Power-to-Gas on an Offshore Platform

System Analysis and Technical Barriers

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Executive Summary

This report addresses the technological rationale and requirements for the installation of a demonstration power-to-gas plant on a disused oil and gas platform in the North Sea. The power-to-gas concept and its component technologies are first explained, including their basic chemistry and thermodynamics and options for product gases and their utilization. In the report’s second part, technological and safety barriers to the plant’s implementation are considered together with approaches to overcoming them.

Contents

1.0 Introduction and Report Framework

1.1 Introduction

The context of the project: Rationale

The attached paper describes the context of the project (read the first couple of pages). It is basically a joint European program mainly between the Netherlands and Germany. Research programs between the Deutscher Verein des Gas- und Wasserfaches (DVGW) (Germany) and the Energy Delta Gas Research (EDGaR) (The Netherlands). In this context a joint treaty was signed between the Dutch energy minister and the German one. And money for this project was taken from the Dutch ministry.

This report is part of a project and the aim of the project is to deliver a pre-feasibility study for the installation of a Power-to-Gas demonstration system on disused oil and Gas platform. Many stakeholders are working to deliver this report, mainly DNV GL and several Masters' students, but they are working on the economics and on finding a location. None are working on the technical part. All these reports will be combined in one report that Prof. Catrinus Jepma, the man in charge of the project, will deliver. This will be the pre-feasibility study for installing a demonstration plant.

The purpose of this report is to identify and clarify from early on, the salient characteristics of P2G systems, the advantages and disadvantages of various technological approaches to P2G, and the main technical barriers and issues when considering installing such a system offshore.

1.2 Benefits of the report

As far as the authors know, few or no studies have been done concerning this report's subject up to now. Hence there is a need to clarify the subject for energy-industry and other business and government professionals as well as for the general public. The reader of this report should be able to easily understand the essential of power-to-gas technology, its advantages, and the barriers to installing a demonstration plant that should be taken into consideration. Identifying these barriers at an early stage helps prevent many problems later on. In particular, it helps in selecting which gas should be the system's output (hydrogen or methane). Moreover, it is of course vital to know which barriers are illusory and which have solutions.

Summary of contents

The first key purpose of this report is to give a brief but comprehensive overview of power-to-gas technology, one of the chemical storage options for renewable energy. The power-to-gas concept is a flexible technology that offers a multitude of possible applications. In this report we describe the current state of the art, actual research and development activities, and future challenges, without making any claim to be complete.

The second part of this paper deals with the technical barriers confronting the installation of a demonstration power-to-gas system on an offshore platform. The major concerns of this section that should be taken into consideration are as follows:

- The security and safety procedures that should be implemented when installing such a system on an already hazardous place like an offshore oil and gas platform;
- The problem with securing the feed inputs to the system, such as electricity and CO_2;
- Materials selection when installing a system in a harsh environment such as the North Sea and the implementation of a corrosion management system.

Currently, power-to-gas technology is economically infeasible. Additional technological and systemic developments are still required. However, in the opinion of the authors, long-term storage of renewable energies will be a crucial backbone of the future energy system. If we do not develop technologies today, we will not be able to meet the requirements of tomorrow.

1.3 The context: Wind and energy storage

In 2009 the European Union set the optimistic and challenging goal of reducing greenhouse gas emissions by at least 80% below 1990 levels by 2015. Realizing this radical transformation requires fundamental changes to the energy system and a large-scale implementation of the existing sustainable and renewable energy sources. Its realization is only possible with a nearly zero-carbon power supply and requires that other sectors, like industry and transportation, should largely rely on sustainable use of energy sources [1]. As wind is an abundant natural resource in the North Sea, the North Sea countries are relying heavily on the development of offshore wind energy to meet their targets.

The current energy system cannot adequately accommodate such an increase in intermittent power sources. The intermittent nature of offshore wind energy requires an increase in flexibility and balancing. The stochastic and completely weather-dependent nature of wind energy has to be kept in balance with the relatively easy-to-forecast but so far inelastic demand of electricity. An increase in the number of wind parks in the North Sea will lead to congestion in the power cables because a substantial share of electricity from renewable energy resources has to be transported to distant cities deeper in the countries. Hence there will need to be an upgrade in the transmission and distribution network [1].

In future, electricity suppliers and producers will be able to predict strong fluctuations in electricity production by means of increasingly better climatic prognosis systems, but this does not completely solve the problem of an intelligent integration of production quantities. Due to primary energy efficiency, as seen from an ecological as well as an economic point of view, systems based on the shutdown of wind power or photovoltaic plants due to excess supply should not be pursued. A sustainable energy system integrates these production methods into the existing structure. For that purpose, the electricity grid can be expanded, and different forms of load management can be applied, both in supply and demand. These solutions should be pursued and further developed.

Nevertheless, load shifting, with or without financial incentive, will not be enough to optimally integrate volatile production into the energy system in the future. Energy storage systems will play a crucial role in the integration of renewable energy sources with volatile production structures. Thereby, large capacities can be stored for future use—there will be no more need for permanent physical adjustment of the grid.

Decommissioning

Production of oil and gas in the North Sea peaked around 2000 and has since gone into decline. As a consequence, the North Sea gas industry expects a large increase in decommissioning programs for platforms during the next two decades. Overall, 500-600 installations need to be abandoned and dismantled, a task that has to be carried out in a harsh maritime environment and that represents a major engineering and financial challenge [2]. The technical costs for this task are estimated to be 50-100 billion euros over the next 40 years with costs largely covered by governments (30-80%) by means of tax deductions and co-ownership schemes [3]. Current regulation–the OSPAR Decision 98/3, a regulatory framework under the OSPAR Convention and national legislation–requires that disused offshore installations be fully removed to shore for waste treatment and disposal. However, the reuse of these installations is allowed if they can be put to another legitimate purpose in the maritime area authorized or regulated by the competent authority and if the new owner of the structure accepts the liability for eventual decommissioning.

Currently, discussions are ongoing about how to deal with disused oil and gas installations. In the light of these discussions, it is foreseen that the current OSPAR regime will see some adjustments when it is renegotiated for the next phase (an event expected for 2018) [4]. Given the current legal framework, it will be possible and highly probable that the reuse of platforms for other purposes will be an acceptable option under specific circumstances.

In this context, it is economically interesting to explore if P2G and chemical storage of the excess electricity at an offshore location could be a feasible option. The main motivation behind this research is to investigate the future role of offshore P2G by reusing the oil and gas platforms in the North Sea.

One might ask: why install a system offshore when it is less challenging and financially more rewarding to install it onshore? There3 would indeed be no good reason if the only benefit from installing an offshore power-to-gas system were the increase of flexibility and improved balancing in the energy system. However there are a number of other reasons why it is logical to develop P2G offshore. These include:

- Postponing decommissioning may itself create an economic value because of the discounted cash flow of the postponed decommissioning reservations made by the oil and gas companies. Such a cash flow could easily be substantial and could mark a major economic distinction between offshore and onshore power-to-gas in favor of the offshore option.

- Offshore chemical conversion may benefit from the use of the existing 10,000 or so of the O&G pipeline network in the North Sea region to transport the gases or possibly fluids to their onshore destinations.

- Issues of public acceptance that may easily arise onshore, because of concerns about the posibility of explosions and health risks from the fluids and gases produced, might be much less severe if conversion activity took place offshore and far away from populated areas.

- Large-scale storage conditions are relatively favorable in the North Sea area because of the large number of nearly empty small gas fields in the area. Thus, not only for public acceptance reasons but also for technical reasons, storage may be relatively easy and cheap.

In sum, even if some costs of offshore power-to-gas may exceed those of similar onshore activities, the various benefits mentioned above will have to be taken into account in order to assess the final economic business case of offshore power-to-gas.

The first part of this report gives a brief but comprehensive overview of power-to-gas technology and a compact technological description of the central elements of this technology. The current state of the art, actual research and development activities, and future challenges of each of these elements are described without making a claim to be complete.

The second part of this report deals with identifying the technical barriers and other considerations confronting the installation of a demonstration power-to-gas system on an offshore platform. The major concerns that should be taken into consideration are described mainly

- the security and safety procedure that should be implemented when installing such a system on an already hazardous place like an offshore oil and gas platform.

- The problems of securing the feed input to the systemsuch as electricity and CO2

- Materials selection when installing a P2G system in a harsh environment such as the North Sea and the implementation of a corrosion management system

2.0 Power-to-Gas

This chapter gives an overview of the technological fundamentals of the power-to-gas (P2G) concept. Following a general introduction to the concept itself, the efficiencies of P2G technology are described. Thereafter, a brief introduction to the electrolysis, methanation, and carbon capture processes is given.

2.1 The power-to-gas concept

In this section a review of basic aspects of water electrolysis is provided and the fundamentals of water electrolysis are discussed to give an overview of basic modes of operation, including electrolyzer efficiency. Then the two main water electrolysis technologies, namely alkaline electrolysis (AEC) and polymer electrolyte membrane electrolysis (PEM) are described in more detail.

As previously noted, the temporal and spatial fluctuations of power generation from renewable energy sources demand both high-capacity distribution systems and intermittent storage possibilities. The P2G concept approaches these demands by the conversion of electrical power into gaseous chemical storage medium: the energy-rich gases hydrogen (H_2) and methane (CH_4) respectively.

The power-to-gas concept is depicted in Fig.2.1 (Sterner 2009; Grond et al. 2013; Müller-Syring et al. 2013a). As shown on the upper left side of Fig. 2.1, renewable electricity is usually transferred to the power grid. On the one hand, however, the transport of electricity is limited by actual grid-side demand, which may result in temporary excess energy. On the other hand, renewable energy production may be located in remote areas with limited transport capacities or completely autarkic structures.

As shown in Fig. 11, the renewable electric power is then used in a water electrolysis plant to produce hydrogen and oxygen from water. Oxygen can be released into the atmosphere, or, preferably, can be used in chemical or metallurgical industrial production processes. However, utilization of the oxygen depends strongly on local variables, particularly distance to potential consumers and consumer demand. The actual product, however, is hydrogen, which can be transported either in its own hydrogen distribution grid, as admixture in the natural gas grid, or by truck or train. Hydrogen can also be stored in appropriate facilities or together with natural gas in existing natural-gas storage infrastructure.

[1]Markus Lehner et al. “Power-to-Gas technology and business models” Springer, 2014

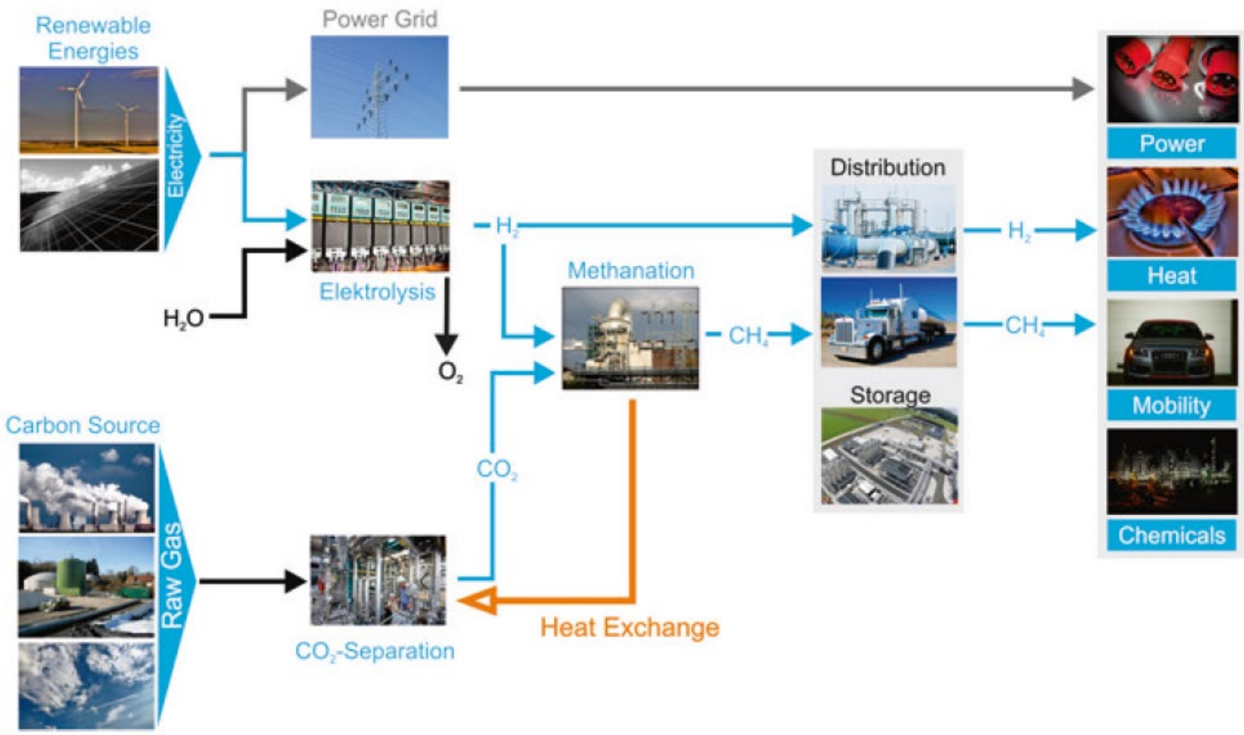

FIGURE 1: THE POWER-TO-GAS CONCEPT

Hydrogen, then, is the first possible end-product of the P2G process chain. But the producible volume of hydrogen is limited both by the lack of hydrogen infrastructure (i.e., hydrogen grid, storage facilities, end-use technologies) and by maximum allowable H_2 content in the natural-gas grid.

The second, optional process step in the P2G process chain is *methanation*. Hydrogen and carbon dioxide (CO_2) synthesize to methane by either a chemically or a biologically catalyzed reaction. The methane produced in this way is called synthetic or substitute natural gas (SNG). The by-product of this reaction is steam (H_2O). The necessary carbon dioxide can be derived from the exhaust or process gases of industrial production, fossil-fuel power plants, or biogas plants, or in principle also from the atmosphere or from seawater (Fig. 2.1). (The latter options are extremely energy-intensive.) Since pure carbon dioxide sources are only rarely available (Ausfelder and Bazzanella, 2008), carbon capture plays a significant role in the P2G concept, both technically and economically.

The main advantage of methane as end-product of the power-to-gas process chain is its unlimited usability in gas infrastructure. SNG bidirectionally links the power grid and the gas grid. Existing transport and storage capabilities of the gas grid are used for the transfer of renewable electricity in the form of SNG. The huge gas storage facilities in Europe enable the intermittent retention of renewable energy in the range of up to 1,000 TWh. Furthermore, the infrastructure for methane utilization also exists and is completely technically mature.

Beside conversion into electricity in combined-cycle plants and utilization as fuel in transport or as industrial feedstock, SNG can be also used for heating. The physical and chemical properties of SNG and natural gas are so similar that no technical changes in the end-use systems are required. In fact, P2G-generated SNG needs almost no new investments in infrastructure for transport, storage, and utilization. This is not only an economic benefit, but also saves time required for official authorizations and eases likely acceptance by the general public, which is commonly low for any infrastructure projects.

In sum, conversion to the energy-rich gases hydrogen and methane enables transport of renewable energy outside the power grid, and also the large-scale, long-term storage of renewable energy. These chemical energy carriers can be reconverted to electricity, but a multitude of other utilization routes are possible; these result in different efficiencies for the total system.

