Public report

Institute for Sustainable Process Technology

Next Level Solid Oxide Electrolysis

Upscaling potential and techno-economical evaluation for 3 industrial use cases

Air Liquide OCI Global bp VOLTA CHEM Powered by TNO TNO Institute for Sustainable Process Technology

Colophon

Published by Institute for Sustainable Process Technology (ISPT).

Authors: Hans van 't Noordende (ISPT), Frans van Berkel (TNO), Maciej Stodolny (TNO)

Cover picture: Maciej Stodolny (TNO)

Lay-out: Hella Hekkelman

This project has been executed with subsidy from Ministry of Economic Affairs and Climate (Topsector Energiesubsidie van het Ministerie van Economische Zaken en Klimaat).

Acknowledgements

The execution of this Next Level Solid Oxide Electrolysis project was a team effort, it took us 12 months to complete this report, with around 20 virtual meetings, 2 live workshops and 2 series of Teams meetings with technology providers. We therefore want to express special thanks to the following persons from our partners and stakeholders who made an important contribution to the design, results and benefits.

Industrial partners:

- Air Liquide: Stefan Barwe and Michael de Pauw;
- BP: Amy Andrews, Hans Becker, Beatriz Fernandez;
- OCI: Filip Raeymaekers.

Knowledge institutes:

- TNO: Frans van Berkel, Maciej Stodolny, Manoj Shinde;
- ISPT: Andreas ten Cate, Annemijn Huijboom, Hans van 't Noordende, Franka Wijnbergen, Carol Xiao.

We also would like to thank the following technology providers for their valuable input and feedback to this SOEC project:

- Bosal: Stefan Pas, Ted Straten;
- Bloom Energy: Akhyl Batheja, Rick Beutel;
- Sunfire: Gerald Hammerschmid;
- Topsoe: Poul Georg Moses, Troels Stummann.

Summary

In this feasibility study, the upscaling potential for Solid Oxide Electrolysis (SOE) is investigated and evaluated for three industrial use cases. It is suggested that an upscaling potential is possible through increase of current density with a factor 2, increased surface areas of cells with a factor 8 and bigger modules of 9 MW. As a result, a substantial CAPEX and footprint reduction could be potentially achieved.

In the Next Level SOE project, ISPT and TNO have performed a feasibility study on Solid Oxide Electrolysis Cells (SOEC) technology with Air Liquide, BP and OCI. The process integration, upscaling potential and technical-economical aspects of brown-field applications of SOEC technology have been evaluated. This feasibility study focuses on three use cases from three different industrial partners with three different applications of SOEC:

- hydrogen production in an ammonia plant at OCI Chemelot site in The Netherlands;
- syngas and green hydrogen production integrated with blue hydrogen and downstream e-fuels as concept study for a potential BP site;
- carbon monoxide production at Air Liquide, Rozenburg Rotterdam site.

Through process integration, excess steam from up or downstream operations can be used. The quality of steam and carbon dioxide is important to protect the electrodes. On system level, the electricity consumption is determined, including the stacks, feed and air heating, air blower and compression (See Table S1). Also, cooling water demand is important as this may contribute to roughly 10% of stack electricity consumption.

Table S1. Summary electricity consumption for the use cases

Electricity consumption	Stack	Other	System
Use case OCI hydrogen	80 MW	12 MW	92 MW
Use case BP 1 hydrogen	462 MW	74 MW	536 MW
Use case BP 2 syngas	786 MW	124 MW	910 MW
Use case Air Liquide carbon monoxide	17 MW	3 MW	20 MW

On system level, the efficiency (LHV) is 83% for hydrogen production, 82% for CO_2 reduction and 92% for syngas production (see Table S2). This is defined as Energy (in product)/Total energy consumption. In case of SOEC and 100% stack efficiency, the system efficiency can be simplified to stack electricity consumption divided by the total electricity consumption. The difference in specific electricity consumption is mainly due to the differences in properties and single pass conversion rate.

Table S2. System efficiencies for the use cases

Based on use case		OCI and BP 1	Air Liquide	BP 2
		Steam electrolysis	CO_2 reduction to CO	Co-electrolysis to syngas
Conversion	kWh/kg product	33.3	2.7	7.1
Compression	kWh/kg product	2	0.2	0.5
e-heaters	kWh/kg product	3.2	0.3	0.6
AC/DC (97%)	kWh/kg product	1.5	0.1	0.2
Total	kWh/kg product	40.0	3.3	8.4
System efficiency	LHV (%)	83%	82%	92%

The SOEC system specific electricity consumption for steam electrolysis is 40 kWh/kg hydrogen and for water electrolysis in the order of 50 kWh/kg hydrogen or higher. The system efficiency (LHV) for high temperature electrolysis would therefore be more than 20% higher than typical for low temperature water electrolysis with AWE and PEM technology. In case of steam generation (HHV), the specific energy consumption is 8 kWh/kg hydrogen higher.

The cost reduction potential is a result of technology improvements to achieve higher current densities, higher scale of manufacturing and upscaling. The current density is a main cost driver (CAPEX), as with higher current densities less SOEC surface area is needed for the same output. It is assumed that technology innovation can drive current density to double before 2030, so increasing from typically 0.7 to 1.5 A/cm^2. The scale of manufacturing is expected to grow significantly, reducing stack manufacturing costs. A major cost reduction factor is upscaling through:

- larger cell areas and larger stacks;
- more cells and stacks per hotbox;
- bigger modules.

A suggested envisaged scaled-up SOE design comprises a typical stack size up to 100 kW and a sizable upscaled repeating module of 9 MW. As an upscaled example, a stack with around 60 large cells of 800 cm^2 and 16 stacks in 1 hot-box of 1.5 MW is proposed. Further bundling of 6 hot-boxes leads to a repeating module of 9 MW. For large-scale applications, these modules can be arranged in a system design of about 90 MW with all the required supporting-systems as power electronics, purification and compression. Such a proposed upscaled 1.5 MW hot-box, comprising 16 stacks of 94 kW, has been discussed with several suppliers. It turned out that large stacks are indeed acceptable and desired. However, there is no clear vision on the ideal upscaled size of a hot-box in the view of pragmatic maintenance requirements (serviceability; allowed partial downtime/turndown; etc.). Therefore, an alternative conceptual scaled-up SOE design is also suggested in this study, comprising around 160 cells per stack of 250 kW. The 1.5 MW hot-box and 9 MW module remain the same. The suggested breakdown with both configurations seems logical based on indicative reliability calculations, but need more testing and full-scale operational data on failure rates.

