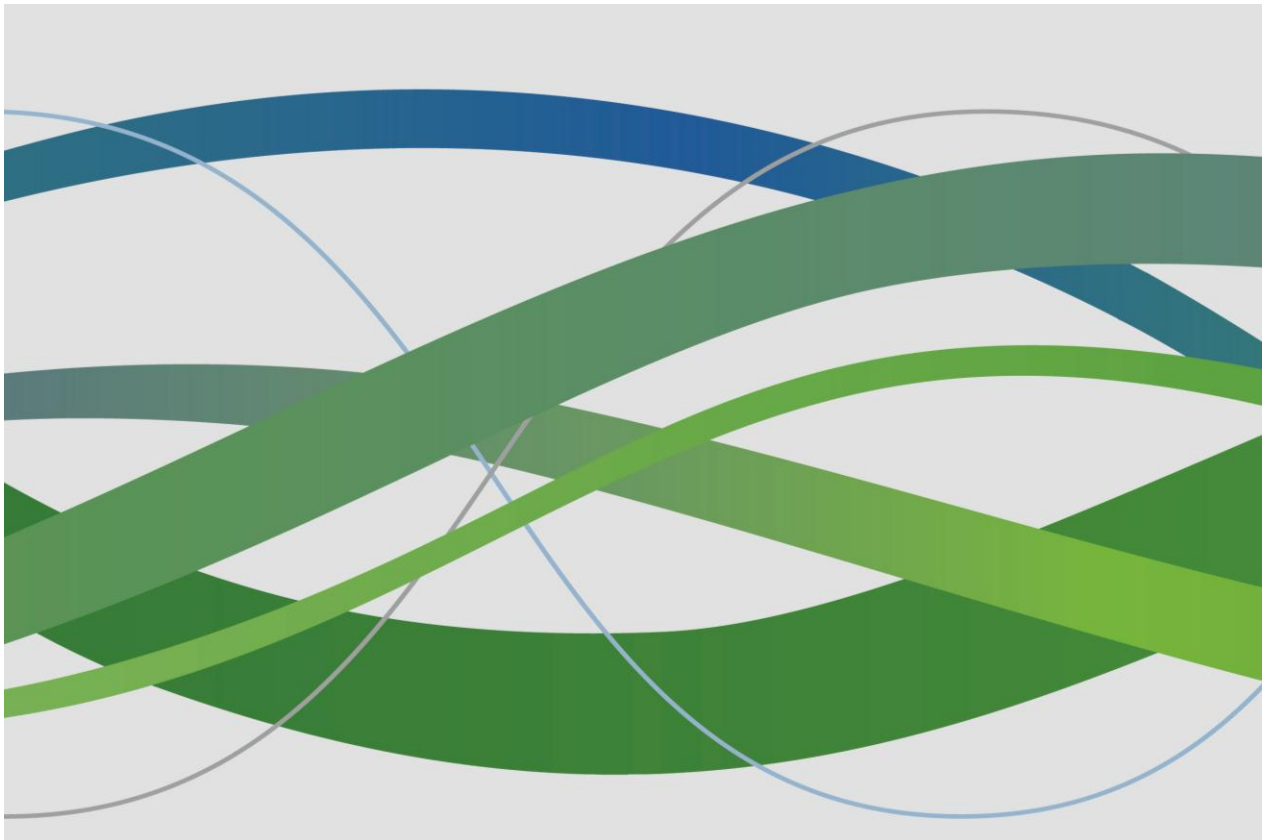


# Final Report

## Systems Analyses Power to Gas

Deliverable 1: Technology Review



Groningen, June 20, 2013

GCS 13.R.23579

## **Systems analyses Power to Gas: A technology review**

Part of TKI project TKIG01038 – Systems analyses Power-to-Gas pathways

Deliverable 1: Technology Review

Groningen, June 20, 2013

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## MANAGEMENT SUMMARY

### Project scope

By order of the Ministry of Economic Affairs and industrial parties, ECN and DNV KEMA are researching the viability and potential future role of power-to-gas (PtG) in the Dutch energy system. This particular report is the first deliverable in this joint project and presents *static data* about different electricity storage techniques and components essential in the PtG value chain, derived from literature and DNV KEMA experts. Based on the data presented in this deliverable, *conclusions are drawn on the technologies to be incorporated in further analyses with the so called “Optiedocument”<sup>1</sup>*. In the fourth quarter of 2013 ECN will disseminate the modeling (with ECN’s Optiedocument) results of the system analysis, which will be the second deliverable of this project.

### Approach

Based on literature research and DNV KEMA expertise a technology review is done for different energy storage technologies and power-to-gas technologies in particular. The technologies assessed in this report are: electrolysis (Alkaline, PEM and SOE), methanation (chemical and biological), compressed air energy storage (diabatic, adiabatic and isothermal CAES), pumped hydro storage, flywheels, superconducting magnetic energy storage, supercapacitors & batteries (lead-acid, Li-ion, NiCd, NaS, VRB & ZnBr).

Based on different service applications for the integration of intermittent energy sources (IES), the assessed technologies are grouped according to the IES integration services. These technologies should subsequently be further assessed in the systems analysis modeling, the project phase to be executed by ECN (conclusions).

### Main conclusions

The conclusions of this report are stated here in bullet points:

- Power-to-gas technology is emphatically distinctive from power storage technologies by its capability of resolving issues resulting from the integration of renewable energy sources in the existing energy system, such as supply/demand imbalance and transportation issues, by conversion of power into a valuable energy carrier that can be applied in different sectors, i.e. the chemical industry, the mobility sector, the gas sector (e.g. for domestic heating) or back into the power sector (by gas-to-power technology). By doing so, facilitating the integration of renewables (by solving problems in the power sector) can contribute to renewable energy targets or emission reduction targets in other sectors.

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<sup>1</sup> ECN’s Optiedocument is an optimization model in which sets of emission reduction measures can be put together in order to find the most optimal (defined by preferences of the user) selection of measures to realize emission reduction targets. The following document can be consulted for background information about this tool: Daniels, B. et al. (2006) Optiedocument energie en emissies 2010/2020, ECN-C--05-105.

- Analyzing the role of power-to-gas in terms of intermittent energy sources integration services it can be concluded that the value of power-to-gas is in its capabilities to deliver community energy storage services, time shifting / load leveling services and transmission & distribution capacity management services. Power-to-gas is found to be unable to deliver ‘frequency support’, ‘uninterruptable power supply’ and ‘forecast hedging’ services. Based on the typical sizes and specifications of the different technologies, it seems reasonable that power-to-gas will be used in systems with a typical size >100 kW.
- When specifically considering power-to-gas for electricity storage, it can best be compared to sodium sulphur batteries and NiCd batteries. Other storage technologies that are potential alternatives (based on some characteristics) are lead-acid, lithium-ion, VRB and ZnBr batteries. Because power-to-gas and batteries can be deployed almost limitless in terms of geographical constraints, they cannot be generically compared to compressed air energy storage and pumped hydro storage, although PtG has lots of characteristics in common with these two. SMES is in R&D stage and not suitable for larger systems. Flywheels and supercaps deliver different integration services and are therefore irrelevant to compare to PtG technologies.

The following phase in this systems analysis study, being the dynamic modeling exercise of ECN, should determine the value of power-to-gas in relation to other sectors like the chemical industry or mobility sector and conclude on the most viable role in the energy system.

Subsequent TKI research and power-to-gas demonstration projects should be focused on the business case of power-to-gas, considering cross sectorial benefits. The TKI program can stimulate the industry to consider power-to-gas technologies in the integration of intermittent sources, which might have a positive effect on the market potential for technology manufacturers. A sufficiently growing market potentially results in a two to three fold decrease in investment costs of electrolysis and methanation technology.

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## 1 INTRODUCTION

A successful transition towards a cleaner and more sustainable energy system in 2050 requires large scale implementation of sustainable and renewable energy sources. The European CO<sub>2</sub> emission reduction target of 80% in 2050, relative to 1990 emission level, implies that the power production sector should be fully sustainable by then and that other sectors, like the industry and mobility sector should rely largely on sustainable use of energy sources [ECF, 2011]. For the Netherlands specifically the implementation of energy saving measures as well as an adequate selection of power resources (e.g. renewable as well as low-carbon) is necessary.

Renewable power sources, like wind and solar energy, can mainly be distinguished from conventional fossil based power sources by their low life cycle carbon emissions and their intermittent<sup>2</sup> character. The combination of these two characteristics introduces numerous challenges regarding their implementation, since low (or zero) carbon power production is essential for staying within the global climate change limits, whereas at the same time our existing energy system is not sufficiently capable of facilitating the accommodation of power sources with such an intermittent character. By introducing intermittent energy sources, the need for overall flexibility in our energy system increases strongly.

Multiple solutions exist for providing the required flexibility, like e.g. dynamic operation of the existing assets, power storage or demand response. Alternative to e.g. batteries or compressed air energy storage, power-to-gas (PtG)<sup>3</sup> gains popularity. PtG is of particular interest because of its potential to provide flexibility to the energy system and hence contribute to the implementation of intermittent energy sources, and at the same time contribute to increase the sustainability in other sectors, like the industry and the mobility sector, by delivery of carbon-free hydrogen or derivatives. The role of PtG in the energy transition has insufficiently been considered until now.

This report is the first deliverable in a larger project that aims to assess the viability and future role of PtG in the Dutch energy system. This deliverable specifically presents an overview of static data about PtG and its energy storage alternatives.

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<sup>2</sup> Intermittent energy sources are sources of energy that are not continuously available due to factors out of direct control.

<sup>3</sup> Power-to-gas has in this project been defined as the conversion of electrical power into hydrogen. It is a technological concept that enables controllable power demand load and offers the opportunity for (1) electricity storage, if hydrogen is converted back to electricity, (2) accommodation in the gas infrastructure, either by direct injection of hydrogen or by the conversion of hydrogen and carbon dioxide into methane by the Sabatier process, (3) application of hydrogen as feedstock in the industry and (4) application of hydrogen as fuel in the mobility sector.



### 1.1 Top consortia Knowledge & Innovation (TKI) Gas

The system analysis study of power-to-gas has been executed in the context of a new business policy of the Dutch government. Core of this policy is private-public partnerships within nine top sectors, aiming for optimal utilization of public resources for knowledge and innovation. This policy has been translated into agreements between Dutch industry, knowledge institutes and the government and resulted in so called Top consortia for Knowledge and Innovation (TKI), which are structural partnerships in which different parties collaborate along the entire knowledge value chain.

The consortium in this project operates within the top sector Gas and specifically focuses on 'power-to-gas' (PtG). The consortium partners are: Alliander, DNV KEMA, Energiebeheer Nederland (EBN), Energy Research Centre the Netherlands (ECN), Energy Valley, Enexis, Nuon Vattenfall, N.V. Nederlandse Gasunie, Rotterdam Climate Initiative (RCI), Siemens Nederland, Taqa Global and Tennet.

### 1.2 System Analyses: Power to Gas

The system analysis study of power-to-gas aims to identify the future role and viability of the power-to-gas concept in the Dutch energy system (within the context of the European energy market). The complexity of the energy system requires an integrated approach in which the entire power and gas value chains are incorporated. The final goal is to draw conclusions on the viability of PtG in the Dutch energy system.

The main research question in the system analyses study has been defined as follows:

*Under which circumstances and in which situations can power-to-gas play a role in the transition towards a cleaner and sustainable energy system in the Netherlands, considering the complexity of the energy system.*

The knowledge that has been developed and the insights given in this project should enable to give answers to questions of the stakeholders, like:

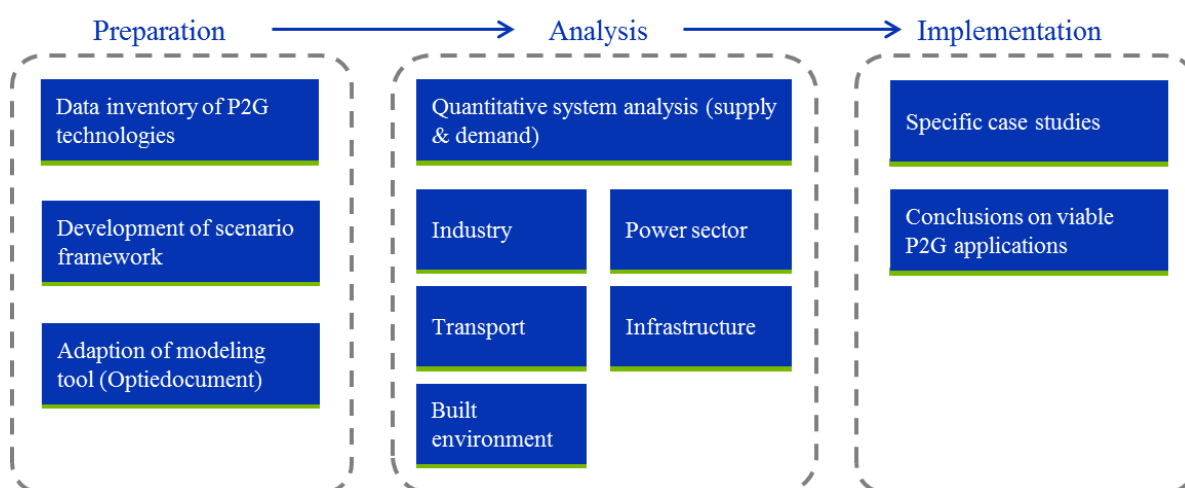
- Under what conditions is it potentially beneficial to invest in PtG technology?
- What is the overall potential of PtG to contribute to a sustainable gas system?
- Which preconditions should be satisfied in order to apply large scale PtG for accommodating excess power production from intermittent energy sources?
- To what extent has PtG the potential to add value in the industrial sector, from a sustainability and economics perspective?

By developing the appropriate knowledge to answer questions like the abovementioned, this project can have impact on short term decisions about technology development and long term decisions on investments and strategy.

Please note that this particular report will not answer the main research question or the other questions stated in this paragraph. This report presents the relevant *static data* that will be input for the dynamic analysis in the following phase of the project. See paragraph 1.2.1 and 1.2.2 for a more detailed description of the scope of this part of the project.

### 1.2.1 Position of this deliverable in the project

The overall systems analysis study can be divided into three main phases (see Figure 1). The focus of this report is on the preparation phase of the overall project. This report is the first deliverable of the project, in which a technology overview is given of the technologies that are relevant for the main research question. It basically contains *static data* about energy storage technologies and power-to-gas in particular.



**Figure 1: Phases that have been defined in this project.**

The data presented in this report is used in the "scenario framework" and "adaption of modeling tool" and is essential input to the subsequent project phases (Analysis and Implementation).

### 1.2.2 Scope of this deliverable

Consistent with the position of this deliverable in the total project (paragraph 1.2.1), this report focuses on the input data needed for further systems analyses with ECN's "Optiedocument"<sup>4</sup>, which is *static data* about different electricity storage techniques and components essential in the PtG value chain. Based on the data presented in this deliverable, *conclusions are drawn on the technologies to be incorporated in further analysis with the Optiedocument*. In the fourth quarter of 2013 ECN will

<sup>4</sup> ECN's Optiedocument is an optimization model in which sets of emission reduction measures can be put together in order to find the most optimal (defined by preferences of the user) selection of measures to realize emission reduction targets. The following document can be consulted for background information about this tool: Daniels, B. et al. (2006) Optiedocument energie en emissies 2010/2020, ECN-C--05-105.

disseminate the modeling (with ECN's Optiedocument) results of the system analysis, which will be the second deliverable of this project.

The technologies reviewed in this document are the ones that are currently missing in the option list of the Optiedocument and considered to be necessary for further analysis. Specifically with regard to the hydrogen production technologies reviewed it needs to be mentioned that the focus is to present technology characteristics for hydrogen production (water electrolysis). Technologies for further processing of hydrogen in e.g. the industry (like fuel synthesis or refinery) or accommodation of excess (curtailed) power in the heat industry (like horticulture or domestic heating) are out of scope of this report because these applications are included in the option list of the Optiedocument analysis. An exception is made for methanation, since this process is not yet included in the Optiedocument.

The data presented in this report are collected from literature and DNV KEMA experts review and reflects the information that is currently publically available. All consortium partners have reviewed this report before it was finalized.

## 2 THE CONTEXT OF POWER TO GAS

The introduction of intermittent energy sources (IES) in the existing energy system enhances the need for flexibility, in order to ensure the reliability of the grid and security of energy supply.

Basically there are two trends regarding the implementation of IES: (1) the effects of wind power integration on the energy system, mainly causing power transmission scale challenges and (2) the effects of photovoltaic solar power (solar-pv) integration, which mainly challenges power distribution scale flexibility.

The Dutch national wind power targets account for approximately 5 GW of installed capacity in 2015 (4 GW onshore and 0.95 GW offshore), 12 GW installed capacity in 2020 (6 GW onshore and 6 GW offshore) and 26 GW of installed wind power in 2050 (6 GW onshore and 20 GW offshore) [NWEA, 2013]. Several studies, performed on the effects of wind power production on the Dutch energy system, presented results on the amount of projected curtailed (wind) power in the future (without storage). Ummels (2009) reports about 6.2 TWh of curtailed wind power for the Netherlands in a scenario of 12 GW wind capacity and no international exchange. Undoubtedly, international exchange is crucial in energy systems analyses, however, it could be argued that whenever oversupply from wind power in Northern Germany occurs there will also be an oversupply of wind power from the Dutch offshore wind parks, limiting the possibilities for international exchange. Consistently, Velthuis (2012) reports 2 – 10 TWh excess wind power per year in 2050 (different scenarios) and De Boer (2012) reports about 2.4 TWh of power to be available for storage at 12 GW wind power installed. However, more detailed analysis from KEMA (2010) shows that the actual curtailment from wind energy is highly sensitive to the installed must-run capacity of combined heat and power units in e.g. industry. Depending on the wind and must-run capacity simulated, the authors found a maximum wind curtailment of 0.5 TWh per year [KEMA, 2010], this excludes solar energy trends though. Encountering the effects of solar power will result in more curtailment.

Solar power ambitions have been set by the Dutch government to 4 GW<sub>p</sub> installed pv power capacity in 2020 [KEMA, 2012]. The total installed solar-pv capacity in the Netherlands in 2011 was about 130 MW<sub>p</sub>, of which 118 MW<sub>p</sub> was installed as grid connected distributed systems and 7 MW<sub>p</sub> as grid connected centralized systems. The other 5 MW<sub>p</sub> was reported to be installed as off-grid systems [Ecofys, 2012]. Arcadis & RebelGroup (2013) estimate that in 2020 electricity production by decentralized solar-pv can be done under the costs for conventional power production. No estimations for the amount of curtailed power from solar-pv were found.

