

Power to gas (H_2): alkaline electrolysis

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Abstract

Alkaline electrolysis as an industrial process has been around since the advent of commercial power at the beginning of the 20th century with most large-scale plants (up to 165 MW) built between the 1920s and 1980s in response to hydrogen demand for the ammonia industry. With the emergence of cheap hydrogen from steam methane reforming from the late 1980s, the production of small-scale plants (around 1 MW) dominated the electrolysis market. But in recent years, plant scale has increased (10 MW with few at 100 MW) compared to scale in the 1990s in response to increased demand for green hydrogen and moving away from hydrogen production from fossil fuels. This chapter addresses the learning rate of alkaline electrolysis systems from the period 1956–2016, issues with generating experience curves for the system as a whole as opposed to on a component basis, associated cost reduction drivers, and the future outlook of the alkaline electrolysis market until 2030.

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10.1 Introduction

Producing hydrogen is based on the scientific principle of dissociation of water, where two molecules of water (H_2O) are separated into two molecules of hydrogen (H_2) and one molecule of oxygen (O_2). The dissociation of water is an endothermic reaction. The use of electricity for producing hydrogen is called electrolysis (Abbasi and Abbasi, 2011; Twiddle and Weir, 2015). Electrolysis is performed by applying a voltage to two electrodes that are submerged in water, to which an electrolyte is added. For electrolytes, high conductivity is important to reduce transport losses. This can be achieved by using strong acidic or strong alkaline electrolytes (Schalenbach et al., 2016a,b). Electrolysis technologies are usually categorized in low-temperature systems with alkaline cells or proton exchange membrane (PEM) cells and high-temperature systems with solid oxide cells. From these types the alkaline electrolyzer is the incumbent technology and currently the most mature and economically attractive technology (IEA, 2019). Common alkaline electrolyzers use potassium hydroxide as electrolyte. These electrolyzers do not require valuable or rare metals. Typically they use electrodes made of nickel (NREL, 2009).

An overview of hydrogen production by electrolysis at the cell level is shown in Fig. 10.1A and at the system level in Fig. 10.1B. Besides the electrolysis module, a typical system includes utilities such as demineralized water, cooling water, instrument air, hydrogen gas dryer, and purifier (NREL, 2009).

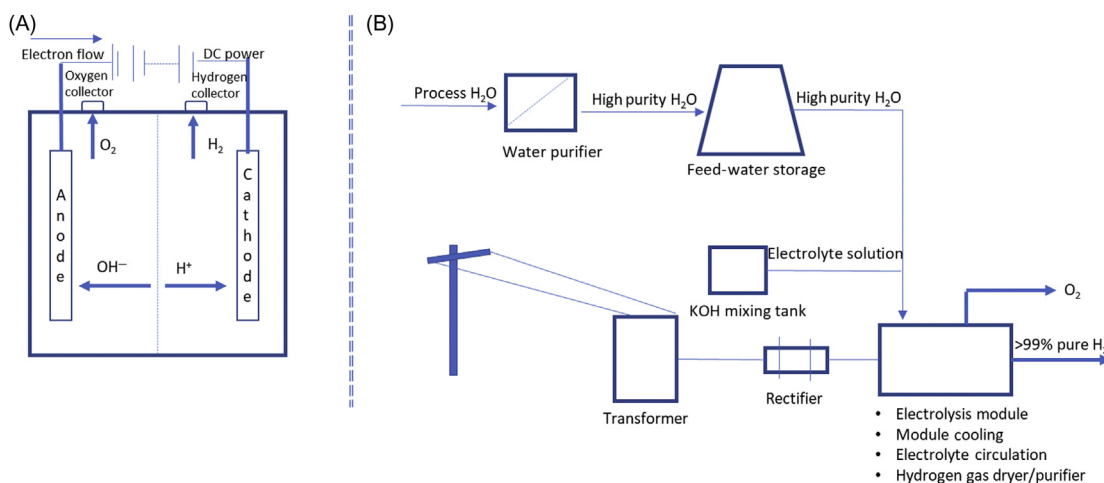


Figure 10.1

Schematic overview of alkaline electrolysis (A) and typical process for hydrogen production via electrolysis (B). Source: Adapted from Santos et al. (2013); NREL (2009).

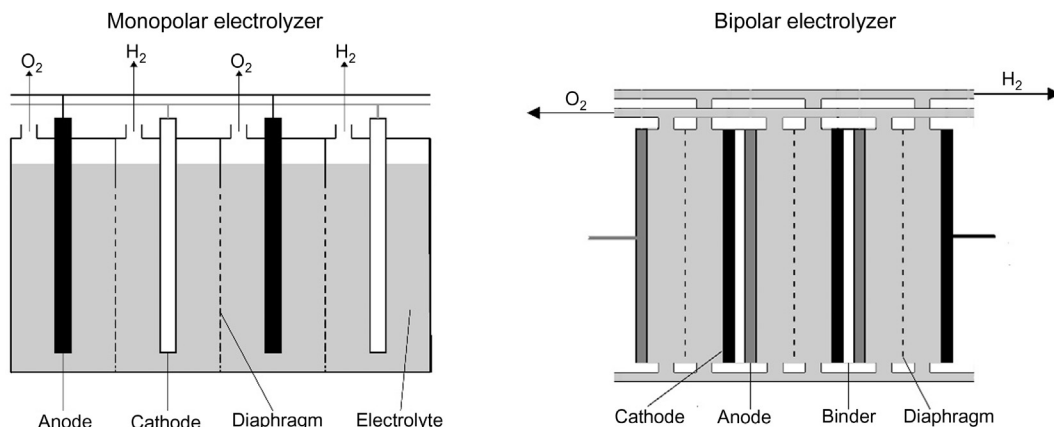


Figure 10.2

Schematic diagram of monopolar and bipolar electrolyzers. Source: Courtesy of [Farlie \(2019\)](#).

Water electrolysis was discovered in 1800 by Nicholson and Carlisle shortly after Volta invented the electric battery ([Kroposki et al., 2006](#)). Water electrolysis as an industrial process has been around since the advent of commercial power at the beginning of the 20th century. For most of the 20th century, there were two competing cell architectures: monopolar and bipolar, though bipolar is currently the dominant cell architecture.

In the monopolar electrolyzer, each cell is located in an individual tank of electrolyte and then connected to other cells by external bus bars, the term monopolar referring to each side of the cell having a single polarity being either an anode or a cathode ([Fig. 10.2](#)).

In the bipolar electrolyzer, cell stacks are assembled back to back similar to a filter press, and each side of the cell is bipolar, being a cathode on one face and an anode on the other. Although the first electrolyzers, coming out of the laboratory, were monopolar, they were closely followed by the Schmidt–Oerlikon cell, the first commercial bipolar electrolyzer, which was introduced in 1902 ([Menth and Stucki, 1978](#)). The electrolyzer industry grew substantially during the 1920s and 1930s with manufacturers Oerlikon, Norsk Hydro, and Cominco supplying plants in multimewatt sizes. Most of these installations were near hydroelectric plants that supplied an inexpensive source of electricity ([Kroposki et al., 2006](#)).