2.2 Efficiencies of power-to-gas process chains

Any technical process involves energy losses, and the high exergy level of electrical power is inevitably reduced by the conversion processes within the power-to-gas process chain. Hence it is preferable to avoid unnecessary conversion steps whenever possible. Electric power should be used as electric power provided sufficient grid capacity is available. The use of electric power can also be accelerated by generating higher demand, for example by increased electrification of industrial processes (Leiter et al. 2014). However, both demand management and extension of the power grid are limited options; hence storage of renewable energy will inevitably be needed as the usage shares of renewable energy (wind, solar, and other sources) continue to increase.

In the power-to-gas process chain, the first usable product is hydrogen. As already mentioned, the chemical, petrochemical, and metallurgical industries all demand significant volumes of hydrogen. But hydrogen's immediate utilization requires either an electrolysis plant near the consumer or else specialized transport facilities, which are poorly developed for hydrogen, at least at present. By contrast, storage options for hydrogen would enable buffering and decoupling from the demand side. Beside storage in underground caverns, the natural gas grid is a potential buffer for hydrogen. (The limitations and challenges of the latter option are described later in a separate section.)

Methanation converts hydrogen to synthetic methane (SNG). The efficiency of the conversion is reported to be 70–85% for the chemical path and greater than 95% for the biological path (Grond et al. 2013). The main benefit of SNG is its unrestricted compatibility with the natural gas grid, and with the utilization options of natural gas.

The re-powering of methane to electricity in combined-cycle plants closes the loop: electric power—SNG—electric power. It opens the possibility of producing electric power in areas far away from the renewable energy sources that are connected by an already existing gas grid. However, the efficiency of this option is the lowest of all the possibilities (see Table 2.1).

Slightly better conversion efficiencies can be achieved by producing electricity from hydrogen. Gas turbines, fuel cells, or reverse fuel cells can be used for that purpose. Fuel cells would also enable the utilization of hydrogen to power vehicles, but fuel-cell–powered cars are technologically not mature, and an infrastructure for hydrogen distribution and storage does not yet exist in most regions.

Table 2.1 Efficiencies for different Power-to-Gas process chains (Sterner et al. 2011)

Path	Efficiency (%)	Boundary conditions
Electricity to gas		
Electricity → Hydrogen	54–72	Including compression to 200 bar (underground storage working pres.)
Electricity → Methane (SNG)	49–64	
Electricity → Hydrogen	57–73	Including compression to 80 bar (feed in gas grid for transportation)
Electricity → Methane (SNG)	50–64	
Electricity → Hydrogen	64–77	Without compression
Electricity → Methane (SNG)	51–65	
Electricity to gas to electricity		
Electricity → Hydrogen → Electricity	34–44	Conversion to electricity: 60 %, compression to 80 bar
Electricity → Methane → Electricity	30–38	
Electricity to gas to combined heat and power (CHP)		
Electricity → Hydrogen → CHP	48–62	40 % electricity and 45 % heat, compression to 80 bar
Electricity → Methane → CHP	43–54	

Generally, the efficiencies of power-to-gas systems are increased when the waste heat of the system is put to use, for example in district heating or in industrial plants nearby (Table 2.1). The level to which the product gases have to be pressurized has an important influence on the total achievable efficiency. The pressure level mainly depends on the facilities used for transport and storage, and is therefore subject to the specific local conditions of a P2G plant.

The utilization paths shown in Table 2.1 cannot be ranked by considering the efficiencies alone. Systemic, economic, and macroeconomic aspects also have to be taken into account. Conversion efficiencies can be improved in two ways: by technical progress in the individual conversion steps, namely water electrolysis and methanation; or by synergies with industrial processes coupled with the P2G plants. Both options are subject of current research: see for example Karlsruhe Institut für Technologie 2014; Schößet al. 2014; Bergins 2014.

2.3 Water electrolysis

This section reviews basic aspects of water electrolysis technologies. First, fundamentals of water electrolysis are presented so as to provide an overview of basic modes of operation, different ways to determine the electrolyzer efficiency, and the fundamentals of performance optimization strategies. Second, the two main water electrolysis technologies, namely alkaline electrolysis (AEC) and polymer electrolyte membrane electrolysis (PEMEC) are described in more detail. The state of the art, typical system setups, operating characteristics, and main component materials are discussed. The technological assets and drawbacks, current and future developments, and future challenges of each of the main technologies will be discussed in section 4.7.

The Greek root *lysis* literally means "breaking" or decomposition. The word electrolysis, accordingly, describes a decomposition process in which electrical energy is the main driving force of a chemical reaction that breaks a molecule apart. In the case of water electrolysis, a direct electric current is applied to water, which causes dissociation (lysis) of water molecules into the product gases hydrogen and oxygen. Hence a water electrolyzer is basically a device that converts electrical (in some cases also thermal) energy into chemical energy.

2.3.1 Thermodynamics of water electrolysis

The overall equation of the basic water-splitting reaction is noted below:

$$H_2O \rightarrow 1/2\ O_2 + H_2 \qquad (3.1)$$

The following reaction is noted: basic watersisf main economic interest. into chemical energy. ges of each of the main technologies will be discussed in section 5.nologies will be dias.gy in the range of up to 1,000 TWh. Furthermore, the infrthe amount of heat that must be supplied to an electrolysis cell to drive the water splitting reaction.

$$\Delta H(T) = \Delta G(T) + T\Delta S(T) \qquad (3.2)$$

The minimum applied cell potential for starting a water-splitting reaction is represented by the reversible voltage Vrev, which is related to the Gibbs free energy change as follows:

$$V_{rev} = \frac{\Delta G}{nF} = 1.23\ \mathrm{V} \qquad (3.3)$$

The water-splitting reaction is represented by the reversible voltage (Vrev, whK); n is the number of electrons transferred in reaction 3.1 times the Faraday constant F of 96,487C/mol: the reversible voltage is calculated as 1.23V.

The thermo-neutral voltage Vth, defined by Eq. 3.4, is related to the enthalpy change associated with the water-splitting reaction.

$$V_{th} = \frac{\Delta H}{nF} = \frac{\Delta G}{nF} + \frac{T\Delta S}{nF} = 1.48\ \mathrm{V} \qquad (3.4)$$

With ΔH of 285,84 kJ/mol and a temperature T of 298 K, a thermo-neutral voltage of 1.48V is obtained. If the voltage E_{cell}, which is applied to the electrolysis cell, is higher than V_{rev} but lower than V_{th}, water splitting takes place simply by absorption of heat from the environment as the cell irreversibly dissipates the heat associated with the change in entropy. If $E_{cell} = V_{th}$, the joule heat generated within the electrolysis cell equals the heat consumption of the endothermic electrolysis reaction and therefore no heat exchange with the environment is required. If $E_{cell} > V_{th}$, the electrolysis cell produces surplus heat due to joule heating and has to be properly cooled in order to reduce system degradation.

The operating temperature and pressure are important parameters for electrolyzer systems and have to be carefully chosen. The influence of pressure on the cell voltage is small and can be estimated with a rewritten form of the well-known Nernst Equation, as follows:

$$\Delta V = V - V^0 = -\frac{RT}{nF} \ln \frac{1}{\sqrt{P}} \qquad (3.5)$$

R is the ideal gas constant (8.314J/mol K) and P the overall pressure within the electrolysis cell, assumed to be equal at both electrodes. An increase in the overall pressure from 1 to 200 bar corresponds to an increase of the theoretical cell voltage V by just 34 mV at 298K and by 122mV at 1,073K respectively. Although raising the operating pressure causes an increase of the theoretical reversible voltage by a few percent, it has various positive, system-relevant effects on the operating voltage and current density as well as on the production costs of compressed hydrogen.

2.3.2 Alkaline Electrolyzers

Working and Design Principles

Alkaline electrolyzers represent the most developed water electrolysis technology to date. AEC electrolyzers are currently the standard systems for industrial/large-scale electrolysis applications. As shown in Fig. 3.2, an AEC cell is basically composed of two electrodes, which are fully immersed in a 20-40wt% aqueous potassium hydroxide (KOH) electrolyte with a microporous diaphragm separating the anodic and cathodic regions. The electrodes are usually made of nickel or nickel-plated steel. (KOH is preferred over sodium hydroxide [NaOH] electrolytes due to its higher conductivity.) The electrolysis cell is housed in a compartment, usually made of steel. Product gas leaving the cell is separated from remaining electrolyte, which is then pumped back into the cell. The liquid electrolyte is not consumed but has to be replenished over time due to various types of losses.

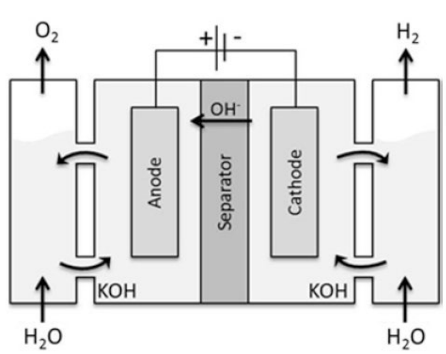

Fig. 3.2 Schematic of the operating principle of an alkaline electrolysis cell

The connection of single electrolysis cells into a stack can be done in either of two ways: in parallel (unipolar electrolyzer) or via a serial connection of adjacent single cells (bipolar electrolyzer). Although bipolar electrolyzers are more complex and demand higher manufacturing precision, they are nowadays preferred over unipolar versions due to their significantly lower ohmic losses.

Conventional electrolyzers are commonly composed of 30-200 cells with an effective membrane area of each cell in the range of 1-3 m^2

Operating Conditions, Performance, and Capacities

Conventional AEC systems are usually operated at current densities in the range of 300-500 mA/cm^2 and at corresponding cell voltages in the range of 1.9-2.4 V. Operating temperatures are commonly in the range of 70-90 °C. Most installed alkaline electrolyzers are working at atmospheric pressure. Pressurized systems are usually operated at up to 15 bars, but seldom above that level. The production capacity of commercially available electrolysis systems covers a wide range: 1–760 scm H_2/h. The largest facilities, comprising several single systems, show total capacities of 10,000+ scm H_2/h. The hydrogen purity is generally at least 99.5+%.

System efficiencies greatly vary with system size and also depend on factors like the particular purity and pressure levels. Typical system efficiencies based on the HHV of H_2 are in the range of 60–80%, corresponding to specific energy demands of 4.3-5.5 KWh/scm H_2. Electrolyzers operated at atmospheric pressure are slightly more efficient than pressurized ones. This difference becomes gradually less important with increasing system size.

In terms of dynamic operation, conventional alkaline electrolyzers can typically be operated at ~20%–100% of rated power, while operation in the lower half of that range usually results in significantly reduced gas quality and ever lower system efficiencies. Conventional systems also tend to have long startup times (minutes to hours, depending on whether starting from stand-by or cold-start) and usually they have trouble keeping up with rapidly changing power inputs.

2.3.3 Polymer Electrolyte Membrane Electrolysis

Working and Design Principles

PEM electrolyzers are the second important water electrolysis technology. PEM technology is generally less developed than AEC systems and up to now its main commercial use has been in small-scale niche applications. However, due to the growing interest in water electrolysis systems in general and the chance to overcome the major restrictions of conventional AEC technology, PEM technology is currently gaining a lot more attention.

In PEM cells, thin proton-conducting membranes are used as solid polymer electrolytes rather than the liquid electrolytes typically used in the conventional AEC electrolyzers. This membrane, commonly referred to as a *membrane electrode assembly* (MEA), is assembled with an electrocatalytic layer on each side. The MEA represents the core element of a PEM cell and is electrically connected via porous current-collector layers to cell-separator plates, which often contain flow-field patterns for optimal mass transport.

In the anode compartment, pure water passes through the seperator plate and/or diffuses through the current collector towards the catalytic zone, where the oxidation reaction shown in chemical Eq. 3.12 takes place. The hydrogen ions are transported across the proton exchange membrane towards the cathode side, where hydrogen is generated per reaction Eq. 3.11.

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$$\text{Cathode} \quad 2H^+ + 2e^- \rightarrow H_2 \tag{3.11}$$

$$\text{Anode} \quad H_2O \rightarrow 1/2\ O_2 + 2H^+ + 2e^- \tag{3.12}$$

Single cells are connected into a stack exclusively in series (bipolar electrolyzer) by means of a filter-press construction method. Commercially available electrolyzer stacks are commonly composed of up to 60 single cells with a typical effective membrane area per single cell of 100-300cm^2, which is a factor of ~5 uthanin AEC systems. Moreover, due to the lack of a liquid electrolyte and all the associated equipment (pumps, gas separation, and so forth) a solid-electrolyte electrolyzer generally allows a significantly more compact system design.

Operating Conditions, Performance and Capacities

PEM systems are usually operated at current densities of 1-2 A/cm^2, which is a factor of about 4 higher than in AEC technology. The corresponding voltages are in the range of 1.6–2V. In the lab, current densities as high as 5-10A/cm^2 at cell voltages less than 2.5V have already been demonstrated. The system efficiencies based on the HHV of H_2 are typically in the range of 60–70%. The operating temperatures are mainly in the range of 6080°C. PEM systems are working at elevated pressure levels of 30-60 bar without additional compression units. A few systems even deliver H_2 pressures of 100-200 bar without the use of compression units.

The production capacities of currently commercially available PEM systems are typically in the range of 1-40 scm H_2/h. The hydrogen purity levels are at least 99.99+%, where oxygen coming from the anode side is the main impurity.

Unlike AEC systems, PEM systems can be operated in a highly dynamic fashion, covering almost the whole range of 0–100% of rated power, and areable to follow power fluctuations within 100s ms.

2.4 Methanation

Methanation means the heterogeneous, gas-catalytic, or biological synthesis of CH_4 from H_2 and CO/CO_2—or, in the case of the biological path, from other carbon sources. It is the second substantial, but optional process step together with electrolysis within the power-to-gas concept. The chemistry of the methanation reaction has been known for more than a century, and chemical methanation processes have been state-of-the-art for several decades. They have been and still are applied to producing substitute natural gas (SNG) from synthetic gas derived from coal or biomass. Gas purification in chemical or petrochemical industries is another widely used application of the methanation process.

Although methanation is technologically mature in these fields of application, specific differences and challenges arise when it is used as a process step within the P2G concept. Starting with the chemical process routes followed by a review of the biological route, this section offers an overview of the state-of-the-art methanation processes currently used in industry. The specifics for the application of this technology as part of P2G will be discussed in section 3.

2.4.1 Chemical process fundamentals

The Sabatier reaction was discovered in 1902, and is described by

$$CO_{(g)} + 3H_{2(g)} \leftrightarrow CH_{4(g)} + H_2O_{(g)} \quad \Delta H_R^0 = -206.2\,\mathrm{kJ/mol} \qquad (4.1)$$

In combination with the shift conversion

$$CO_{2(g)} + H_{2(g)} \leftrightarrow CO_{(g)} + H_2O_{(g)} \quad \Delta H_R^0 = +41.2\,\mathrm{kJ/mol} \qquad (4.2)$$

a formulation for the reaction of CO_2 with hydrogen can be given:

$$CO_{2(g)} + 4H_{2(g)} \leftrightarrow CH_{4(g)} + 2H_2O_{(g)} \quad \Delta H_R^0 = -165.0\,\mathrm{kJ/mol} \qquad (4.3)$$

Reaction enthalpies in Eqs. (4.1)-(4.3) are given for a temperature of 25°C. These two reactions are strongly exothermic and are equilibrium reactions. Equation4.3 is often interpreted as the sum of Eqs. 4.1 and 4.2:that is. CO_2 methanation is achieved by intermediate conversion to CO.