Total Investment Costs (TIC) are estimated in this study at around 4,800 €/kW in 2020 and 1,200 €/kW in 2030 based on literature and engineering factors. Due to limited information on stacks and balance of stacks costs, a bottom-up cost estimate proved to be difficult. It is suggested that a CAPEX reduction with a factor 4 could potentially be achieved through upscaling, mass fabrication and innovation of cell (or stack) components.

For a 800 MW conceptual electrolysis plant, as the one that would be needed for the BP use case, 289 modules of 9 MW each would be needed (provided with SOE plant specific infrastructure such as transformers, steam/heat lines, storage/pipelines, a compressor station and gas purification). For a 100 MW plant, as in the OCI case, about 11 modules of 9 MW would be needed. For a 20 MW plant, as in the AL case, at least two 9 MW modules would be needed. More attention is needed to address dynamic performance, reliability and degradation of stacks and incorporate this in the design and operation and maintenance strategy.

From a sustainable point of view, the origin of the excess steam is important and should be in line with the RFNBO requirements according the delegated Acts 27 and 28 from the Renewable Energy Directive (RED) II. Lessons learned from this project show that low pressure steam can be generated from residual heat and not necessarily requires high/medium pressure steam from the processing plant. Moreover, the advantage is that the quality of the generated steam would be more consistent with the feedstock restrictions from the SOEC.

A roadmap is given to be able to develop and deploy the SOEC technology this decade. As a next step, it is suggested to develop a pilot plant to demonstrate the technology on a 5 to 10 MW scale.

Contents

1 Introduction

1.1 General

A drastic modification of our energy system and industrial processes is required to address the effects of climate change by moving from fossil fuels to low-carbon energy sources. There is need for technologies capable of converting electricity into energy carriers like chemicals and fuels, suitable for heavy transport at high efficiencies. Electrolysis technology lies at the heart of power-to-X (P2X) solutions, where X can be hydrogen, ammonia, syngas, synthetic fuels and other products. Combining electrolysis with renewable electricity decouples the production of fuels and chemicals from fossil resources, paving the way towards a renewables-based energy system.

Solid oxide electrolysis cells (SOEC) technology has great potential as an innovative technology for hydrogen production and circular carbon. SOEC converts steam and carbon dioxide electrochemically into hydrogen, carbon monoxide and oxygen. SOEC can be integrated with a range of down-stream processes, resulting in the generation of synthetic fuels, methanol, ammonia and recycling captured carbon dioxide. The omission of phase shift from water to steam and favourable thermodynamics at higher operating temperatures give a higher energy efficiency than Alkaline water electrolysis (AWE) and Proton Exchange Membrane (PEM) water electrolysis. The energy efficiency can be further increased by heat integration in existing chemical processes. Despite the promise of the emerging SOEC technology many uncertainties remain for the fuel and chemical industry about the practical merits of SOEC technology and the economic viability for integration in existing processes.

1.2 The project

In the Next Level SOE project ISPT and TNO have performed a feasibility study on SOEC technology with three industrial use cases at Air Liquide, BP and OCI. The goal is to determine the upscaling, process integration and cost reduction potential of brown field applications of SOEC technology in the chemical and fuels industry. The feasibility study focuses on three use cases from three different industrial partners with three different applications of SOEC.

The case studies are:

- hydrogen production in an ammonia plant at OCI Chemelot site in The Netherlands;
- syngas and green hydrogen production integrated with blue hydrogen and downstream e-fuels as concept study for a potential BP site;
- carbon monoxide production at Air Liquide, Rozenburg Rotterdam site.

For each use case, the design of the SOEC technology in the industrial environment, including options for scaling-up, and up and downstream heat integration, have been explored. SOEC technology is very promising, however further insights are necessary to fulfil the technical and economic viability of integration in existing industrial processes. Besides CAPEX and OPEX, this study aimed to assess the system efficiency based on realistic use cases.

2 Solid Oxide Electrolysis

A solid oxide electrolysis cell (SOEC) is an electrochemical cell capable of converting steam (and/or carbon dioxide) to hydrogen (and/or carbon monoxide) and oxygen. The SOEC consists of a ceramic oxygen ionic conducting electrolyte, surrounded by two porous electrodes. Steam is converted at the porous cathode into hydrogen and oxygen ions under the uptake of electrons. Under an applied voltage the oxygen ions are transported through the dense ceramic oxygen ion conducting electrolyte to the porous anode where oxygen is formed with the release of electrons.

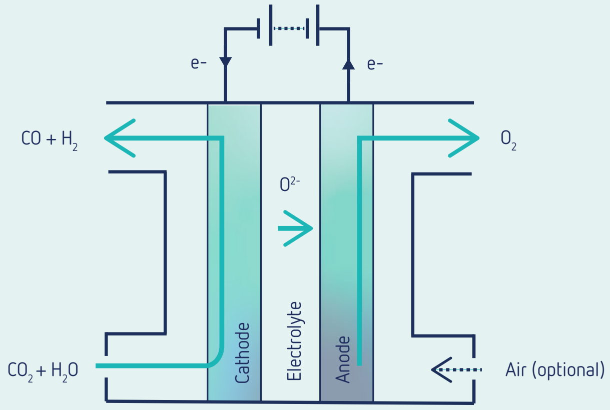

Figure 1. A solid oxide electrolysis cell (SOEC)

SOEC technology operates at high temperature, typically between 600 and 850°C, which is required to have sufficient oxygen ion conductivity in the ceramic electrolyte. AWE and PEMWE technologies operate at low temperature, typically at 60-100°C. The high operating temperature for SOEC creates two main advantages compared to low temperature electrolysis technologies: thermodynamic efficiency and faster kinetics. The theoretical thermodynamic efficiency for splitting of water/steam and carbon dioxide increases with increasing temperature. Going from 60 to 800°C, the voltage required for electrolysis goes down by approximately 25-30%. The combined advantages of increased thermodynamic efficiency and kinetics for SOEC are shown in Figure 2.