Several alkaline electrolysis plants with capacity of up to 165 MW were built in the last century in countries with access to large hydropower resources—Canada, Egypt, India, Norway, and Zimbabwe ([IEA, 2019](#)). Commercialization of bipolar designs was largely led by Norsk Hydro that built the Rjukan plant rated at 125 MW prior to 1940. The world's largest operating electrolysis plants were built in the 1940s after World War II for ammonia production during the reconstruction of Europe ([Christiansen and Andreassen, 1984](#)) and

later for ammonia plants in Africa including the hydrogen plant at Aswan, the world's largest water electrolysis plant with a nominal rating of 162 MW and a hydrogen generation capacity of 32,400 m³/h (KIMA). Following these developments, electrolysis played a niche role in providing hydrogen in markets that were not economically serviced by merchant gas produced from fossil fuels. The introduction of liquid hydrogen, which came with the US space program in late 1950 (Sloop, 1959), further extended the reach of merchant gas supply and reduced market share for hydrogen supplied by electrolysis. This, in turn, reduced the average unit size additions of electrolyzers. With declining costs for renewable power (solar photovoltaic (PV) and wind), interest is now growing in water electrolysis for hydrogen production and in the scope for further conversion of that hydrogen into hydrogen-based fuels or feedstocks, such as synthetic hydrocarbons and ammonia, which are more compatible than hydrogen with existing infrastructure (IEA, 2019).

In countries with readily accessible renewable resources and significant dependence on natural gas imports, hydrogen produced from electrolysis connected to renewable electricity may be cheaper than producing it from natural gas. This statement is apparent in a country such as China. Currently, the share of electrolyzers being built in China is increasing (IEA, 2019). IEA's (2019) estimates that in China, for an alkaline electrolyzer with a CAPEX of 398€₂₀₁₇/kW connected to hybrid onshore wind and solar PV systems running at 5000 load hours and with a electricity price of 15€₂₀₁₇/MWh, the price of hydrogen ranges between 1.4 and 2.2€₂₀₁₇/kgH₂. The prices for a similar system in Europe running at 5000 load hours with an electricity price of 41€₂₀₁₇/MWh start from 2.3€₂₀₁₇/kgH₂ and can exceed 3.5€₂₀₁₇/kgH₂. The price of hydrogen from natural gas in China ranges between 1.9 and 2.5€₂₀₁₇/kgH₂ (IEA, 2019). Currently, several projects are under development globally with electrolyzer sizes of 10 MW or more, with few projects aiming for 100 MW electrolyzer units (IEA, 2019).

10.1.1 Global hydrogen capacity

Currently, the global demand for pure hydrogen is around 70 Mt, which is used in oil refining and the ammonia production industry. An additional 45 Mt of hydrogen as part of a mixture of gases, such as synthesis gas, is used in methanol and steel production. Less than 0.001 Mt per year of pure hydrogen is used in fuel-cell electric vehicles, mostly derived from natural gas (IEA, 2019).

The majority of hydrogen produced today is derived from fossil fuels—mainly natural gas, and around 60% of it is produced in production facilities where hydrogen is the primary product. Other fossil fuel sources are coal, while a small fraction comes from renewable sources, namely, water electrolysis (IEA, 2019). One-third of global supply is “by-product” hydrogen, meaning that it comes from facilities and processes designed primarily to produce something else. This by-product hydrogen often needs dehydrating or other types

of cleaning and can then be sent to a variety of hydrogen-using processes and facilities. Most hydrogen is currently produced near to its end use, using resources extracted in the same country (IEA, 2019).

Hydrogen can be obtained from fossil fuels and biomass, or from water, or from a mix of both.

Around 2% of the global total primary energy demand is used for the production of hydrogen today (IEA, 2019). Natural gas is currently the primary source of hydrogen production via steam methane reforming (SMR). A total of 6% of the global natural gas use is dedicated to a hydrogen production of around 52 Mt (IEA, 2019). The second dominant source is coal due to its dominant role in China. A total of 2% of the global coal use is dedicated for hydrogen production (16 Mt). Oil and electricity account for 1.4 Mt of the dedicated production of which electricity only accounts for 0.1% of the total dedicated hydrogen production which translates to around 0.07 Mt (IEA, 2019).

Besides fossil sources, hydrogen is also produced from renewable sources such as electrolysis. Less than 1% of dedicated hydrogen production globally comes from water electrolysis today, and the hydrogen produced by this means is mostly used in markets where high-purity hydrogen is necessary (e.g., electronics and polysilicon) (IEA, 2019). It is important to note that this share differs from shares of 4% reported by other authors (Bertuccioli et al., 2014; Rashid et al., 2015; IRENA, 2018). This discrepancy in share could be attributed to alkaline electrolysis being a global traded commodity, which creates an uncertainty in accounting for the total installed capacity. In addition to the hydrogen produced through water electrolysis, around 2% of total global hydrogen is created as a by-product of chloralkali electrolysis in the production of chlorine and caustic soda (IEA, 2019).

Producing all of today's global dedicated hydrogen output (70 MtH₂) from electricity would result in an electricity demand of 3600 terawatt hours (TWh), which roughly translates to 14% of the global electricity supply. This is more than the total annual electricity generation of the European Union, which accounts for 13% of the global electricity supply (IEA, 2019).

Table 10.1 shows the performance of renewable hydrogen production technologies compared to conventional hydrogen production on small and large scale.

Alkaline electrolyzer is considered the most mature and economically attractive electrolyzer technology. However, it remains far more expensive than large-scale SMR. As PEM and SOEC electrolyzer technologies are less developed, they are considered to have greater potential for cost reductions and technology improvements (OECD/IEA, 2015). Furthermore, PEM are better suitable for electrolysis with intermittent electricity sources, such as wind or solar (OECD/IEA, 2015; Götz et al., 2016), due to its flexibility with

Table 10.1: Overview of hydrogen production methods.

Application	Power or capacity	Efficiency	Initial investment	Lifetime	Maturity
Steam methane reformer (large scale)	150–300 MW	70%–85% (LHV)	~ 805€ ₂₀₁₇ /kW	30 years	Mature
Steam methane reformer with carbon capture, utilization and storage (CCUS)	150–300 MW	65%–70% (LHV)	~ 1500€ ₂₀₁₇ /kW	25 years	Demonstration
Alkaline electrolyzer	Up to 150 MW	63%–70% (LHV)	440–1200€ ₂₀₁₇ /kW	60,000–90,000 h	Mature
PEM electrolyzer	0.5 MW	50%–60% (LHV)	970–1600€ ₂₀₁₇ /kW	30,000–90,000 h	Early market
Solid oxide electrolyser cell (SOEC) electrolyzer	12 MW	74%–81% (LHV)	~ 2500–5000€ ₂₀₁₇ /kW	10,000–30,000 h	R&D
	Lab scale				

CAPEX for electrolysis technology represents system costs including power electronics, gas conditioning, and balance of plant. CAPEX ranges reflect different system sizes. LHV, Lower heating value.