Lower temperatures result in significantly higher equilibrium constants and therefore in better conversion rates. But lower temperatures also cause unfavorable reaction kinetics; hence appropriate catalysts are used. Because they reduce the volume of the chemical reaction [Eq. (4.3)], higher pressures basically support better conversion rates. Since CO and CO_2 participate in the reaction scheme, depending on the operating conditions, the Boudouard equilibrium may also have to be considered as an undesirable side reaction, forming coke in the reactor:

$$CO_{2(g)} + C_{(s)} \leftrightarrow 2CO_{(g)} \quad \Delta H_R^0 = +172{,}45\,\mathrm{kJ/mol} \qquad (4.4)$$

The product gas leaving the reactor contains steam, CO, and unconverted educts as well as the product CH_4. The product composition can be influenced by the methanation process concept, the reaction parameters, and also the reactor type used. Moreover, the catalyst applied influences kinetics, conversion rate, and selectivity of the process.

Catalytic active substances for the hydrogenation of CO_2 or CO are group VIII metals: that is, the Fe-group, the Co-group, and the Ni-group (Mills and Steffgen 1974). Mainly due to their moderate cost and satisfactory performance in conversion rates and selectivity, Ni-based catalysts are widely utilized for methanation processes today. Usually, silica-based carriers are used, but zeolites or metal carriers are known (Kaltenmaier 1988; Wang et al. 2011; Weatherbee and Bartholomew 1982).

However, catalysts are sensitive to poisons, which may result in catalyst deactivation. Typical catalyst poisons are heavy metals, but also sulfur compounds or oxygen (Bartholomew 2001). This is of special significance for methanation processes as part of P2G, as described later. Generally valid statements on both the kinetics and the mechanism of the hydrogenation of CO_2 or CO are still not available.

Process Concepts and Stage of Development

Historically speaking, two main phases of process development can be identified (Kopyscinski et al., 2010).

In the first phase, driven by the first oil crisis and by strategic considerations, coal-to-gas (CtG) processes were developed in the 1970s using fossil coal as feedstock. The typical process path is gasification, gas cleaning and conditioning, followed by methanation and a necessary gas upgrading to meet the requirements for injection of the substitute natural gas (SNG) produced into the gas grid. Industrial-scale plants based on this technology have been built and operated in the USA (US Department of Energy 2014), and also using a coal-to-liquid (CtL) process in South Africa by Sasol.

The second phase, starting around the year 2000, has focused on the conversion of biomass as feedstock (biomass-to-gas/BtG or biomass-to-liquid/BtL). Both smaller plant scales and differing feed-gas compositions of synthesis gas derived from biomass make previously developed plant concepts for coal-to-gas plants difficult or impossible to utilize directly. Hence, new process developments have been initiated. The renaissance of methanation is mainly driven by the intended transition of the energy system towards renewable sources, and also by rising prices for natural gas. Within the process chains of CtG and BtG, methanation is one process step. The developed chemical methanation processes of the past decades can be classified as follows (Bajohr et al. 2011):

2-phase systems (gaseous educts, solid catalyst):

- Fixed bed
- Fluidized bed
- Coated honeycombs

3-phase systems (gaseous educts, liquid heat carrier, solid catalyst)

- Bubble column (slurry)

A central issue is the heat management of the reactors. As described earlier, all the chemical reactions involved are strongly exothermic. Hence temperature regulation of the processes is challenging, and is solved in various ways depending on the reactor type. Further information can be found in Elvers et al. (1989), Kopyscinski et al. (2010), and Bajohr et al. (2011).

2.4.2 Biological process routes

The chemical catalysts and process routes above described can be substituted with bio-catalysts (enzymes) where the methanation of hydrogen and carbon dioxide is carried out in a biological system. Methanogenic microbes, which belong to the domain of Archaea, produce the necessary enzymes. Biological methanation is particularly known in biogas processes in which two main reaction paths can be distinguished:

Acetoclastic methanogenesis

$$CH_3COOH_{(g)} \leftrightarrow CH_{4(g)} + CO_{2(g)} \quad \Delta G_R^0 = -33.0\,\frac{kJ}{mol} \qquad (4.5)$$

and hydrogenotrophic methanogenesis

$$CO_{2(g)} + 4H_{2(g)} \leftrightarrow CH_{4(g)} + 2H_2O_{(g)} \quad \Delta G_R^0 = -135.0\,kJ/mol \qquad (4.6)$$

Both metabolic pathways are catalyzed by different strains of Archaea. Methane production based on acids (Eq. 4.5) is the dominant process route for the decomposition of biomass. But the second biological pathway (Eq. 4.6) is also utilized in a biogas plant populated with a mixed microbe population (Karakashev et al. 2005).

Different process concepts are available for the biological catalysis of hydrogen to methane. Either an optimized biogas plant is utilized (integrative methanation), in which both pathways described occur simultaneously, or in reactors for selective hydrogen utilization (selective methanation). Integrative methanation is described in the literature at both laboratory and pilot scales (Luo et al., 2012). Hydrogen is used as co-substrate in addition to manure or sewage sludge. Hydrogen conversion rates of 80% are reported; these depend on the hydrogen partial pressure and the mixing intensity. Control of the pH value in the system and an instantaneous conversion of the hydrogen to methane seem to be crucial for a stable operation of the process. Selective methanation utilizes adapted microbes under optimized process conditions in a bioreactor. It can be linked to a biogas process, but a self-sustaining operation is also possible, though this needs its own carbon source as well as hydrogen. Laboratory tests indicate a hydrogen conversion rate greater than 90% at operating temperatures of 55°perating temperatures of 55a hydrogen conversion rate greater than 9ing factor (Luo and Angelidaki 2012).

Biological methanation is an up and coming technology that is gaining in importance. Its advantages compared to conventional, chemical methanation are that it operates at moderate temperatures (30-60°C) and moderate pressure, as well as having a higher tolerance for pollutant substances in the feed gases. One of its disadvantages is that it operates in a three-phase system resulting in a mass transfer limitation between the gas and the liquid phase.

Microbes need, beside the feed gases described, other nutrients like salts, which have to be provided in the bioreactors. The long-term stability of such biological systems and of the microbe itself, the selectivity of the biological reactions, and performance under intermittent operating conditions are still subjects of research.

Table 4.2 summarizes the properties of the methanation concepts introduced above. It is obvious that all of the process concepts show specific advantages and disadvantages.

Table 4.2 Comparison of different methanation concepts, modified and extended from Bajohr et al. (2011)

Concept	Chemical methanation			Biological methanation
	Fixed bed	Fluidized bed	Bubble column	
Heat release	−−	+	++	++ (no issue)
Heat control	−−	o	++	++ (no issue)
Mass transfer	o	++	−−	−−
Kinetics	+	+	+	o
Load flexibility	o	−−	o	−−
Stress on catalyst	+	−−	+	++ (no issue)

++ very good, + good, o average, − poor, −− very poor

Experience on an industrial scale is only available for fixed-bed chemical methanation. In any case, the specific requirements for utilizing methanation as part of power-to-gas need further research and development.

The biological process route will be eliminated as an option in our case, since it requires a larger space to be employed, and space is at a premium on an offshore platform. In addition it requires a constant supply of biomass, which is very hard to transport to the platform. Therefore, regardless of the promise it shows of being preferable to chemical routes, the biological process will be discarded and the chemical routes chosen.

2.5 Carbon capture and storage

CO_2 capture and storage (CCS) involves capturing the CO_2 arising from the combustion of fossil fuels, as in power generation, or from the preparation of fossil fuels, as in natural-gas processing. It can also be applied to the combustion of biomass-based fuels and in certain industrial processes, such as the production of hydrogen, ammonia, iron and steel, or cement. Capturing CO_2 involves separating it from some other gases, for example, in the flue gas stream of a power plant. The CO_2must then be transported to a storage site where it will be stored away from the atmosphere for a very long time (IPCC, 2001a). In order to have a significant effect on atmospheric concentrations of CO_2, storage reservoirs would have to be large relative to annual emissions.

2.5.1 CCS fundamentals

In order to help the reader understand how CO_2 capture and storage could be used, some of the key features of the technology are briefly introduced here. As mentioned earlier, power plants and other large-scale industrial processes are the primary candidates for capture and are the main focus of this section.

The purpose of CO_2 capture is to produce a concentrated stream of CO_2 at high pressure that can be readily transported to a storage site. Although, in principle, the entire gas stream containing low concentrations of CO_2 could be transported and injected underground, energy costs and other associated costs generally make this approach impractical. It is therefore necessary to produce a nearly pure CO_2 stream for transport and storage.

Depending on the process or power plant application in question, there are three main approaches to capturing the CO_2generated from a primary fossil fuel (coal, natural gas or oil), biomass, or mixtures of these fuels:

- *Post-combustion systems* separate $CO_2$from the flue gases produced by the combustion of the primary fuel in air. These systems normally use a liquid solvent to capture the small fraction of CO_2(typically 3e gases produced by the combustion of the primary fuel in air. These systems normally use a liquid

- *Pre-combustion systems* process the primary fuel in a reactor with steam and air or oxygen to produce a mixture called y use a liquid solvent tng mainly of carbon monoxide and hydrogen. In a second reactor called a ons of fuels and iditional hydrogen, together with CO_2, is produced by reacting the carbon monoxide with steam. The resulting mixture of hydrogen and CO_2can then be separated into a CO2 gas a stream of hydrogen. If the $CO_2$is stored, the hydrogen is a carbon-free energy carrier that can be combusted to generate power and/or heat.

- *Oxyfuel combustion systems* use oxygen instead of air for combustion of the primary fuel to produce a flue gas that is mainly water vapor and CO_2. This flue gas hashigh CO_2concentrations (greater than 80% by volume). The water vapor is then removed by cooling and compressing the gas stream. Oxyfuel combustion requires the upstream separation of oxygen from air, with a purity of 95–99% oxygen assumed in most current designs. Further treatment of the flue gas may be needed to remove air pollutants and noncondensed gases (such as nitrogen) before the CO_2 is sent to storage.

Figure TS.3 shows a schematic diagram of the main capture processes and systems. All require a step involving the separation of CO_2, H_2, or O_2 from a bulk gas stream (such as flue gas, synthesis gas, air, or raw natural gas). These separation steps can be accomplished by means of physical or chemical solvents, membranes, solid sorbents, or cryogenic separation. The choice of a specific capture technology is determined largely by the process conditions under which it must operate.

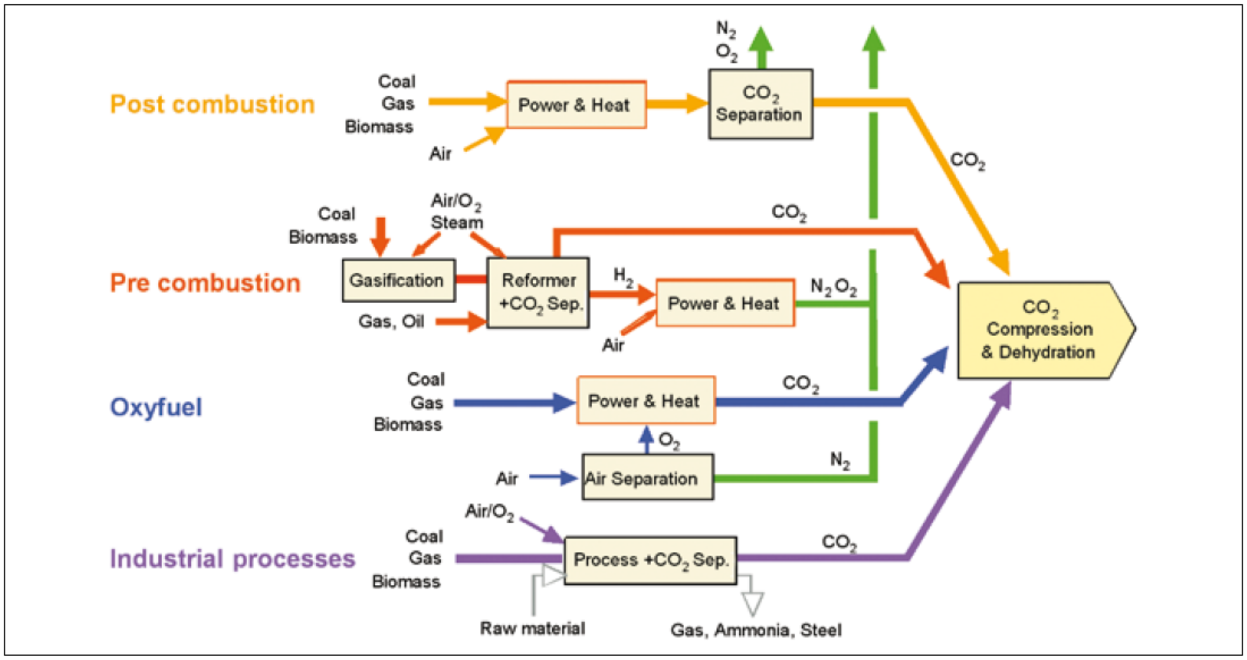


FIGURE 2: CO2 CAPTURE SYSTEM (CCS IPCC AND ADAPTED FROM BP)

2.5.2 CO_2 storage

This section examines two types of geological formation that have received extensive consideration for the geological storage of CO_2 and are applicable offshore: oil and gas reservoirs and deep saline formations. In both cases, geological storage of CO_2 is accomplished by injecting it in dense form into a rock formation below the earth's surface. Porous rock formations that hold or (as in the case of depleted oil and gas reservoirs) have previously held fluids, such as natural gas, oil or brines, are potential candidates for CO_2 storage.

Storage in oil and gas reservoirs: CO_2 can be injected into nearly depleted oil/gas reservoirs to be stored. The CO_2 is immiscible with oil; it reacts with the residual crude oil and dissolves the light hydrocarbons. If injected at the required flow and pressure, up to 40% of the residual oil left in an active reservoir can be extracted after primary production [22]. This technique is called enhanced oil recovery (EOR).The fluid injection methods have been widely used in the oil and gas extraction industry for decades to enhance the recovery of the residual oil and gases. The technologies for injection of CO_2 for EOR are mature, and many studies focus on various aspects of EOR, such as migration simulation, geochemical modeling, and leakage/risk assessment [21].

This means that there is an economic incentive to inject CO_2 into depleted oil and gas reservoirs. The additional extracted oil and gas extracted via EOR can offset the high CCS cost commonly involved in the process.

Storage in saline aquifers: Most of the deep aquifers at 700–1000m below ground level are composed of high-salinity brines [21]. These aquifers currently have no purpose or commercial value but offer interesting for injected CO_2 captured from a CCS process. Deep saline aquifers can be found in many areas both onshore and offshore and are considered to have enormous potential for storage of CO_2. That said, despite the high potential for CO_2 storage, little is known about CO_2 storage in saline aquifers. However, White et al. [23] extensively reviewed the existing projects exploiting deep saline aquifers for storage of captured CO_2 and concluded that storage of CO_2 in deep saline aquifers is technically feasible and can have little or no negative environmental impacts.