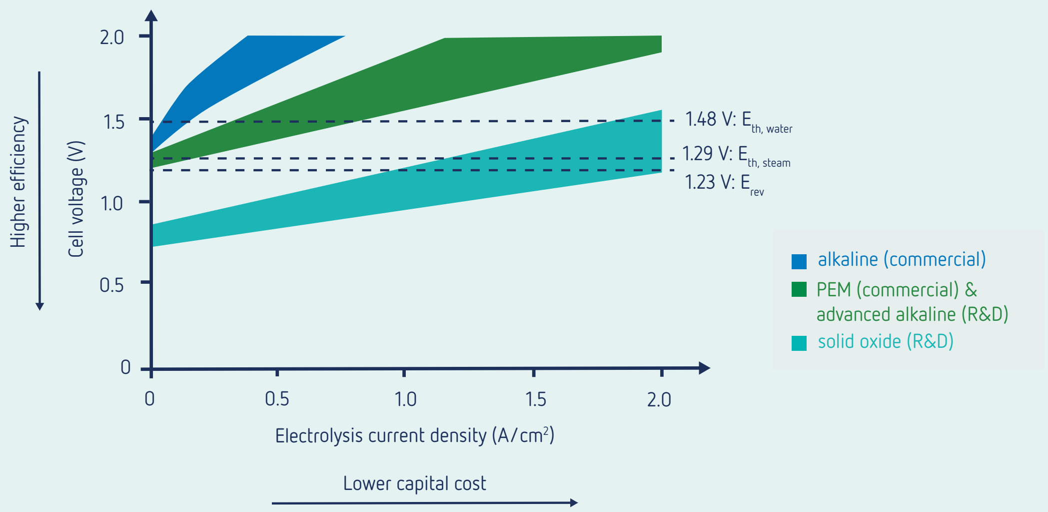

Figure 2. Current density-Cell voltage relationship for both high and low temperature electrolysis technologies

A SOEC is typically operated at the thermo-neutral voltage[1] for splitting of steam (1.29 V), while the thermo-neutral low temperature water electrolysis technologies is 1.48 V, so the efficiency gain on stack level is typically 15%. The thermo-neutral voltages are calculated using Faraday's law, and can be expressed in both Higher and Lower Heating Values.[2] The abovementioned thermo-neutral voltages refer to the Lower Heating Value (LHV)[3] for steam splitting and for water splitting to the Higher Heating Value (HHV). AWE and PEM are typically operated at higher voltage-levels than the thermo-neutral voltage around 1.8 V since a higher cell potential (V) for AWE and PEM is needed to compensate for ohmic losses. Consequently, the stack electricity consumption for the generation of hydrogen is lower for the SOEC steam electrolysis technology, which falls in the order of 33 kWh/kg H_2, compared to approximately 48 kWh/kg H_2 for the low temperature water electrolysis technologies.

SOEC can be integrated (heat and process) with a range of existing downstream (exothermic) industrial processes, which results in the generation of synthetic fuels, methanol, ammonia, and recycling of captured carbon dioxide. Moreover, gas crossover and process safety is less of an issue since hydrogen and oxygen will not build up as it will not build up to large volumes in the system as it will auto-ignite instantaneously due to higher temperatures.

[1] Voltage needed to drive the reaction with no additional heat production

[2] Faraday's law: Electropotential E (V) = LHV or HHV / (n* Faraday's constant), n=2

[3] Lower heating value (LHV) of water is 237.2 kJ/mol and higher heating value (HHV) is 285.8 kJ/mol, so difference of 45.6 kJ/mol H_2O for heating water from 0 - 100 °C and evaporation (at 1 bara).

3 System Design for Use cases

This section describes the system design for all use cases. Based on the feedstock (CO_2 and/or steam) and product volumes, the required electrolyser power capacity and specific energy consumption have been determined. Process model and simulations of all use cases have been performed in Aspen Plus. Process flow diagrams and mass and energy balances have been prepared.

3.1 Use case OCI

The use case for OCI is based on the integration of a SOE steam electrolysis system in an existing ammonia production plant. Hydrogen product from the electrolyser can be mixed with synthesis gas upstream of the ammonia synthesis section. Oxygen product could be potentially used to increase the reforming efficiency but it is not considered in this study. Preferably residual heat is used towards the SOEC. The integration of SOE will reduce the consumption of natural gas as a feedstock and fuel.