Source: Adapted from IEA (2019); IEA *Global Trends and Outlook for Hydrogen (2017)*.

dynamic operation. PEM's flexibility toward dynamic operation is detailed in [Section 10.4](#). Such electrolysis units are currently reaching demonstration scale and have not yet seen large deployments ([REN21, 2017](#)). Technology advancements are needed before being ready for widespread commercialization ([IRENA, 2018](#)).

10.2 Data availability and methodological issues

Data availability on CAPEX and capacity of alkaline electrolysis systems is highly limited, mostly attributed to the privacy suppliers place on revealing cost data. Therefore capacity and CAPEX data for the years 1956–2016 were gathered from a few sources: [Braun \(1978\)](#), [Christiansen and Grundt \(1978\)](#), [Costa and Grimes \(1967\)](#), [Evangelista et al. \(1975\)](#), [NEL Hydrogen \(2015a,b\)](#), [Next Hydrogen Corporation \(2016\)](#), [Saba et al. \(2017\)](#), [Schmidt et al. \(2017a,b\)](#), [Schoots et al. \(2008\)](#), and [Tilak et al. \(1981\)](#). Monetary data from these sources are referred to as CAPEX, but due to the lack of transparency regarding the link between CAPEX and cost or prices, it is safe to assume that the CAPEX data represents prices due to the difficulty of acquiring true manufacturing costs of alkaline electrolysis systems. Using prices as proxy for costs leads to the assumption of perfect market

competition, which is not the case for alkaline electrolysis systems. There are few major manufacturers of alkaline electrolysis systems: Hydrogenics, Hydrotechnik GmbH, McPhy, NEL Hydrogen, Next Hydrogen, PERIC, Teledyne Energy Systems, and Tianjin Mainland Hydrogen Equipment. Having a few major manufacturers for a globally traded commodity indicates toward an oligopoly and not perfect market competition. [Saba et al. \(2017\)](#) gathered CAPEX data for alkaline electrolyzers through literature review for the past 30 years. Most of the CAPEX data collected were based on expert estimations, and a few were based on manufacturers' CAPEX. These estimations are based on electrolysis market developments and on scenarios proposed at the time of estimation. These scenarios may not always reflect market development of alkaline electrolyzers. Most of the large-scale plants were built prior to 1980 ([Saba et al., 2017](#)), while currently small-scale electrolyzers (1–10 MW) are being sold ([IEA, 2019](#)) with a great share of the manufactured alkaline electrolyzers coming from China, which probably indicates that the market is/has shifted/shifting toward China. In combination with alkaline electrolyzers being a global traded commodity, this creates an uncertainty in accounting for the total installed capacity of alkaline electrolyzers and therefore makes it difficult to calculate the total cumulative global installed capacity of alkaline electrolysis. An issue regarding the CAPEX reported by the literature sources is the lack of transparency pertaining to the components these CAPEX data comprised. All of the gathered data analyze alkaline electrolyzer *systems* and not only the *stacks*. Some of the literature reviewed by Saba et al. provide CAPEX data that covers all plant equipment, from the rectifier to the gas holder, building of plant, office buildings, miscellaneous, and interest during construction while in other literature sources, the specifics of CAPEX are not mentioned. The same can be said for other sources such as [Schmidt et al. \(2017a,b\)](#) and [Tilak et al \(1981\)](#). Some sources do not specify if the H₂ is produced at ambient pressure or pressurized. The choice of investing in an ambience of pressurized plant can have a significant effect on the CAPEX of the electrolyzer. The CAPEX of pressurized plants (with and without installations and commissioning) is usually 20%–34% higher than for ambient systems ([NEL, 2015](#); [Smolinka et al., 2010](#)). Therefore due to the discrepancies in the composition of acquired CAPEX data, the CAPEX data points represented in the experience curve ([Fig. 10.3](#)) are not explicitly defined, but the data points generally encompass the price of the module and the inclusion/exclusion of other system components such as the gas holder, rectifier, compressor, office buildings, and other miscellaneous capital costs. The CAPEX data is represented as €/kW_{input}.

Methodological issues can be attributed to the type of data available. CAPEX and capacity data from Saba et al. were provided in \$_{base year}/kW_{input/output} and in N m³/h or kg/day or MW, respectively. This data was then converted to a standard unit of €₂₀₁₇/kW_{input} for CAPEX and MW for installed capacity. Capacity data in N m³/h was first converted into kg/h (1 N m³H₂ = 0.0899 kgH₂) and then converted to MW using the higher heating value (HHV) of hydrogen (HHV_{H₂} = 141.88 MJ/kg). CAPEX data in \$_{base year}/kW_{input} was first

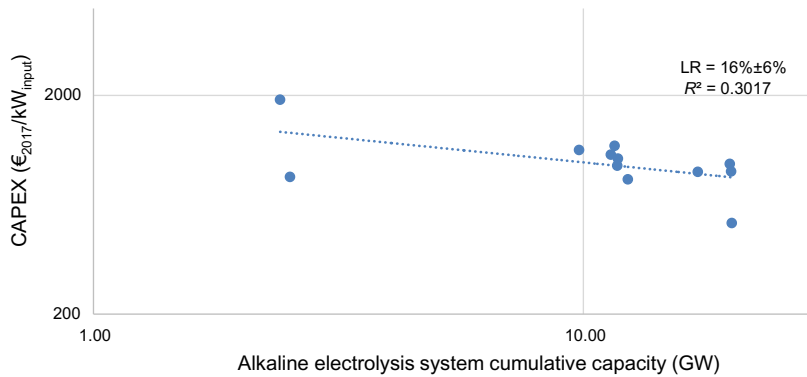


Figure 10.3

Global experience curve for the CAPEX of alkaline electrolysis systems from 1956 to 2016. Source: *Own data collection.*

corrected for inflation to $\$_{2017}/\text{kW}_{\text{input}}$ using the consumer price index from OECD, and a dollar to euro exchange rate from Eurostat was used to convert $\$_{2017}/\text{kW}_{\text{input}}$ into $\text{€}_{2017}/\text{kW}_{\text{input}}$. This method was also used to convert data from NEL Hydrogen and Next Hydrogen to the desired units ($\text{€}_{2017}/\text{kW}_{\text{input}}$ and MW). Another method would involve the conversion of the dollar value to euro in the given year and then corrected for inflation for the base year. This method was not chosen since a significant amount of data points exist prior to 1999 (introduction of the euro) and therefore circumvents the issue regarding the conversion of dollars to euros prior to the introduction of the euro. A third method would be to identify the most stable currency in the EU prior to the introduction of the euro and convert the dollar value to that currency and correct for inflation till the year 1999 and then use the euro inflation rate post 1999. This method was discarded since it is difficult to identify and provide sound reasoning for the choice of the country. All CAPEX data from Braun (1978), Christiansen and Grundt (1978), Evangelista et al. (1975), Costa and Grimes (1967), and Tilak et al. (1981) and some CAPEX data from Saba et al. (2017), Schmidt et al. (2017a,b), and Schoots et al. (2008) were provided in $\$/\text{kW}$ for years prior to the introduction of the euro (the euro was introduced in 1999). Therefore there exists an uncertainty in the dollar to euro exchange rate and euro inflation rate prior to 1999.