2.5.3 CO_2 transport

Except when plants are located directly above a geological storage site, captured CO_2 must be transported from the point of capture to a storage site. This section reviews the principal methods of CO_2 transport.

CO_2 transport pipelines today operate as a mature market technology and are the most common method for transporting CO_2. Gaseous CO_2 is typically compressed to a pressure above 8 MPa in order to avoid two-phase flow regimes and to increase the density of the CO_2, thereby making it easier and less costly to transport. CO_2 can also be transported as a liquid in ships or in road or rail tankers that carry it in insulated tanks at a temperature well below ambient, and at much lower pressures.

In some situations or locations, transport of CO_2 by ship may be economically more attractive, particularly when the CO_2 has to be moved over large distances or overseas. Liquefied petroleum gases (LPG, principally propane and butane) are transported on a large commercial scale by marine tankers. CO_2 can be transported by ship in much the same way (typically at 0.7 MPa pressure), but this currently takes place on a small scale because of limited demand. The properties of liquefied CO_2 are similar to those of LPG, and the technology could be scaled up to large CO_2 carriers if a demand for such systems were to materialize. Road and rail tankers are also technically feasible options. These systems transport CO_2 at a temperature of -20ºC and at 2 MPa pressure. However, they are uneconomical compared to pipelines and ships, except on a very small scale, and are unlikely to be relevant to large-scale CCS.

Many projects have been designed to capture carbon on shore from power plants and store it offshore. These include the Peterhead project in the UK and Nuon Magnum and ROAD (Rotterdam Opslag en Afvang Demonstratie project) in the Netherlands. However, most of these projects have been canceled or are delayed waiting for funding from their governments.

One interesting project that is still in the demonstration phase is the K12-B project, where carbon is captured offshore and the CO_2 is used for enhanced gas recovery.

3.0 Offshore power-to-gas demonstration plant

This section presents in outline the components and processes that comprise the proposed offshore P2G plant, how the hydrogen generated could be fed into the existing natural-gas grid, how heat generated by the process can be managed and utilized, and how an electrolyzer for the plant from available technologies can be selected by considering their respective advantages and disadvantages.

3.1 General description of the demonstration plant

This section provides a high-level description of the demonstration plant. At this stage of the project (pre-feasibility) it is useful to know and understand the main components of the demonstration plant. At a later stage, once a suitable platform is selected, more details, such as capacity, suitable technology for each component, and details of the needed equipment can be provided.

Section 2 provided a summary description of the main components of the P2G system: electrolysis, methanation processes, and carbon capture and storage. However, a P2G plant does not consist only of these components: many others, including a water treatment plant, H_2 and CO_2 storage facilities, and a gas purification plant are required also. The first part of this section will explain the system as a whole and why each component is needed. The second part will discuss what should be taken into consideration if hydrogen is chosen as an end product. Finally, the third section will explain how to deal with the heat generated from the methanation process.

As an important input to electrolysis, pure water is needed for the production of hydrogen. In order to get pure water, a desalination and water treatment plant is needed. Depending on the size of the treatment plant, this process might be considered a barrier since it requires a large space on deck and require a lot of energy. Since the type of treatment plant greatly depends on the volume of water needed, we will not go into detail at this stage, but it should be taken into consideration when choosing the size and location of the system.

Another important input for the electrolysis is electricity. (This issue is discussed in more detail in section 4.1.) The electric power and the treated water are used in a water electrolysis plant to produce hydrogen and oxygen. In our case, the oxygen will be released into the atmosphere. In the case where electrolysis on its own is chosen (no methanation process) the main output of the system will be hydrogen, which will be admixed into the natural gas grid; the admixing of hydrogen will be discussed in detail in the next section.

When synthetic natural gas is chosen to be produced, the electrolysis unit supplies the necessary hydrogen for the methanation process. A schematic overview of a chemical methanation unit of a power-to-gas plant is given in Fig. 4.5.

The operation of the electrolysis is unsteady as it follows the fluctuating input of renewable power to the system. But chemical methanation especially has to be steadily operated with elevated temperatures and pressures. Neither frequent start-up and shut-down cycles nor significant load changes are possible. Specific sensitivity to load changes depends on the reactor concept, but basically the load flexibility is limited. Hence an intermittent storage of hydrogen is necessary; the size of the storage tank depends on both the fluctuations in electrolysis and the load flexibility of methanation (Schaub et al. 2014). The same considerations are basically also valid for the second educt gas, carbon dioxide. The intermittent storage of carbon dioxide is simpler than that of hydrogen.

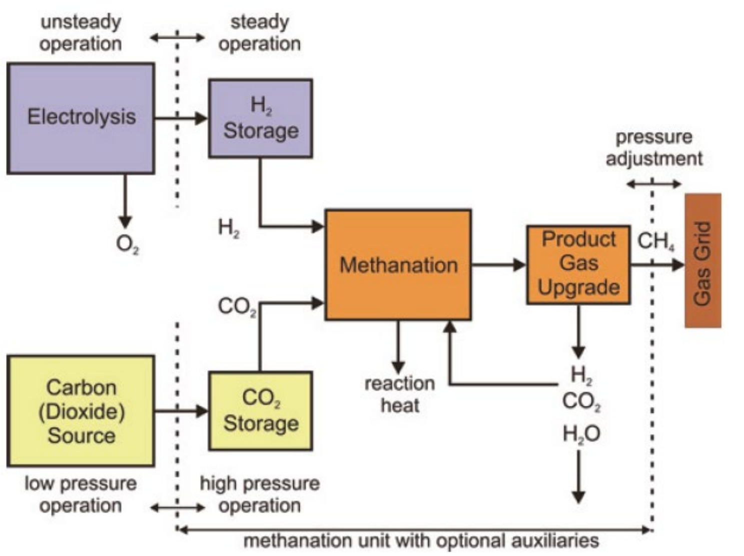


FIGURE 3: SCHEME OF A CHEMICAL METHANATION UNIT WITHIN POWER-TO-GAS CONCEPT (LEHNER ET AL.)

Due to the high critical temperature of 31°C, CO_2 can be liquefied by compression. Whereas conventional methanation processes and catalysts have been developed for carbon oxide as feed gas, power-to-gas methanation utilizes CO_2 as educt.

The educt gases—hydrogen and carbon dioxide—have to be compressed to the operational pressure of the methanation system. Electrolysis is already operated with elevated pressures depending on the utilized technology. In contrast, carbon dioxide sources are most probably at atmospheric pressure, and thus need compression in case of chemical methanation.

Means to improve the economic viability of the methanation process should be considered. The cost effectiveness of methanation can be positively influenced in the following ways:

- by reducing the effort required for gas upgrade downstream from the reactor;
- by utilizing the released reaction heat within the power-to-gas process chain and outside the system, respectively (this will be discussed in more detail in section 3.4);
- by increasing the lifetime of the catalysts; and
- by achieving high annual operational hours.

The product-gas upgrade aims to meet the relevant regulations for injection of SNG or biogas into the gas grid. Multi-stage methanation reactors enable high methane yields and thus result ideally in a simple water condensation unit as the means of product gas upgrade. Other potential upgrade systems are based on membranes or pressure swing adsorption. Depending on the entry point to the gas grid, a pressure adjustment between the methanation unit and local grid pressure is required.

Plant size, reactor design, set-up of the process chain and annual operating hours of an electrolysis and methanation unit within a power-to-gas system substantially depend on the specific local conditions: available space and allowable weight that can be added to the platform, available quantity and temporal profile of renewable power and thus hydrogen production, carbon dioxide sources as well as size, pressure level and load flow of the natural gas grid. Therefore, each electrolyzer and methanation unit of a power-to-gas process chain has to be tailored to the specific boundary conditions for each platform. Since no platform has been selected yet, and since the size of the demonstration plant greatly depends on the specific boundary condition of each platform, at this stage of the project we cannot provide further detail about the specifications for the demonstration plant, such as size.

3.3 Integration of hydrogen into the natural gas grid

The products of the chemical conversion in a power-to-gas plant—hydrogen and SNG (methane)—have to be preferentially transported by the natural gas grid and stored in the grid as well as in the connected large-scale storage facilities.

Hence the impacts of the injection into the grid of hydrogen or SNG have to be evaluated. Furthermore, the requirements for the injected gas composition and gas volume, as well as any restrictions for the product gas injection have to be considered.

The case of SNG as end product of the power-to-gas process chain is less critical than that of hydrogen, because natural gas consists to a large extent of methane. Accordingly, a practically unlimited injection of SNG into the gas grid is possible. Since methanation is an equilibrium reaction, parts of the educt gases, hydrogen and carbon dioxide, are not converted to methane. Furthermore, the product-gas mixture emerging from the methanation reactor contains significant amounts of steam, the main byproduct of the methanation reaction. Accordingly, a product-gas upgrade is necessary in order to meet the requirements for injection of the produced SNG into the gas grid.

The injection of hydrogen into the natural gas grid raises a number of questions that have been investigated in some recent studies (Müller-Syring et al. 2012, 2013b; Florisson 2010; Müller-Syring and Henel 2014;).

The main advantage of this transport technique is that no additional pipe is required to transport hydrogen. The disadvantage is that the production of hydrogen is limited to the admixing percentage and is completely dependent on the flow of natural gas in the pipes.

The current admixing limit in the Netherlands is set at 0.02%, and the target limit for 2023 is set at 0.5%. [13]. The *Naturalhy* project, which extensively studied the effects of hydrogen admixture in the gas grid, concluded that mixtures of H_2 up to 50% vol. in the natural gas transmission line is acceptable depending on the steel type and the operating conditions. Leakage rates will increase but are still economically and ecologically tolerable (Müller-Syring et al. 2013b; Florisson 2010). The same study concluded that a hydrogen mixture of up to 20% in the gas grid is possible in some parts of the natural gas system, where the end users' appliances and machines are properly adjusted; adaption of burner nozzles is required for the higher flame velocities (Müller-Syring et al. 2012)

In detail, the following problems have to be considered when choosing to admix hydrogen at higher levels than 0.5%:

- The influence on gas characteristics like Wobbe index and heating value: with increasing amounts of hydrogen, both Wobbe-index and heating values are lowered.
- The tolerable percentage of hydrogen strongly depends on the properties of the natural gas quality in the grid. An admixture of from 5 % to 15 % of hydrogen is possible (Müller-Syring et al. 2013b).
- The impacts on the gas infrastructure: piping, controls, fittings, valves, gaskets, and metering systems. In particular, the metering systems have to be adjusted for hydrogen admixtures.
- Gas turbines are more sensitive to hydrogen. Most of the manufacturers limit the hydrogen content to 1 or 2 vol.%, but laboratory tests show the possibility of admixtures up to 14 % (Müller-Syring et al. 2012). Similar considerations are valid for gas motors.
- The impacts on underground gas storage facilities: for the storage of natural gas, salt caverns, and depleted gas reservoirs are currently being used. Especially for porous subsurface reservoirs, some fundamental questions are still open, for example microbiological reactions in the reservoir, de-mixing processes, and general impacts on geochemical conditions.

3.4 Heat management

As previously mentioned, utilization of the generated heat will increase both the efficiency of the system and the economic viability of the methanation process, and hence the economic viability of the whole P2G.

The aim of heat integration in general is to couple the released heat from the methanation reaction with the required thermal energy for the CO_2 capture process. Thus the economy of the system can be improved by energy savings in the CO_2 separation and by decreasing the cooling demand of the methanation reactor. The possibility of heat integration between methanation and carbon capture processes has been simulated by Fraubaum and Haider (2014) with ASPEN. An example of P2G was simulated in this study and two different methanation processes were elaborated.

Depending on which methanation process is used, the released heat from the reactors can be used to produce superheated steam or high-pressurized saturated steam. In both cases, the steam produced had a significantly higher energy level than that required for the CO_2 desorption (2 bars, 120.3°C). This means that the heat produced can be utilized in another process. In the onshore P2G system, the steam can be expanded in a condensing turbine. Since possible carbon sources originate from industrial processes, like fossil power plants and steel plants, steam-power plants already exist, and therefore only steam turbines need to be adapted.

In our case, the heat generated from the methanation process can be utilized in several ways. If the CCS process is happening offshore, as in the case of natural-gas sweetening, the released heat can be used for the process. The additional heat can then be used to reduce the high energy requirements of the water desalination plants, to reduce heat demand for the gas processes available at the platform, or as in the onshore case, it can be expanded in a condensing turbine if a steam-power plant already exists at the platform.

3.5 Electrolyzer selection

Water electrolysis plays a central role in power-to-gas systems as it represents the linkage between electrical and chemical energy, independent if the produced hydrogen is used in its elemental form or as an intermediate for further chemical reactions. The most important demands on electrolyzers for power-to-gas systems are highly dynamic modes of operation, wide partial load ranges with sufficiently high efficiencies and satisfying gas purity levels, compact stack designs, high unit-power densities, high production capacities, and low-investment operating costs. Although water electrolysis is already a well-established technology, further improvements are required to meet these requirements.

Currently, a lot of fundamental and applied research and development efforts are underway to pave the way for a broader implementation of electrolytic hydrogen production into the market and to facilitate a larger integration of the power-to-gas technology into the electrical grid.

There are two main commercialized water electrolysis technologies now available: alkaline electrolysis (AEC) and polymer electrolyte membrane electrolysis (PEMEC). Each is at a different level of development.

The main technical differences between these two technologies are the operating temperature, the operating current density and voltage, the class of materials used for catalysis, the pH value, the type of the electrolyte used, and thus the configuration of the particular electrolyzer system. An overview of the important parameters of the two main water electrolysis technologies is given in Table 3.1. For each parameter, typical values are presented.

Table 3.1 Important parameters of the main water electrolysis technologies

	AEC	PEMEC
Ions electrolyte	OH^-	H^+
Current density (A/cm^2)	<0.5	>1
Cell voltage (V)	>1.9	>1.8
Temperature (°C)	60–80	60–80
Operating pressure (bar)	<30	<200
(Voltage) Efficiency (%)	60–80	65–80
Spec. el. energy consumption (kWh/scbm)	>4.6	>4.8
Lower partial load range [% of nominal load (NL)]	30–40	0–10
Overload (% of NL)	<150	<200
Capacity (scbm H_2)	<760	<40
Cell area (m^2)	<4	<0.3

scbm standard cubicmeter

Alkaline low-temperature electrolysis technology is the oldest, currently most mature and cheapest technology available. In large-scale electrolytic hydrogen production plants, exclusively alkaline electrolyzers are being used so far. However, low current densities and rather limited modes of dynamic operation are currently major limitations of that technology. To make the AEC technology more compatible with power-to-gas applications, further developments are essential.

Acidic solid polymer electrolyte (PEM) technology has made significant progress over the past century and is on its way to leave niche applications. Due to various unique advantages over alkaline systems like the compact system design, high current densities, high operating pressures, high flexibility with respect to modes of operation, and wide partial load ranges, PEM technology offers a great potential to become a serious competitor to alkaline electrolysis systems for many types of applications. Due to these advantages, PEM technology is probably the most compatible technology for power-to-gas applications at present. The most limiting disadvantages of that technology are its high costs, limited resources, and the lack of adequate scale up procedures.

4.0 Barriers

This section addresses barriers to the implementation of a demonstration P2G plant aboard an offshore platform in the challenging environment of the North Sea. The first part of the section deals with the problems of distant and fluctuating electricity supply to an offshore P2G facility.