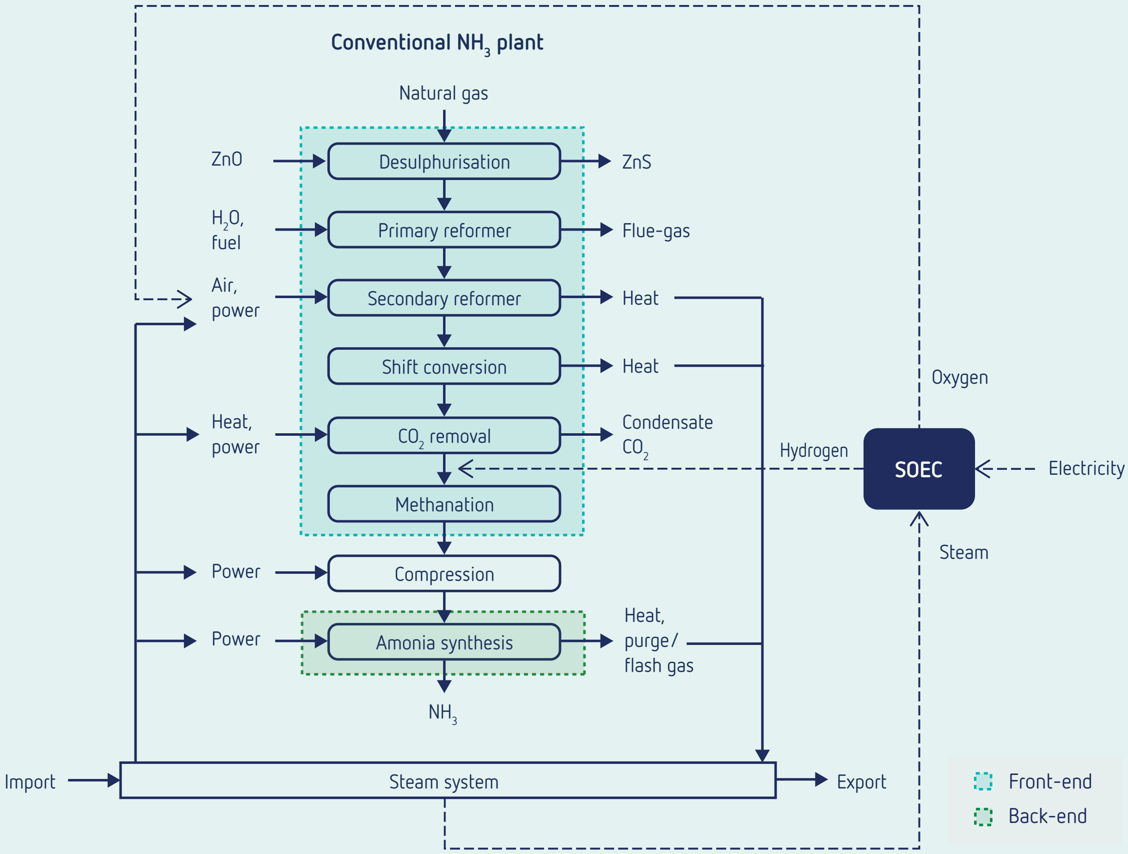

Figure 3. Use case OCI – Steam methane reforming process

3.1.1 Basis of Design

The main guiding parameter for basis of design is the hydrogen production rate (2,300 kg/h). The following parameters were considered in system design (see Figure 4).

- Plant capacity: H_2 production of maximum 2,300 kg/h (18 kt/y).
- H_2 tie in points: Upstream of methanation unit or downstream of methanation unit.
- Required purity of H_2: O-eq. continuous < 10 ppm / peak (hr) < 50 ppm and No S- / Cl-compounds.
- Steam quality is not continuously monitored and is of insufficient quality.
- Preferred option is to generate steam using available waste heat from flue gases and from available reaction heat (40 barg saturated steam, from ammonia conversion).
- Electrolyser size: 80 MW.
- Enriched air with 30%vol O_2.
- Required purity of demineralised water: VGB or ASME standard.
- Steam for OCI use case will be generated using available waste heat and demin water, for example through flue gas heat recovery.
- Single pass conversion of steam to hydrogen is assumed to be 80%.
- The inlet to SOE stack is assumed to be 90/10 of steam/hydrogen on molar basis. Recycle of hydrogen to the stacks is needed to keep the cathode in the reduced state.
- Produced hydrogen to tie-in methanation in the existing ammonia production process: 30 bara.
- Drying unit is present in the existing ammonia production process.
- Oxygen recycle into secondary reforming is not considered in this study.

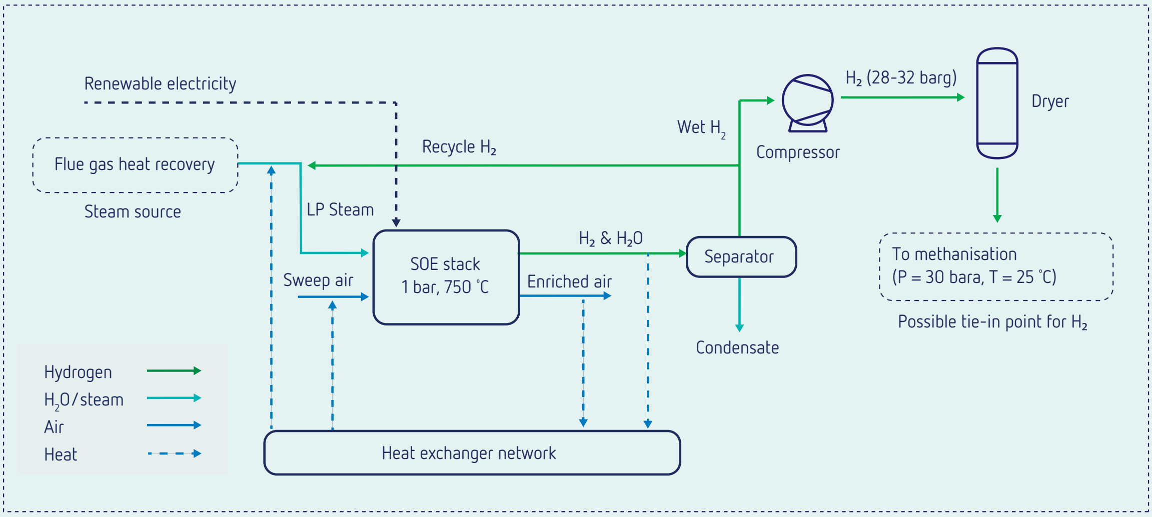

Figure 4. System design for hydrogen producing (OCI)

3.2 Use cases BP

Two SOE cases have been considered based on availability of excess steam and heat from a Blue Hydrogen production Plant (SMR-steam methane reforming or ATR- Autothermal reforming) (see Figures 5 and 6). The first use case (Case BP 1) is based on converting steam to green hydrogen to be used as feedstock in refinery units. The second use case (Case BP 2) considers feeding steam with CO_2 to produce syngas, to be used as feedstock for producing e-fuels and oxygen. The oxygen stream could be used in the Blue H_2 plant, however that option is not considered in this study.