Cumulative installed capacity data derived from Schmidt et al. (2017a) was provided in kWh (storage). This data was reproduced as kW using a C-rate (power to energy ratio) defined by Schmidt et al. ($1 \text{ kW} = 10 \text{ kWh}$). A different C-rate (or a C-rate changing over time) would affect the cumulative installed capacity, thereby affecting the learning rate. Here, CAPEX data was provided in $\$_{2015}/\text{kWh}$ and was converted to $\text{€}_{2017}/\text{kW}_{\text{input}}$ using the currency conversion method detailed in the previous paragraph and using the C-rate provided by Schmidt et al. (2017a).

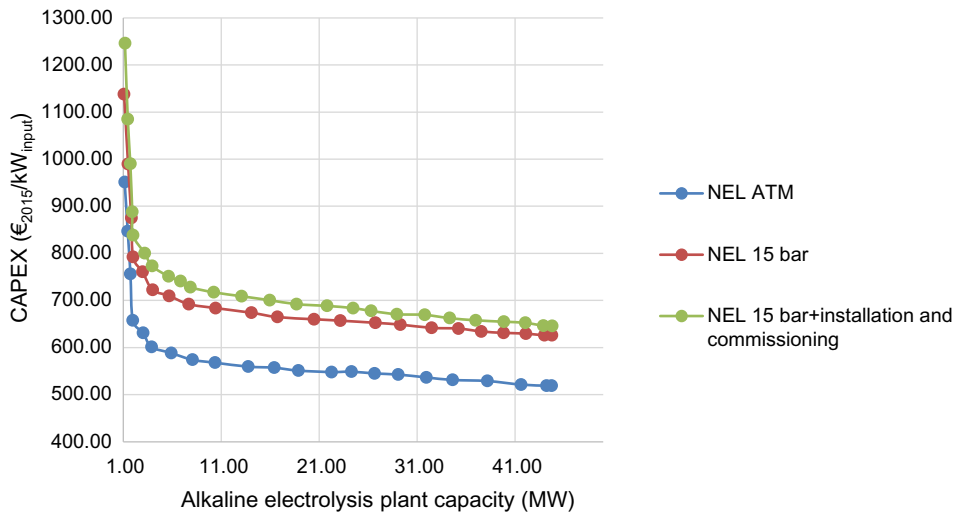


Figure 10.4

Development of CAPEX costs for large alkaline electrolyzer systems over plant capacity (1–44 MW) according to NEL. The graph shows the inclusion of pressurized systems and installations and commissioning on the CAPEX of alkaline electrolysis systems. Source: *Adapted from Saba et al. (2017).*

The CAPEX data collected from the various sources correspond to capacities that range from 1 to 100 MW. This data was not normalized to a specific capacity in order to facilitate observations on the underlying reasons for different CAPEX reported for the same capacity installed in the same year. The CAPEX for larger systems are usually lower than small systems (eg: Fig. 10.4) and therefore renders the poor distribution of the CAPEX data in Fig. 10.5.

In order to know the true cost of hydrogen, it is important to know the learning rate for the levelized cost of hydrogen (LCOH₂), which includes CAPEX, OPEX, and electricity/fuel cost, as it provides a better indication of the true cost of hydrogen production from alkaline electrolysis and provides a sound basis for comparison with SMR, which is the dominant technology in hydrogen production. Fig. 10.6 provides the share of CAPEX, OPEX, and electricity cost for alkaline electrolysis.

For large multimegawatt units the dominant single input in the cost of hydrogen beyond electricity is the capital cost of plant equipment (Kuckshinrichs et al., 2017). With increasing emphasis being placed on utilizing low-cost intermittent power sources, such as wind and solar, the cost of plant will play an even larger role—for two reasons: (1) electricity's share of cost is reduced and (2) with the decrease in utilization due to the intermittent nature of renewable resources, the share of CAPEX to total cost will increase.

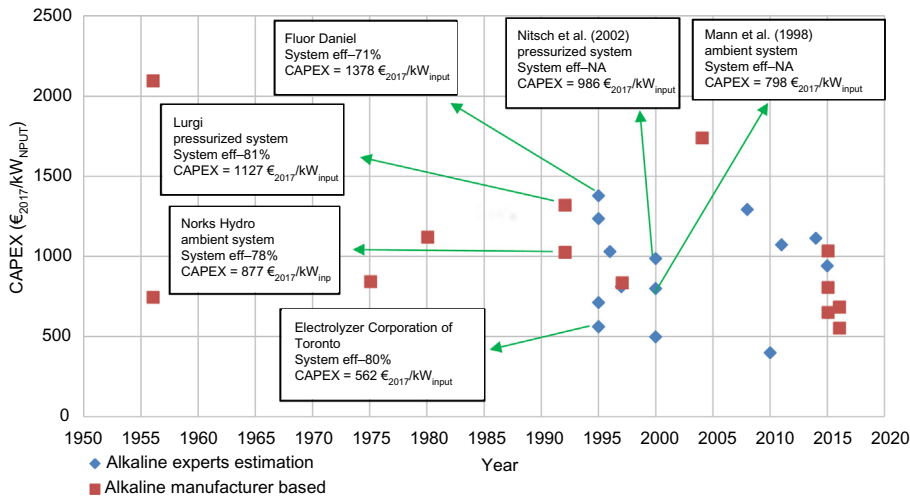


Figure 10.5
CAPEX of alkaline electrolysis systems plotted against time.

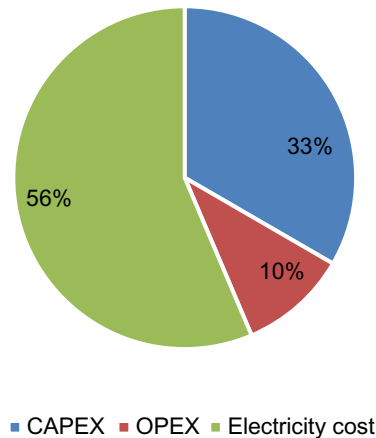


Figure 10.6
Cost breakdown of levelized cost of hydrogen (LCOH₂) of alkaline electrolysis. Source: *Adapted and modified from IEA (2019); Thomas (2018).*

Using the data presented in the material handling study conducted by [Felgenhauer and Hamacher \(2015\)](#), and assuming plant capacity of 50 kg/h, the contribution of capital cost to total cost is projected to grow from around 15% under the conditions presented (100% utilization) to 35% when the cost of power is reduced by 50% and utilization is reduced by the same amount.