### 2.1 Intermittent energy sources (IES) integration service applications.

The trends that are mentioned in Chapter 2 are indications for the need for energy storage in the Dutch energy system. In order to identify the appropriate technologies serving the integration of intermittent energy sources, the service applications need to be identified, after which the technologies can be

classified. Seven types of service applications can be considered for supporting the integration of intermittent energy sources.

### **Frequency support**

Frequency support refers to stabilizing the grid frequency in case of very sudden large decreases in wind power generation. It offers ‘prompt’ spinning reserve for mitigating supply-demand imbalance. A storage system applied to provide such service should be able to discharge power almost instantly, for duration up to 30 minutes.

### **Uninterruptable Power Supply (UPS)**

An uninterruptible power supply or uninterruptible power source (UPS) is an electrical apparatus that provides emergency power to a load when the input power source fails (1-10 kW, up to 300-1,000 kW). This is an existing market for storage systems, where the storage system is used to supply electricity to the end users in cases of problems. These end users (like datacenters) are used to deal with costs for reliability of the electricity supply. Quick response and power supply for a period of several minutes up to an hour is required.

### **Community Energy Storage (CES)**

CES service applications refer to district-level energy storage. A Community Energy Storage system (CES) is a small energy storage unit connected to secondary transformers that serve a few houses or small commercial loads. CES can also be configured to act like a virtual substation battery. In this layout, a number of CES devices are aligned, so they feed into one substation through the CES integrated control system. These devices operate together like one fleet, which yields an aggregate storage capacity of multi megawatts and multi-hours to benefit the grid.

CES devices can facilitate the integration of renewable power resources into the grid for distributed generation. These devices could help smooth, shape, and firm renewable energy, as well as help to level out the load, which would reduce generation needed during peak times and decrease utilities’ capital investment (or defer capital spending on transmission and distribution systems). Such applications require a system to charge and discharge power, depending on the district characteristics even up to 2 to 3 times a day. The power discharge capacity should be in the range of MW’s which should be able to last for a few hours.

### **Home Energy Storage (HES)**

HES service applications have similar functionalities as CES but are smaller and dedicated for household applications. Such systems are typically installed to optimize domestic solar-pv utilization or to optimize the energy consumption of the end user, e.g. to minimize the needed capacity of the grid connection.

## Forecast hedging

This type of service application would imply that stored energy will be used to mitigate penalties incurred when real-time generation falls short to the wind energy generation bid, three hours prior to delivery [ULB, 2010; EPRI-DOE, 2004]. Like frequency support, forecast hedging is mainly focused on the energy delivery or discharge from a storage system.

## Time shifting

Wind generation time shifting pertains to the storage of energy generated during low demand periods (6:00 pm – 6:00 am) and discharged during high demand periods (6:00 am – 6:00 pm). This service application mainly aims to optimize the utilization of cheap electricity, produced at times of low demand, by storing it for delivery at times of high demand. Additionally, this application prevents renewable power from being curtailed. This application typically requires 5 to 12 hours of equivalent full power uptake and discharge [ULB, 2010; EPRI-DOE, 2004].

## Transmission & Distribution (T&D) capacity management

Insufficient transmission or distribution capacity imposes power delivery constraints, which can be mitigated by transmission/distribution curtailment application of storage technologies. The value of this service application is mainly in the avoidance of transmission and distribution network upgrades. In this case, the storage facility must be directly connected to the intermittent energy source.

### 2.1.1 IES integration system requirements

The abovementioned service applications for supporting the integration of intermittent energy sources are characterized in Table 1.

The first column of the table describes five categories of requirements that the services (first row) should meet. These categories are:

- Action required: indicates whether the technology applied for a service should take power from the grid or discharge power to the grid.
- Storage unit power: Indicates the uptake or discharge power capacity (in MW's) that a technology should meet.
- Equivalent full power discharge duration: Indicates the time that the technology should be able to discharge power at its maximum power capacity.
- Energy discharge per event: Indicates the amount of power that should be discharged per event (occurrence). It states the storage capacity (MWh) requirement that a technology should meet.
- Number of events (or cycles): This parameter gives insight in how often the support system should be able to operate in order to satisfy the service needs. An important characteristic for storage technologies is the amount of cycles in their lifetime.
- System response: Indicates the time frame in which a technology should be able to respond to fluctuations in power rating of the power source in order to meet the service application requirement.

**Table 1: IES integration system requirements**

	Frequency support	UPS	HES	CES	Forecast hedging		Time shifting / load leveling		T&D cap. management	
Action required	Uptake & discharge	Discharge	Uptake & discharge	Uptake & discharge	Uptake & discharge		Uptake & discharge		Uptake & discharge	
Storage unit power (MW)	1 - 50	50 kW – 1 MW	5 -100 kW	50 kW – 1 MW	2 - 50	50 - 200	2 – 50	50 - 200	2 – 50	50 – 2,000
Equivalent full power discharge duration	<30 minutes	<8 hours	1-8 hours	1-8 hours	< 3 hours		5 – 12 hours			
Energy discharge per event (MWh)	0.2 – 25	0.01 – 8	1-10 kWh	10-100 kWh	6 MWh – 24 GWh					
Number of events (potentially)	10x/day	< 2x/month	~1x/day	~3x/day	~3x/day		~3x/day		~3x/day	
System response time	<1 second	<1 second	<1 minute	<1 minute	<1 minute		<15 minutes		<15 minutes	

Sources: EPRI-DOE (2004), ULB (2010) & DNV KEMA.

Typically, frequency support and UPS services require systems that can deliver power within one second, forecast hedging requires a response within seconds while the other services can work with systems that have a little longer response time. For a UPS system the service application does not require a storage system to instantly absorb power, all other services require the support systems both to absorb and discharge power.

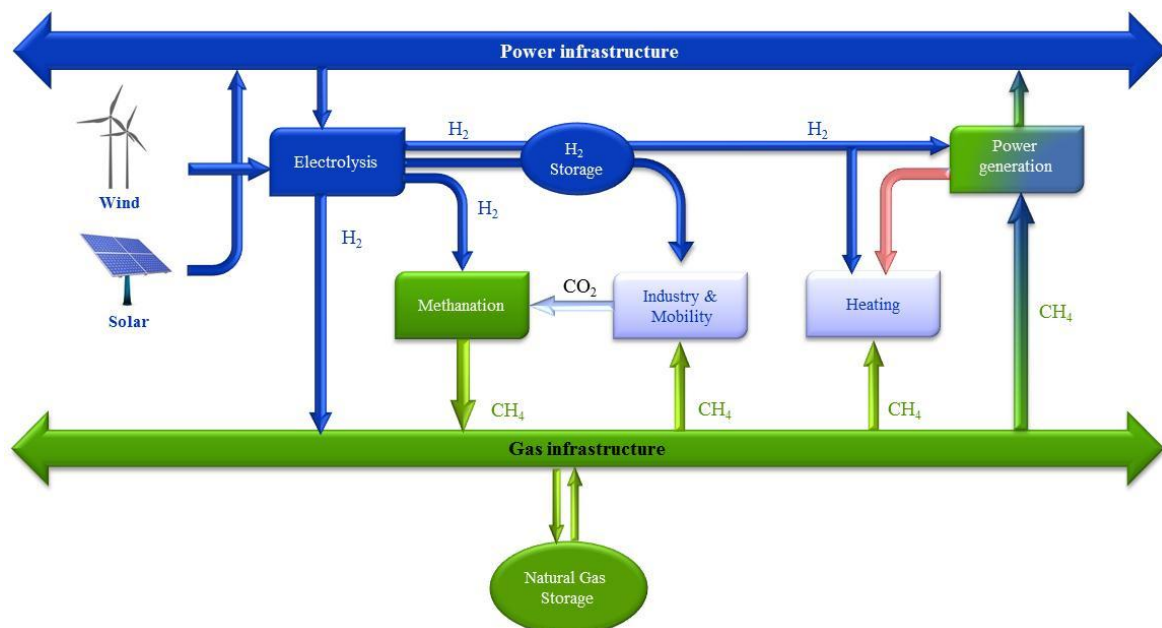
## 2.2 Perceived role of power-to-gas

From an exergetic perspective electricity should always be deposited as electricity on the electricity grid when possible (highest efficiency). However, when problems occur in the electricity sector (such as congestion, negative electricity prices or physical damage) or an electricity infrastructure is lacking at the production site the electricity can be converted into hydrogen. This hydrogen can then be accommodated directly 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 moment, or converted into methane. The conversion into methane can be appropriate whenever injection of hydrogen in the gas grid is preferred but limited by hydrogen specifications.

Another reason to do PtG could be to overcome continuous transmission capacity constraints (grid specific) or to transport energy over long distances. In this situation, electricity will be converted into hydrogen or hydrocarbons continuously.



The pathways from electricity to one of the end products mentioned above are visualized by Figure 2. With technology that is available today, the first step in the conversion of electricity into hydrogen is indispensably by means of water electrolysis. Whenever hydrogen is produced different pathways are possible. In case hydrogen is converted into methane or other hydrocarbons, a carbon source (e.g. CO<sub>2</sub>) is required for synthesis.



**Figure 2: Schematic description of the power-to-gas concept.**

The amount of hydrogen that can be added to natural gas in the natural gas infrastructure is limited because of the effects of hydrogen on the Wobbe index of natural gas, on the combustion behavior of the gas mixture, and the effects on materials integrity. The allowable amount of hydrogen blending is case specific and differs between different end-user sectors. See Appendix A for additional information. Currently DNV KEMA is closely involved in discussions with the Dutch government and regulator about the future gas specifications and involved in large project aiming to define the limits of hydrogen in different gas systems.

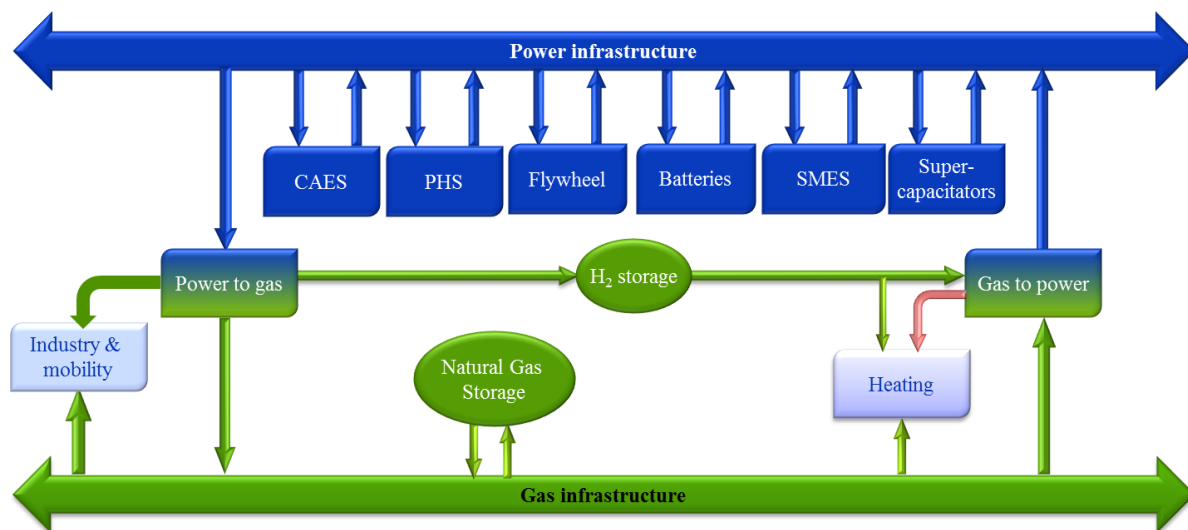
Because of the limitations for hydrogen injection into the natural gas grid, the potential storage capacity of hydrogen in the gas infrastructure is significantly lower than the total storage capacity of methane. The total storage potential needed in the future will be assessed in the subsequent phases of this project.

### 2.2.1 Power to Gas in relation to energy storage system requirements

Power-to-gas is distinctive from power storage technologies by the characteristic that gas (hydrogen or methane) is being produced as an intermediate product. This gas can subsequently be processed as gas or reconverted into electricity again. In case of conversion into power again, there are in general two possibilities: (1) hydrogen from electrolysis is stored and is reconverted by a fuel cell, or (2)



hydrogen/methane is accommodated in the gas infrastructure and reconverted into power by conventional (existing) gas power plants. The mentioned pathways are visualized by Figure 3. The first option is preferred in case power generation must be realized at the same location as where the imbalance occurs (physical constraint) or whenever no gas infrastructure is present. However, this requires the PtG system to be equipped with a hydrogen buffer and fuel cell technology. The second option requires less investment and is typically suitable for service applications related to market issues (since supply and demand do not strictly have to be physically coupled), such as forecast hedging and time shifting service applications.



**Figure 3: Schematic description of energy storage systems.** The abbreviations are ‘compressed air energy storage’, ‘pumped hydro storage’ and ‘superconducting magnetic energy storage’.

Figure 3 clearly shows the distinctive character of PtG, compared to dedicated storage technologies. Using PtG technologies, electrical power can be converted into hydrogen or methane and applied in the chemical industry, as a feedstock, or directly or indirectly as fuel in the mobility sector. According to Hydrogenics (2013) and Solar Fuel (2013) PtG is emphatically of interest for application of (otherwise curtailed) power in industry and mobility. None of the other technologies are able to meet this same feature.

### 2.2.2 Power to Gas & Gas to Power

When assessing the role of PtG in the energy system it is of importance that it is being assessed against alternatives based on the equal assumptions. As described in paragraph 2.2 there are numerous pathways that can be considered, meaning that the assessment is not straight forward.

One of the parameters is the efficiency of PtG systems and pathways. De Boer (2012) studied the overall efficiency of different PtG systems and concluded that it is in the range of 77% in case of power-to-hydrogen, to as low as 18% in case of power-to-methane-to-power (with extraction from CO<sub>2</sub> from the atmosphere). Please consult appendix C for a more detailed overview of efficiencies.

The research of De Boer (2012) excluded efficiency improvement developments that are expected in the near future and also excluded the option to convert hydrogen to electricity by means of fuel cell technology.

However, it should be noted that the efficiency is only relevant in the narrow perspective of PtG, in which the technology is solely applied for direct power storage application. Efficiency is less important in the broader perspective of enabling delivery of renewable gas in other sectors, such as the industry or mobility sector.

### 2.2.3 **Power-to-Gas demonstration plants in Europe**

Currently about 30 PtG demonstration plants are reported on the internet and in literature, of which the most have been deployed in Germany, see appendix B for an overview of these projects. Most of the PtG projects are focused on hydrogen, few on the production of methane. A large part of the demonstration projects in which hydrogen is produced for grid injection, storage or direct application, is being operated flexible. The power-to-methane plants that are in operation (or under construction) are mostly base load plants.

The largest PtG demonstration plant is currently being developed by Solar Fuel GmbH, by order of Audi AG and is built in Werlte in Germany. This plant has an electrical capacity of 6.3 MW<sub>e</sub>, producing 360 Nm<sup>3</sup>/hr methane which will be injected in the local gas distribution grid. The CO<sub>2</sub> source for the methanation process is the stripped CO<sub>2</sub> from a waste treatment biogas plant nearby.

At this moment most projects are in the construction or planning phase, therefore only very generic information is available about these plants. The demonstration projects will not be discussed in detail here.

### 3 TECHNOLOGY REVIEW

This chapter presents static data and characteristics of different technologies that are available (or those that are in R&D and demonstration phase) for storage of electricity. These technologies are: power-to-gas, compressed air energy storage, pumped hydro storage, flywheels, supercapacitors, superconducting magnetic energy storage and batteries. Technologies for further processing of hydrogen from power-to-gas (like fuel synthesis) or application of curtailed power in the heat industry (like horticulture or heat networks) will not be discussed here since that is covered by the Optiedocument analyses. Additional information about the availability of metals that are used in different technologies is given in Appendix E.

#### 3.1 Power to Gas

With the technology currently available, the production chain of power-to-gas consists of electrolysis and optionally methanation can be included. Electrolysis relates to the conversion of electricity into hydrogen. Methanation is the synthesis of hydrogen and carbon dioxide to methane. Additional to the power-to-gas technologies mentioned in this paragraph it might be needed to consider gas compression and hydrogen storage in buffer tanks, depending on the specific PtG chain. For the characteristics of compression and hydrogen buffer tanks appendix D can be consulted.

##### 3.1.1 Electrolysis

Each year, roughly 600 billion cubic meter of hydrogen<sup>5</sup> is produced, mainly for industrial applications, which is mainly done by methane steam reforming. Less than 1% is produced by electrolysis. The principle of electrolysis of water is well-known for more than 200 years and is mainly used in the industry.

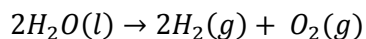
Electrolysis requires a high purity of the water from which hydrogen is produced. Therefore a treatment step in which minerals and ions are removed is always required before water can be used for electrolysis. The removal of the minerals and ions can be accomplished by the use of a reverse osmosis process. In this process, water is led through a membrane in which minerals are separated from the water. The membrane acts as a filter having microscopic holes. The removal efficiency of the ion is determined by the size of the ion components, the polarity and the electrical charge of the components.

For de-ionization, the water is contacted by an ion exchanger. Ion-exchangers are columns in which a fixed bed of adsorption materials has been applied. The ion exchanger replace positive ions for hydrogen ions (with similar electro valences) and negative ions are replaced by hydroxide ions. Finally, the ion-exchanger can be regenerated by flushing with saline, hydrochloric acid or sodium hydroxide, depending on the applied ion exchange materials.

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<sup>5</sup> Hydrogen has a calorific value of 3.54 kWh/Nm<sup>3</sup> (HHV), after Smolinka et al. (2011).