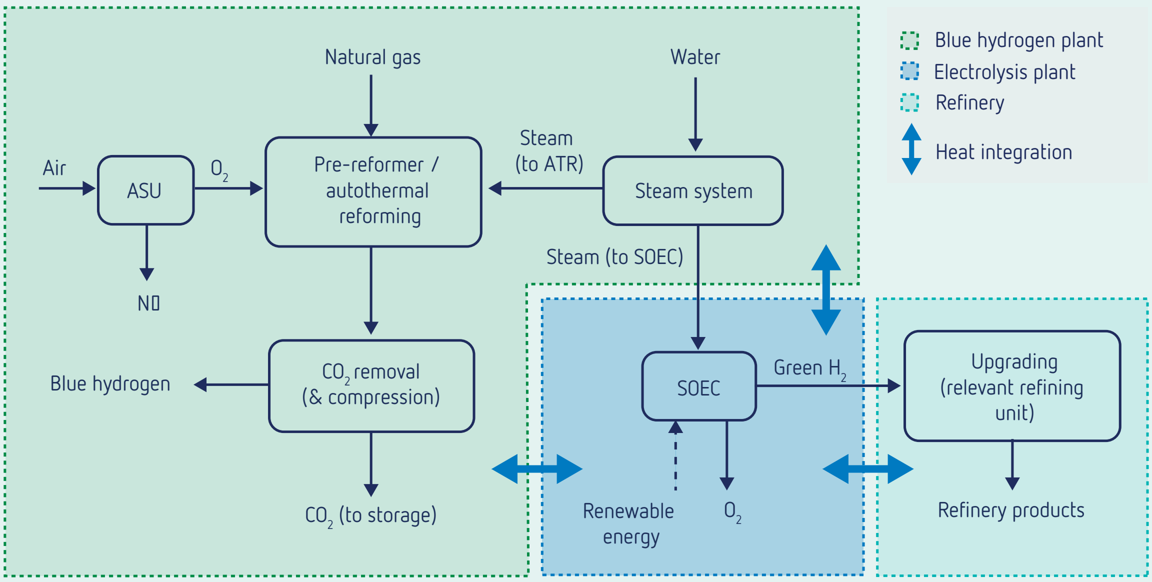

Figure 5. BP use case 1 for green hydrogen production

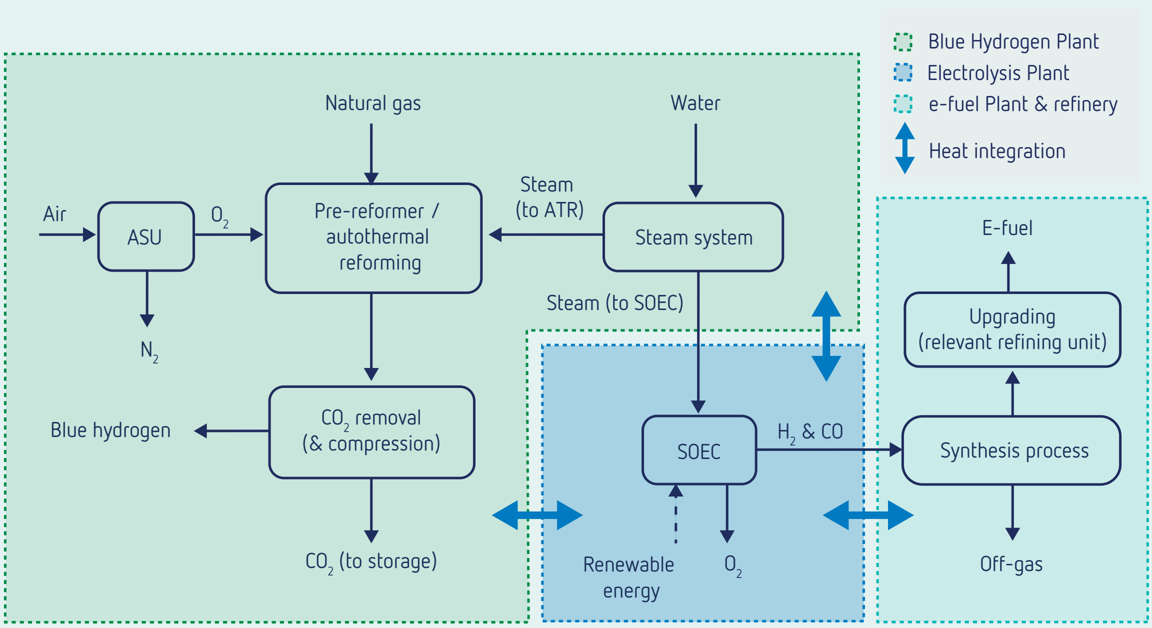

Figure 6. BP use case 2 e-fuel production schematics

3.2.1 Use Case BP1: Green Hydrogen production

Basis of Design:

Mainly guiding parameter for basis of design is the available steam flow rate (150 tph). The following assumptions were considered in system design (see Figure 7).

- Plant capacity: Hydrogen production of 13.5 t/h.
- Required purity of hydrogen: up to 99.9% (vol).
- Steam is assumed to be purified up to SOEC specification. Upstream water Upstream water/steam purification and associated costs are outside the scope of this study.
- Steam specification: 42 barg and 380°C.
- Electrolyser size: ~ 500 MW.
- Continuous operation: base load of renewable power 8,000 h/y.
- Hydrogen product specification: 35 barg to be used in the hydro-processing unit.
- Enriched air with 30.vol% O_2.
- Steam supply is through 40 bara excess steam.
- Pressure reduction in steam turbine with power generation.
- Single pass conversion of steam to hydrogen is assumed to be 80%.
- The inlet to SOE stack is assumed to be 90/10 of steam/hydrogen on molar basis. Recycle of hydrogen to the stacks is needed to keep the cathode in the reduced state.

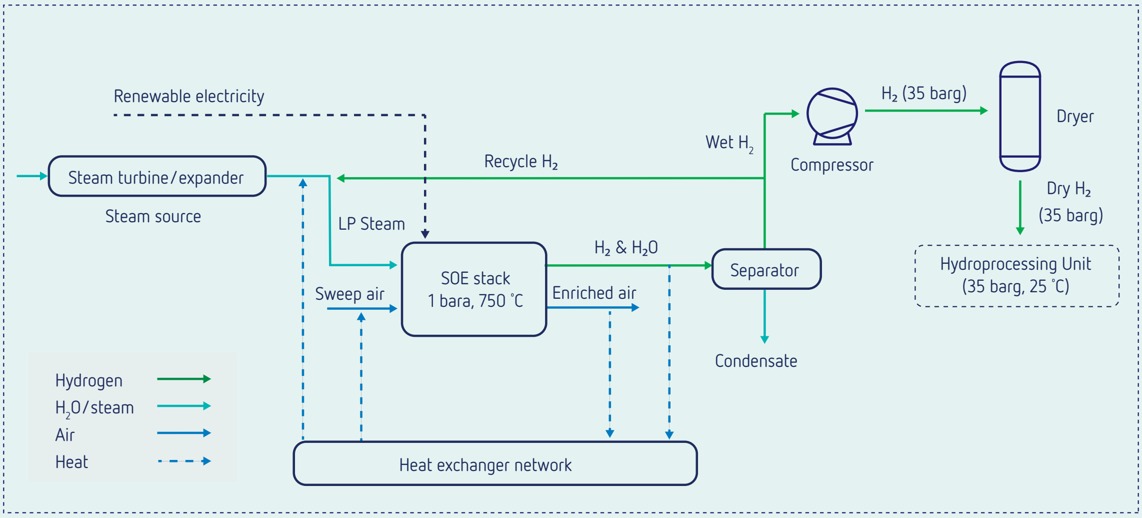

Figure 7. System design BP green hydrogen production

3.2.2 Use Case BP2: e-fuel production

This case covers co-electrolysis of steam and CO_2 to produce syngas. Hence, conversion of syngas to e-fuels can be a next step.