The second subsection provides an explanatory review of the oil and gas industry's techniques of risk assessment and management. On this basis the third subsection addresses the specific and critical issue of corrosion risk and its management via the selection of appropriate materials and the integration of inherent safety early in the design phase. Next, options for the sourcing o CO2 for the plant are considered, including two relevant projects currently in operation. Finally, issues of actual installation are considered, including CO2 sourcing, questions of plant weight and volume and platform structure, and issues with the available electrolytic technologies.

When introducing an innovative idea such as P2G on offshore platforms. A PESTEL (political, economic, social, technical, environmental, and legal) analysis should be conducted to identify all the barriers/issues that should be considered and overcome. It is not only technical barriers that can be show-stoppers; most of the time it is economic and political factors that terminate a such a project even though it is technically feasible. The political factor is extremely important in our case since the project affects many countries, with each country having its own procedures, standards, and laws. Considering all these procedures for every country is extremely time-consuming and will require a lot of careful planning and a high level of consensus between all the parties involve.

At this phase of the project, then, it is first important to know from a technical viewpoint whether or not the project can be executed and to determine that no major barrier is a show-stopper. This is the major reason why this study and this report were done.

This section will describe the main barriers that have the most impact on the project. The first barrier is the source of electricity, since the system cannot be run without one.

4.1 Source of electricity

The source of electricity for the P2G depends on the capacity of the plant. For this reason this section will be divided into parts. The first part will discuss which source of electricity is suitable for the implementation of power-to-gas project on a large scale. The second part will be about a proper source of electricity for the demonstration plant.

4.1.1 Large-scale implementation of offshore P2G

Since the liberalization of the electricity market in the late 1990s, cross-border ultra-high-voltage (UHV) connections are no longer used only to provide assistance in the event of failures or shortages, but also to facilitate the growing trade in electricity across these connections. This development is opening up national electricity markets. The result is a strong European market characterized by transparency and stable prices.

The European electricity market is undergoing major changes. National borders are becoming less and less relevant. European policy is aimed at increasing interconnection capacity so as to create a single, integrated electricity market. Besides benefiting the market, interconnectors also play an important role in the integration of renewable energy in the European electricity grid. In addition, large-scale plans for offshore wind farms in the North Sea have inspired numerous proposals for connecting wind farms to an international offshore grid. These links will make it possible to trade carbon free hydropower and wind energy.

Interconnections between two countries can be constructed in several ways:

An above-ground connection between the UHV grids of two neighboring countries. The various interconnections between the Netherlands and Germany/Belgium are examples of this method. These connections use alternating current, which is the standard throughout the European grid.

An offshore grid, such as a North Sea HVDC offshore grid. The undersea electric cable is the conventional way of connecting two countries. The cable uses direct current as standard, which is converted into alternating current at both ends. One example is the cable link between the Netherlands and Norway, which has been supplying mainly renewable hydroelectricity from the Norwegian fjords to the Dutch high-voltage grid since 2008. Ideas for developing a more advanced offshore grid are growing in number, and different configurations forW interconnection are being assessed for feasibility:

Wind-farm hubs. Connecting various offshore wind farms in close proximity to each other, thus forming only one transmission line to shore.

Tee-in connections. Connecting a wind farm or a wind-farm hub to a pre-existing or planned transmission line or interconnector between countries, rather than directly to shore.

Hub-to-hub connections. Linking several wind-farm hubs to create transmission corridors between multiple countries (the wind-farm hubs belonging to different countries are connected to shore, but then also connected to each other). This can be understood as an alternative to a direct interconnector between the countries in question.

The selection of one or several connection systems to be developed for the offshore grid depends on many factors. But no matter which connection concept is selected, the disused oil and gas platforms where the power-to-gas systems will be installed can be connected to the grid. In this way, the grid will include both offshore sources of electricity, such as the wind farms, and offshore outlets of electricity, such as the oil and gas platforms, where electricity will be consumed whenever curtailment is needed to produce either hydrogen or synthetic methane. This concept will increase the versatility and flexibility of the offshore grid and reduce the impact of wind power’s intermittency.

The obstacles that must be overcome to establish this offshore grid are many. The economic and legal framework for offshore wind differs from country to country, and within those domains there are huge challenges, such as the organizational and political issues that must be dealt with. When several countries are planning to develop an offshore grid, this is not a minor step. For this reason and until the offshore grid is established, a way has to be found to supply electricity to the demonstration plant.

4.1.2 Source of electricity

One solution that immediately comes to mind is taking electricity from the nearest wind farm. Since the aim of installing power-to-gas is to reduce curtailments of these wind farms, it is clear that offshore wind farms should be connected to our demonstration plant. However, as previously explained, many factors determine the selection of the location of the platform where the system will be installed. One major factor is the source of electricity but there are other key factors to consider, such as availability of space on deck and CO_2. All these factors should be satisfactorily addressed so to select a proper location for the demonstration plant. In addition, the nearest wind farm could be several tens of kilometers away from the platform. It could be economically infeasible to install several kilometers of cables for a small demonstration plant. For the above reasons another electricity source should be found. Of course if all other essential conditions are satisfied and a wind farm is located near the platform, this solution is ideal.

Another solution could be supply the demonstration plant form the electricity generated on board the platform. We will elaborate this idea and explain its advantages.

The power demand of an offshore installation such as an oil or gas platform is substantial. Depending on the requirements of the process and equipment on the installation, the required power may range from a few megawatts to hundreds. Platforms are typically fitted with bulky and heavy power generation equipment designed to ensure redundant capacity to meet the high availability requirements. The power arrangement typically consists of four gas turbine units, one used at full capacity and the remaining three throttled to meet varying demand or otherwise reserved for redundancy. This redundant capacity is necessary to meet the high availability requirements of each independent platform. However, operating gas turbines at low efficiency results in high fuel consumption and elevated emissions.

We suggest supplying electricity to the power-to-gas system from these onboard power generation systems. Whenever one turbine is operating at level below its rated power, the power-to-gas system will be "plugged in." The amount of electricity consumed by the power-to-gas system will be selected so that this turbine will be working at its highest efficiency. In this way the power generation system will be working at its highest efficiency and hydrogen or methane will be produced from the otherwise unused electricity.

The objective of the demonstration plant is to check the feasibility of the power-to-gas system when installed at an offshore platform and connected to a strongly fluctuating wind power source. In our case, the demonstration plant is not connected to a wind source; however, the proposed source is as fluctuating and intermittent as wind power.

The electricity consumed at the platform–and thus the functioning of the generators–depends on many variables such as the gas treatment process, fluctuating gas demand, and weather. Moreover, the goal of connecting the power-to-gas system to the generators is to increase their efficiency during specific short-term periods when needed. Hence the actual working of the power-to-gas system will be very fluctuating and intermittent, much as if it was connected to a wind source. When the electricity source is found not to be following the wind source, we have the option of controlling it to suit demand by simply turning it off more frequently.

4.2 Safety and Risk Assessment

Another main barrier to system implementation is the safety and security procedures for installing hydrogen based system on the platforms. It is crucial to tackle this issue as early as possible to prevent any incident that could cause irreparable damage to public perception of hydrogen, which could slow or even stop the development of the project.

The oil and gas industry is by its very nature hazardous. A hazard is something that can potentially cause any of the following:

- Harm to human beings, including ill health, injury, or death
- Damage to property, plant or equipment, products, or the environment
- Production losses (for example from plant shut-downs) or increased financial liabilities.

In this industry, there are inherent risks of accidents happening at any stage: exploration, extraction, refining, and final delivery of the product. Here, however, we will be concerned with risks aboard marine oil and gas drilling platforms and the hazards associated with such risks. These risks include fire, explosion, environmental contamination, and injury to personnel. More specifically, we will be discussing risks associated with the introduction of power-to-gas (P2G) technology on marine drilling platforms, and how those risks can be effectively identified, analyzed, and reduced to a level that is as low as reasonably practicable.

Fortunately, the oil and gas industry has evolved multiple techniques for these purposes. But in order for the techniques to be effectively deployed, resources need to be made available to ensure that the control measures implemented as a result of identification and analysis are robust and appropriate, and that the platform is staffed by workers and managers who have the experience and knowledge they need in order to perform their work safely.

4.2.1 Risk Assessment: An Introduction

What is a risk? For our purposes, a risk is the likelihood—which may or may or may not be represented as a mathematical probability—that a hazard will result in harm. In other words, it is the chance, whether great or small, that a person may be injured or sickened, that some plant or equipment may be damaged or destroyed, or that the surrounding environment (in this case, the ocean) may be polluted or otherwise adversely affected. In the industry, any assessment of risk of an event—say, a chemical leak—is typically accompanied by an estimate of how serious the resulting harm will be: how likely is the event, and how destructive is it likely to be?

Risk assessment allows relevant risks to be identified and appropriately considered and analyzed. On marine drilling platforms, which are extremely hazardous environments, those risks involve the entirety of plant, equipment, processes, systems, and infrastructure: all of them have the potential to cause harm. Clearly, when introducing a new (and also inherently hazardous) technology like P2G to such an environment, risk assessment must be thorough, comprehensive, and realistic.

The main techniques for risk assessment in the oil and gas industry are the following:

- The 5-Step Approach
- Qualitative Assessment Techniques
- Semi-Quantitative Assessment Techniques
- Quantitative Assessment Techniques

4.2.2 The 5-Step Approach

This is an overarching, commonsense approach to identifying and managing risk. All approaches to risk assessment and management must include in some way these same basic steps and their sub-steps, and in that sense the process outlined here forms the essential foundation of all of them. For that very reason, the 5-Step approach is also broad and unspecific, as will be seen below. It also lacks ways to arrive at estimates of three key elements of a hazard: its likelihood, the severity of its potential consequences, and the various types of cost these consequences could incur. Here are the steps:

Step 1: Identify the hazards throughout the installation

Step 2: Decide who and what might be harmed and how

Step 3: Evaluate the risks and decide on precautions

Step 4: Record the findings and implement the recommended precautions

Step 5: Regularly review the assessment and update as needed

Step 1: Identify the hazards

The first step is to work out how people, plant, or the environment could be harmed. To help identify the hazards, the following substeps are required:

- Have assessors with the relevant sets of expertise tour the platform and note what could reasonably be expected to cause harm in the event of mechanical failure or human error.
- Consult the platform workers for their views and opinions on each of these likely hazards.
- Review system and component manufacturers' manuals or data sheets, which should highlight hazards associated with machinery or substances, and cross-check with the workers' actual experience and observations.
- Especially during the first few months after any new system or component has been installed, consult the platform's accident log and ill-health records. These can often indicate less obvious hazards as well as highlighting trends.

Step 2: Decide who and what might be harmed and how

For each hazard noted by the assessment team, there must be clear identification of the categories of workers who might be harmed and/or plant or equipment that might be damaged or destroyed, and whether and how the marine environment might be polluted. This clarity will help identify the best way of managing each corresponding risk (see Step 3). In each case, identify how the people or plant might be harmed—that is, what sort of injury or damage might occur. (In the case of a release of contaminant—most likely crude oil—into the marine environment, the type of damage is known, but long-term consequences depend primarily on the scale of the contamination.)

Step 3: Evaluate the risks and decide on precautions

With the hazards identified, the next step is to decide what action to take to reduce the risks associated with those hazards. In most countries, the law requires employers (meaning in our case the operators of offshore drilling platforms) to do everything 'reasonably practicable' to protect people and the environment from harm. This standard is codified in the phrase *As Low As Reasonably Practicable*, known in the industry by its acronym ALARP. When implementing Measures to reduce identified risks to ALARP have been ordered into the *Hierarchy of Control*. The Hierarchy prioritizes broad types of control measure: risk reduction should start at the top of the list because the types of measure are listed in diminishing order of effectiveness.

- Elimination
- Substitution
- Engineering controls

- Administrative controls
- Personal Protective Equipment (PPE)

Obviously, if a potential hazard can be minimized by eliminating the hazardous element (device, process, procedure) altogether, that is optimal. Substituting a less hazardous element that performs the same function in a less hazardous way is the next best option. And so on.

Step 4: Record the findings and implement them

The next step is to implement the measures indicated by the risk assessment in order to achieve risks ALARP. It follows that a risk assessment is not expected to eliminate all risks, but is required to be *suitable and sufficient*. In order for it to meet these criteria, the assessment will need to be able to show that:

- A proper check was made of each potential hazard by a qualified assessor
- All workers who might be affected were consulted
- All significant hazards were addressed
- The recommended measures are suitable and sufficient, and the remaining risk is low
- All the workers or their representatives were involved in the process.

If the risk assessment concludes that multiple improvements should be made, a prioritized plan of action should be drawn up.

Step 5: Regularly review the risk assessment and update as necessary

Inevitably, new equipment or changes in substances used and procedures undertaken will introduce new hazards to the platform. Hence all control measures should be reviewed on an as-needed basis: every time a significant change in equipment, system, or procedure is to be implemented, it should be assessed for risk and suitable and sufficient control measures put in place.

4.3 Other Risk Assessment Techniques

Besides the 5-step approach, there are techniques available that take more specific approaches to risk assessment and control. These include *qualitative* risk assessment techniques, *semi-quantitative* techniques, and *quantitative* techniques. All these types of technique are regarded as more comprehensive than the 5-Step approach and can take in a wider range of factors, including financial cost, loss of time, loss of business, loss of reputation, and so forth.

4.3.1 Qualitative Risk Assessment

A qualitative risk assessment is derived from the conclusions reached by an assessor who has used expert knowledge and experience to judge whether current risk control measures are adequate: that is, whether in the assessor's opinion they reduce the risk to ALARP, or whether supplementary or different measures need to be applied.

Using the combined skills of a team of assessors offers advantages. Such a team typically generates a more complete picture of the risks involved than a single assessor can. Moreover, if the team members work independently on risk assessment before coming them together, more assertive members will be less likely to exert undue influence. The team can then compare observations and ideas until they reach a set of consensus decisions on which risk control measures should be implemented.

A qualitative judgment on the severity of a risk involves two parameters: the likelihood of an event occurring and the severity of the consequences if it does.

Severity can be assessed in terms of its effect on the following variables:

- Harm caused
- Time lost
- Cost over and above normal operation
- Quality of output or product reduced
- Inconvenience

4.3.2 Semi-Quantitative Risk Assessment

Whatever the approach, effective risk management requires decisions that employ as broad a knowledge base as possible. It also requires a degree of consistency in the formation of judgments. In a qualitative assessment, both the likelihood and the severity of the harmful event are subjective, in the sense that they are the informed personal opinion of the assessor(s). By contrast, using a semi-quantitative approach involves applying a numerical value to the event's likelihood and severity. The judgments that comprise assessments are of course still personal, but if assessors regularly rate risks on a numerical scale, the judgments are more likely to be self-consistent. A simple example of the kind of rating used is shown below.

Numerical values applied to levels of event likelihood and consequence severity

Likelihood can be defined as	Severity can be defined as
5 Very likely	5 Catastrophic
4 Likely	4 Major
3 Fairly likely	3 Moderate
2 Unlikely	2 Minor
1 Very unlikely	1 Insignificant

Source: Adapted from WISE global training

Risk rating/prioritization

When judging the risk of a particular activity or process, the risk assessor or risk assessment team use a scale like the one above to arrive at an estimated likelihood rating (say, 3) and the consequence severity rating (say, 4). The next step is to multiply the likelihood (3) by the consequence (4) to get a prioritization rating of 3 x 4 = 12 (Tolerable). This is done using a scale matrix like the one shown below.