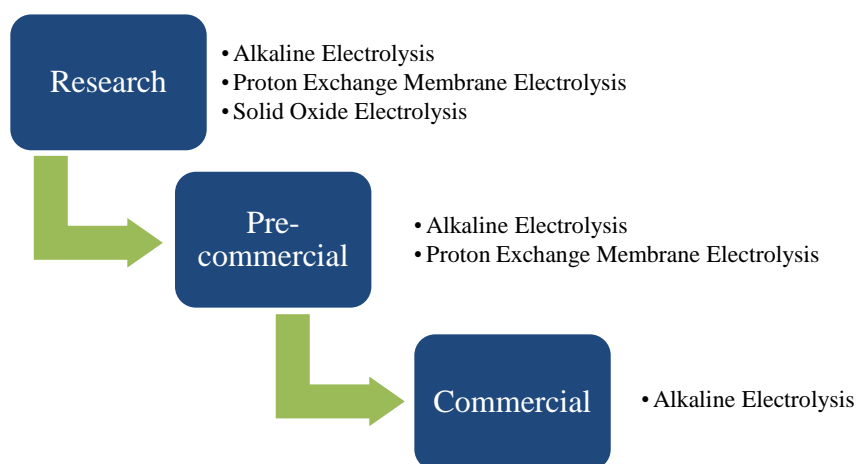
After de-ionization and demineralization water is split into hydrogen and oxygen by applying a direct electric current on the water to drive the chemical reaction. The chemical reaction is elaborated in Figure 4.



**Figure 4: Reaction of water electrolysis**

In water electrolysis a direct electric current causes a shortage of electrons to the anode, and an excess of electrons at the cathode. The positively charged particles migrate to the negatively charged cathode and receive an electron. As a result, a hydrogen atom and a water molecule are formed. By repetition of this process, a second hydrogen atom is formed. Both hydrogen atoms react to form a hydrogen molecule.

Different techniques for water electrolysis can be identified: alkaline water electrolysis (commercially available) and proton exchange membrane electrolysis (pre-commercial) are the most common and available techniques. Solid oxide electrolysis is still in a research phase and currently not commercially available. The techniques and the state of development (see Figure 5) are elaborated in the paragraphs below.



**Figure 5: Graphical indication of the state of development of the different types [Jensen et al., 2008]**

The amount of hydrogen that can safely be added to natural gas (without having increased risk for flash-back, engine knock or integrity) strongly depends on the composition of the natural gas at the injection point and should therefore specifically be assessed per case (location, gas grid, flow, composition, end-users in the grid, etc). As stated above, the technically allowed hydrogen limit can be 25% in the best case or even 0% in the worst case. Currently, the maximum allowed hydrogen fraction in the Dutch G-gas grid (low calorific Groningen gas quality, from the Slochteren gas field) is 0.02 vol% (Donders et al., 2010). From 2021 onwards the maximum allowed hydrogen fraction will be 0.5 mol% (EL&I, 2012). See appendix A for additional information. In Germany higher

percentages of hydrogen are allowed (up to 10% in the near future), unless there are technical limitations or safety issues for transportation and end-use applications.

### 3.1.1.1 Alkaline Electrolysis

The alkaline water electrolysis is commonly used due to its durability, maturity and the relative low costs. The anode and cathode materials in these systems are typically made of nickel-plated steel and steel respectively. The electrolyte in these systems is a liquid one based on a highly caustic KOH solution.

According to most of the literature available about alkaline electrolysis, it would be unable to provide the required flexibility for IES integration, because its ramp rate is often reported to be ‘minutes’, it would be unable to deploy the system fast from a cold start situation and it would have a lower part load of 20-40% of the max capacity [Smolinka et al., 2001; Muller-Syring et al., 2012]. However, Hydrogenics (2013) clearly states that these performance characteristics result from the fact that industry never demanded for flexible operation of alkaline electrolyzers, so the technology has never been designed to operate as such. Currently, with the integration of intermittent sources, the demand for flexible operation arises. Alkaline electrolyzers are very well capable of flexible operation with a power load ranging from 5% - 100%, being able to ramp within this range within seconds [Hydrogenics, 2013]. Even cold start hurdles can be solved relatively easy, according to the electrolyser manufacturer, who emphasizes that the cold start time mainly depends on the required hydrogen purity, and could be up to 10 minutes. Smolinka et al. (2011) expects short-term increases of the technical performances of alkaline electrolyzers, which is in line with the information from Hydrogenics (2013).

The characteristics of alkaline electrolysis processes are given in Table 2, divided in the current (2011) situation and the future perspective for the short-term (2015) and mid-term (2020) period.

**Table 2: Characteristics of alkaline electrolysis**

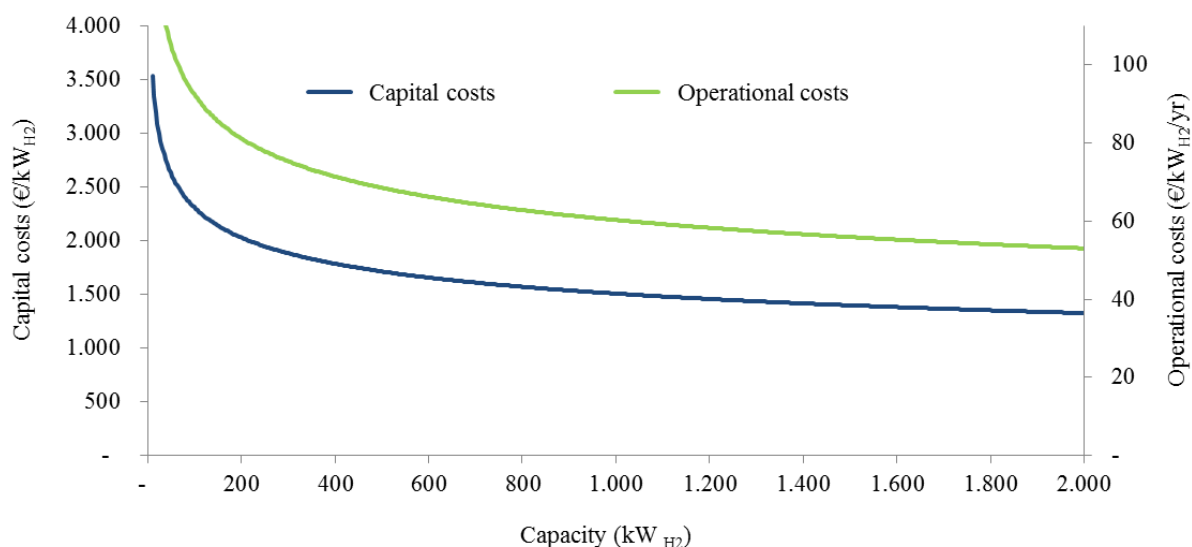
Characteristic	2011	2015	2020	Reference
Delivery pressure (bar)	<30	60	60	Smolinka (2011)
Power density (kA/m <sup>2</sup> )	2 - 4	< 6	< 8	Smolinka (2011)
Cell Voltage (V)	1.8 - 2.4	1.8 - 2.2	1.7 - 2.2	Smolinka (2011)
Load density (W/cm <sup>2</sup> )	1	1	2	Smolinka (2011)
Cell surface max. (m <sup>2</sup> )	4	4	4	Smolinka (2011)
Efficiency (%)	62 - 82	67 - 82	67 - 82	Smolinka (2011)
Maturity	Commercial			
Power consumption per stack (kWh/Nm <sup>3</sup> H <sub>2</sub> )	4.2 - 5.9	4.2 - 5.5	4.1 - 5.2	Smolinka (2011)
Power consumption per system (kWh/Nm <sup>3</sup> H <sub>2</sub> )	4.5 - 7	4.4 - 6	4.3 - 5.7	Smolinka (2011)
Lower part load (%)	20 - 40	10 - 20	10 - 20	Smolinka (2011)
		5	5	Hydrogenics (2013)

Characteristic	2011	2015	2020	Reference
Production rate H <sub>2</sub> per stack (Nm <sup>3</sup> /hr)	760	1.000	1.500	Smolinka (2011)
Capacity rate per system (kW <sub>e</sub> )	3,800	5,000	7,000	Smolinka (2011)
Lifetime (hrs)	90,000	90,000	90,000	Smolinka (2011)
Deployment time*	5 min			Muller-Syring et al. (2012)
	sec			Hydrogenics (2013)
Cold start time	Min - hrs	Min - hrs	Min - hrs	Muller-Syring et al. (2012)
	< 10 minutes			Hydrogenics (2013)
Annual cost improvement (%)	0,4			McKinsey (2010)
Learning rate (%)	18%			Schoots (2008)
Annual availability	90%	90%	90%	Schoots (2008)

\*Deployment time from stand by modus

The efficiency of alkaline electrolysis is assumed to be equal over the years. However, the hydrogen production rate per stack increases by a factor of 2. The characteristic for the annual availability is related to the maintenance requirement level, described in Schoots et al. (2008).

Data from Weinert (2005), Ewan & Allen (2005), Hydrogen Technologies (2011), Angstrom (2011) and Smolinka (2011) was analyzed in order to produce a graph on the costs for alkaline electrolysis, see Figure 6. The capital costs line is a trend line function of numerous data points, the operational and maintenance cost curve represents 4% of the investment costs annually, after Greiner et al. (2007), excluding the costs for electricity.



**Figure 6: Capital and operational costs alkaline electrolysis (in €<sub>2011</sub>) [Weinert, 2005; Greiner et al., 2007; Ewan & Allen, 2005; Hydrogen Technologies, 2011; Angstrom, 2011; Smolinka, 2011]**

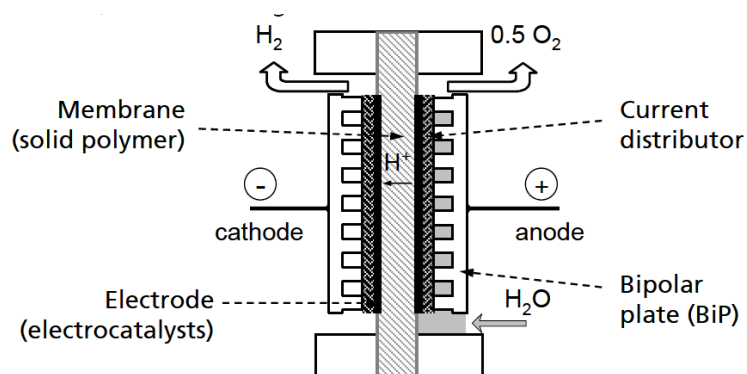
The cost graphs shown in Figure 6 include the costs for water deionization and demineralization but exclude compression costs.

Summarized, the advantages of alkaline electrolysis include its maturity, flexibility and durability. Disadvantages are the use of a highly caustic electrolyte and its inability to produce hydrogen at high pressures. By increasing the operational pressure or temperature for alkaline electrolysis water molecules can be split with lower currents (so higher splitting efficiency). However, this only benefits the overall efficiency if waste heat or pressure can be used. In the context of PtG methanation can be an interesting heat source because the Sabatier reaction produces high temperature heat as a by-product (described in paragraph 3.1.2).

### 3.1.1.2 Proton Exchange Membrane

The most suitable alternative for alkaline electrolysis is the Proton Exchange Membrane (PEM) electrolysis. PEM electrolysis is built around a proton conductive polymer electrolyte. A general figure of a PEM electrolysis cell is shown in Figure 7. The cell consists of an anode (oxygen production) and a cathode (hydrogen production) and a proton exchange membrane (PEM) in between, by which the two gaseous components are separated. PEM technology is increasingly being applied in fuel cell technology, in which the exact opposite reaction of the electrolysis reaction occurs.

In most PEM cells the electrode is directly in contact with the membrane. These arrangements form the MEA (membrane electrode assembly), which is the key component of a PEM electrolysis cell. Both sides of the MEA porous current collector are permeable for the product gas and water. The bipolar plates frame the two half-cells and are equipped with a so-called flowfield in order to ensure the transportation of liquid water to the cell and the escape of the product gases.



**Figure 7: Principle of a PEM electrolysis cell [Smolinka, 2011]**

PEM electrolysis units are currently between R&D and pre-commercial stage and only commercially available as production units with a maximum capacity of 50 kW<sub>e</sub>. However, the technology for PEM electrolysis is strongly developing. Numerous manufacturers report future capacities per system to be in the MW scale and investment costs are expected to be comparable or even less than the investment



costs for alkaline electrolysis. Siemens (2011) even reports to be able to bring 90 MW (90 MW nominal power, 270 MW max power) systems on the market between 2015 and 2020.

**Table 3 : Characteristics of PEM electrolysis**

Characteristic	2011	2015	2020	Reference
Delivery pressure (bar)	<30	60	60	Smolinka (2011)
Power density (kA/m <sup>2</sup> )	6 - 20	10 - 25	15 - 30	Smolinka (2011)
Cell Voltage (V)	1.8 – 2.2	1.7 – 2.0	1.6 – 1.8	Smolinka (2011)
Load density (W/cm <sup>2</sup> )	4.4	5.0	5.4	Smolinka (2011)
Cell surface max. (cm <sup>2</sup> )	300	1,300	5,000	Smolinka (2011)
Efficiency (%)	67 - 82	74 - 87	87 - 93	Smolinka (2011)
Maturity	R&D – Pre commercial			
Power consumption per system (kWh/Nm <sup>3</sup> H <sub>2</sub> )	4.5 - 7.5	4.3 - 5.5	4.1 - 4.8	Smolinka (2011)
Production rate H <sub>2</sub> per system (Nm <sup>3</sup> /hr)	30	120	500	Smolinka (2011)
Capacity rate per system (kW <sub>e</sub> )	150	500	2,000	Smolinka (2011)
Lower part load (%)	0 - 10	0 - 5	0 - 5	Smolinka (2011)
Lifetime (hrs)	20,000	50,000	60,000	Smolinka (2011)
Deployment time (sec)*		10 sec	10 sec	Muller-Syring (2012) & Siemens (2011)
Cold start time (minutes)	10 min	10 min	10 min	Muller-Syring (2012) & Siemens (2011)
Annual cost improvement (%)	2.2			McKinsey (2010)
Annual availability	91%	91%	91%	Schoots (2008)

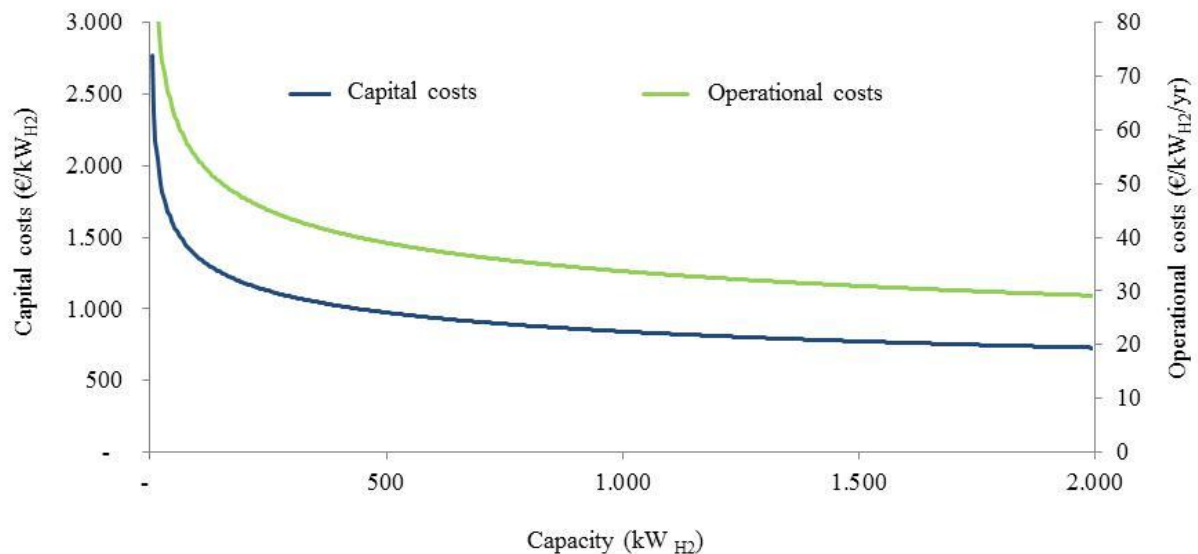
\* Deployment time from standby modus

Currently, the specific power consumption of a stack varies from 4,5 kWh/Nm<sup>3</sup> H<sub>2</sub> to 7,5 kWh/Nm<sup>3</sup> H<sub>2</sub> and might be improved to 4,1 to 4,8 kWh/Nm<sup>3</sup> H<sub>2</sub> within the next decade. Based on the characteristics in Table 3 a large increase in maximum cell surface is foreseen to maximize the load density.

Additionally, the production rate and lifetime might increase significantly up to 2020. It should be noted that PEM electrolysis is currently mainly used in applications where the overall efficiency is not critical. However, the overall efficiency is estimated to increase from 67-82% up to 87-93%.

The future expected capital costs for PEM electrolysis are presented in Figure 8 and are based on Smolinka et al. (2011), who extrapolated the cost function in order to identify the economies of scale towards the year 2020 (with the assumption of a power density of 20 kA/m<sup>2</sup>). However, currently the costs of PEM electrolyzers (max 50 kW<sub>e</sub> commercially available) are 2.000 – 10.000 €/kW [Smolinka et al., 2011]. The operational costs as shown in Figure 8 are assumed (based on operational and maintenance costs of alkaline electrolysis) to be an annual percentage (4%) of the capital investment, excluding the costs for electricity.





**Figure 8: Future (>2020) projected capital and operational costs of PEM electrolysis (in €<sub>2011</sub>), based on Smolinka (2011).**

In comparison the costs for PEM fuel cell technology for application in cars is max. 800 €/kW<sub>H2</sub> (avg. 500 €/kW<sub>H2</sub>) in 2010 and max. 100 €/kW<sub>H2</sub> (avg. 43 €/kW<sub>H2</sub>) in 2020 [McKinsey, 2010]. Tsuchiya et al. (2004) calculated the potential future investment costs of PEM fuel cells in mass production, based on learning curve cost reduction estimates, to be under 80 €/kW in 2020, which implies a cost reduction of about 60% in 10 years. If this same trend holds for PEM electrolysis this technology will be of great interest.

Jensen et al. (2008) and Zeng & Zhang (2010) reported several advantages for PEM in comparison to alkaline electrolysis: higher energy efficiency, higher production rates, more compact design and suitable for the MW scale in the near future. PEM electrolysis offers very fast shut down and start up times with a part load range of 5-100% [Ulleberg et al., 2010]. Disadvantages are the uncertainties regarding the lifetime, expensive polymer membranes and expensive porous electrodes [Ulleberg et al., 2010; Zeng & Zhang, 2010].

### 3.1.1.3 Solid Oxide Electrolysis (SOE)

As an alternative to alkaline electrolysis and PEM electrolysis, solid oxide electrolysis (SOE) can be considered. SOE mainly distinguishes itself from the other technologies by the ability to produce synthesis gas (H<sub>2</sub> and CO) from an input of power, water and CO<sub>2</sub>. Additionally the temperature range (from 700°C to 1,000°C) in which this technology operates is significantly higher than alternatives, but enables the reaction efficiency (splitting water vapor) to be significantly higher (approaching 100%, excluding the energy requirements for heat supply) [Hauch, 2007]. When the energy requirements for heating are included, the total energy efficiency is in the range of 50% - 90% [Stempien et al., 2012].