Basis of Design:

The main guiding parameter for basis of design is the available CO_2 flow rate (190 tph). Following assumptions were considered in system design (see Figure 8).

- Plant capacity: Syngas production of 110 t/h.
- Required purity of syngas: Syngas with ratio H_2/CO 2:1 and sulphur, nitrogen containing species < 1 ppm.
- Steam is assumed to be purified up to SOEC specification. Upstream water Upstream water/steam purification and associated costs are outside the scope of this study.
- CO_2 stream is purified up to specification, including Sulphur, NO_X, HCN, NH_3 can and CH_4. These trace components can impact SOEC system performance. Moreover, purification of CO_2 stream can be necessary as it impacts downstream e-fuel synthesis process.
- CO_2 purification process and associated costs are outside the scope of this study.
- CO_2 stream specification at 30 barg and 30°C.
- Electrolyser size: ~ 900 MW.
- Continuous operation: base load of renewable power 8,000 h/y.
- Syngas product specification: 30 barg to be fed into Fischer-Tropsch synthesis to produce e-fuel.
- Enriched air with 30.vol% O_2.
- Pressure reduction in steam turbine with power generation.
- Single pass conversion of Steam and CO_2 to syngas is assumed to be 85%.

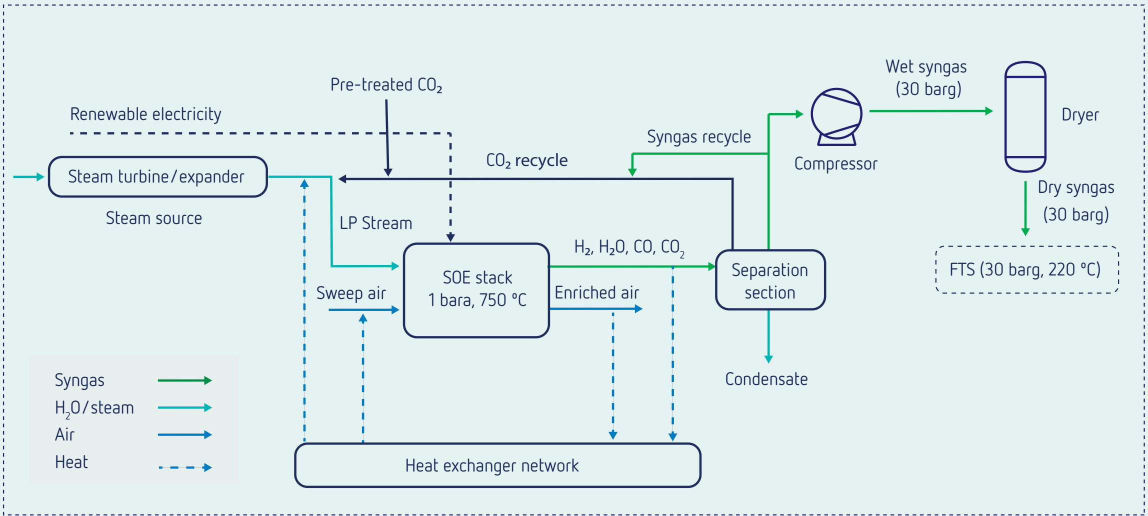

Figure 8. System design BP e-fuel production

- Recycle of syngas to the stacks is needed to keep the cathode in the reduced state.

3.3 Use case Air Liquide

Air Liquide produces industrial gasses for large industrial players. Within the portfolio there is amongst others O_2, H_2, N_2, CO and Argon. Air Liquide would like to investigate to use SOE for converting carbon dioxide into carbon monoxide as raw material for production of specialty chemicals like poly urethanes. This scheme could be the first step into producing renewable or low carbon CO and providing an alternative to the production of CO from methane. Because SOEC requires both electricity and heat as utilities, the interest of Air Liquide was to integrate SOEC as part of the existing production facilities with steam methane reformers and introduce carbon-looping to reduce the carbon footprint.

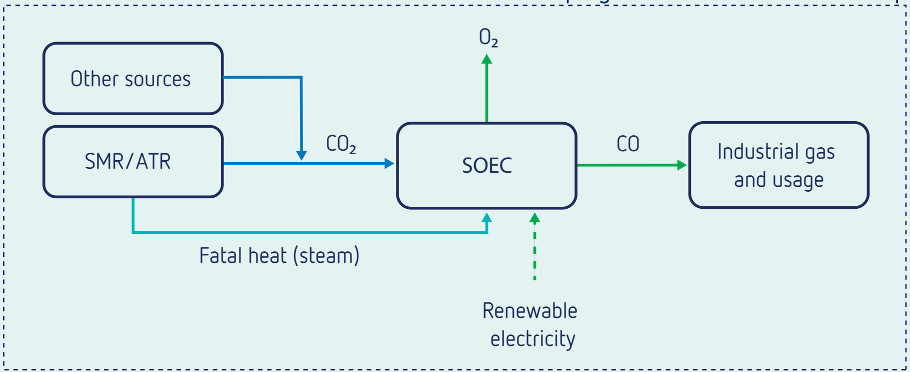

Figure 9. Use case Air Liquide – CO-plant

Basis of Design:

The main guiding parameter for basis of design is CO production rate (5,000 Nm^3/h). Following parameters were considered in system design (see Figure 10). The purity of inlet CO_2 stream determines the downstream system design for required purity of CO product. Hence, CO_2 will be supplied from the liquification unit.

- Plant capacity: CO production of 5,000 Nm^3/h (~ 50 kt/y).
- CO_2 feedstock source: CO_2 liquification unit.
- Waste Heat available at site: 10 MW available at ~ 110°C (water condensates) and ~ 5 MW available at 140°C (stack outlet).
- Required purity of CO stream: CO ≥ 96 mol%.
- Enriched air with 30.vol% O_2.
- Single pass conversion of CO_2 to CO is assumed to be 50%.
- The inlet to SOE stack is assumed to be 95/5 of CO_2/CO on molar basis for Air Liquide CO use case. This is needed to keep the Ni-based fuel electrode (cathode) in reduced condition.