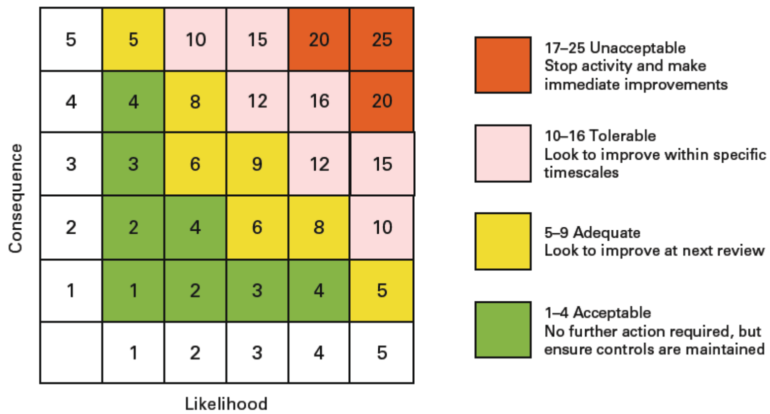


Figure 3.1 Risk rating matrix
Source: Wise Global Training.

In this way, the semi-quantitative risk rating system yields an overall numerical value to the risk being evaluated. The value can then be used to assign a priority the actions required, as shown in the grading on the right of the matrix. As already noted, the values assigned using the likelihood-severity scale are subjective (though based in expert knowledge, and, in the case of an assessment team, in expert consensus). By using a matrix like this, trained risk assessors increase the consistency of their assessments both within and between teams.

4.3.4 Quantitative Risk Assessment

While the assessment approaches described above are useful up to a point, the complex processes and operations aboard an offshore drilling platform, together with the high levels of associated hazards, require a sophisticated approach to risk. Quantitative risk assessment, as its name implies, uses special quantitative tools and techniques in order to identify hazards and to estimate the likelihood of their being realized and the severity of the consequences. These numerical estimates of the risks can then be evaluated against known numerical risk criteria.

4.4 Risk Management Tools

As we have noted, offshore drilling will remain a hazardous industry, and the platform itself together with its technologies and systems is an inherently hazardous environment. But this doesn't mean that hazards cannot be reduced to ALARP. When a project is in the design stage, some risks and hazards can be designed out using modeling as a tool.

Two commonly used modeling techniques are:

HAZID (Hazard Identification study)

HAZOP (Hazard and Operability study)

HAZID (Hazard Identification Study)

A Hazard Identification Study (HAZID) is as a rule a qualitative risk assessment and is judgment-based. It is usually undertaken by a team of people chosen for their particular knowledge, experience, and/or expertise. A HAZID has two phases:

Failure Case Selection: compiling a list of hazards that can then be evaluated using further risk assessment techniques.

Hazard Assessment: conducting a qualitative evaluation of how significant the hazards are and how to reduce the risks associated with them.

The following are essential qualities of a HAZID:

- The scope of the study should be clearly defined, so that those who read the study (especially management at whatever levels are appropriate) fully understand which hazards have been included and which excluded.
- The study should take a structured approach (system by system, process by process, and so forth) so as to be comprehensive in its coverage of relevant hazards.
- However, the study should also be creative and dynamic, incorporating hazardous elements not in the original outline as assessors recognize them and noting potentially hazardous interactions between elements in the event of an accident. This will allow the widest possible range of hazards to be considered.
- The study should include historical data and previous experiences (including those of the workers on the installation) so that lessons learned can be incorporated into the assessors' recommendations and acted on.

Hazard checklists

These are an effective means of producing a comprehensive list of standard hazards. These lists can be used for hazard identification studies at the concept and design stages so as to incorporate and address the widest necessary range of safety-related issues. A hazard checklist is also used to confirm that good risk management practice has been built into a project at the design stage.

Using keywords as a prompt can be useful when considering hazards in HAZID. The table below shows examples of keywords and some of their associated hazards. The list is not intended to be comprehensive.

A sample hazard checklist

Key words	Hazards
Fire	Blowout which has ignited Process leak which has ignited Product storage leak which has ignited
Loss of breathable atmosphere	Ingress of smoke Asphyxiation
Toxic gas release	Ingress of toxic gas Asphyxiation
LPG/LNG release/leak	Explosion from contact with a source of ignition Hydrate formation on valves Cold burns/frostbite Brittle fracture of steel component(s)
Hydrocarbon release/ leak	Explosion from contact with a source of ignition
Collision/crash	Helicopter crash Vessel colliding with rig
Structure failure	Crane collapse Rig leg collapse

Source: Adapted from New South Wales Department of Planning (2011) *Hazardous Industry Planning Advisory Paper No. 8.* HAZOP Guidelines, Sydney, State of New South Wales ISBN 978 0 73475 872 9 available at: http://www.planning.nsw.gov.au/Portals/0/HIPAP%208%20Final%202011.pdf

Hazard Checklists: Strengths and Weaknesses

The strengths of a hazard checklist are as follows:

- Relatively cheap to produce, can be created by a single analyst
- Can be used to help prevent recurrence of previous types of harmful incident
- Can be applied to concept designs with a minimum of installation information
- Helps in applying experience gained from previous risk assessments.

The weaknesses:

- May not be able to anticipate unforeseen potential hazards in new designs
- Does not encourage new thinking about types of possible hazard specific to the installation.

Evidently, a generic checklist is a useful tool for risk assessment but should be employed in combination with other hazard identification study methods.

HAZOP (Hazard and Operability study)

A HAZOP study should preferably be carried out as early in the design phase as possible so as to have influence on the design. On the other hand, carrying out a HAZOP requires for obvious reasons a fairly complete design. As a compromise, the HAZOP is usually carried out as a final check when the detailed design has been completed. A HAZOP study may also be conducted on an existing facility to identify modifications that should be implemented to reduce risk and operability problems, or when plant alterations or extensions are to be applied to an existing facility.

A HAZOP study is used to methodically examine every part of a process or system in order to find out (a) how deviations from the intended operation can happen, and (b) whether further control measures are required in order to prevent hazards arising from these deviations from actually occurring. To do this, the HAZOP starts from a complete description of the process, including Piping and Instrumentation Diagrams (P&IDs) or their equivalent.

A HAZOP begins with 'what if' questions to identify problems before the start of operations. Every part of the installation is systematically examined by a team comprised of experts with a wide range of skills and experience relevant to the installation. Each question is set around *guide-words* developed from method study techniques. A guide-word is a short word or phrase used to help assessors imagine a deviation from the intent of the design or process. The most commonly used set of guide-words is: *no*, *more*, *less*, *as well as*, *part of*, *other than*, and *reverse*. In addition, guide-words like *too early*, *too late*, and *instead of* are used, the latter mainly for batch-like processes. The guide-words are applied, in turn, to all the relevant *parameters* of the process in question such as pressure, temperature, or composition. This allows the question being asked to explore every possible way the operation could deviate from the normal intended operation of the process, and thus to test its integrity.

The systematic nature of this technique helps failure case identification. The HAZOP is also useful in communication between the design team and the installation's operator(s). In addition, it provides training opportunities for key production staff on new installations.

The first step in the HAZOP procedure is selecting a line in the process under study. A team member with the appropriate knowledge describes the normal operating procedure or function of this line. Various scenarios prompted by the guide-word list are then applied to a relevant parameter (for example, *more* + *pressure*) to imagine a deviation from normal operation. What could cause this particular deviation is then discussed. The next step is for the team to consider how credible this particular scenario is, how significant its effects would be, and whether additional safeguards are required.

The strengths of HAZOP are as follows:

- Well known and widely used, so its advantages and disadvantages are well recognized.
- Makes optimum use of the knowledge and experience of operational staff on the team.

- Systematically examines every part of the design in order to identify every conceivable deviation, including both any possible technical faults and any human errors that may occur.
- While identifying existing safeguards, is also able to evolve further controls or safeguards.
- Particularly advantageous for on offshore installations when a team is used, since a team can include a wide range of disciplines from a variety of organizations, needed given the complexities of operations in a marine environment.

Its weaknesses are:

- Success depends on the effectiveness of the chairperson and the knowledge and experience of the team.
- Best suited for use in identifying process hazards; for it to be used for other types of hazards, it will require modification.
- Procedural/process descriptions may not be available in sufficient detail to help generate all conceivable scenarios.
- Documentation required to record the study comprehensively can be extensive and overwhelming.

That said, the costs of conducting a HAZOP study and any implementations it recommends will be more than offset by the savings, from commissioning times to lives and environmental quality saved.

Risk assessment approaches: A summary

In this series of summary descriptions of the major approaches to risk assessment used in the oil and gas industry, there has been a movement from the general to the specific and from the straightforwardly subjective to the semi-objective.

The 5-Step approach outlines the indispensable elements of a risk assessment and control process but says nothing about how judgments of risk are arrived at, nor about likelihood, severity, or types of cost.

A straightforwardly *qualitative approach* relies admittedly and solely on the judgment of experienced experts, and hence the choice of assessor or assessors becomes the critical component in such approaches' success. However, qualitative approaches do introduce the notions of likelihood and severity, even if these estimates are not necessarily expressed in relation to commonly-shared numerical scales or values.

Semi-qualitative approaches introduce the assignment of such values in a *risk ratingmatrix* of likelihood against severity in order to arrive at a single numerical value for the risk being assessed. For this reason it is a useful tool for members of an assessment team to use in coming to a consensus estimate of any particular risk in the systems and procedures they have been examining. Also, insofar as the reports of previous assessment teams on similar sets of potential hazards are available to the team in question, the team's consensus judgments can be measured against comparable situations and hence gain in objectivity.

Quantitative assessments involve the use of more sophisticated modeling tools to arrive at greater objectivity. They are also as a rule performed in the design phase of a project, which increases their likely preventative impact. HAZID, while still ultimately dependent on qualitative assessments of likelihood via failure case selection, typically makes use of hazard checklists and historical data as benchmarks. The HAZOP study is the most thorough quantitative approach, requiring complete description of a process and all the ways it interacts with the installation's various systems, and uses the guide-word method and a parameter list to drive a meticulous consideration of every possible hazard by the team. Note, however, that both HAZID and HAZOP still include the requirement of subjective assessment and creativity; in effect, the guide-word system is also a stimulus to the imagination of team members, helping them conceive of hazards they might otherwise have missed.

As Low As Reasonably Practicable (ALARP)

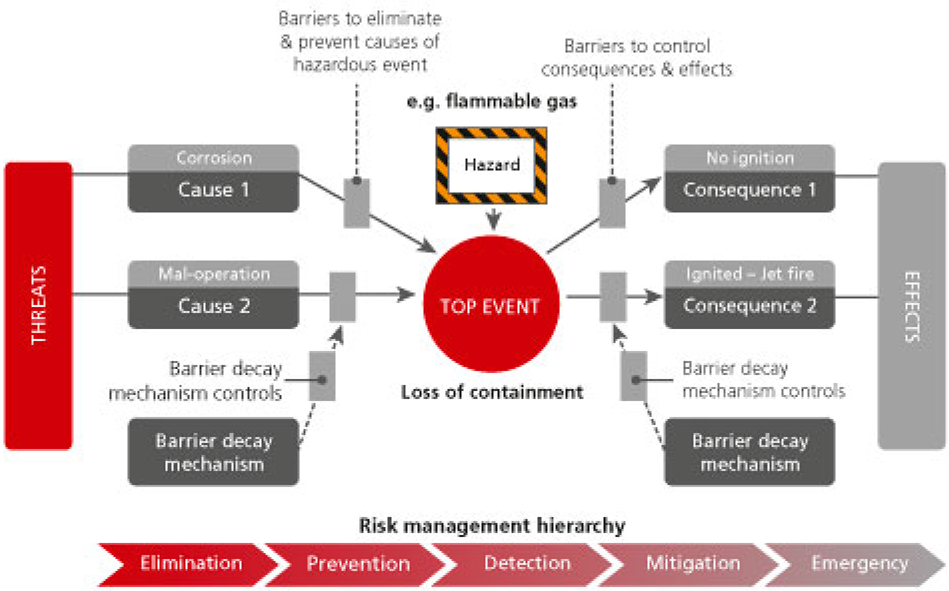
In discussing risk controls above, we have several times used the term "as low as reasonably practicable" (ALARP). In concrete terms, this means that organizations should implement appropriate safety measures to protect their employees, their plant, and its human and natural environment unless the cost in terms of money, time, and/or difficulty is grossly disproportionate to the risk reduction achieved. Once all such measures have been adopted, and assuming that they are monitored and amended as necessary, the risks are said to be "as low as reasonably practicable."

In the oil and gas industry, and particularly on offshore installations, the risks of fire and explosion and their consequences are both inherently high, not only in financial terms, but also to human life and the environment. Because of these potential consequences, the standard of "reasonable" in the industry is much higher than in most other sectors. Consequently, more stringent control measures will need to be put in place to reduce the risk to a level which can be regarded as low as reasonably practicable.

Prevention for ALARP Risk: Barrier modeling

Part of risk reduction aboard offshore facilities is *barrier modeling*, again best done first during the late design phase of a project. The barrier modeling approach uses what is called the *bow-tie risk model* as its framework. This sets out in a simple figure the *hazard*, the *top event* (the unintended loss of control or leak event), the *threats* that cause it, and the *consequences* that might result.

Between (literally, in many cases) the threats and the top event are *prevention barriers* – those controls (or controls and safeguards) that stop a threat from propagating through to the top event. Similarly, between the top event and the consequences are *mitigation barriers*, whose function is to reduce the severity of the potential consequences. This figure is usually extended to depict *barrier decay mechanisms* (or escalation factors), which show how the main pathway barriers can degrade and what specific controls are put in place to prevent this (for instance, training, competence, inspection, and/or preventive maintenance). The figure is often enhanced using color coding to show which group is responsible for each barrier (operations, maintenance, corporate, contractors, etc). Below is a simplified bow-tie diagram:



Source: DNV-GL Oil and Gas Updates

Many platform operators develop a collection of these bow-ties for their major activities—typically 10-20. When fully detailed and built out, these diagrams define all the major controls deployed to make the offshore facility safe for its workers and to protect against environmental contamination. The diagrams are then shared with staff and contractors for training purposes and with regulators to demonstrate safe control. In offshore installations, bow-ties are the primary operational tool for addressing major hazards both before (prevention barriers) and during and after (mitigation barriers) major accidents and for enabling staff and contractors to manage these safely. Risk management via barrier modeling requires the following steps:

- Building out the bow-tie diagrams and sharing them with staff and contractors
- Clearly assigning responsibility for the implementation and maintenance of each barrier to the appropriate individual or team
- Verifying that there are sufficient barriers in place for all threats— more barriers for higher risks, fewer for lower risks

- Regularly and frequently (as close to real time as possible) checking to ensure that the specified barriers are still in place and operational—that they contain no significant "holes."
- Modifying and updating the bow-tie as needed when processes are significantly altered or new technologies or systems installed.