10.3 Results

10.3.1 Experience curve

Fig. 10.3 shows the global experience curve for alkaline electrolysis systems. It shows the CAPEX (€₂₀₁₇/kW_{input}) of alkaline electrolysis systems over the time frame 1956–2016. Over this period a learning rate of $16\% \pm 6\%$ was established using a confidence interval of 95%. Within this dataset, the CAPEX declined from 1900€₂₀₁₇/kW_{input} in 1956 to a range of 500–900€₂₀₁₇/kW_{input} in 2016. This spread-in in the current CAPEX can be attributed to the wide range in capacity (1–100 MW). With a wide CAPEX range and cumulative capacity being in the order of 100–200 MW, the uncertainty overwhelms the expected learning in the coming decade. Another reason for the wide spread-in CAPEX is the components used in the electrolyzer system. These include unipolar or bipolar modules, pressurized or ambient systems, gas conditioning, compressor, power electronics, operating conditions, and stack configuration (Saba et al., 2017; Kuckshinrichs et al., 2017). These components can have an effect by either increasing or driving down the CAPEX of the alkaline electrolysis system. As mentioned in Section 10.2, pressurized systems usually increase the CAPEX of alkaline electrolysis systems by 20%–34%.

Fig. 10.3 shows a sharp increase in cumulative installed capacity of alkaline electrolysis systems from 2 to 9 GW. Cumulative installed capacity of 2 GW can be attributed to capacity installation between the 1920s and 1950s, which correlates with the need for hydrogen in the ammonia industry in the 1940s. The decline in installed capacity between the 1950s and 1970s can be attributed to the competition with cheap hydrogen produced from SMR due to the development of natural gas production. Between the late 1970s and the mid-1980s, with concerns about security of supply of fossil fuels, significant development of bipolar electrolyzer technology was undertaken and hydrogen production from electrolysis increased. Table 10.2 shows a list of the major large-scale alkaline electrolyzer plants built between the 1920s and 1980s.

After 1990, with cheap natural gas prices, the hydrogen cost from SMR was much cheaper than hydrogen from alkaline electrolysis (IEA, 2019). Therefore since 1990, it can be

Table 10.2: Major large-scale plants between 1920 and 1980.

Plant location	Country	Supplier	Capacity (MW)	Year of construction
Rjukan	Norway	Norsk Hydro (now NEL)	165	1927
Glomfjord	Norway	Norsk Hydro (now NEL)	135	1953
Trail	Canada	Cominco	90	1939
Nagal	India	Denora	125	1958
Aaswan	Egypt	BBC	162	1977

Source: Adapted and modified from Smolinka et al. (2010); Sunde (2012).

assumed that this cost difference led to the scaling down of alkaline electrolysis with most producers selling between 1 and 10 MW electrolyzer systems in the order of a few dozen per year and a few large-scale electrolyzer systems sold in the order of one to two per year (NEL Hydrogen, 2015a; Saba et al., 2017; IEA, 2019). The smaller plants play a niche role in providing limited amounts of hydrogen when SMR is not possible.

Therefore based on the wide spread of CAPEX, cumulative capacity being in the order of 100–200 MW and the different components that drive up or down the CAPEX of alkaline electrolysis systems, the poor R^2 of 0.3017 can be explained.

Fig. 10.5 represents the same data as Fig. 10.3 and shows the CAPEX of alkaline electrolysis systems plotted against time. It shows CAPEX derived from expert estimations and manufacturers' prices. It shows that the CAPEX of alkaline electrolysis systems, estimated by experts, falls in the range of manufacturers' prices for the years 1996 and 2015, which aids in adding validity to the expert estimates. From this graph, it can be observed that CAPEX of alkaline electrolysis systems shows a decline from a range of $2100\text{--}750\text{€}_{2017}/\text{kW}_{\text{input}}$ (average of $1900\text{€}_{2017}/\text{kW}_{\text{input}}$) in 1956 to a range of $900\text{--}500\text{€}_{2017}/\text{kW}_{\text{input}}$ (average of $700\text{€}_{2017}/\text{kW}_{\text{input}}$) in 2016, which correlates with the CAPEX decline seen in the experience curve (Fig. 10.3). The shape of the data plot in Fig. 10.5 is slightly wedge-shaped, a consequence of the wide spread of CAPEX and corresponding capacity data acquired from expert estimates and manufacturers' prices. The CAPEX in 2016 was 63%–73% lower than the CAPEX in 1956. The cost reduction in the past decade was more moderate. This could be explained with the maturity of alkaline electrolysis technology (Saba et al., 2017) since alkaline electrolysis systems have been available in the MW scale since the 1950s. Drivers for these cost reductions are detailed in Section 10.3.2.

Though the graph shows a partial decline, the wide spread of CAPEX and capacity data points within the same year adds to the uncertainty of predicting the trend of CAPEX for alkaline electrolysis systems and therefore bolsters the uncertainty of generating a reliable learning rate for the alkaline electrolysis system.

Fig. 10.5 also shows the CAPEX of three pairs of alkaline electrolysis systems of the same size and built in the same year. Further on, we illustrate the underlying reasons for the variation in cost: In 1992 the graph shows two 100 MW bipolar plants built by Norsk Hydro (efficiency—78%, ambient pressure) and Lurgi (efficiency—81%, 31 bar) with a CAPEX of $877\text{€}_{2017}/\text{kW}_{\text{input}}$ and $1127\text{€}_{2017}/\text{kW}_{\text{input}}$, respectively. The 28% increase in the Lurgi plant CAPEX can be attributed to the difference in pressure (ambient vs 31 bar) and efficiency (78% vs 81%). This 28% CAPEX increase falls within the range (20%–34%) reported by Smolinka et al. (2010) and NEL (2015).

For the year 1995, Thomas and Kuhn (1995) reported a CAPEX of $1378\text{€}_{2017}/\text{kW}_{\text{input}}$ estimated by Fluor Daniel, Inc. in 1991 (based on forecast) and a CAPEX of $562\text{€}_{2017}/\text{kW}_{\text{input}}$

estimated by the Electrolyser Corporation of Toronto (estimation made in 1995), both for 100 MW systems. The CAPEX estimated by the Electrolyser Corporation of Toronto excludes components, such as the compressor, storage tank facilities, and engineering, while these components are included in the estimation made by Fluor Daniel, Inc., who report that compressor, storage tank, and engineering account for 36% of the CAPEX. Therefore the high CAPEX reported by Fluor Daniel, Inc. can be attributed to the inclusion of the previously mentioned components and the year the estimation was made.