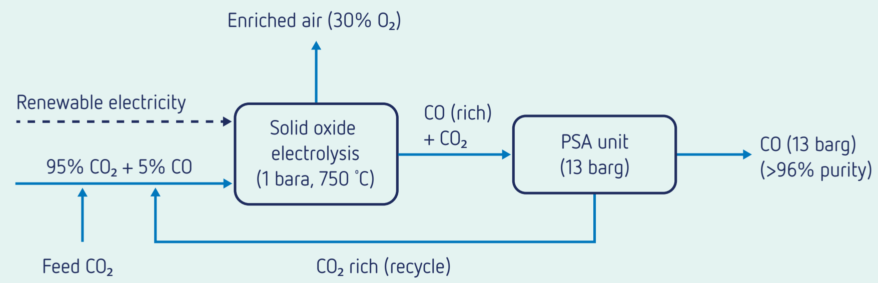

Figure 10. Carbon monoxide production system design

3.4 Process Model and Process Design results

3.4.1 System energy consumption

Overall SOEC system energy consumption depends on various factors such as mode of SOEC operation (endothermic, exothermic, thermoneutral), operating parameters, single pass conversion, and heat integration. In all use cases, thermoneutral mode of operation is assumed for conversion and efficiency purposes (most efficient electricity consumption is at thermoneutral voltage). This section shows energy consumption for all the use cases. Table 1 summarises the electricity consumption for the use cases. On system level, the other electricity consumers include feed and air heating, air blower and compression.

Table 1. Summary electricity consumption for the use cases

Electricity consumption	Stack	Other	System
Use case OCI hydrogen	80 MW	12 MW	92 MW
Use case BP 1 hydrogen	462 MW	74 MW	536 MW
Use case BP 2 syngas	786 MW	124 MW	910 MW
Use case Air Liquide carbon monoxide	17 MW	3 MW	20 MW

According to the heat and material balances, the enthalpy in the feed for use cases is as follows (see Table 2). The enthalpy for steam utilisation should be added to the system energy provided that steam generation is additional to the brown-field processes. However, it is assumed that excess steam is used and therefore this energy consumption is not considered.

Table 2. Summary steam generation for the use cases

Enthalpy steam generation	Steam	Remarks
Use case OCI hydrogen	20 MW	Steam generation with waste heat recovery
Use case BP 1 hydrogen	115 MW	Steam at 42 bara (12 MW turbine generation 42-8 bara)
Use case BP 2 syngas	107 MW	As above
Use case Air Liquide carbon monoxide	-	Not applicable

3.4.2 Specific energy consumption

Tables 3 to 6 show the specific energy consumption values for the use cases based on electrical energy consumption, thermal energy for steam generation and production rates. For OCI use case, the hydrogen production rate is 2.3 tph and the specific electricity consumption is 39.8 kWh/kg hydrogen. In case no excess steam is available, the additional specific energy consumption for steam generation is 7.9 kWh/kg. For BP case 1, the specific electricity consumption is 38.8 kWh/kg hydrogen and the hydrogen production rate is 13.5 tph. The specific energy consumption is is 13.5 tph; with 1 kWh/kg of electricity produced by the steam turbine. In case no excess steam is available, the additional specific energy consumption for steam generation is 8.5 kWh/kg. For BP case 2, the syngas production rate is 110 tph and the specific electricity consumption is 8.3 kWh/kg syngas. In case no excess steam is available, the additional specific energy consumption is 1.0 kWh/kg. For Air Liquide case 2, the carbon monoxide production rate is 6.2 tph and the specific electricity consumption 3.2 kWh/kg CO).

Table 3. Specific energy consumption OCI green hydrogen use case

Component	Value	Unit
Electric heating feed	1.2	kWh/kg H_2
Electric heating air	1.8	kWh/kg H_2
H_2 compressor	2.2	kWh/kg H_2
SOEC stack (DC)	34.6	kWh/kg H_2
Total LHV	**39.8**	**kWh/kg H_2**
Steam generation (if required)	7.9	kWh/kg H_2
Total (with steam generation required)	47.7	kWh/kg H_2

Table 4. Specific energy consumption BP green hydrogen use case 1

Component	Value	Unit
Air blower	0.3	kWh/kg H_2
Electric heating feed	1.1	kWh/kg H_2
Electric heating air	1.9	kWh/kg H_2
H2 compressor	2.3	kWh/kg H_2
Steam turbine	-1.0	kWh/kg H2
SOEC stack (DC)	34.2	kWh/kg H_2
Total LHV	**38.8**	**kWh/kg H_2**
Steam generation (if required)	8.5	kWh/kg H_2
Total (with steam generation required)	47.3	kWh/kg H_2

Table 5. Specific energy consumption BP green hydrogen use case 2

Component	Value	Unit
Electric heating feed	0.2	kWh/kg syngas
Electric heating air	0.4	kWh/kg syngas
Syngas compressor	0.4	kWh/kg syngas
Steam turbine	-0.1	kWh/kg syngas
SOEC stack (DC)	7.1	kWh/kg syngas
Air Blower	0.1	kWh/kg syngas
Total LHV	**8.3**	**kWh/kg syngas**
Steam generation (if required)	1.0	kWh/kg syngas
Total (with steam generation required)	9.3	kWh/kg syngas

Table 6. Specific electricity consumption Air Liquide carbon monoxide use case

Component	Value	Unit
Electric heating feed	0.2	kWh/kg CO
Electric heating air	0.1	kWh/kg CO
Compression	0.2	kWh/kg CO
SOEC stack (DC)	2.7	kWh/kg CO
Total	**3.2**	**kWh/kg CO**

3.4.3 Cooling requirements

Cooling is required in the product gas stream. The cooler and knock-out drum for water removal are located in the suction header of the compressor. In addition, the compressor has interstage coolers. In Table 7, the cooling water duties are indicated. For cooling either air-fin coolers or cooling water heat exchangers are needed. The cooling requirements may not be overlooked in the system design as cooling capacity may be limited on plant level in the case of brownfield applications, especially with cooling water in the summer. About 11% of the stack duty (MWe) is needed as cooling duty (MWth) to cool down to around 40-50°C.