An example of a barrier: Personal protective equipment

The most obvious form of barrier is personal protective equipment (PPE). This barrier is designed to protect the wearer from hazard but, as illustrated, it can fail in several ways. Knowing how these failures happen allows the operator to anticipate them and install control measures to minimize the risk of harm. Below are some potential "holes" in the PPE barrier:

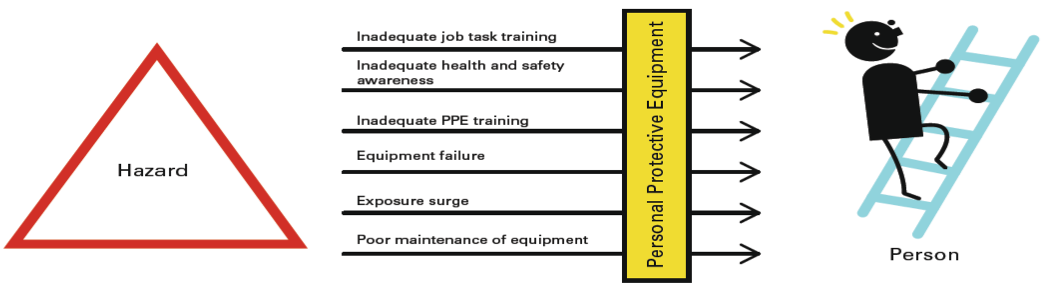


Figure 3.3 Ineffective barrier
Source: Wise Global Training.

And here are some effective barriers that can be added to reinforce the final barrier, the PPE:

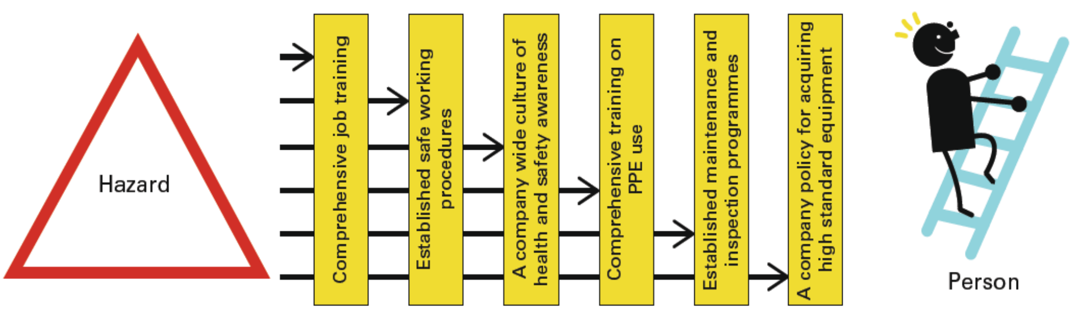


Figure 3.4 Effective barriers
Source: Wise Global Training.

In this way, the risk can be minimized by implementing several barriers—only one of which, the quality of equipment dictated by company policy, is even indirectly physical. Although any of these barriers can be breached in several ways, each of them reduces the exposure to some extent. In order for the hazard to be realized, all of the barriers would have to be breached simultaneously. The most important fundamental barriers are:

- Good design and operational specifications
- Good operational processes and procedures

- Robust inspection and maintenance techniques and schedules
- Adequately trained (and retrained) and fully competent personnel

The risks associated with the introduction of a P2G system on an offshore platform are high from both sides: the risk from the P2G system to the platform and the risk from the platform to the P2G system. These two has aspects of risk must be taken into consideration from early on in the project so that risk reduction will be inherent in the design. Fortunately, the oil and gas industry has already established standards and guidelines to deal with all potential risks and hazards. This section aims to increase awareness of both the hazards and the risk assessment methods (guidelines, standards, and techniques) used to mitigate them, so that during the next stage of the project (the actual feasibility study) the appropriate risk assessment methods will be implemented and risk will be inherently minimized in the design stage.

The hazards involved in implementing offshore P2G are not the first and most important hazards in the industry, and if previous hazards were overcome, these can be too. However, the extra care required during the design and execution will constitute an important additional cost to the system.

4.5 Material selection, corrosion risk assessment, and corrosion management

Introduction

When considering installing a P2G system offshore, a major concern is the harsh conditions that the system will be facing in the North Sea, which are quite different from typical conditions onshore. One of the major differences is corrosion level. At sea, corrosion is much more rapid and severe than inland. This has to be taken into consideration at an early stage of the design phase.

This subsection discusses what actions should be taken to incorporate established knowledge concerning corrosion identification and corrosion management for the marine environment and how it could be applied to our case. First, a corrosion risk assessment of the existing power-to-gas infrastructure has to be made so as to identify possible threats and hence the changes that must be made in order to implement a P2G system offshore. These changes has to be implemented at the design stage. The concept of inherent safety will be introduced, and what should be considered at a high level at that stage. The criteria needed when selecting materials for a power-to-gas system will be discussed. Finally, the implementation of a corrosion management system and corrosion monitoring for the power-to-gas system will be summarized. These steps–corrosion risk assessment, needed changes and materials selection in adapting P2G technology for offshore, and corrosion monitoring systems—should be followed in the order presented here so as to eliminate all the threats caused by corrosion and to prevent future problems.

- This section is based on:
- The NORSOK standards prepared and published with support from the Norwegian Oil Industry Association (OLF), the Federation of Norwegian Industry, the Norwegian Shipowners' Association, and the Petroleum Safety Authority of Norway. The NORSOK standards are normally based on recognized international standards, adding the provisions deemed necessary to fill the broad needs of the Norwegian petroleum industry. Section 3.5, Materials Selection, is based on NORSOK standards.
- A review of corrosion management for offshore oil and gas processing prepared by Capcis Ltd. for the Health and Safety Executive. The document has been produced in response to an initiative led by the Offshore Safety Division of the UK Health and Safety Executive (HSE) and supported by the UK offshore industry.

4.5.1 Corrosion risk assessment on existing projects

A Corrosion Risk Assessment must be completed and inspection data must be collected and analyzed on the already available and functioning power-to-gas systems (which are currently all onshore). Necessary corrective action(s) required need to be identified and put into place to make the system suitable for Offshore environment.

For any system there are only six different options that can be considered:

Appropriate Materials	Options	C-Mn Steels, corrosion resistant alloys, non-metallics
	Locations	Pipework, vessels, tanks, valves. CRAs for lines/deadlegs that don't receive inhibitors
	Actions	Selection of appropriate material at construction/major refurbishment stage
Chemical Treatments	Options	Corrosion inhibitors, biocides, oxygen scavengers
	Locations	Pipework, vessels, tanks. Use selected packages in gas lines/water lines
	Actions	Batch/continuous dosing, package modification
Coatings & Linings	Options	Organic coatings, metallic coatings, linings, cladding
	Locations	Gas and liquid phases, internal & external
	Actions	Inspect during application, future inspection & repair schedule depends on duty
Cathodic Protection	Options	Sacrificial anodes, impressed current systems
	Locations	Vessels containing aqueous liquids, large bore pipework
	Actions	Need ability to monitor performance on-line
Process Control	Options	Identify key parameters, pH, water-cut, temp, pressure, dehydration
	Locations	Internals of vessels/pipework
	Actions	Dehydration of gas, control velocity/fluid shear stress, pressure reduction
Design Detailing	Options	Ensure ease of access/replacement
	Locations	Eliminate crevices, galvanic effects
	Actions	Stress raiser elimination, ensure smooth fluid flow

4.5.2 New Build - Inherent Safety

The planning process should encourage control of risks using the concept of *inherent safety*. The principles of inherent safety are more effective at the concept stage and detailed design stages. According to the*Review of Corrosion Management for Offshore Oil and Gas Processing*, the general principles include:

- Addressing the issue explicitly at the earliest stages of concept design to eliminate, where possible, hazards associated with corrosion damage that combine with operational loads to produce failures. Design assessments should look for sites of probable corrosion and consider the use of corrosion-resistant materials or another effective method of corrosion control.
- Designing to minimize corrosion damage to safety critical items and systems.
- Ensuring that key support structures for equipment have high reliability and resistance to failure.
- Selecting locations, configurations, and orientations that minimize threats to the integrity of equipment: for example, design detailing of impingement/wear plates and drainage, and removal of deadlegs where corrosive conditions develop and chemical treatments are ineffective.
- Designing to survive local/component failure by maximizing redundancy.
- Designing to allow more reliable and effective inspection and ensure adequate access for inspection/monitoring equipment.
- Designing for maintainability— easy removal of pumps, motors, valves.

4.5.3 Materials Selection

General principles for materials selection are as follows:

The materials selection process should reflect the overall philosophy regarding design lifetime, cost profile (CAPEX/OPEX), inspection and maintenance philosophy, safety and environmental profile, failure risk evaluations, and other specific project requirements.

Materials selection requirements

Materials selection should be optimized and should provide acceptable safety and reliability. As a minimum, the following should be considered:

- Corrosivity, taking into account specified operating conditions including start up and shut-down conditions;

- Design life and system availability requirements;
- Failure probabilities, failure modes, and failure consequences for human health, environment, safety and material assets;
- Resistance to brittle fracture;
- Inspection and corrosion monitoring;
- Access and philosophy for maintenance and repair;
- Minimum and maximum operating temperature;
- Minimum and maximum design temperature;
- Weldability (girth welds and overlay welds);
- Hardenability (carbon and low alloy steels).

For the final material selection, the following additional factors should be included in the evaluation:

- Priority should be given to materials with good market availability and documented fabrication and service performance.
- The number of different materials should be minimized considering stock, costs, interchangeability, and availability of relevant spare parts.
- Environmental impact assessment and authority permissions, e.g., on discharge of chemicals like corrosion, must be obtained.
- Inhibitors should be considered.

4.5.4 Corrosion Management

Finally, after the completion of the design, a corrosion management program should be prepared and implemented before the startup of production.

In this document, corrosion management is defined as follows:

“Corrosion management is that part of the overall management system that is concerned with the development, implementation, review, and maintenance of the corrosion policy.”

A general corrosion management system has been outlined that provides a progressive framework compatible with the requirements of an offshore safety management system aimed at securing the integrity of topside processing equipment. The safety management system comprises effective plans and organizations to control, monitor, and review preventative and protective measures to secure the health and safety of employees.

This section, however, does not provide a prescriptive framework for corrosion management. Rather, it outlines techniques that have been shown to be successful in the identification and management of the risks posed by corrosion to offshore processing facilities.

Why Manage Corrosion?

It is widely recognized within the oil and gas industry that effective management of corrosion will help achieve the following benefits:

- Statutory or corporate compliance with safety, health and environmental policies
- Reduction in leaks
- Increased plant availability
- Reduction in unplanned maintenance
- Reduction in deferment costs

4.5.5 Structured framework for corrosion management

In the operation of an offshore oil and gas facility, the management of corrosion falls within the functions of many parts of the operator's organization and increasingly extends into contractor organizations. It is therefore important that corrosion management activities are carried out within a structured framework that is visible and understood by all parties and where roles and responsibilities are clearly defined.

The key elements of such a framework, based on an existing HSE model [3], are illustrated in Figure 3. Figure 3 shows the specific feedback loops necessary for control, review, audit and reporting purposes.

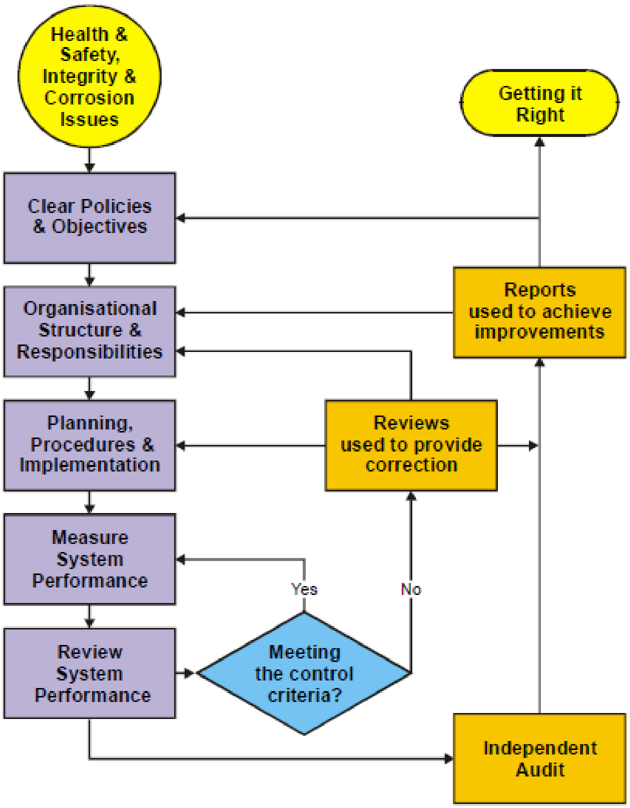


Figure 3. Development of the Management Process

A structured approach like this one is typically adopted, for instance, by Total Quality Management (TQM) schemes [4] and is used to control risks within organizations.

The success of any corrosion management system relies on the regular auditing and measurement of performance. Audit and measurement activities also contribute feedback, helping to ensure continuous improvement in corrosion management activities.

Practical experience from the North Sea has shown that the development of comprehensive corrosion management systems, coupled with a commitment by the operator, the maintenance contractor, and specialists, sub-contractors, and consultants, can lead to a major improvement in the operation of offshore topside process facilities.

Corrosion monitoring

Management of corrosion risks is achieved through a combination of proactive and reactive monitoring measures.

Proactive measures are those whereby the requirements and implementation of the monitoring system or inspection program are identified and put in place before any corrosion or deterioration has been observed, based either on the output of a Corrosion Risk Assessment or on some other review and identification of areas of possible or likely corrosion.

Reactive measures are implemented after a problem has been identified, either as a consequence of proactive monitoring or because of an incident or observation of a problem.

Proactive monitoring itself consists of *in-line* and *online* systems. These involve the collection of data, which enhances knowledge of the rate of corrosion degradation and allows steps to be taken that will prevent failure.

Also required are *offline* systems that employ techniques to retrospectively identify corrosion degradation and quantify its causes, onset, extent, and degree to which it has occurred. Reactive monitoring will normally be limited to off-line systems, and is also normally aimed at quantifying the extent and distribution of any deterioration that has occurred.

Successful corrosion management requires that cost-effective combinations of various mitigation procedures be employed that minimize risks to asset integrity, control hydrocarbon releases, and ensure safety. The choice of corrosion control for any specific asset depends on factors such as fluid composition, pressures and temperatures, aqueous fluid corrosivity, facility age, and the technical culture of the organization.

4.6 CO2 Source Offshore

We briefly described in section 2.5 how CO_2 is captured and how it can be transported to the offshore platform. In this section we will describe what options are available as sources of CO_2 offshore. The availability of CO_2 is a major barrier to the installation of the demonstration plant. Since CO_2 is required for the production of methane, without a reliable supply of CO_2 the power-to-methane system is not possible. The source of CO_2 is one of the factors, along with the availability of electricity, that determines the selection of location of the installation of the demonstration plant.

In the case where CO_2 is needed offshore, two options arise to deliver a reliable constant source of CO_2. The first option is for CO_2 to be captured onshore and transported to the platform. Part of it will be used for the methanation process and the rest, which constitutes the major part, will be stored in geological storage mediums or used for enhanced oil recovery. The second option is for CO_2 to be captured offshore from direct purification of the extracted natural gas. Part of the extracted CO_2 will be used and the remainder will be stored or used for enhanced gas recovery.