The first promising results on hydrogen production with SOE were already reported in 1980 by Dönitz et al. Main focus of research on SOE in general has been to utilize waste heat from nuclear power production [Hauch, 2007]. That's also why energy requirements for heat supply are often neglected. Besides the requirements for addition of high temperature heat, an important disadvantage of this historical drive, with respect to the contexts of PtG, is that the technology has been developed for steady-state application and is less suitable for flexible operation. Typically, SOE cells have a deployment time of more than 15 minutes [Hauch, 2007] from standby and hours from cold start [Muller-Syring et al., 2012].

The abovementioned ability of SOE to produce synthesis gas offers the possibility to integrate the conversion of synthesis gas to methane ( $\text{CH}_4$ ) or hydrocarbon transportation fuels (like methanol or dimethylether). Since such conversion processes are based on highly exothermal catalytic reactions, the integration of the synthesis catalysts into the SOE potentially increases overall system efficiency because heat produced during the catalytic reaction ( $300^\circ\text{C}$  to  $550^\circ\text{C}$ ) can be used to produce steam for the SOE reaction. A system for methane production via  $\text{CO}_2$  electrolysis has been proposed by Jensen [Jensen et al., 2008 & Jensen et al., 2005], see Figure 9.

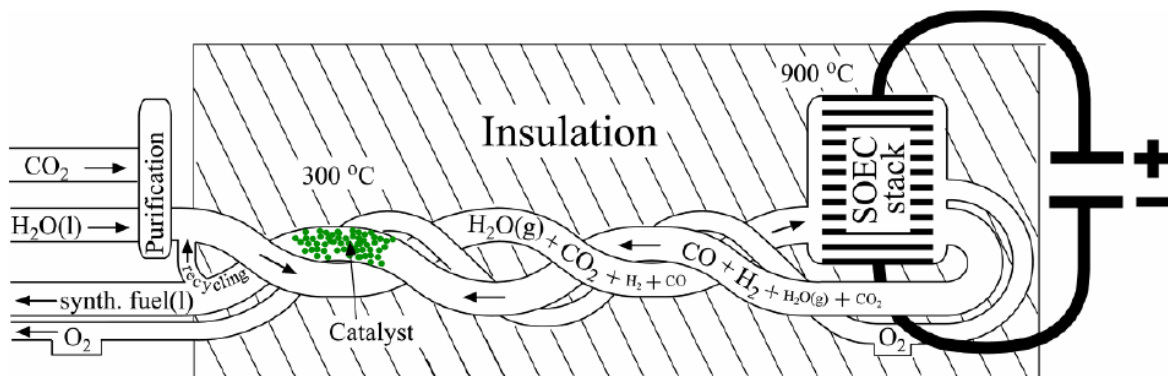


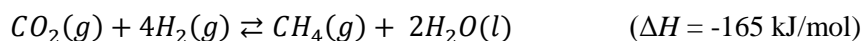
Figure 9: SOE integrated with synthesis gas conversion [Jensen et al., 2008]

From literature research it seems that there is at this moment one institute developing the SOE technology, this is the Risø National Laboratory, part of the Technical University of Denmark. There is very little information available about this technology, specifically information on the economic perspective is rarely available. Jensen et al. (2008) report that SOE cells might be brought on the market in the future for 280 – 440 €/kW<sub>e</sub>, however, at this moment it is not realistic to consider this (low) range investment costs because of the immaturity of the technology.

### 3.1.2 Methanation

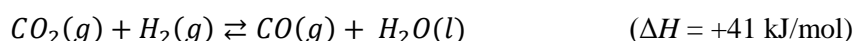
A second step in the PtG chain could be methanation, in case the injection is limited by the effect of hydrogen on the natural gas properties. Methanation described the catalytic conversion of hydrogen and carbon dioxide into methane. The process is based on the Sabatier reaction, named after the discoverer of the process Paul Sabatier. Methanation has become a well know process due to the production of synthetic natural gas, which became popular during the 70s. At that time the oil crisis resulted in high petroleum fuel prices, which made producing methane from coal and biomass

(syngas) an interesting alternative. The opposite reaction (methane steam reforming) is widely applied for the production of hydrogen from methane [Kopyscinski et al., 2010]. The Sabatier reaction is shown in Figure 10.



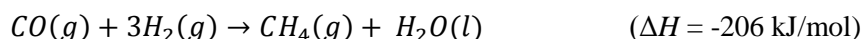
**Figure 10: Reaction methanation**

The reaction happens in two steps. The first step is the endothermic reaction shown in Figure 11.



**Figure 11: First reaction step methanation**

The second step is the exothermic reaction shown in Figure 12.



**Figure 12: Second reaction step methanation**

Besides the needs for hydrogen as reactant, carbon dioxide or carbon monoxide is needed for the catalytic conversion into methane. The way of capturing the required CO<sub>2</sub> is an important determinant for the energy efficiency of the methanation process. Capturing CO<sub>2</sub> is an energy intensive process. CO<sub>2</sub> sources can for instance be the atmosphere, biomass, biogas, sewage stations or fossil fuel driven power plants combined with carbon capture and storage [Sterner, 2009].

Using CO<sub>2</sub> from the atmosphere enables to physically decouple the methanation plant from a point source of CO<sub>2</sub>, which increases the amount of suitable locations. However, this process has a low efficiency because the atmospheric CO<sub>2</sub> content is only about 390 parts per million. Experiments at the Fraunhofer ZWS institute showed that the absorption of CO<sub>2</sub> from the atmosphere is an energy efficient solution [Bandi et.al., 1995]. This technique requires 8.2 GJ of electricity and 2,300,000 m<sup>3</sup> of air from the atmosphere to produce 1 ton of CO<sub>2</sub> [Weimer, 1996; Sterner, 2009]. With an electricity price of 0.05 €/kWh, this results in 0.20 €/Nm<sup>3</sup> of CO<sub>2</sub> (and thus 0.20 €/Nm<sup>3</sup> of methane produced in the Sabatier process for capturing CO<sub>2</sub>) [Sterner, 2009]. When obtaining the CO<sub>2</sub> from conventional power plants by scrubbing, about 2 – 4.8 GJ<sub>e</sub> per ton of CO<sub>2</sub> is needed [Muller et al., 2011], which is 0.05 – 0.13 €/Nm<sup>3</sup> CO<sub>2</sub> (and thus 0.05 – 0.13 €/Nm<sup>3</sup> of methane produced in the Sabatier process for capturing CO<sub>2</sub>). However, APS (2011) estimates somewhat higher costs for CO<sub>2</sub> capture from the atmosphere, being in the range of 0.8 – 0.9 €/Nm<sup>3</sup> CO<sub>2</sub>. Sterner (2009) stresses that as long as concentrated CO<sub>2</sub> sources are available, it is more energy and cost efficient to use them instead of using CO<sub>2</sub> from the atmosphere.

The methanation process can be executed either chemically or biologically. Both principles are based on the chemical reaction shown in Figure 10, but are fundamentally different.

### 3.1.2.1 Chemical methanation

Chemical methanation is matured 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. Nickel is often chosen as a catalyst because of the favorable costs relative 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 [DNV KEMA]. The carrier metal is usually a metal oxide, e.g. alumina oxide, because of its high specific surface [Ross, 1985]. The energetic efficiency of the methanation process is in the range of 70% to 85%, with the remaining 15% - 30% being emitted as high temperature heat (with respect to the energy in the outgoing gas stream relative to the energy in the incoming gas stream).

**Table 4: Characteristics chemical methanation**

Characteristic	Value	Reference
Process temperature (°C)	200 - 750	Sterner (2009) & Kopyscinski (2010) & DNV KEMA
Delivery pressure (bar)	4 - 80	Kopyscinski (2010) & DNV KEMA
Max. production capacity (MW <sub>CH<sub>4</sub></sub> )	<500	Potocnik (2010b)
Maturity	Commercial*	DNV KEMA
Catalyst cost (€/kg in 2013)	250	DNV KEMA
Space velocity (hr <sup>-1</sup> )	3,000 – 6,000	Boreskov (2011) & Hoekman (2010)
Chemical load reactant gas to cat (Nm <sup>3</sup> *h <sup>-1</sup> *kg <sup>-1</sup> )	3 - 6	Boreskov (2011) & Hoekman (2010)
Density (kg/m <sup>3</sup> )	1,300	Muller-Syring (2012)
Lifetime catalyst (h)	24,000	DOE-NETL (2008)
Lifetime catalyst (Nm <sup>3</sup> gas/kg cat)	72,000 - 144,000	Calculated
Deployment time (min)**	< 5	DNV KEMA, Solar Fuel (2013)
Cold start time	hours	Muller-Syring (2012), DNV KEMA
Standby energy requirements (% of max capacity)	1%	Solar Fuel (2013)
Methanation efficiency (excl. electrolysis)	70 - 85%	Sterner (2009) & Kopyscinski (2010)
Annual availability	85%	Zwart et al. (2006)

\*Large plants are commercially available. Smaller units (several MW's) are not available off the shelf.

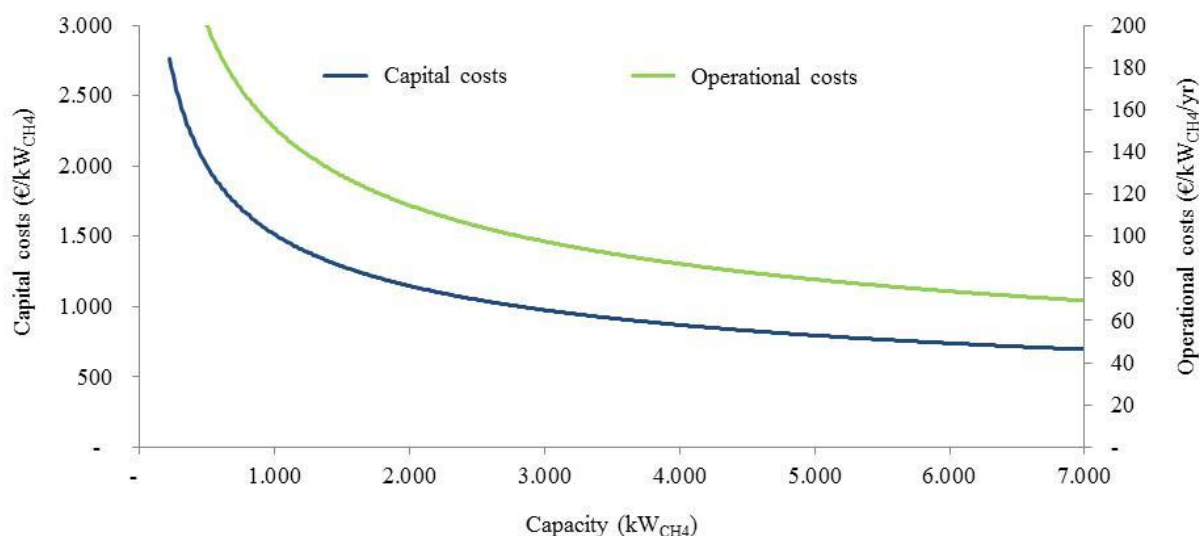
\*\*Deployment time from standby modus

The characteristics for chemical methanation show wide ranges in general, caused by complexity of the technology and the process. The unpredictability of the exothermic catalytic reaction results in uncertainty of the values.

The chemical load for the catalyst is based on a stoichiometric conversion ratio of 4:1, as given in Figure 10. The lifetime of a catalyst is strongly dependent on operational conditions. The values given

in Table 4 estimates in case of proper operation, without contaminants and trace components in reactant gas.

The costs of methanation are shown in the graph below (see Figure 13) and is derived from data from Zwart et al. (2006), DNV KEMA (2013), Haldor Topsoe (2011) and Solar Fuel (2013). The costs are based on plants with a capacity of  $<10\text{MW}_{\text{th}}$  combined with a scale exponent. It must be noted that the investment costs seems to be somewhat high, which is related to the fact that small scale ( $<20\text{MW}_{\text{CH}_4}$ ) units are currently not being offered off the shelf. When the market for small scale methanation develops, it is expected that these units can be purchased for 300 – 500 €/kW.



**Figure 13: Capital and operational costs of chemical methanation plants.**

The annual operation and maintenance costs are assumed to be 10% of the capital costs per year (including replacement of the catalyst and excluding the costs for hydrogen), after Zwart et al. (2006).

### 3.1.2.2 Biological methanation

As an alternative to chemical methanation, biological methanation can be considered to carry out the power-to-gas process. With this type of methanation, hydrogen is converted together with carbon dioxide to methane, wherein the conversion takes place with the same reaction as in the chemical methanation. The difference with the catalytic methanation lies in the temperature ranges used for the reaction and the response time (or deployment time). The biological metabolic processes of bacteria and archaea operate at mesophilic (20-40°C) or thermophilic (45-60°C) temperatures, in contrast to the temperature ranges used in chemical methanation. Regarding the response time Electrochaea states that the system can respond in seconds at smaller scale and within minutes for larger scale plants (due to gas volume inventory). The bacteria used are very capable of staying dormant for weeks or months and react very rapidly when the production process is started. The method for biological methanation is currently developing from research stage (available in test reactors up to 1,000 liters of reactor volume [Schmack, 2012a] to demonstration phase [Electrochaea, 2011].

Besides the pathway whereby methanation is carried out with thermophilic archaea with hydrogen and carbon dioxide, there is a second method which is the same as the last stage in the digestion phase of producing biogas. In a conventional process biogas is produced with about 60% methane and about 35% of carbon dioxide. This existing carbon dioxide can be methanized additionally using a surplus of hydrogen [Hey, 2012].

**Table 5: Characteristics biological methanation**

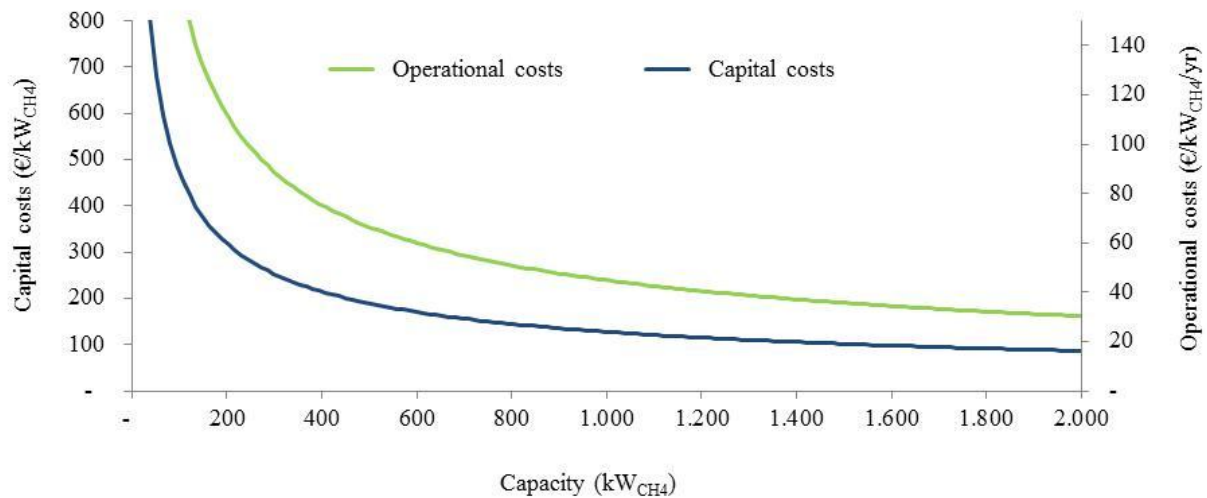
Characteristic	Value	Reference
Delivery pressure (bar)	1 - 3	Krassowski (2012)
Maximum production capacity (MW <sub>CH<sub>4</sub></sub> )	15	Krassowski (2012) & Electrochea (2012)
Maturity	Pre-commercial	Electrochea (2012)
Deployment time*	seconds	Electrochea (2012)
Cold start (from dormancy) time	minutes	Electrochea (2012)
Annual availability	90%	Assumption
Methanation efficiency (excl. electrolysis)	95-100%	Electrochea (2012)
Thermodynamic efficiency	82%	Electrochea (2012)

\*Deployment time from standby modus

The main advantage of biological methanation is that, according to the manufacturers, it is very well capable to respond within seconds in its full power range. Furthermore, its efficiency is very high, the biological process doesn't require a nickel based (or precious metals) catalyst and it is capable of handling traces of H<sub>2</sub>S in the input gas stream, in contrast to chemical methanation. Only impurities with oxygen should be avoided, because the methanogenic microorganisms are strictly anaerobic. An expected disadvantage could be the energy requirements for maintaining a constant temperature of 20-40°C or 45-60°C degrees. These same temperature ranges are used in anaerobic digestion of biological waste and require about 5% of the total energy production capacity.

The challenge for application of biological methanation is to develop fully operational controllable system and to up-scale it to MW scale. The biological methanation efficiency is reported to be over 95% and methane contents were reported to be about 95% (Smack, 2012b). There is very little operational experience with this technology though, so its capabilities should be proven in field practice.





**Figure 14: Capital and operational costs of biological methanation (€<sub>2011</sub>) [Krassowski, 2012]**

The economics shown in Figure 14 are based on Krassowski (2012) who elaborates on the economics of the system. The operational costs are assumed to be 10% of the capital costs per year and consist of 5% heating requirements and 5% miscellaneous [DNV KEMA, 2013]. Electrochaea (2012) expects a quick road to market period, with an introduction of market roll out of >20 MW methanation after 2014. Methanation of hydrogen on microbial pathways has the potential to become an inexpensive, flexible and an alternative to catalytic methanation.