For the year 2000, [Mann et al. \(1998\)](#) and [Nitsch et al. \(2002\)](#) reported the CAPEX of two 2 MW systems at $798\text{€}_{2017}/\text{kW}_{\text{input}}$ (based on forecast) and $986\text{€}_{2017}/\text{kW}_{\text{input}}$ (estimation based on historical data). The CAPEX estimated by [Nitsch et al. \(2002\)](#) is 23% higher, which can likely be attributed to the different pressure conditions [ambient ([Mann et al., 1998](#)) vs 30 bar ([Nitsch et al., 2002](#))], and the year of estimation [1998 ([Mann et al., 1998](#)) vs 2002 ([Nitsch et al., 2002](#))].

Therefore the wide range in CAPEX for the same capacity can be attributed to the dynamics of the system and inclusion/exclusion of different components. These include choices made on the type of cells (unipolar or bipolar), whether the system is pressurized or ambient, and the inclusion of components, such as compressor, gas rectifier, storage tank, and other engineering and balance of plant (BOP) costs in the CAPEX breakdown. Therefore it can be concluded that the CAPEX has a significant dependency on the dynamics and components that comprise the system and therefore generating experience curves for the entire system is not the soundest method to apply as it leads to significant uncertainty.

[Fig. 10.4](#) retrieved for [Saba et al. \(2017\)](#), which was derived from [NEL \(2015\)](#), shows the CAPEX of large-scale alkaline electrolyzer systems from 1 to 41 MW capacity. Information on the methodology used by NEL to derive this curve was not available. It can be assumed that probably a fixed cost for a 250 kW system was used as the base line. The plot was then extrapolated to 41 MW plant capacity assuming scaling effects. Therefore the data may not represent the true cost of alkaline electrolysis systems at their respective capacity. NEL currently only produces ambient systems, a decision which could be based on its low costs as seen in [Fig. 10.4](#). The three trend lines show CAPEX of the system at ambient, pressurized, and pressurized with installation and commissioning. Pressurized alkaline electrolysis systems show around a 20% increase in CAPEX when compared to ambient systems and a further 28% increase when installations and commissioning are included in the CAPEX. Therefore it can be assumed that for an ambient system, installation and commissioning will drive up the CAPEX by 8%. This finding affirms the earlier statement made that CAPEX of alkaline electrolysis systems significantly depends on the dynamics and components that surround the alkaline electrolyzer stacks. The graph also shows a steep decline of more than 60% when plant size is increased from $250\text{ kW}_{\text{input}}$ to $2.5\text{ MW}_{\text{input}}$ and

then approaches a value of $516\text{€}_{2017}/\text{kW}_{\text{input}}$ (Saba et al., 2017). These sharp reductions in CAPEX in the small capacity range can be attributed to the peripheral costs, which are independent of the capacity (Smolinka et al., 2010).

From the analysis, it can be concluded that the CAPEX of alkaline electrolysis system for a given capacity depends on the type of cells (unipolar or bipolar); pressurized or ambient; inclusion/exclusion of gas conditioning, power electronics, compressor, and other installation costs and operating conditions, which in turn determines the choice of materials used and the cost components included in CAPEX calculation. These added components along with the uncertainty surrounding the composition of the cost breakdown of alkaline electrolysis system data; it can be deduced that generating experience curves for the entire alkaline electrolysis system can lead to much uncertainty.

From this analysis, it can be recommended to study the learning rate of the electrolyzer stacks and other components, such as the rectifier and gas chamber, separately and analyze if a decline in CAPEX is a result of scaling up the technology or mass fabrication and trying to achieve optimal configuration of the electrolyzer stacks via multistacking (e.g., one 40 MW stack or twenty 2 MW stacks) (IEA, 2019). So far, however, lack of publicly available data has prevented a more detailed analysis of the individual electrolyzer components.

10.3.2 Drivers

Early developments that led to cost reduction in alkaline electrolyzers can be linked to developments in cell architecture.

Monopolar cells used steel or cement tanks and heavy metal electrodes connected by copper bus bar and were favored for their reliability and ease of maintenance, it being easy to replace a cell, but were generally of lower efficiency compared to bipolar designs. Monopolar electrolysis plants need lower voltage and higher current configurations, which result in significantly higher rectification costs. Advanced monopolar designs were commercialized in 1980 (Crawford and Benzmira, 1986), but bipolar stack design ultimately prevailed as bipolar stack costs came down, and emphasis was placed on packaging plants in shipping containers (Fairlie and Scott, 2000). Today, almost all electrolyzers have a bipolar stack design.

The commercialization of bipolar designs in the 1940s (Christiansen and Andreassen, 1984) and significant developments of the design in the late 1970s and early 1980s, with concerns about security of supply of fossil fuels, were undertaken as part of a large initiative to position hydrogen as an alternative transportation fuel (Vandenborre et al., 1982). Employing more efficient electrode materials and separators, significant gains in efficiency were made with current density increasing from 0.15–0.2 to 0.2–0.4 A/cm²

(Schmidt et al., 2017a,b). These developments led to smaller, more compact systems and the introduction of packaged or containerized plants, which were cheaper to site and erect. Membrane materials used to keep hydrogen and oxygen separate in the cell evolved from the use of asbestos to **Ryton PPS** to current separators based on inorganic chemistry (Vermeiren et al., 1998).

The technical development of alkaline electrolysis over the past 120 years has largely focused on increasing current density and a general improvement in cell efficiency, largely made possible with improved electrode materials and cell membranes. These improvements have led to more compact plants requiring fewer cell parts and lower stack costs (LeRoy and Stuart, 1978; Schmidt et al., 2017a,b). BOP costs have also decreased and this can be attributed to developments in cells working at near atmospheric pressure that are controlled using water seals and gasholders (LeRoy and Stuart, 1978). These have evolved with improved materials and sealing technology to pressurized cell designs, lowering downstream gas conditioning and compression costs (Schmidt et al., 2017a,b).

Ursua et al. (2012) reports that most price reductions can be attributed to technological improvements at a modular level since all electrolyzers consist of an electrolyzer stack, comprising up to 100 cells, and the BOP. Stacks can be mounted in parallel using the same BOP infrastructure, which is why electrolyzers are highly modular systems. Some of the improvements mentioned are as follows:

- Minimizing the space between the electrodes in order to reduce the ohmic losses thus making it possible to work with higher current densities. Currently, distances among the electrodes less than 1 mm are typical, which is referred to as zero-gap configuration.
- Development of new advanced materials to be used as diaphragms replacing the previous ones made of asbestos. In this regard the use of porous separators, made of polysulfide possibly combined with ZrO₂ (zircon) has become widespread.
- Development of high-temperature alkaline water electrolyzers: working temperatures up to 150°C increase the electrolyte conductivity and promote the kinetics of the electrochemical reactions on the electrode surface, although this has not yet entered the market due to issues related to corrosion.
- Development of advanced electrocatalytic materials to reduce the electrode over voltages.

