWh hydrogen) - @ power prices of 7,5 , 5,3,5 and 0 cent/kWh.	@ 7,5 c/kWh - 26,2 c/kWh @ 5 c/kWh - 22,1 c/kWh @3,5 c/kWh - 19,6 c/kWh @3,5 c/kWh - 13,7 c/kWh	@ 7,5 c/kWh - 14,8 c/kWh @ 5 c/kWh - 11,3 c/kWh @3,5 c/kWh - 9,1 c/kWh @3,5 c/kWh - 4,1 c/kWh	@ 7,5 c/kWh - 10,4 c/kWh @ 5 c/kWh - 7,3 c/kWh @3,5 c/kWh - 5,4 c/kWh @3,5 c/kWh - 1,0 c/kWh

Table 1: Summarizing results for production of hydrogen for a 10 MW unit

Methane production (Input - hydrogen from 10 MW electrolyser)	2015	2020	2030
Capital cost for methanisation unit - million €/MW	1	0,33	0,3
Efficiency	83%	83%	83%
Operation and maintenance cost million €/year	0,2	0,07	0,06
Capital and maintenance cost c/kWh methane	8,6	1,9	1,3
Methane production - total cost (cent/kWh CH_4) - @ power prices of 7,5- , 5, 3,5 and 0 cent/kWh.	@ 7,5 c/kWh - 34,8 c/kWh @ 5 c/kWh -30,6 c/kWh @3,5 c/kWh - 28,1 c/kWh @0 c/kWh - 22,3 c/kWh	@ 7,5 c/kWh - 16,7 c/kWh @ 5 c/kWh - 13,2 c/kWh @3,5 c/kWh - 11,0 c/kWh @0 c/kWh -6,0 c/kWh	@ 7,5 c/kWh - 11,7 c/kWh @ 5 c/kWh - 8,6 c/kWh @3,5 c/kWh - 6,7 c/kWh @0 c/kWh -2,3 c/kWh

Table 2: Summarizing results for production of methane from a 10 MW (electrolyser) unit