### 3.2 Compressed Air Energy Storage (CAES)

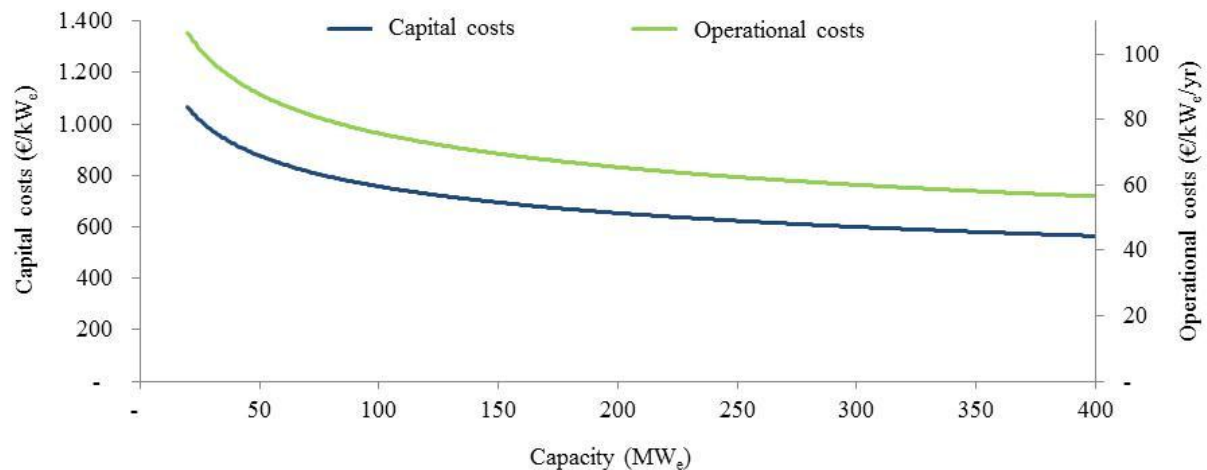
CAES stores electricity mechanically by compressing air and injecting it into underground structures or steel tanks [Hadjipaschalis et al., 2009]. When electricity is required the compressed air is released to drive turbines. During compression heat is produced while during expansion the air cools down and must be re-heated. The way the cooling and reheating is handled characterizes the CAES concept.

#### 3.2.1 Diabatic CAES

The diabatic CAES concept is the combination of natural gas combustion and compressed air to drive the turbines. Such a plant consists of a compressor unit, gas turbine, and underground compressed air storage in aquifers, porous rock sand or large caverns in underground salt domes [Das & McCalley, 2012]. The air is compressed to approximately 50 to 70 bar; the resulting heat is removed. In periods of high electricity demand, natural gas is combusted and heats the compressed air before its expansion in the turbine.

The system is scalable from approximately 5 to 300 MW, based on standard gas turbines. The air expanders are counting for up to 65% of the electrical power production. About 65% to 75% of the electricity input is returned to the grid, but as natural gas is consumed during the discharge, the cycle efficiency of such system is lower [Tønnesen et al., 2010]. The heat removal during air compression and subsequent reheating during expansion results in a relatively low cycle efficiency of 42 % [Burkhardt et al., 2009]. Alternative designs of the cycle comprise the recuperation of exhaust heat

from the turbine to preheat the air before expansion; this results in an improved overall efficiency of up to 54 % [JRC, 2011]. The capital and operational costs reported in literature can be found in Figure 15.

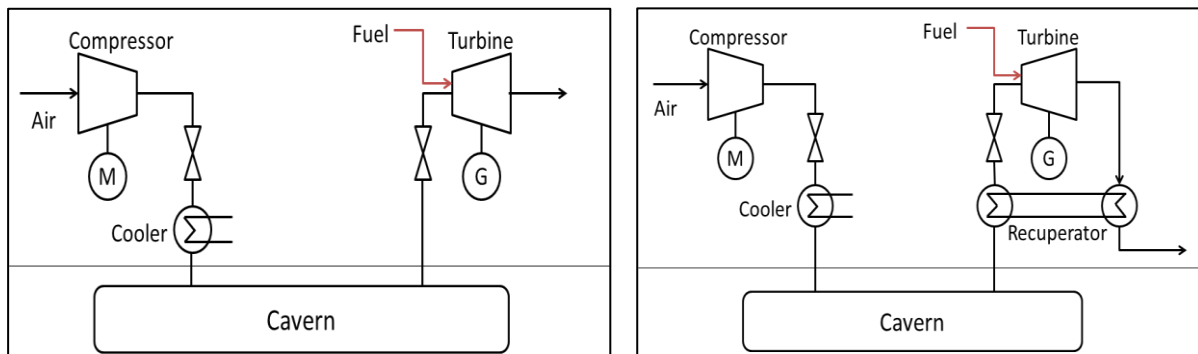


**Figure 15: Capital and operational costs of diabatic CAES [NREL (2012), Wolf et al. (2009), EPRI (2010), JRC (2011)].**

Worldwide there are two diabatic CAES power plants in operation. The first commercial CAES system (290 MW) was built in 1978 in Huntorf (Germany) with the intention to compensate for the fluctuations in electricity demand and allow for a continuous operation of a nearby nuclear power. Further reasons were to guarantee security of supply (the black start up capability of the CAES power plant and its ability to ramp up without power after a power system breakdown) as well as the refining of base load to peak load. In recent years, the operation of the power plant Huntorf has fundamentally changed. Through grid extensions security of supply has improved significantly. While originally only rare inserts were provided, the plant now operates on a daily basis in order to provide for minute reserve capacity [Burkhardt et al., 2009].

A second plant operates since 1991 in McIntosh, Alabama and features a capacity of 110 MW. Various CAES plants have been planned in the meanwhile but none has been constructed yet. This is mainly due to consolidation of the energy suppliers and the extension of the power grid increasing the flexibility in power supply [Burkhardt et al., 2009].





**Figure 16: Diabatic CAES concepts: without heat recovery (left) and with heat recovery (right)**

The advantage of diabatic CAES is the maturity of this technology, the long life expectancy, the large power capacity and the fast ramp up rate compared with gas turbines (after 3 minutes already 50 % of the capacity is available, and after 11 minutes 100% is available). Furthermore almost zero self-discharge takes place and the capital and maintenance costs per unit energy are relatively low.

**Table 6: Characteristics of diabatic CAES plants**

Characteristic	Value	Reference
Typical production capacity (MW)	5 - 300	Chen et al., 2009
Maturity	Commercial	Burkhardt et al., 2009
Deployment time (minutes)	10-14 minutes	NREL, 2012
Efficiency	42-54%	Burkhardt et al., 2009
Cycle lifetime (cycles)	5,000-200,000	JRC, 2011
Life time (yr)	30	IEA-ETSAP & IRENA, 2012
Self-discharge	0	JRC, 2011

However, the economic use of diabatic CAES plants is questionable because of its dependence on natural gas. With only two plants in operation the construction of CAES plants remains a custom undertaking with no clear experience curve [IEA, 2009]. Further drawbacks are the limited availability of sites (underground storage facilities) as well as the relatively low cycle efficiency. That is why the installation of new diabatic CAES plants is uncertain.

### 3.2.2 Adiabatic CAES

In the adiabatic process, there is no need for additional gas co-firing. The required process heat for expansion is obtained from the heat produced during the previous air compression. The ambient air is compressed in several stages to between 52 and 62 bar [Burkhardt et al., 2009]. With the help of a downstream cooler, the air is cooled to 50 °C. The heat is temporarily stored in a solid, fluid or molten salt solutions at temperatures of 50 to more than 600 °C [Bullough et al., 2004].

During unloading, the hot air with a pressure of 41-55 bar is expanded in the turbine which drives the generator. By storing and re-using the heat of compression it is expected to achieve efficiencies up to 70% [Burkhardt et al., 2009]. This concept is still under development; a first pilot and test facility will

be constructed in Germany in 2013. Involved parties are RWE, General Electric, Züblin and DLR. The power plant will have a capacity of about 90 MWe and have a storage capacity of about 360 MWh. RWE will operate the installation on a daily basis for energy balance purposes and providing peak electricity to the spot market [RWE Power, 2011]. The capital costs for adiabatic CAES plants are estimated at 600 - 1200 €/kW [Zach et al., 2012; Burkhardt et al., 2007; Wolf et al., 2009].

**Table 7: Characteristics of adiabatic CAES systems**

Characteristic	Value	Reference
Typical production capacity (MW)	5 - 300	Chen et al., 2009
Maturity	R&D	Burkhardt et al., 2009
Deployment time (minutes)	10-15 minutes	NREL, 2012
Efficiency	70%	Wolf et al, 2009
Cycle lifetime (cycles)	5,000-20,000	JRC, 2011
Life time (yr)	30	IEA-ETSAP & IRENA, 2012
Self-discharge (%/month)	0	JRC, 2011

Adiabatic CAES features the same advantages as diabatic CAES regarding the black start up capabilities, the large storage capacities and the long lifetime expectancy. In contrast to diabatic CAES it does not require any fuel during its operation and therefore has no emissions. Furthermore, the cycle efficiency is much higher with (up to 70%). Minor losses occur during heat storage. However, the heat exchangers and storage facilities cause higher total investment costs.

The adiabatic CAES storage technology is in an advanced stage of design. The process imposes high demands on the individual system components and materials. Until today concepts for the heat storage as well as for compressors operation at very high temperatures have been developed. However, both the heat storage as well as the compressor are not yet commercially available in the required size. The demonstration and commercialization still requires large efforts [Burkhardt et al., 2009] and is not expected before 2020.

### 3.2.3 Isothermal CAES

Isothermal CAES is an advanced adiabatic CAES concept aiming at a continuous heat removal from the air during the compression cycle and heat addition during air expansion. There are currently no commercial isothermal CAES implementations but several possible solutions have been proposed based upon reciprocating machinery. One idea is to spray a liquid (e.g. water) inside a pneumatic cylinder during compression. This provides for a fast heat transfer. After compression the liquid is removed and the heat is passed through a kind of thermal storage medium. A similar process occurs during expansion. When power production is needed the same piston/cylinder system is run in reverse mode using the compressed air as the driving force. According to claims by companies developing isothermal CAES (e.g. Lightsail Energy, SustainX and Oscomp) the round-trip efficiency of this process can be up to 80% [Energy Storage News, 2012].

SustainX is constructing a 1.5MW pilot system in Seabrook, New Hampshire to demonstrate their modular isothermal CAES system. This isothermal CAES system is scheduled for completion in 2013, with another field-deployed CAES system ready for operation by 2014. SustainX is aiming at a commercial production in 2015 [DOE Energy Storage Database, 2012]. The estimated capital costs are approximately 1000-1500 €/kW [EPRI, 2010 & Wolf et al., 2009].

**Table 8: Characteristics of isothermal CAES systems**

Characteristic	Value	Reference
Typical module capacity (kW)	5	Wolf et al., 2009
Maturity	R&D	Wolf et al., 2009
Deployment time	minutes	Wolf et al., 2009
Efficiency	70-80%	Wolf et al., 2009
Cycle lifetime (cycles)	15,000	NREL, 2012
Life time (yr)	30	IEA-ETSAP & IRENA, 2012
Self-discharge (%/Month)	0	JRC, 2011

Another way of isothermally compressing air or gas is the liquid piston technology. The basic operation principle is compressing and expanding air/gas trapped in a storage vessel by adjusting the amount of fluid in the vessel. The operational pressure is 100-250 bar. During loading a piston is energized by a motor which acts as a compressor by accumulating fluid in the vessel. During unloading the compressed gas is expanded and fluid is expelled from the vessels and drives the piston generating electricity. This technology is neither available on a commercial basis yet, nor are any demonstration activities reported [Hadjipaschalis et al., 2009].

The advantage of isothermal CAES in comparison with the other CAES concepts is its scalability and independence from the availability of underground structures. Isothermal CAES can also be used as energy storage on distribution level. However, the storage costs for above-ground CAES are estimated to be five times more expensive than underground salt-based compressed air storage [IEA, 2009].

### 3.3 Pumped Hydro Storage

Pumped Hydro Storage is the most mature and widely used technology for large-scale energy storage accounting for 95% of the currently installed storage capacity. PHS systems typically consist of two reservoirs located at different elevations, a pump and a turbine [IEA-ETSAP & IRENA(2012)]. Through moving water between these reservoirs electricity is either stored as potential energy or, during peak-load periods, the system generates power like a conventional hydropower plant [Hadjipaschalis et al., 2009].

Taking into account the elevation losses, generation losses and losses from water evaporation from the surface, the overall cycle efficiency of PHS is approximately 70–85%. The relatively low energy density of PHS systems requires either very large reservoirs or a large difference in height level [Hadjipaschalis et al., 2009]. This is the main reason for geographical limitations for siting.

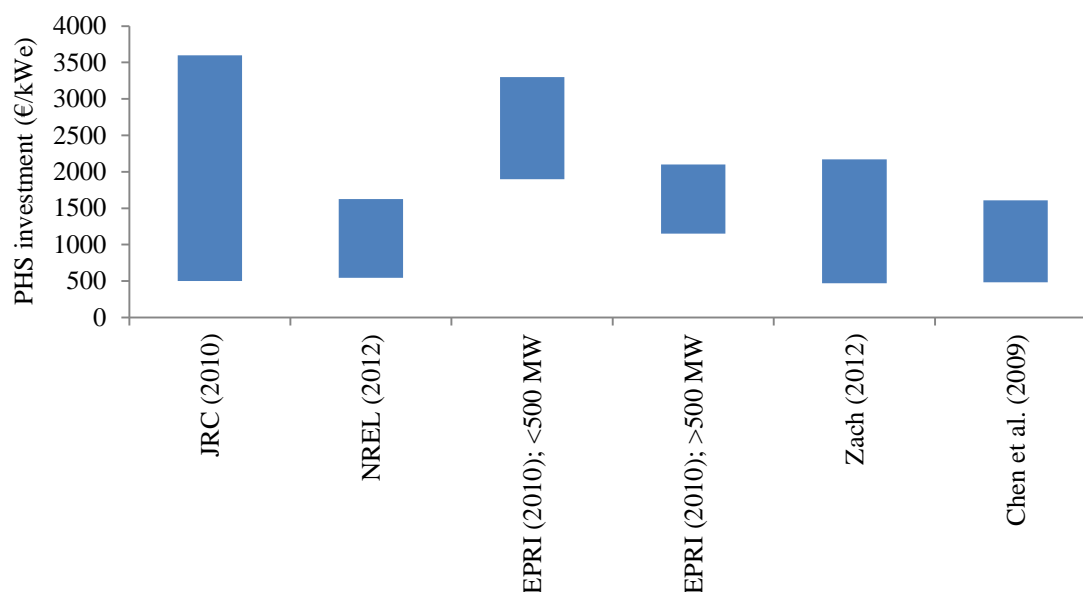
Additionally there is concern about the environmental effects of constructing and operating PHS plants. For area's without required elevation potential and the discussion about environmental effects, concepts for 'energy islands' are being designed and even demonstrated, like e.g. an open coast sea concept in Japan [IEA, 2009] or Plan Lievense in the Netherlands.

**Table 9: Characteristics of Pumped Hydro Storage systems**

Characteristic	Value	Reference
Typical production capacity (MW)	5,000	JRC, 2011
Maturity	Commercial	JRC, 2011
Deployment time	minutes	Chen et al., 2009
Efficiency	70-80%	Chen et al., 2009
Cycle lifetime (cycles)	20,000-50,000	JRC, 2011
Life time (yr)	> 30	IEA-ETSAP & IRENA, 2012
Self-discharge (%/month)	0	JRC, 2011

PHS systems are very flexible and can be used for load shifting, refining off-peak electricity to peak electricity, as spinning or standing reserve, energy balancing and seasonal fluctuations regulation [EPRI, 2010]. The main advantages of PHS systems are the high storage capacity, quick start up capabilities, low self-discharge, long technical life-time of more than 40 years and a high number of cycles. Currently PHS is a cost effective means of storing large amounts of electrical energy. The technology is very reliable and mature, therefore there is no experience curve efficiency expected [IEA, 2009]. However, the initial investment costs are high, the realization phase could be long (especially for obtaining environmental permissions and connection to the grid, long construction time). Furthermore, high capital costs and the geographical limitations are critical factors.

The capital costs for a PHS installation 1,900-3,300 €/kW for installations up to 500 MW and 1,150-2,100 €/kW for installations larger than 500 MW [EPRI, 2010]. Figure 17 shows the PHS capital costs according to different literature sources.



**Figure 17: Capital costs of pumped hydro storage**

### 3.4 Flywheel

Flywheels store energy mechanically as kinetic (rotational) energy by bringing a mass into rotation around an axis [Tønnesen et al, 2010]. The main components of a flywheel storage system are the rotor bearings, the power interface and a containment system that provides a high vacuum environment. During loading, electricity is accelerating the flywheel via an electric motor. The amount of stored energy depends on the rotational velocity and the momentum of inertia; the faster the flywheel spins, the more energy is stored [Hadjipaschalis et al., 2009]. The rotational speed can reach up to 30,000- 50,000 rpm. During discharging, the flywheel rotation drives the generator (electric motor) to produce electricity [IEA-ETSAP & IRENA, 2012].

Formerly, flywheels were mainly constructed of metallic materials however, recently flywheels are often (partially) constructed of fiber composite materials. The efficiency of flywheels is high and typically in the range of 90–95% [Chen et al., 2009]. Flywheels can provide different capacities and time services: they range from a few kW (delivering energy for a few hours) over a few hundred kW (for 15 seconds to minutes' service) to 600–1,200 kW for time service of 10-15 seconds [IEA-ETSAP & IRENA, 2012]. Because of their modular design flywheels can feature any capacity ranging from a few kW to multi-MW utility applications. Flywheels feature an extremely fast response time being less than a second. This property is attractive for ancillary services in the power grid and makes flywheels most suitable for frequency regulation.

At present, commercial flywheels are mostly used to provide back-up power to uninterruptible power systems (UPS), e.g. data centers and medical devices [Tønnesen et al, 2010]. The largest installed system is located in Japan and can supply 160 MW over a period of 30 seconds. Furthermore, applications to mitigate variations of wind power from individual wind turbines and wind farms in

small grids have also been successfully demonstrated [IEA-ETSAP & IRENA, 2012]. Investment costs are approximately 2,970 – 3,500 €/kW [IEA, 2009].

**Table 10: Characteristics of flywheels**

Characteristic	Value	Reference
Specific energy (Wh/kg)	100-130	Castelvecchi, 2007
Maximum production capacity (MW <sub>e</sub> )	160	Tønnesen. et al, 2010
Typical system capacity (kW <sub>e</sub> )	100-250	IEA-ETSAP & IRENA, 2012
Typical system capacity (kWh <sub>e</sub> )	30	DNV KEMA
Maturity	Commercial	IEA-ETSAP & IRENA, 2012
Deployment time (seconds)	4 seconds	Tønnesen et al, 2010
Efficiency	90-95 %	Chen et al., 2009
Cycle lifetime (cycles)	125,000-150,000	Tønnesen. et al, 2010
Life time (yr)	> 20	JRC, 2011
Self-discharge (%/month)	20	Hadjipaschalis et al., 2009

In addition to the high efficiency and fast response time, flywheels need very little maintenance. Flywheels are a very reliable technology that has been successfully demonstrated since 1985. The disadvantage of this energy storage technology is the high self-discharge rates with minimum rate of 20% of the stored capacity per hour making it unsuitable for long-term energy storage. Furthermore, the capital costs are very high [Hadjipaschalis et al., 2009].