10.4 Future developments

10.4.1 Current and future markets

Section 10.2 highlights the effect capacity factor has on the levelized cost of hydrogen. The future competitiveness of low-carbon hydrogen produced from natural gas with CCUS or

from renewable electricity (from solar PV or onshore wind) thus mainly depends on gas and electricity prices. At low gas prices, renewable electricity must reach a cost range less than 8.7€₂₀₁₇/MWh for electrolysis to become cost-competitive with natural gas with CCUS. Higher gas prices would make higher cost renewable electricity cost-competitive: at a gas price of 33€₂₀₁₇/MWh, renewable electricity would be competitive at up to around 26–39€₂₀₁₇/MWh (IEA, 2019).

Increasing shares of variable renewables in grid electricity leads to intermittency and surplus electricity, which may be available at low cost and can be used to produce hydrogen, although a low availability of surplus electricity is unlikely to have a major impact in driving down costs. Running the electrolyzer at high full-load hours and paying for the additional electricity is maybe cheaper than running with low full-load hours (IEA, 2019). The relationship between electricity costs and operating hours becomes apparent when looking at electrolyzers that use grid electricity for hydrogen production. Very low-cost electricity is generally available only for a limited number of hours within a year, which implies low capacity factor and high hydrogen costs, which reflect CAPEX costs (IEA, 2019). With increasing load hours, electricity costs increase, but the high capacity factor leads to a decline in the cost of producing a unit of hydrogen up to an optimum level at around 3000–6000 equivalent full-load hours (IEA, 2019). Beyond that, higher electricity prices during peak hours lead to an increase in hydrogen unit production costs.

Dedicated electricity generation from renewables offers an alternative to the use of grid electricity for hydrogen production. With declining costs for solar PV and wind generation, building electrolyzers at locations with excellent renewable resource conditions could become a low-cost supply option for hydrogen, even after taking into account the transmission and distribution costs of transporting hydrogen from (often remote) renewable locations to the end users (IEA, 2019)

Historically, alkaline electrolyzers were connected to hydropower dams (Kroposki et al., 2006) and could run on constant mode. In more recent years alkaline electrolyzers have been connected to the grid with a share of renewables or to dedicated renewable electricity supply (IEA, 2019). This could lead to issues of intermittency and therefore requires the electrolysis system to be flexible by accommodating dynamic operation. Current alkaline electrolysis systems do not possess the flexibility to run at dynamic operation. They typically operate at 20%–100% rated power (Lehner et al., 2014). Operating in the lower half of the range results in significantly reduced gas quality and increasingly reduced system efficiency (Lehner et al., 2014). Alkaline electrolysis systems tend to have long startup times and have difficulty to adjust to rapid changes in power inputs (Lehner et al., 2014). PEM electrolyzers, on the other hand, offer flexible operation since they can operate from 0% to 160% rated power (IEA, 2019) and are able to respond to power fluctuations within 100 ms (Lehner et al., 2014). But the downside to this is that PEM electrolyzers

require expensive electrode catalysts such as platinum or iridium and membrane materials. They also have shorter lifetimes than alkaline electrolysis and are more expensive (Schmidt et al., 2017b; IEA, 2019). With an increasing share of renewables, and the assumption that PEM electrolyzers will undergo cost reductions (Schmidt et al., 2017b; IRENA, 2018; IEA, 2019), the potential of PEM electrolyzers in the future might be promising and therefore could be interesting to generate and assess learning curves for PEM.

Asahi Kasei Corporation produces hydrogen via chloralkali process, which is a form of electrolysis (brine) and is powered by electricity. Currently, up to 0.5 MtH₂ worldwide is vented to the air and 22 MtH₂ is used for low-value applications, such as heat and power generation, without purification (IEA, 2019). This potential, in addition to hydrogen from alkaline electrolysis, could be tapped and used as feedstock in the iron and steel and chemical industry. But chloralkali is not as attractive as electrolytic hydrogen since it is more expensive and is only available as a by-product, therefore not being able to meet global hydrogen demand.

Due to China's dependency on imported natural gas and abundant availability of renewable resources, hydrogen production from electrolysis is gathering attraction. In some places in China, renewable energy has been deployed at a rapid rate that electricity networks have had difficulty adapting in real time (IEA, 2019). This has provided an opportunity for producers of hydrogen and hydrogen-rich chemicals to tap into renewable resources. China is the world's largest user of nitrogen fertilizers, consuming 46 Mt/year (IEA, 2019). This provides further opportunity for China to tap into the electrolysis market for hydrogen production, which is a feedstock for the ammonia industry. IEA conducted a detailed economic assessment on hydrogen production from electrolysis, based on hourly solar and wind data over a year in five locations across different provinces—Xinjiang, Qinghai, Tibet, Hebei, and Fujian (IEA, 2019). The assessment suggests that hydrogen can be produced at a cost of 1.7–2€₂₀₁₇/kgH₂, which is much cheaper than costs in Europe (> 4€₂₀₁₇/kgH₂) (IEA, 2019). In some provinces the lowest production costs are reached by using only solar (Qinghai) or wind (Hebei and Fujian), while in Xinjiang and Tibet, performance is best with a combination of the two (IEA, 2019). Though curtailment in China is declining, there still exists a large curtailment potential. In 2017 over 100 TWh of solar, wind, and hydropower output were curtailed, which is roughly equivalent to electricity consumption in The Netherlands (IEA, 2019). Installing electrolyzer plants in regions with excess renewable electricity potential could aid in the growth of cheap hydrogen produced from electrolysis. China's major source of primary energy is coal. In Northeast China, inflexibility of coal plants caused by heat loads was a factor in the curtailment of 40 TWh of wind power in 2017 (IEA, 2019). Until other sources of energy are implemented to meet this heat demand, electrolytic hydrogen at full-load hours and cheap electricity prices could potentially be used to avoid curtailment of either coal or renewable energy. These opportunities will probably aid in China becoming the dominant market for electrolysis system production.

Accounting for the assumption that in the future, low-cost dedicated renewable electricity will be available at a level to ensure the electrolyzer can operate at relatively high full-load hours is therefore essential for the production of low-cost hydrogen. This also highlights that in the future, CAPEX will have a major share in the cost/kg of hydrogen produced from electrolysis.

10.4.2 Future drivers in CAPEX reduction

The two factors that will drive future cost reduction of electrolyzers are likely: (1) scale of manufacturing and (2) incremental future innovation. Manufacturing cost reductions can be achieved by increasing the scale of production by moving to assembly line manufacturing, investing in tooling, such as injection molding of parts, material substitution, and ultimately automation.