4.6.1 First Option: CO2 is captured onshore and transported to the platform

As briefly discussed in Section 2, the methanation process requires a constant source of CO_2. CO_2 is emitted principally from the following:

- The burning of fossil fuels, both in large combustion units such as those used for electric power generation and in smaller, distributed sources such as automobile engines and furnaces used in residential and commercial buildings.

- In a much smaller quantity, also from some industrial and resource extraction processes, notably natural gas production.

CCS would most likely be applied to large point sources of CO_2 such as power plants or large-scale industrial processes. Since most of these sources are available onshore, it is obvious that this option will be widely applied. However, to reduce transportation cost, the sources closed to the shore should be considered first.

4.6.2 Second Option: Carbon is captured offshore

The second option is natural-gas sweetening: offshore capture by directly extracting CO_2 from the natural gas to reduce its CO_2 content.

Raw production natural gas must be purified to meet specified quality standards dictated by the major pipeline transmission and distribution companies. These quality standards vary and are usually a function of a pipeline system's design and the markets it serves. Often, the standards specify that the natural gas contain no more than 2%-3% carbon dioxide.

Carbon dioxide is a naturally occurring diluent in oil and gas reservoirs, and it can react with H_2S and H_2O to form corrosive compounds that threaten steel pipelines. It is therefore critical that pipeline levels of carbon dioxide are no more that 2%-3%. Well-head natural gas can contain as much as 30% carbon dioxide. Removal of CO_2 from natural gas utilizes membrane technologies or larger amine plants.

While accurate figures are published for annual worldwide natural gas production (BP, 2004), none seem to be published on how much of that gas contains CO_2 . Nevertheless, a reasonable assumption is that about half of raw natural-gas production contains CO_2 at concentrations averaging at least 4% by volume. These figures can be used to illustrate the scale of this CO_2 capture and storage opportunity. If half the worldwide production of 2618.5 billion m^3 of natural gas in 2003 is reduced in CO_2 content from 4 to 2% mol, the resultant amount of CO_2 removed would be at least 50 Mt CO_2 yr-1.

Currently, there are three operating natural gas plants in the world that are designed to capture and store CO_2 : a Statoil plant at Sleipner in the North Sea, the K12B project in the Dutch North Sea still under development, and the BP-Sontrach-Statoil In Salah plant in Algeria. Both the Sleipner and the In Salah facilities are capable of capturing about 1 Mt CO_2 /yr. Below is an overview of the projects that could be interesting for our project and are located in the North Sea

Overview of the Sleipner Project

The Sleipner CO_2 gas processing and capture unit was built in order to evade the 1991 Norwegian CO_2 tax. Sleipner earns CO_2 credit for the injected CO_2 and does not pay the tax.

Sleipner was the world's first commercial CO_2 storage project. The natural gas produced from the Sleipner West field contains up to 9% CO_2. However, in order to meet the required export specifications and the customers' requirements, this has to be reduced to a maximum of 2.5%. The CO_2 is removed from the hydrocarbons produced at an offshore platform before being pumped back into the ground, and the hydrocarbons are then piped to land. Had this process not been adopted, and the CO_2 produced been allowed to escape to the atmosphere, the licensees of the Sleipner West field would have had to pay NOK 1 million/day in Norwegian CO_2 taxes. By May 2008, Statoil had stored over 10 million tons of CO_2. There is no evidence of CO_2 leakage and the CO_2 remains in situ. CO_2 is captured using amine technology. Injection into the Utsira Formation currently costs $17 US/Ton CO_2. The Utsira Formation is a 200-250m thick massive sandstone stratum, which is estimated to be capable of storing 600 billion tons of CO_2. Three-D seismic monitoring of CO_2 injection into the Utsira Formation shows that there is no leakage of the CO_2 into other layers.

Overview of the K12-B project

The K12-B gas field is located in the Dutch sector of the North Sea, some 150 km northwest of Amsterdam (Figure 1). It has been producing from the Upper Slochteren Member (Rotliegend) since 1987. The natural gas produced has a relatively high CO_2 content (13%) and the CO_2 is separated from the production stream prior to gas transport to shore.

The CO_2 used to be vented into the atmosphere (the usual industry practice) but is now injected into the field above the gas-water contact at a depth of approximately 4000 m. K12-B is the first site in the world where CO_2 is injected into the same reservoir from which it originated. CO_2 injection began in May 2004. At the same time, extensive measurement programs have been undertaken. These programs are dedicated to determining the potential for both CO_2 storage and enhanced gas recovery (EGR).

Figure 1.
K12-B platform and location.

The project is being carried out in 3 phases:

Phase 1: The feasibility study where first costs estimates indicated that the costs for a full-scale injection will range between € 5-10 per ton of CO_2 .

Phase 2 (still under production): The pilot study, where in 2004-5, two tests of CO_2 injection into the reservoir were made and CO_2 injection tracers were used to trace the migration pathways. Current monitoring activities are funded by the TKI-Gas project *Innovative tracer injection in K12-B*. The participants are GDF Suez E&P, CSIRO, and TNO.

Phase 3: The scale-up to subsequent industrial phase, whose injection potential is about 310,000 to 475,000 tons/year of CO_2 .

As of March 2015, CO_2 injection continues, and since 2004 a total of 90 kT of CO_2 has been injected in the nearly depleted gas field K12-B.

4.6.3 Factors Affecting CCS Implementation

The implementation of CCS is very dependent on the cost of capture, and in the case of capture from a power plant, its impact on the price of electricity. It is also dependent on policymakers and the economic situation. Many CCS projects completed the design phase and feasibility study but were canceled at the last minute, while many demonstration plants were proven successful but were never upgraded to the industrial level. These circumstances greatly affect the implementation of power-to-gas projects offshore, since in such projects CO_2 is needed to produce synthetic methane. As discussed earlier, without a constant supply of CO_2, synthetic methane cannot be produced.

The issue of CO_2 supply also affects the installation of our demonstration plant, since the selection of the location is completely dependent on the source of CO_2. With few or no CCS projects in operation, the power-to-methane project cannot be implemented, and the option of simply producing hydrogen should be selected.

However, the availability of a demonstration plant such as the K12-B project makes the task easier. The demonstration plant can be easily installed next to the separation plant and some of the extracted CO_2 could be used for the methanation process. The platforms where the K12-B and Sleipner projects are situated are both very attractive for installing the demonstration plant, although K12-B is a bit more desirable because of its location closer to shore.

In fact a comparison study of the location of wind farms (since electricity is the most important input for the P2G system) and of the K12-B and Sleipner platforms, or any platform near a source of CO_2, should be performed. Where a wind farm is close enough to such a platform and all other requirements are met (security, availability of space on board, and so on) this platform should be used for the demonstration plant. This recommendation is of course from a technical point of view and does not take into consideration other barriers, whether financial, environmental, or political.

4.7 Weight and Volume analysis

Weight and volume analysis is an important factor to consider when exploring the possibility of installing a P2G system on existing oil and gas platforms. This barrier depends very much on the size of the P2G plant and on the chosen platform, since platforms come in different types and sizes depending on the purpose of the platform and the depth of the sea where they are located. After selecting an appropriate platform (that is, a platform close to sources of electricity CO_2 and where all other requirements are met) we select the size of the P2G plant it can accommodate. Once the size of the P2G is plant determined, a weight and volume analysis should be done to check that the platform's structure and volume can accommodate the additional system. If not, some equipment can be decommissioned, structural reinforcement can be done, or an addition to the platform can be installed. It all depends on the specific platform in question.

Oil and gas platforms are carefully designed to achieve weight and space saving while incorporating all the necessary process and utility equipment, including a drilling rig, injection compressors, gas turbine generators, accommodation for operating personnel, piping, a crane, a helipad, and oil and gas storage. For this reason it is very difficult to install a new system without sacrificing another system already installed.

Offshore structures are mainly designed for the following types of loads:

- Permanent load (dead load)
- Operating live load
- Environmental loads
- Wind load
- Wave load
- Earthquake load
- Construction-installation loads
- Accidental loads

Although the design of offshore structures is dominated by environmental loads, especially wave load [11], the extra weight added by the P2G system should be analyzed. The platform should be able to accommodate the following additional equipment: AC-DC converter (if needed), electrolyzer, methanation process, water treatment station, post-treatment station for gases, gas storage, and all the related piping, instrumentation, and firefighting equipment.

In the case of the large-scale implementation of P2G, the gas storage and the electrical hub together add the biggest weight to the platform. An example is Borwin2, an 800MW transformer station located about 100 km northwest of the North Sea Island of Borkum in Germany. From available public information, this HVDC platform weighs about 12,000 tonnes, with a length of 72m and a width of 51m [12].

Given that the size of a typical platform in the North Sea is around 70x80m, a detailed weight-and-volume analysis should be done to determine which components should be removed before the installation of the P2G system.

In the case where the volume is not enough, a neighboring platform could be used, since the platforms are usually installed in clusters with several kilometers between each platform. One platform could be used for the P2G process and the other as a HVDC platform. If the structure of the platform cannot handle the weight added, additional pillars could be put in place to compensate for the added load.

The demonstration plant will be relatively small. However, it will still constitute an extra load and require extra space on the platform. Once the platform that meets all the other requirements (source of electricity and source of CO2), a detailed weight and volume analysis should be done to determine which components should be removed and if they can be removed before the installation of the P2G system. This platform may be still functioning, and hence perhaps no equipment can be removed to accommodate the P2G system. In this case an extension of the platform can be installed for the P2G system.

4.8 Installation of the system offshore

In designing the system and constructing its various components, the harsh environment offshore should be taken strongly into consideration. The system must be weather-resistant (wind, water and salt) and much more durable than the systems onshore (see above on Corrosion Management).

In addition, the fact that the system will be transported to an offshore site should be addressed in the design phase. Specifically, the system should be modular and compact to facilitate transportation and reduce installation time offshore.

4.9 Technology statuses and challenges for water electrolyzers

Independent of the particular technology, the current major drawbacks of currently available water electrolysis systems are limited capacity, suboptimal degradation behaviors, and high front-end investment and operating costs. Substantial R&D efforts are still needed for each of the water electrolysis technologies to overcome those problems and to pave the way for a broader introduction of electrolytic hydrogen production into the market.

4.9.1 Technology status and challenges for alkaline water electrolyzers

Alkaline water electrolysis is a mature technology that is currently standard for industrial electrolytic hydrogen production at a MW (industrial) scale. The key advantages of this technology are its proven durability, maturity, availability, lack of PGM-containing component materials, and comparatively low specific costs.

Two critical disadvantages of alkaline electrolyzers are low current densities and low operating pressures. The current density significantly influences specific system size and hydrogen production costs, which gives it particular importance. Improving the catalytic activities of the electrodes, developing more advanced electrode designs, optimizing the separators, and raising system pressure are topics of current R&D activities, aiming to increase current density by a factor of 1.5–2. For many applications, especially where the hydrogen produced has to be stored or transported, external compressors are required. This adds cost and complexity to alkaline electrolysis systems. Hence the advantages of raising the operating pressures are manifold. An increase up to 60 bar is a widely shared goal of current developments.

With respect to system durability, however, typical degradation rates of 1–3 µV/h are offering tens of thousands of hours of operation and a regular general overhaul every ~10 years. This satisfies industrial requirements already quite well.

All this holds for conventional, industrial applications under broadly constant operating conditions and fairly constant H_2 production levels. In the course of power-to-gas applications, electrolyzers are coupled to renewable sources of electricity, which mostly supply intermittent power. Up to now, this dynamic operation commonly results in lower gas quality, lower system efficiency, more frequent system shut-downs and generally reduced system durability. The system's ability to follow rapid load variations is not limited by the kinetics of participating electrochemical reactions but rather by the inertia of auxiliary system components. Recent reports show that advanced alkaline systems, which are specially designed for intermittent power applications, are able to provide an extended dynamic range of ~10–100% of rated capacity and improved response times in the few-seconds range. Relatively long cold start times, the necessity of holding currents during stand-by, and gas purity problems during partial load periods are still some of the most critical issues for intermittent operation of alkaline electrolyzers. However, the implications for operational lifetime of such intermittent operation remain mostly unknown, and elucidation of those complex problems is the subject of various current research projects. In addition, these advanced systems are only available on a small scale and, like other electrolysis technologies, need to be scaled up.

The specific investment costs for alkaline systems in €/kWel predominantly depends on the system size and the operating pressure. Pressurized systems are roughly estimated to be 20–30% more expensive than atmospheric systems over a wide range of system sizes. Raising the capacity of electrolysis systems from the kWel to MWel+ range results in a reduction of investment costs by a factor of ~2.5–3. This yields a rough estimate of specific investment costs of around 1,000–1,300 €/kWel on average. The electrolysis stack generally accounts for 50–60% of the total system costs. This is true for basic system configurations. However, upgrading the system with components like (for example) enhanced purification systems, compressors, more efficient AC/DC converters, and so forth can easily add additional 25–50 % to the basic costs. For alkaline technology it is generally estimated that cost reductions in the future will be mainly driven by economies of scale rather than by the further development of particular components.

In summary, alkaline electrolyzers are based on a technology that is highly developed, scaled up, proven, and comparatively cheap. Low current densities and limited modes of dynamic operation are currently major limitations of that technology. To make this technology fully compatible with P2G applications, further research is required.

4.9.2 Technology status and challenges for PEMEC electrolyzers

PEMEC technology is generally less mature than AEC technology and up to now has been used exclusively for small-scale applications. However, this technology has received a great deal of attention in the past decade. This is mainly because of its key advantages like high cell efficiencies, high current densities at low corresponding cell voltages, and hence high power densities and the ability to provide highly compressed hydrogen. Furthermore, PEM technology allows a highly flexible mode of operation enabled by very fast shut-down and startup times, very fast load following, and a partial load range of 5–100%. Those advantages perfectly match many of the basic requirements of P2G applications, being directly coupled to fluctuating renewables, and being connected to high-pressure hydrogen storage units.

The main weak points of the PEM technology are the difficult upscaling procedures due to system complexity, limited global availability of PGMs for catalysis, and expensive component materials, which together lead to rather high specific system costs.

In the past, low system durability has also often been noted as a disadvantage. Recently, however, significantly improved degradation rates in the range of 10 µV/h or lower have been announced by various manufacturers. This shows that efforts to solve stability problems are on the way to catching up with AEC technology. In spite of the difficulties of upscaling, system size has increased significantly during recent years. Major PEM manufacturers announced in 2013 that they are working on stacks in the several-100s kW to even MW range, to be launched in the next few years.

Considering current R&D trends, it is not generally expected that cell efficiencies, operating pressures, or current densities will be significantly increased in the near future. It seems that the focus is presently more on further development of other factors such as materials cost and easier upscaling.

5.0 Conclusion

This report was prepared for two purposes.

- The first is to increase awareness of P2G as a technology so that government and business professionals and the general public understand what it is, its advantages, the options it offers and their corresponding outputs.
- The second is to identify the technical barriers to the installation of a demonstration power-to-gas system offshore on a disused or still functioning platform.

Note that we have only identified the technical barriers. All the other barriers (PESTEL) are not within the scope of this report. At this stage (pre-feasibility) it is more important to determine whether the project can become technically feasible and whether any major technical barrier can halt it. At later stages all the PESTEL barriers can be analyzed. Furthermore, we have not even identified all the technical lbarriers, since other unforeseen ones will emerge when a platform is selected and when the system is in design and planning phase.