### 3.5 Supercapacitors

Supercapacitors (also referred to as electrochemical double layer capacitors or ultra-capacitors) store electrical energy by separating charges [Chen et al., 2009]. Generally, a capacitor consists of two metal plates separated by a non-conducting layer called a dielectric. When one plate is charged with electricity (direct-current), the other plate will have induced in it a charge of the opposite [Hadjipaschalis et al., 2009]. The electrodes of super-capacitors are made from high surface area material such as porous carbon (1000-2000 m<sup>2</sup>/g) with an aqueous or non-aqueous electrolyte. The high electrode surface enables energy storage with high power density (up to 6–8 kW/kg) [IEA-ETSAP & IRENA, 2012]. Investment costs are approximately 1,200 – 2,000 €/kW [IEA, 2009].

Marketed for the first time in 1978 to provide back-up power for computer memory, super-capacitors were then used in a variety of commercial applications, emergency power and energy storage with short charging/discharging times. Due to the short response time and the high power density, super-capacitors can be used for power quality applications as well as for regenerative braking. Super-capacitors can provide effective short duration peak power and short-term peak power back up for UPS applications [Hadjipaschalis et al., 2009]. For applications with renewable power systems, super-capacitors are still under development, often in combination with battery systems: the super-capacitor compensates for short-term power output variations while long-term variations are handled by batteries [IEA-ETSAP & IRENA, 2012].

**Table 11: Characteristics of super-capacitors**

Characteristic	Value	Reference
Specific energy (Wh/kg)	30	Tønnesen.A.E. et al, 2010
Maximum production capacity (MW)	10	Tønnesen.A.E. et al, 2010
Typical module capacity (kW)	100-250	Chen et al., 2009
Maturity	R&D	IEA-ETSAP & IRENA, 2012
Deployment time (seconds)	< 1 second	Tønnesen.A.E. et al, 2010
Efficiency	85-95 %	Tønnesen.A.E. et al, 2010
Cycle lifetime (cycles)	500,000	Hadjipaschalis et al., 2009
Life time (years)	> 20	JRC, 2011
Self-discharge (%/month)	14	Hadjipaschalis et al., 2009

In addition to the high efficiencies of this storage technology, the minimal degradation in deep discharge or overcharge and fast charging velocities, supercapacitors feature long lifetime of hundreds of thousands of cycles.

The limiting factor is the high self-discharge rate of supercapacitors which can reach 14 % of nominal energy per month [Hadjipaschalis et al., 2009]. Small electrochemical capacitors are well developed; large units with energy densities higher than 20 kWh/m<sup>3</sup> are still in the development stage [Chen et al., 2009].

### 3.6 Superconducting magnetic energy storage (SMES)

SMES is the only known technology to store electrical energy directly into electric current. In SMES system electric energy is stored in a magnetic field created by circulating current in coils made from superconducting materials and kept at superconducting temperature [Tønnesen, 2010]. The electrical storage is carried out by passing through an inductor (coil) made from a superconducting material. A SMES system consists of a superconducting coil, a DC/AC converter, a quench protection system and a magnet cooling system [IEA-ETSAP & IRENA, 2012]. SMES has a very high energy storage efficiency (>97%) and a rapid response time of a few milliseconds. This form of energy storage enables fast uptake and discharge capacity for short periods of time. Typical ratings for SMES are 1-10 MW with a low self-discharge time of seconds, as given in Chen et al. (2009).

SMES is still in development before it can be taken into commercial consideration for use in ancillary service [Tønnesen et al. (2010)]. As disadvantage for this technique, Chen et al. (2009) describes the high cost and environmental issues associated with strong magnetic field as the major issues for the implementation of SMES units.

### 3.7 Batteries

Batteries store electricity electrochemically through a reversible chemical reaction. The basic components are the container, the electrodes (cathode and anode) and the electrolyte. By loading the



battery, the electricity is transformed into chemical energy, while during discharge, electrochemical reactions occur at the two electrodes generating a flow of electrons through an external circuit [JRC, 2011]. In this paragraph the investment costs of the batteries are described. The operational and maintenance costs (excl. electricity) is for all batteries in the range between 1% – 5% of the investment costs per year [DNV KEMA].

### 3.7.1 Conventional Batteries

#### 3.7.1.1 Pb- acid

The most widely applied technology for electrochemical electricity storage is the lead-acid (Pb-acid) battery technology. This type of battery is characterized by the creation and breaking of chemical bonds when the ions move between anode and cathode side. In charged state the battery consists of lead metal and lead oxide electrodes in an electrolyte solution of sulphuric acid (app. 37%) and water. During discharge the electrodes react to form lead sulfate consuming the sulphuric acid dissolved in the electrolyte [Chen et al., 2009].

**Table 12: Characteristics of lead acid batteries**

Characteristic	Value	Reference
Specific energy (Wh/kg)	30-50	JRC, 2011
Typical module capacity (kW)	1-50,000	JRC, 2011
Maturity	Commercial	JRC, 2011
Deployment time (seconds)	10 seconds	Black & Veatch, 2012
Charge time (min)	120-360	DNV KEMA
Efficiency	70-85%	Chen et al., 2009
Cycle lifetime (cycles)	500-1,000	Chen et al., 2009
Discharge level	80%	Sauer et al., 2007
Life time (yr)	4-8	Chen et al., 2009
Self-discharge (%/month)	2	Chen et al., 2009

The main advantage of this type of batteries is the great operational experience for over 130 years and its reliability. It is specifically popular for interruptible power supply, power quality and spinning reserve applications [Chen et al., 2009]. About 70% of the lead-acid batteries are applied in vehicles, about 20% for communication purposes and 10% for other purposes [Beaudin et al., 2010].

The major drawbacks are the short cycle life, high maintenance requirements, poor cold temperature performance and its safety characteristics (emission of explosive gas and acid fumes) [Beaudin et al., 2010]. Furthermore, there are restrictions regarding the capacity use: in order to prevent rapid degradation the capacity should be used at 75-80% [Chen et al., 2009]. This makes them unsuitable for applications where complete discharge may occur.



### 3.7.1.2 Nickel based batteries

The nickel-based batteries are mainly the nickel–cadmium (NiCd), the nickel–metal hydride (NiMH) and the nickel–zinc (NiZn) batteries; the most widely used for the applications studied in this study is the NiCd battery. All three types of Ni-batteries use the same material for the positive electrode and the electrolyte (nickel hydroxide and an aqueous solution of potassium hydroxide). The material for the negative electrode differs: the NiCd type uses cadmium hydroxide, the NiMH uses a metal alloy and the NiZn uses zinc hydroxide [Hadjipaschalis et al., 2009].

Generally, the NiCd battery is the only one of the three types of nickel-based batteries that is commercially used for industrial applications such as in large energy storage for renewable energy systems. NiCd batteries score best in terms of typical operational life and cycle life. The capital costs for NiCd batteries are in the range of 250-1,000 €/kW [JRC, 2011]. NiMH could be an interesting alternative, however the development of other new batteries like Li-ion is more promising and happens faster, resulting in NiMH getting great competition for service applications stated in this report. Therefore NiZn and NiMH are not considered in this study. Only NiCd systems are further being considered, as these systems are already on the market.

**Table 13: Characteristics of Nickel Cadmium batteries**

Characteristic	Value	Reference
Specific energy (Wh/kg)	50-80	Hadjipaschalis et al., 2009
Maximum production capacity (MW)	50	JRC, 2011
Typical module capacity (kW)	1 – 40,000	JRC, 2011
Maturity	Commercial	JRC, 2011
Deployment time	seconds	JRC, 2011
Charge time (hours)	1 – 4	DNV KEMA
Efficiency	60-91 %	JRC, 2011
Cycle lifetime (cycles)	1,500-3,000	Hadjipaschalis et al., 2009
Discharge level	80%	Sauer et al., 2007
Life time (yr)	20	JRC, 2011
Self-discharge (%/month)	6-18	DNV KEMA

NiCd batteries have an efficiency of 60-91 %, depending on the type of technology used during manufacture. Besides, NiCd batteries feature a robust reliability and very low maintenance requirements but relatively low cycle life (1,500 - 3,000 cycles). These advantages over lead acid batteries favor their application for power tools, portable devices, emergency lighting, uninterruptable power supply, spinning reserve and generator starting [Hadjipaschalis et al., 2009].

Despite the above advantages of the NiCd batteries over the lead–acid batteries, NiCd and the rest of the nickel-based batteries have several disadvantages compared to the lead–acid batteries. Self-discharge rates for an advanced NiCd battery are much higher than those for a lead–acid battery because they can reach more than 10% of rated capacity per month [Hadjipaschalis et al., 2009]. On top of that, the energy efficiencies for the nickel batteries are lower than for the lead–acid batteries.

But the main drawback of NiCd batteries is the relatively expensive manufacturing process. NiCd batteries also suffer from “memory effect” when deep discharge occurred repeatedly. Finally, cadmium is a toxic heavy metal hence posing issues associated with the disposal of NiCd batteries [Chen et al., 2009].

### 3.7.2 Sodium Sulphur (NaS)

A sodium sulphur (NaS) battery consists of liquid (molten) sulphur at the positive electrode and liquid (molten) sodium at the negative electrode separated by a solid alumina ceramic electrolyte. The electrolyte is selective to the positive sodium ions. When discharging, positive sodium ions flow through the electrolyte while the electrons flow in the external circuit of the battery, producing an electrical potential difference (voltage). This process is reversible as charging causes sodium polysulphides to release the positive sodium ions back through the electrolyte to recombine to elemental sodium [Chen et al., 2009]. The capital costs amount to 1,420-2,500 €/kW [NREL, 2012].

**Table 14: Characteristics of sodium sulphur batteries**

Characteristic	Value	Reference
Specific energy (Wh/kg)	150-240	JRC, 2011
Maximum production capacity (MW)	50	Chen et al., 2009
Typical module capacity (kW)	500-50,000	JRC, 2011
Maturity	Pre-commercial	JRC, 2011
Deployment time	seconds	JRC, 2011
Charge time (hours)	4 -8	DNV KEMA
Efficiency	85-92%	Chen et al., 2009
Cycle lifetime (cycles)	2,500-4,500	JRC, 2011
Discharge level	100%	Sauer et al., 2007
Life time (yr)	10-15	JRC, 2011
Self-discharge (%/month)	100	JRC, 2011

Typically these batteries operate in a temperature range of 300 to 350 °C. Once running, the process heat produced during charging and discharging is enough to maintain operating temperatures. NaS batteries are highly energy efficient (85 - 92%) and are made from inexpensive and non-toxic materials. However, the high operating temperatures and the highly corrosive nature of sodium make them unsuitable for small-scale applications.

NaS batteries are currently used in electricity grid related applications such as peak shaving and improving power quality [Hadjipaschalis et al., 2009]. This type of batteries seem to be promising for supporting intermittent renewable energy sources (peak shaving) because they can operate in the MW scale and have the appropriate characteristics for load follow and for storage for about 7 hours at rated capacity. Its main disadvantage is the lack of operational experience and the currently high investment costs.

### 3.7.3 Lithium ion

Lithium-ion batteries are made up from cathodes of lithium metal oxide (e.g.  $\text{LiCoO}_2$ ,  $\text{LiMO}_2$ ,  $\text{LiNiO}_2$  etc.) and anodes of graphitic carbon. The electrolyte consists of lithium salts (such as  $\text{LiPF}_6$ ) dissolved in organic carbonates. Charging the battery causes the lithium atoms in the cathode to become ions and migrate towards the anode through the electrolyte. There they combine with external electrons and are deposited between the carbon layers as lithium atoms. This process is reversed during the discharge process [Chen et al., 2009]. Literature reports 300 - 2,300 €/kW for capital costs [IEA-ETSAP & IRENA, 2012].

**Table 15: Characteristics of Lithium ion batteries**

Characteristic	Value	Reference
Specific energy (Wh/kg)	200	Chen et al. 2009
Typical module capacity (kW)	1-1000	IEA-ETSAP & IRENA, 2012
Maturity	Pre-commercial	IEA-ETSAP & IRENA, 2012
Deployment time	seconds	JRC, 2011
Charge time (min)	15-60	DNV KEMA
Efficiency	90-95 %	JRC, 2011
Cycle lifetime (cycles)	10,000	JRC, 2011
Discharge level	80 %	Sauer et al., 2007
Life time (yr)	8-15	IEA-ETSAP & IRENA, 2012
Self-discharge (%/month)	5	Hadjipaschalis et al., 2009

Li-ion batteries feature very high energy efficiency (90%), high energy density, fast charging, long durability and light weight. Self-discharge rate is very low at a maximum of 5% per month. Battery lifetime can reach more than 10,000 cycles.

They are typically used for small scale applications (portable devices), PV support and vehicles. In order to become suitable for large-scale application in power generation, Li-ion batteries need to improve regarding their manufacturing costs, power size, capacity and safety (especially abnormal heating due to overcharging is an issue) [IEA-ETSAP & IRENA, 2012]. Furthermore, the lifetime of a lithium-ion battery is sensitive to high temperatures and deep discharges; both can severely increase aging of the battery [Hadjipaschalis et al., 2009].

### 3.7.4 Flow battery

A flow battery is a form of a battery in which the electrolyte flows through a power cell in which the chemical energy is converted to electricity. In contrast to conventional batteries flow batteries store energy in the electrolyte solutions [Chen et al., 2009].

#### 3.7.4.1 VRB

Vanadium Redox flow Batteries (VRB) make use of the ability of vanadium to exist at four different oxidation levels. The so-called vanadium redox couples ( $\text{V}^{2+}/\text{V}^{3+}$  on the negative side and  $\text{V}^{4+}/\text{V}^{5+}$  on the positive side) are diluted in an aqueous sulphuric acid solution. During the charging and

discharging protons are exchanged between the two electrolytes through a hydrogen-ion permeable membrane. The two electrolytes are circulated by pumps. The energy efficiency can reach 85% [Chen et al., 2009].

VRBs are suitable for a wide range of stationary energy storage applications including enhanced power quality, UPS, peak shaving, increased security of supply and integration with renewable energy systems. The capital costs found in literature range between 2,300 and 3,100 €/kW [IEA-ETSAP & IRENA, 2012; JRC, 2011]

**Table 16: Characteristics of Vanadium Redox flow Batteries**

Characteristic	Value	Reference
Specific energy (Wh/kg)	15-70	Mahnke et al., 2012
Typical module capacity (kW)	50-10,000	IEA-ETSAP & IRENA, 2012
Maturity	Pre-commercial	IEA-ETSAP & IRENA, 2012
Deployment time	milliseconds	JRC, 2011
Efficiency	70-85%	DNV KEMA
Cycle lifetime	13,000	AzRISE, 2010
Discharge level	100%	Sauer et al., 2007
Life time (yr)	20	JRC, 2011
Self-discharge (%/month)	0	Mahnke et al., 2012

VRB batteries are in an early phase of commercialization. The global installed capacity of VRB batteries is estimated at a few tens of MW, ranging from a kW to a MW scale. The large capacity potential makes them well-suited to support wind power electricity generation [IEA-ETSAP & IRENA, 2012]. Research focuses on increased energy density, improved membrane performance, new stack design and cost reduction. For VRB in particular, the replacement of vanadium media with vanadium bromide, the so-called second generation of VRB flow batteries, allowed to increase the energy density and to find further applications in mobile devices [EERA, 2011].

#### 3.7.4.2 Zinc Bromine

An alternative flow battery concept is the Zn/Br flow battery. Each cell of a ZnBr battery consists of two compartments separated by a polyolefin membrane and an electrode made up from carbon-plastic composites; each compartment contains a different electrolyte. During discharge, Zn and Br combine into zinc bromide. During charge, zinc will be deposited as a thin film in the anode and bromine evolves as a dilute solution in the cathode compartment. The net efficiency of this battery is about 75% [Chen et al., 2009] and the capital costs in the range of 1,120-2,400 €/kW [EPRI, 2010].

**Table 17: Characteristics of Zinc-Bromine batteries**

Characteristic	Value	Reference
Specific energy (Wh/kg)	60-80	JRC, 2011
Typical module capacity (kW)	40-2,000	IEA, 2010
Maturity	Pre-commercial	Chen et al., 2009
Deployment time	milliseconds	JRC, 2011
Efficiency	70-75%	JRC, 2011
Cycle lifetime (cycles)	4,000-5,000	Sauer et al., 2007
Discharge level	100 %	Sauer et al., 2007
Life time (yr)	20	IEA, 2010
Self-discharge (%/month)	0	Sauer et al., 2007

Over the years, several ZnBr batteries have been built and tested up to a capacity of 1 MW. Suppliers offer commercial modular units with a storage capacity of 50 kWh and 500 kWh [IEA-ETSAP & IRENA, 2012].

## 4 COMPARISON OF TECHNOLOGIES

In this chapter a summary is presented from the technology review provided in Chapter 3, of which all data is summarized in Table 18. Resulting from Table 18 all technologies are benchmarked against each other in Figure 18 in terms of costs, state of development and average efficiency. Following, the technologies are classified according to the IES<sup>6</sup> integration system requirements of different services applications as presented in Table 1. This classification enables us to conclude in Chapter 5 which technologies should be compared in ECN dynamic systems analysis.

### *Technology maturity*

Table 18 shows that a large share of these technologies is currently in a commercial or pre-commercial stage of development. However, only alkaline electrolysis, chemical methanation, pumped hydro storage, lead-acid batteries, nickel cadmium batteries and flywheels are being widely applied. Biological methanation, diabatic CAES, li-ion batteries, NaS batteries, NiMH batteries and flow batteries are commercially available or in an early commercial stage but gained very little operational experience in kW or MW scale storage yet. PEM electrolysis is commercially available for small units (<50 kW) but in development stage for large systems. Isothermal and adiabatic CAES, supercapacitors and SMES are currently in R&D stage.