Incremental innovation will be led by increasing cell current density, which has the effect of reducing the number of parts needed, and changes in architecture, to facilitate scale-up and reduction of BOP costs. Advanced alkaline designs, introduced by manufacturers, embody a number of these advances, including scaling up production per unit with single stacks up to 10 MW (Asahi Kasei Corporation), multistacking, which is shown to be cheaper than single large-scale stacks (IEA, 2019), internal gas–liquid separators/gas coolers that avoid need for external vessels, and electrolyte circulation that relies on gas-lift circulation rather than external pumps (Next Hydrogen Corporation, 2016) and pressurization (up to 35 bar) that reduces downstream gas drying and compression costs (Green Hydrogen, 2019). The need to increase operating flexibility to take advantage of lower electricity costs and to provide ancillary services to the grid, such as grid regulation services, will also have an impact on cell design and stack architecture. Development of RuO/IrO-based catalysts with improved kinetics can achieve current densities up to 1 amp/cm² increasing the operating range and ultimately reducing stack costs (Schmidt et al., 2017a,b), although it is important to note that Ir is one of the rarest elements in the Earth's crust, with annual production averaging around 3 million tonnes (USGS Platinum Group Statistics, 2019). Therefore large-scale use of Ir could drive up the cost in the future. Other developments, such as moving toward zero-gap membrane electrode assemblies using thinner separators and microporous electrodes, are projected to achieve better efficiency than those of PEM electrolyzers with acidic Nafion membranes (Schalenbach et al., 2016a,b).

10.4.3 Future CAPEX of alkaline electrolysis systems

The current electrolysis annual market size, estimated to be 100 MW (Hebling et al., 2018), is expected to grow at a 6% compound annual growth rate (CAGR) during the period 2017–23 (Water Electrolysis Market, 2018) with the European Union and a major consortium of car companies and energy companies expecting electrolysis to expand into a

multibillion dollar industry by 2030 (Hydrogen Road Map Europe, 2019). At 6% yearly growth rate between 2017 and 2023, the cumulative capacity additions will reach around only 1 GW by 2023. Extrapolating the experience curve from Fig. 10.3, using this growth rate, provides a cumulative capacity of 20.01 GW with an average CAPEX of 692€₂₀₁₇/kW_{input}. A recent survey of manufacturers and industry experts showed that industry could ramp up capacity to 2 GW/year by 2020 (Hebling et al., 2018). But with hydrogen from SMR being the most inexpensive (1.3€₂₀₁₇/kgH₂) (IEA, 2019) production route due to cheap gas prices, this assumed ramp-up capacity seems too optimistic.

According to the expert elicitation method used by Schmidt et al. (2017b), increasing R&D support alone is seen to have a small effect on reducing capital cost, but R&D support along with production scale-up can lead to a 27% drive-down of CAPEX by 2030. This drop is mostly attributed to production scale-up through improved manufacturing methods and automation as well as increased operational experience leading to optimized system design (new electrocoating methods, increased current density, and more stable electrodes for high-temperature operating conditions) (Schmidt et al., 2017b). A 27% drop in CAPEX by 2030 from current levels translates to an average CAPEX of around 500€₂₀₁₇/kW_{input}, which is lower than the average CAPEX (600€₂₀₁₇/kW_{input}) quoted by Saba et al. (2017), which was based on expert estimates. Extrapolating the experience curve in Fig. 10.3 requires a cumulative installed capacity of 80 GW by 2030 to achieve 500€₂₀₁₇/kW_{input}. This roughly translates to two doublings, or a capacity addition of 60 GW between 2023 and 2030 to achieve this cost reduction. The projected cost reported by the IEA (2019) lies within a range of 750–350€₂₀₁₇/kW_{input}. These findings highlight that increasing R&D support alone is likely going to have a small effect on reducing capital cost. Arguably, the benefits of these advances are hidden in the metric of cost/kW, which does not account for increases in efficiency, and reduction in BOP costs, which will impact the total cost of hydrogen. It also highlights that scaling up, mass fabrication, and multistacking will play major roles to drive down the CAPEX of alkaline electrolysis systems

10.5 Summary and conclusion

The experience curve for alkaline electrolysis system between 1956 and 2016 shows a learning rate of 16% ± 6% with CAPEX decreasing from 2100 to 750€₂₀₁₇/kW_{input} in 1956 to a range between 900 and 500€₂₀₁₇/kW_{input} in 2016. These values fall in the range (440–1200€₂₀₁₇/kW_{input}) reported by the IEA's (2019). The observed reductions in CAPEX can be attributed to developments in cell architecture, increasing current density, and improving cell efficiency. The experience curve for alkaline electrolysis systems shows a poor fit ($R^2 = 0.307$), which can be attributed to discrepancies in the CAPEX composition of the gathered data and the wide spread in capacity (1–100 MW). Systems with the same

capacity and manufactured in the same year have different CAPEX, which can be explained by

1. The inclusion/exclusion of CAPEX of other system components, such as rectifier, dryer, compressors, and other engineering costs, which could account for around a 36% increase in CAPEX.
2. The pressure at which the system operates with pressurized systems being 20%–34% more expensive than ambient systems.
3. Installation and commissioning, which could drive up the CAPEX by 8%.

Engineering and installation could be used as interchangeable terms and therefore overlap might exist in the % increase in CAPEX presented in (1) and (3).

It can therefore be recommended to avoid extrapolating the learning curve of an alkaline electrolysis system to estimate the future costs of stacks and the future costs of the system. It is recommended to generate experience curves for each component that makes up the system to know the true CAPEX and learning rate of alkaline electrolysis systems. With increasing share of renewable electricity and intermittency, PEM, due to its flexibility with dynamic operation, might play an important role in hydrogen production in the future. Similarly to alkaline electrolysis system, it is recommended to generate experience curves for PEM systems on a component level (stack, gas dryer, compressor, etc.). The two factors that will drive future cost reduction of electrolyzers will be scale of manufacturing by increasing the scale of production by moving to assembly line manufacturing and investing in tooling, such as injection molding of parts, material substitution, and ultimately automation and incremental future innovation. With the current electrolysis market estimated to be 100 MW/year and is expected to grow at 6% CAGR during the period 2017–23, the CAPEX of alkaline electrolysis systems will drop to around $692\text{€}_{2017}/\text{kW}_{\text{input}}$ at a cumulative capacity of 20.01 GW. Though [Schmidt et al. \(2017b\)](#), through expert elicitation process, estimated a 27% drop in CAPEX by 2030 due to R&D and production scale-up. This translates to a cumulative capacity addition of 80 GW with CAPEX of the system around $500\text{€}_{2017}/\text{kW}_{\text{input}}$. In order to achieve this target, around 60 GW or two doublings of cumulative capacity is required, which highlights the major role production scale-up will play in driving down the CAPEX of alkaline electrolysis systems.

The levelized cost of hydrogen does mainly determines the total cost of hydrogen, but with decreasing cost of renewable electricity (wind and solar PV) and electrolyzer plants operating between 3000 and 5000 load hours to match renewable electricity supply; the share of CAPEX in the cost of hydrogen will likely be the dominant factor in driving down costs. The future cost of hydrogen will be dependent on: (1) the cost reduction potential in the CAPEX and all the components it encompasses, (2) gas and renewable electricity prices, and (3) availability of renewable electricity for hydrogen production from electrolysis, which in turn affects the capacity factor and the levelized cost of hydrogen.

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