### *Storage capacity of power-to-gas*

Regarding the storage capacity of PtG technologies the entire Dutch gas infrastructure has been considered as storage medium. The total energy storage capacity of the Dutch gas infrastructure is 552 TWh, including the salt cavern potential and other natural gas storage facilities. The storage capacity in the Dutch gas infrastructure for hydrogen is found to be about 0.83 TWh's, which results from the future (2021) Dutch gas injection specifications for hydrogen of 0.5 mol%<sup>7</sup>. At this moment the hydrogen limit is even lower, 0.02 vol%. Please consult Appendix A for additional information about the addition of hydrogen to the natural gas infrastructure.

### *Power-to-gas & Gas-to-power*

For the PtG technologies Figure 18 also gives insight in the additional costs and efficiency losses for GtP conversion, either by fuel cells (with an efficiency of 56%, after McKinsey (2010)) or by conventional gas turbine power plants (based on 36% conversion). However, it should be noted that PtG preferably should not be applied solely for electricity storage applications but a synergy should be found with hydrogen or methane demand in the gas sector, chemical industry or mobility sector.

<sup>6</sup> IES = Intermittent energy sources

<sup>7</sup> 0.5 mol% equals 0.5 vol%

### *Technology economics*

The economics of PtG and electricity storage technologies is only relevant when considering the amount of cycles that the technology is able to last in relation to the amount of cycles needed, because this determines its specific costs (e.g. €/MWh's) and its lifetime. Case specific analysis should determine the amount of cycles requested and the suitable technologies in that case. According to Figure 18 the cost range of the technologies mutually differs and can be quite large. Solely focusing on investment costs the largest variations can be found for pumped hydro storage, lithium-ion batteries and VRB batteries. For PHS this can be explained by the dependence on location specific characteristics. Li-ion and VRB batteries are in development stage and therefore different data is reported about these technologies.



**Table 18: Technical features of energy storage technologies**

	Electrolysis		Methanation		CAES			PHS	Flywheel	Supercap	Batteries						SMES
	Alkaline	PEM	Chemical	Biological	Diabatic	Isothermal	Adiabatic				Lead-acid	NaS	NiCd	Li-ion	VRB	ZnBr	
Storage power per system (MW)	7	2	<500	12	5-300	Un-known	5-300	250-1500	10-160	10	0.2-20	<35	50	0.05-5	4	2	0,5
Storage capacity per system	0.83 TWh <sup>1</sup>		552 TWh <sup>2</sup>		1.1-2.7 GWh	Un-known	0.2 – 10 GWh	1.6 – 14 GWh	0.03 MWh	Un-known	250 MWh	300 MWh	100 MWh	24 MWh	250 MWh	5-250 MWh	Un-known
Efficiency (%)	62-82	67-93	70-85 <sup>5</sup>	95-100 <sup>5</sup>	42-54	70-80	70	70-80	90-95	85-95	70-85	85-92	60-91	90-95	70-85	70-75	90-99
Discharge time (h)	24+		24+		2-24	4	3-10	4-10	0.4	0.008	3.2-10	4	2	1-4	5	10	sec - min
Minimum load (%)	10-40	0-10	0	0	50	Un-known	Un-known	33	0	0	0	0	0	0	0	0	0
Lifetime (cycles*1000)	90,000 hrs	60,000 hrs	24,000 hrs <sup>4</sup>	Un-known	5-200	15	5-200	20-50	125-150	500	0.5-1	2.5-4.5	1.5-3	10	13	4-5	100
Deployment time	<10 sec	<10 sec	5 min	<10 sec	10 min	1 min	4 min	2 min	4 sec	<1sec	10 sec	sec	sec	sec	millisec	millisec	millisec
Cold start time	minutes	minutes	hrs	minutes	10 min	Un-known	Un-known	minutes	4 sec	<1sec	10 sec	sec	sec	sec	millisec	millisec	millisec
Maturity <sup>3</sup>	Com	PC	Com	PC	Com	R&D	R&D	Com	Com	R&D	Com	PC	Com	PC	PC	PC	R&D

<sup>1</sup> Hydrogen storage capacity based on maximum allowable hydrogen fraction in the natural gas grid in 2021 (0.5 mol%)

<sup>2</sup> Methane storage capacity based on the capacity of the Dutch gas infrastructure, including salt caverns and current natural gas storage facility potentials.

<sup>3</sup> Com = commercially available; PC = pre-commercial (or demonstration) stage; R&D = Research and development stage.

<sup>4</sup> Life time of chemical methanation based on life time of catalyst (in appropriate operational circumstances)

<sup>5</sup> Methanation efficiency. Does not include electrolysis efficiency.

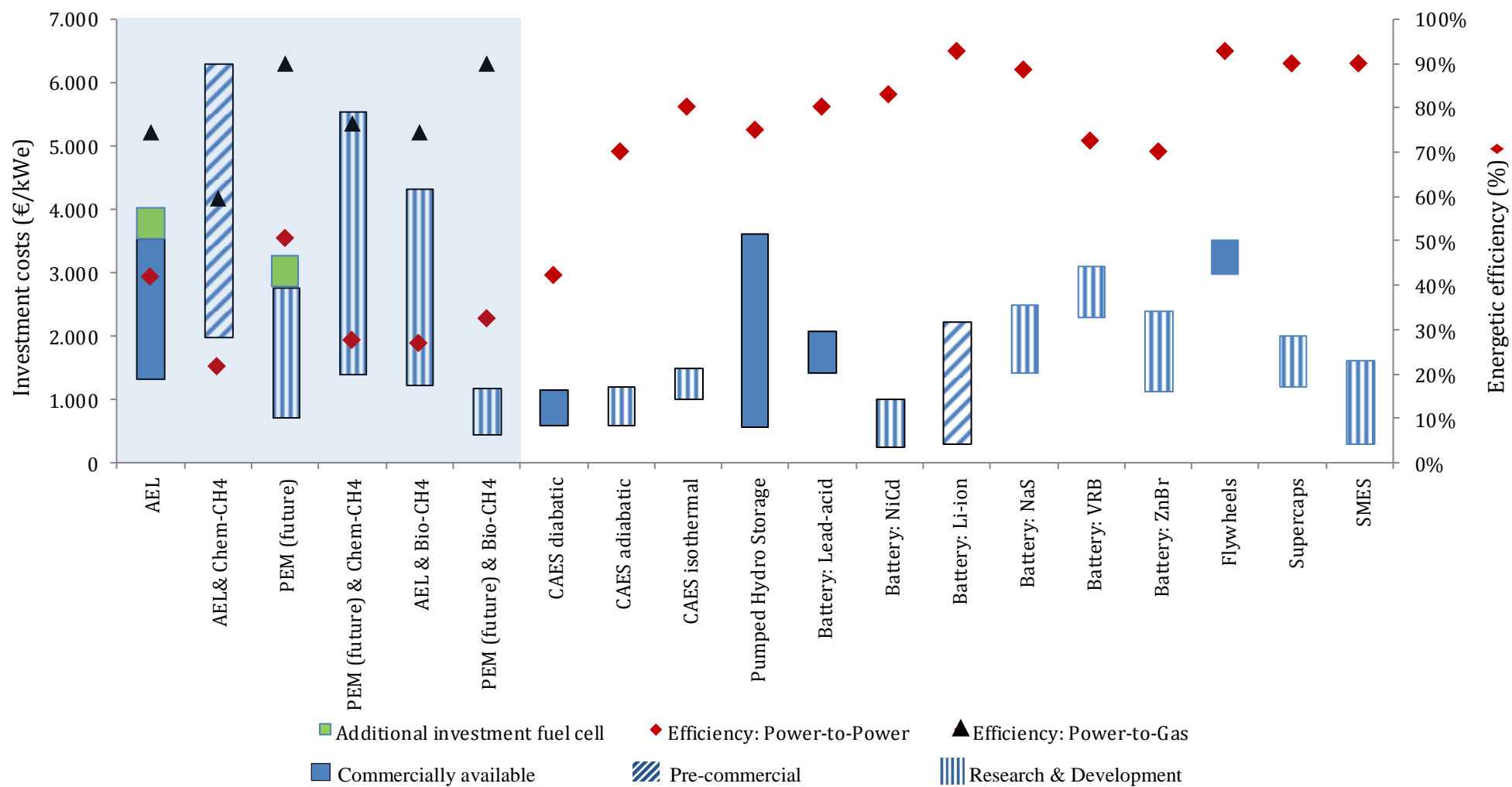


Figure 18: Visual graphic technical features: investment costs, stage of development and efficiency.

Following from Table 18 and Figure 18 the technologies are benchmarked in terms of intermittent energy sources integration service applications in Table 19.

**Table 19: Classification of technologies according to IES<sup>8</sup> system requirements.**

	Frequency support	UPS	HES	CES	Forecast hedging		Time shifting / load leveling		T&D cap. management	
Action** required	Uptake & discharge	Discharge	Uptake & discharge	Uptake & discharge	Uptake & discharge		Uptake & discharge		Uptake & discharge	
Storage unit power (MW)	1 - 50	50 kW – 1 MW	5 -100 kW	50 kW-1 MW	2 - 50	50 - 200	2 – 50	50 - 200	2 – 50	50 – 2,000
Equivalent full power discharge duration	<30 minutes	<8 hours	1-8 hours	1-8 hours	< 3 hours		5 – 12 hours			
Energy discharge per event (MWh)	0.2 – 25	0.01 – 8	1-10 kWh	10-100 kWh	6 MWh – 24 GWh					
Number of events	10x/day	< 2x/month	~1x/day	~3x/day	~3x/day		~3x/day		~3x/day	
System response time	<1 second	<1 second	<1 minute	<1 minute	<1 minute		<15 minutes		<15 minutes	
Suitable technology	Flywheels NiCd Li-ion NaS Supercaps SMES VRB ZnBr	NiCd Li-ion NaS VRB ZnBr	Alkaline* PEM* Lead-acid NiCd Li-ion NaS VRB ZnBr	Alkaline* PEM* Bio-CH <sub>4</sub> * Lead-acid NiCd Li-ion NaS VRB ZnBr	Lead-acid NiCd Li-ion NaS VRB ZnBr	Alkaline* PEM* Bio-CH <sub>4</sub> * PHS CAES*	Alkaline PEM Bio-CH <sub>4</sub> Chem-CH <sub>4</sub> * Lead-acid NaS VRB ZnBr	Alkaline PEM Bio-CH <sub>4</sub> Chem-CH <sub>4</sub> * Lead-acid NaS PHS CAES	Alkaline PEM Bio-CH <sub>4</sub> Chem-CH <sub>4</sub> * Lead-acid NaS VRB ZnBr	Alkaline PEM Bio-CH <sub>4</sub> Chem-CH <sub>4</sub> * PHS CAES

\*From standby modus (hot start) only. Technologies that are not market with \* can also respond from cold start within the response requirement.

\*\* For power-to-gas technologies the discharge of power inevitably involves gas-to-power for conversion into electricity again.

<sup>8</sup> IES = Intermittent energy sources

Power-to-gas technologies do not appear in the column of forecast hedging service requirements, because this service particularly focusses on the discharge of power, could be provided by conventional gas turbines or fuel cell technology. However, PtG can undoubtedly play an important role in production of renewable gas for this service. Solid Oxide Electrolysis doesn't appear at all in Table 19 because its response time is more than 15 minutes, even from standby modus.

Resulting from the classification of technologies according to the IES integration service applications, the most relevant PtG technologies are alkaline electrolysis (particularly because it is commercially available), PEM electrolysis, biological methanation and chemical methanation. These technologies should be assessed against the following alternatives: batteries, CAES, PHS and SMES. Flywheels and supercaps deliver different integration services and are therefore irrelevant to compare to PtG technologies.

With conventional CAES and PHS there are some major drawbacks, in advantage of PtG technologies and batteries, i.e. they are indispensably coupled to specific locations and the constraints that are accompanied with that (excluding isothermal CAES, which is in early R&D stage).

## 5 CONCLUSIONS FOR POWER-TO-GAS

This report provides detailed data of various technologies that facilitate the integration of renewable power sources into the existing energy system, with a specific focus on power-to-gas technology (electrolysis and methanation).

### *The future role of power to gas*

Power-to-gas technology is emphatically distinctive from power storage technologies due to its capability of resolving issues resulting from the integration of renewable energy sources in the existing energy system, such as supply/demand imbalance and transportation issues, by conversion of power into a valuable energy carrier that can be applied in different sectors, i.e. the chemical industry, the mobility sector, the gas sector (e.g. for domestic heating) or back into the power sector (by gas-to-power technology). By doing so, facilitating the integration of renewables (by solving problems in the power sector) can contribute to renewable energy targets or emission reduction targets in other sectors.

### *Service applications supporting the integration of intermittent energy sources*

There is a clear distinction between the integration of wind power and solar power in the energy system and the accompanying effects. Referring to the national targets for wind power, the flexibility needs for supporting wind integration will mainly affect the power transmission system. In contrast, the integration of solar-pv will mainly affect operation of the power distribution system, since solar power will be installed more distributed.

Analyzing the role of power-to-gas in terms of intermittent energy sources integration services it can be concluded that the value of power-to-gas is in its capabilities to deliver ‘community energy storage’ (distribution scale) services, ‘time shifting / load leveling’ (distribution & transmission scale) services and ‘transmission & distribution capacity management’ (transmission & distribution scale) services. Power-to-gas is found to be unable to deliver ‘frequency support’, ‘uninterruptable power supply’ and ‘forecast hedging’ services, because these services require technologies that can instantly be deployed to deliver electrical power for short periods of time, which is not the habitat of power-to-gas technologies. However, these services can be delivered by gas-to-power.

Based on the typical sizes and specifications of the different technologies, it seems reasonable that power-to-gas will be used in systems with a typical size >100 kW and is therefore less suitable in ‘home energy systems’. Although it is technically possible to apply for that service, the business case seems to be better for battery systems on such scale.

### *Benchmarking power-to-gas*

When specifically considering power-to-gas for electricity storage, it can best be compared to sodium sulphur batteries and NiCd batteries, based on power capacity, storage capacity, responsive characteristics and investment costs. It should be noted though that the cycle efficiency of sodium sulphur batteries is higher. Other storage technologies that are potential alternatives (based on some characteristics) are lead-acid, lithium-ion, VRB and ZnBr batteries. Also compressed air energy storage and pumped hydro storage have similar characteristics, however, they are emphatically

dependent on geographical constraints like e.g. salt caverns for compressed air energy storage and mountain areas for pumped hydro storage. Because power-to-gas and batteries can be deployed almost limitless in terms of geographical constraints, they cannot be generically compared to compressed air energy storage and pumped hydro storage. A site specific assessment is always required in order to determine the appropriate technology to solve the issue at stake. SMES is in R&D stage and not suitable for larger systems. Flywheels and supercaps deliver different integration services and are therefore irrelevant to compare to PtG technologies.

#### *Electrolysis and methanation*

Alkaline electrolysis is commercially available technology. There is still large potential for optimization of the performance of this technology. Especially in terms of its responsive characters alkaline electrolysis can successfully be optimized to satisfy the flexibility requirements that come with the integration of renewables. Just like proton exchange membrane (PEM) electrolysis, alkaline electrolysis is capable of ramping within seconds (when operating in standby modus). However, the large difference between the technologies is in the cold start capabilities. PEM is perceived to be able (in the future) to start from cold conditions and directly ramp to nominal or even 300% of max capacity. Based on cost estimations and response time (including cold start) capabilities PEM electrolysis seems to have a better perspective for the future. However, at this moment alkaline electrolysis can sufficiently satisfy the flexibility needs and is an essential building block in the development of power-to-gas.

The implementability of power-to-gas can be enhanced by methanation of hydrogen and carbon dioxide. Chemical methanation is very well known, widely applied in coal gas (syngas) methanation processes and commercially available for large scale plants. However, it has always been applied for continuous performance and has not been designed for flexible operation (both ramp rate as well as cold start capabilities). Neither there has been a demand for small scale installations. Resulting, currently chemical methanation units are not very flexible and are not commercially available for the capacity range up to 20 MW. Biological methanation seems to be very promising in terms of flexible operation, conversion efficiency and investment costs but this technology is in its R&D stage and the operational experience in field practice is almost zero.

#### *Concluding remarks*

The following phase in this systems analysis study, being the dynamic modeling exercise of ECN, should determine the value of power-to-gas in relation to other sectors like the chemical industry or mobility sector and conclude on the most viable role in the energy system.

Subsequent TKI research and power-to-gas demonstration projects should be focused on the business case of power-to-gas, considering cross sectorial benefits. Stimulating the industry to consider power-to-gas in the integration of intermittent sources potentially results in a 2 to 3 fold decrease in investment costs, resulting from a growing market for electrolysis and methanation.

## 6 FURTHER CONSIDERATIONS

### *Seasonal storage of energy*

Considering its characteristics, power-to-gas is expected to have specific value as technological concept for seasonal storage of energy. Mainly solar power that has been produced during summer time can be stored in the gas infrastructure (with a total storage capacity of 552 TWh's) and utilized in gaseous form during winter times for domestic heating. Considering seasonal energy storage in relation to renewable sources is a promising concept based on its characteristics but not yet considered to be relevant for the near future because the prospected renewable power penetration does not yet advocate for such storage periods. When aiming for a 100% renewable energy system or carbon neutral energy supply, power-to-gas could very well be one of the essential technologies to deliver seasonal energy storage services.

### *Important aspects to consider in the PtG business case.*

In addition to the production of hydrogen, water electrolysis deposits oxygen. Oxygen is applied in numerous sectors, like for instance in refineries, the chemical sector and the biological and medical sector. In these sectors oxygen has different economic values and therefor represents a certain economic value in the power-to-gas value chain. When assessing the business case for power-to-gas, this gas stream should be considered.

Comparable benefits exist for chemical methanation, resulting from the strongly exothermic character of the Sabatier process. When hydrogenating CO<sub>2</sub> a constant thermal energy deposit is being produced, in the form of approximately 300 °C steam. This thermal energy is of particular interest for industrial appliances, in high temperature electrolysis or for district heating purposes.

The business case for PtG might strongly be affected by the market price for carbon dioxide, especially when considering the use of CO<sub>2</sub> in the methanation process. However, it should be noted that the emission trading system (ETS) has not yet resulted in a reliable CO<sub>2</sub> market that encourages investors to act.



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## APPENDIX A: ALLOWABLE HYDROGEN FRACTION

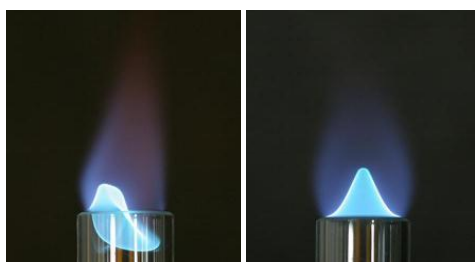
The maximum allowable hydrogen fraction in the natural gas grid is needed in order to calculate the hydrogen storage potential. The maximum allowable hydrogen fraction differs for the different gas grids in The Netherlands.

Addition of hydrogen to natural gas changes the combustion properties of natural gas and its presence might thus cause unwanted effects in end-use equipment. Moreover, hydrogen addition to natural gas can have a negative effect on the integrity of the natural gas grid. As a result, the allowable fraction of hydrogen in natural gas is limited.

Addition of hydrogen to natural gas results in a reduction of the Wobbe Index of the gas. The Wobbe index is important since it is a measure for the thermal load of the fuel. A hydrogen fraction of about 25% is allowed for high caloric gas when hydrogen is added to natural gas with a Wobbe index equal to the upper index. A hydrogen fraction of 0% is allowed for high caloric gas with a Wobbe index equal to the lower index. The Wobbe index in the gas grid varies between the upper and lower index, depending on the quality of the gas. The Wobbe index always has to be between the lower and upper limit. The same principle counts for low caloric gas, only the allowed fraction is lower (about 0-10%). In addition there are other combustion properties that are affected when hydrogen is added. For example, hydrogen increases the combustion rate and therefore increases the risk of (flame) flash back (figure 19) in appliances with burners (domestic appliances, turbines etc.), so the flame stability decreases when increasing the fraction of hydrogen.

Also engines are sensitive to hydrogen; an increase in the hydrogen fraction promotes spontaneous ignition of the unburned mixture in the gas cylinder, called engine knock. Engine knock can cause severe damage to the engine and thus should be avoided.

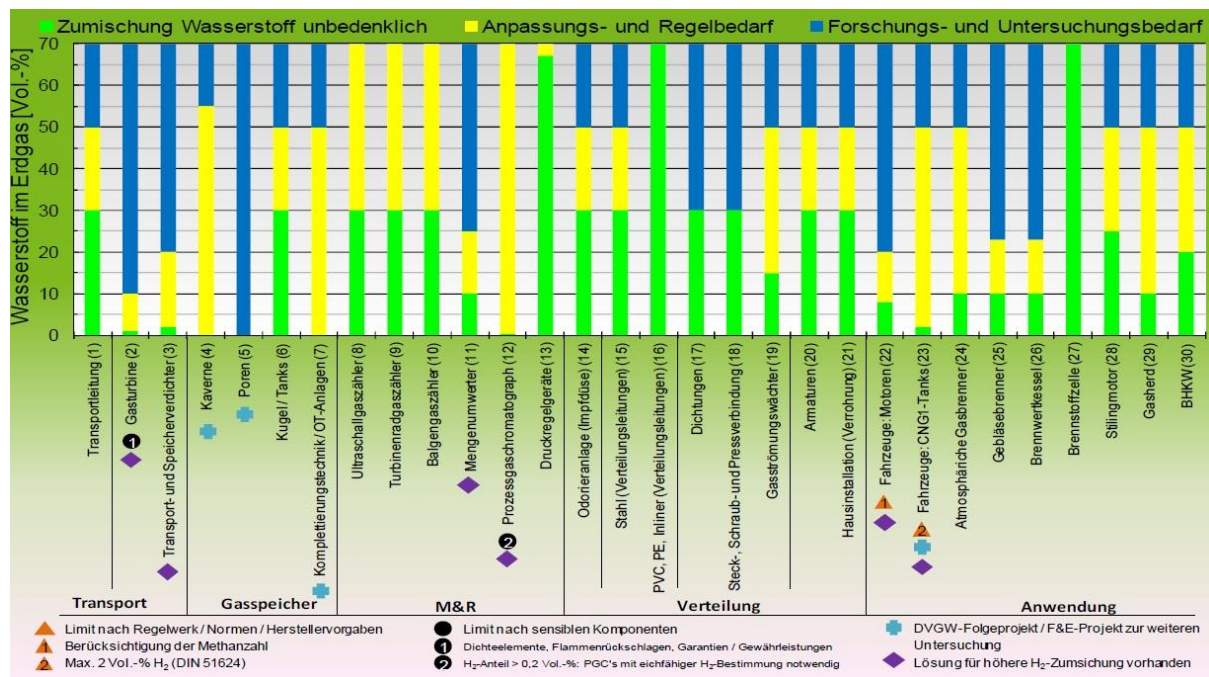
DNV KEMA developed gas interchangeability methodologies to determine the maximum amount of hydrogen that can be added to natural.



**Figure 19: The Flame stability of natural gas with a 5 vol% hydrogen fraction on the left and the flame stability of normal Dutch natural gas on the right (Sloterdijk & Gersen, 2012).**

Other problems related to adding hydrogen are: problems with gas turbines, storage problems, leakage problems and problems related to the use of gas as a feedstock in industrial processes.

Muller-Syring et al. (2012) reported an overview of the sensitivity of the gas value chain for hydrogen addition, see Figure 20. With three colours they indicate the amount of hydrogen that is technically allowable per process, where a green bar means that mixing of hydrogen is harmless, a yellow bar means that technological and regulatory adaption is required and a blue bar means that research and development is needed.



**Figure 20: Overview hydrogen tolerance of selected items in the natural gas infrastructure (Muller-Syring et al., 2012)**

The amount of hydrogen that can safely be added to natural gas (without having increased risk for flash-back, engine knock or integrity) strongly depends on the composition of the natural gas at the injection point and the appliances downstream to the injection point. The hydrogen tolerance should therefore specifically be assessed per case (location, gas grid, flow, composition, end-users in the grid, etc) and could be as low as 0 vol%.

Currently, the maximum allowed hydrogen fraction in the Dutch gas transmission grid is 0.02 vol% (Donders et al., 2010). From 2021 onwards the maximum allowed hydrogen fraction will be 0.5 mol%<sup>9</sup> (EL&I, 2012).

<sup>9</sup> 0.5 mol% equals 0.5 vol%.

## APPENDIX B: POWER-TO-GAS DEMONSTRATION PLANTS

**Table 20: Data sheet of PtG demonstration plants (March 2013)**

	Project	Installed power (kW)	Electrolysis technique	Methanation principle	Application	Power load
1	Werlte (D) – Audi AG	6.000	Alkaline	Chemical	Gas grid - mobility	Base load
2	Aragon (S) – IThER	4.000 + 70	Alkaline + PEM	n/a	Mobility	unknown
3	Falkenhagen (D) – E.ON AG	2.000	PEM	n/a		Flexible load
4	Puglia region (I) – INGRID Project	1.200	Alkaline	n/a	Gas grid	Flexible
5	Grapzow (D) – RH <sub>2</sub> WIND Project Gruppe	1.000	Alkaline	n/a	CHP & gas grid	Flexible
6	Graben (D)	1.000	unknown	Chemical	Gas grid	unknown
7	Sudenburg (D) – Greenpeace Energy (& Gasunie) <i>Canceled</i>	1.000	Alkaline	n/a	Gas grid	unknown
8	Hamburg (D) – Vattenfall	900	Alkaline	n/a	Mobility	Base load
9	Prenzlau (D) – Enetrag AG	500	Alkaline	n/a		Base load
10	Frankfurt (D) – Thuga & ITM Power	360	PEM	n/a	Gas grid	Flexible load
11	Foulum (DK) Electrochaea	250	PEM	Biological	Gas grid	Flexible load
12	Stuttgart (D) – Solar Fuel & Fraunhofer IWES	250	PEM	Chemical	Gas grid	unknown
13	Karlsruhe (D) – DVGW & KIT	200	unknown	Chemical	Gas grid	unknown
14	Xermade (S) - Sotavento Project	200	Alkaline	n/a	Engine	Flexible load
15	Herten (D) – Stadt Herten & Evonic Industries	165	PEM	n/a	Mobility	unknown
16	Leverkusen (D) – CO <sub>2</sub> RECT Project: Siemens & RWE	100	unknown	unknown	unknown	unknown
17	Schwandorf (D) – Eucolino: Schmack & Viessmann	100	unknown	Biological	Gas grid	unknown
18	Ibbenburen (D) – RWE, CERAM Hyd	100	unknown	unknown	Gas grid	unknown
19	Utsira (N)	50	Alkaline	n/a	Fuel cell & hydrogen turbine	unknown
20	Freiburg (D) – H2Move: Fraunhofer ISE	40	unknown	unknown	unknown	unknown

	Project	Installed power (kW)	Electrolysis technique	Methanation principle	Application	Power load
21	Tahivilla (S) – Hidrolica Project	40	PEM	n/a	Fuel cell	Flexible load
22	Stuttgart (D) – Solar Fuel & Fraunhofer ZWS	25	PEM	Chemical	Gas grid	Flexible load
23	SamsØ (DK) – SamsØ Energy Academy	20	unknown	unknown	unknown	unknown
24	Groningen (NL) – DNV KEMA	7	PEM	Chemical	Gas grid	Base load
25	Berlin (D)	6	unknown	unknown	Gas grid	unknown
26	Rostock (D) – WTI	3	unknown	unknown	Mobility / fuel	unknown
27	Dortmund (D) - DWE & DBI	N/A	unknown	unknown	unknown	unknown
28	Copenhagen (DK) – Haldor Topsoe	N/A	unknown	unknown	unknown	unknown
29	Augsburg (D) – Erdgas Schwaben: Solar Fuel, GASAG & Thuga	N/A	unknown	Chemical	unknown	unknown
30	France (GRHYD) - GdF, GRdF, Areva, GNVert, etc.	N/A	unknown	unknown	Mobility & gas grid	Flexible





Figure 21: Overview of power-to-gas demonstration projects in Europe.

## APPENDIX C: DATA SHEET POWER-TO-GAS EFFICIENCIES

**Table 21: Efficiencies in different power to gas configurations. Gas to electricity efficiency of 53.6% used, which is based on 2009 Dutch power plant and CHP plant data. All data based on lower heating value.**

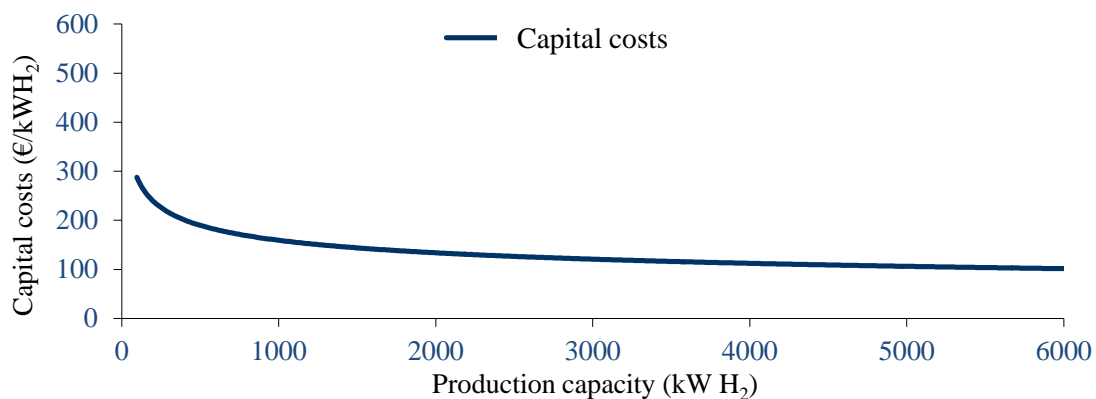
	Pressure (bar)	CO <sub>2</sub> source	Efficiency min	Efficiency max	Efficiency average
Power to methane to power	200	Concentrated	26.3%	34.3%	30.3%
Power to methane	200	Concentrated	49.0%	64.0%	56.5%
Power to methane to power	200	Atmosphere	18.2%	26.3%	22.2%
Power to methane	200	Atmosphere	34.0%	49.0%	41.5%
Power to methane to power	80	Concentrated	26.8%	34.3%	30.5%
Power to methane	80	Concentrated	50.0%	64.0%	57.0%
Power to methane to power	80	Atmosphere	18.8%	26.3%	22.5%
Power to methane	80	Atmosphere	35.0%	49.0%	42.0%
Power to methane to power	0	Concentrated	27.3%	34.8%	31.1%
Power to methane	0	Concentrated	51.0%	65.0%	58.0%
Power to methane to power	0	Atmosphere	19.3%	26.8%	23.0%
Power to methane	0	Atmosphere	36.0%	50.0%	43.0%
Power to hydrogen to power	200	Unknown	28.9%	38.6%	33.8%
Power to hydrogen	200	Unknown	54.0%	72.0%	63.0%
Power to hydrogen to power	80	Unknown	30.5%	39.1%	34.8%
Power to hydrogen	80	Unknown	57.0%	73.0%	65.0%
Power to hydrogen to power	0	Unknown	34.3%	41.3%	37.8%
Power to hydrogen	0	Unknown	64.0%	77.0%	70.5%

*Sources: Müller et al., 2011; Sterner, 2009; Sterner and Jentsch, 2011; IEA, 2011*

The values given in this Appendix exclude efficiency improvements that are expected in the near future (as reported in paragraph 3.1.1), innovative electrolyser technologies like solid oxide electrolysis and also excludes the conversion of hydrogen into power by means of fuel cell technology. However, it gives insight in the efficiency range of currently available power-to-gas technologies.

## APPENDIX D: HYDROGEN COMPRESSION AND STORAGE COSTS

For temporary storage of hydrogen it is assumed that the produced hydrogen is compressed up to 200 bar, equivalent to the maximum cylinder pressure. To determine the cost of compression, both capital and operating costs are assessed, including maintenance and electricity costs. The investment cost of compressors are obtained from quotations from compressor manufactures (total 50 data points) and Weinert (2005), see Figure 22.



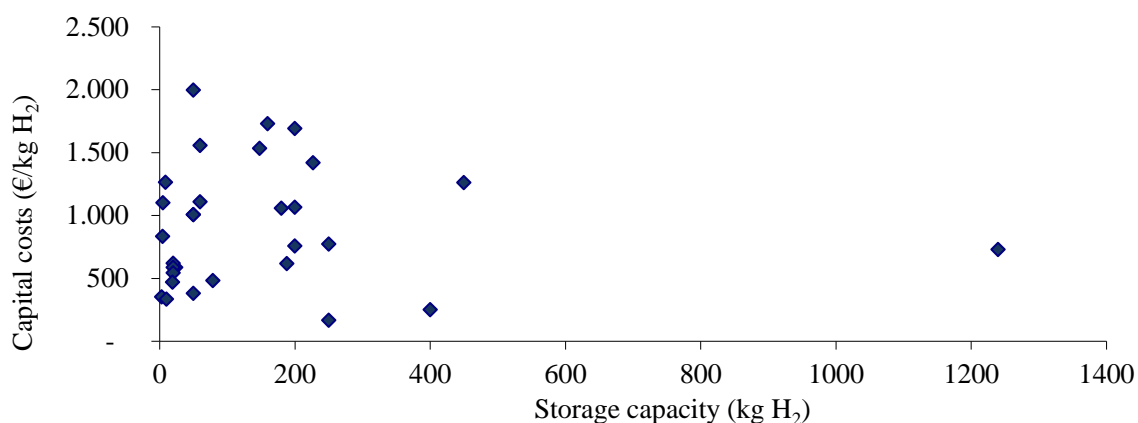
**Figure 22: Capital costs for hydrogen compression**

The electricity costs for compression of hydrogen are derived from DNV KEMA's input-output calculation model for determining the energy requirements for compression of gas. It takes into account the chemical, thermodynamically and physical parameters of hydrogen, the characteristics of hydrogen compressors [DNV KEMA] and the electricity retail price of 0.07 euro/kWh [Drift, 2007]. For injection into the gas grid the suction pressure is assumed to be atmospheric and the discharge pressure of the compressor was set to 8 bars. This results in energy requirements of 1.3 kWh/Nm<sup>3</sup> hydrogen and operational costs of 0.008 €/Nm<sup>3</sup> hydrogen. The specific work for compression of hydrogen from atmospheric pressure to 200 bars (for storage) is 3.6 kWh/kg hydrogen, which translates into 0.02 €/Nm<sup>3</sup> hydrogen.

The maintenance costs are assumed as 4% of the capital costs annually, based on information of three manufactures.

Furthermore, in order to ensure that the discontinuous production of hydrogen can be continuously used for injecting into the gas transportation, temporary storage of hydrogen in cylinders considered. The investment costs are obtained from a study by Weinert (2005) in which a comprehensive inventory is done into systems for hydrogen storage. Figure 23 shows the gathered information.





**Figure 23: Capital costs for hydrogen storage**

The calculations for the capital costs for hydrogen storage, shows an average of the data points in Figure 23, which corresponds to about 900 €/kg. Translated into units as used in this report are the investment costs 24 €/kWh H<sub>2</sub> storage capacity. Hydrogen storage in cylinders is considered to peak shaving hydrogen production before it can be fed in. After pressure reduction the hydrogen can be fed into the gas network system.

## APPENDIX E: AVAILABILITY OF METALS

This table gives insight in the availability of metals used in the technologies discussed in this document.

**Table 22: Availability of metals**

Metal	Technology	Reserves (kilotons)	Annual production <sup>1</sup>	Years left <sup>2</sup>	
Bismuth	SMES	320	7.4	43	USDOl, 2013
Cadmium	NiCd batteries	500	23	22	USDOl, 2013
Copper	SMES	680,000	17,000	40	USDOl, 2013
Lead	Lead-acid & SMES	89,000	5,200	17	USDOl, 2013
Lithium	Li-ion batteries	13,000	37	351	USDOl, 2013
Magnesium	SMES, PEM	2,400	6	393	USDOl, 2013
Nickel	NiCd, PEM, methanation catalyst	75,000	2,100	36	USDOl, 2013
Platinum group metals	PEM	66,000	379	174	USDOl, 2013
Sodium sulfate	NaS batteries	3,300,000	4,000	825	Beaudin et al., 2010
Strontium	SMES	6,800	380	18	USDOl, 2013
Titanium	Flywheel, PEM	5280	166	32	Beaudin et al., 2010
Vanadium	VRB batteries	14,000	63	222	USDOl, 2013
Zinc	ZnBr batteries	250,000	13,000	19	USDOl, 2013
Zirconium	PEM	48,000	1420	33	USDOl, 2013

<sup>1</sup> Based on 2012 production rates

<sup>2</sup> At constant use of 2012 production rate

This overview of the availability of metals for the technologies discussed does not include the technology improvement and recycling prospects and is a simple overview based on the 2012 production rates and total reserves.