Table 7. Cooling requirements per use case

Cooling duty	Value	Cooling/ stack duty
Use case OCI hydrogen	8.9 MW	11.2%
Use case BP 1 hydrogen	52.1 MW	11.2%
Use case BP 2 syngas	56.5 MW	7.2%
Use case Air Liquide carbon monoxide	1.6 MW	9.5%

4 Upscaling potential

This section presents the SOE technology scale-up options and feasibility towards multi-MW to GW-scale to meet the project objective of developing scale-up scenarios towards large scale SOEC to shorten time to market and bring the technology to next level. The suggested scaled-up SOE with a sizable bigger module is of importance for further future roll-out of the technology on a realistic industrial scale.

4.1 Definitions

Since there is currently no unified well-established naming of the upscaled SOE technology, we provide an overview here of the encountered terminology used by various technology suppliers and suggest a nomenclature to be used in this report.

The components of SOE technology include stacks (comprising of solid oxide cells). High temperature balance of stack HT BoS are defined as a hot-box HT BoS and referred to by brand-names as HOT-BOX/ MODULE/ CORE for respectively Bloom Energy/SUNFIRE/ TOPSOE. Multiple hot-boxes integrated with common low temperature balance of plant LT BOP (including e.g. purification and compression units) and power electronics are defined as a repeating module and referred to by brand-names as STAMP/ SYSTEM/ MODULE, for respectively Bloom Energy/ SUNFIRE/ TOPSOE. Figure 11 provides an overview of such terminology and related equipment suppliers.

When several repeating modules are combined together this makes a system and with a large plant infrastructure (i.e. transformers, steam supply, storage/pipelines, purification, civil, process automation, up and downstream integration), a complete SOE plant is formed.

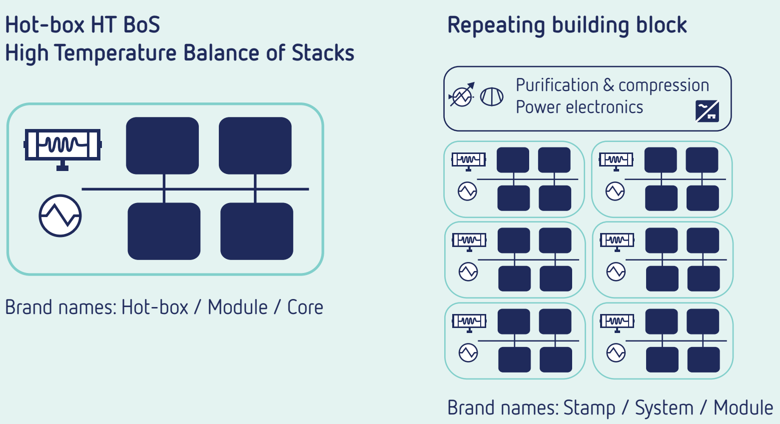

Figure 11. SOE terminology overview: Hot-box HT BOS (i.e. stacks and high temperature balance of stacks) with brand-names HOT-BOX/MODULE/CORE and repeating module with brand-names STAMP/SYSTEM/MODULE for respectively Bloom Energy/SUNFIRE/TOPSOE.

4.2 Cost reduction potential of SOE technology upscaling

SOE scale-up towards a multi-MW system brings significant opportunity for cost reductions. There are several measures to decrease the SOE system level CAPEX further by 2030. As shown in Figure 12, the SOE system level CAPEX reductions can be obtained by increasing solid oxide cell area (from 100 cm^2 up to 800 cm^2), enabling increased production volume of SOE cells (from 1,250 m^2/y; ~10 MW/y towards > 40,000 m^2/y; 300 – 500 MW/y), increasing stack current density (from 0.85 A/cm^2 up to 1.5 A/cm^2), and increasing system scale (from 100-200 kW up to 500+ kW per repeating module; from 1-10 MW towards 100+ MW SOE plant).

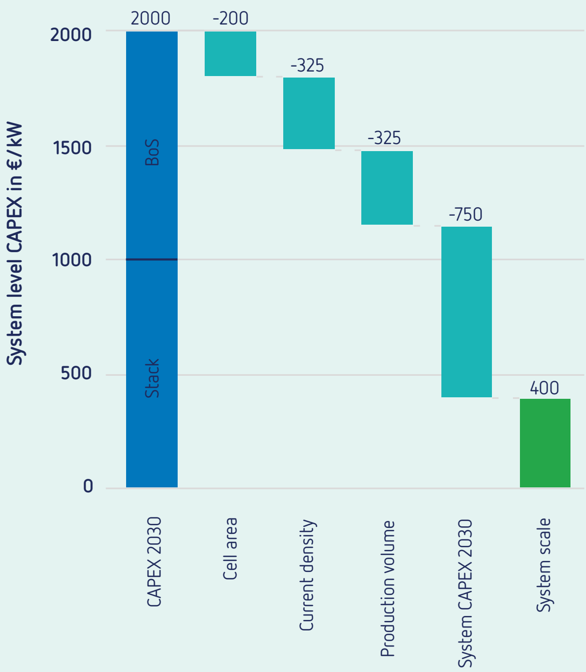

Figure 12. Measures to decrease the SOE CAPEX

4.3 Upscaling potential – upscaled repeating building SOE blocks (modules) for multi-MW SOE plants

In order to move SOE technology to industrial scale application in 2030, the scale-limitations need to be removed to reach SOE plant scale > 100 MW and provide green hydrogen with competitive Levelised Costs of Hydrogen (LCOH) < 3 €/kg as a feedstock in industry. To reach SOE technology industrial roll-out, it is a prerequisite to scale-up SOE cell, stack, and hot-box Balance of Stacks (BoS) in capacity size and performance followed by high volume cost-efficient manufacturing. Furthermore, the overall system design needs to balance each of the aspects of the system and indicate the optimal module size based on a compromise between decreasing specific CAPEX and increasing OPEX (due to maintenance requirements and downtime). Preliminary estimates (based on discussions with top three largest full SOE system suppliers Bloom Energy/Sunfire/Topsoe) predict an optimal hot-box HT BoS size of about 500-1,500 kW, which would then be clustered in repeating modules to realise multi-MW plants. As indicated the SOE-plant will operate at thermo-neutral voltage to optimise electricity consumption and costs.

Figure 13 provides SOE scale-up roadmap towards multi-MW plant with required upscaling of cells, stacks, hot-box HT BoS towards larger repeating module and ultimately multi-MW SOE plant.

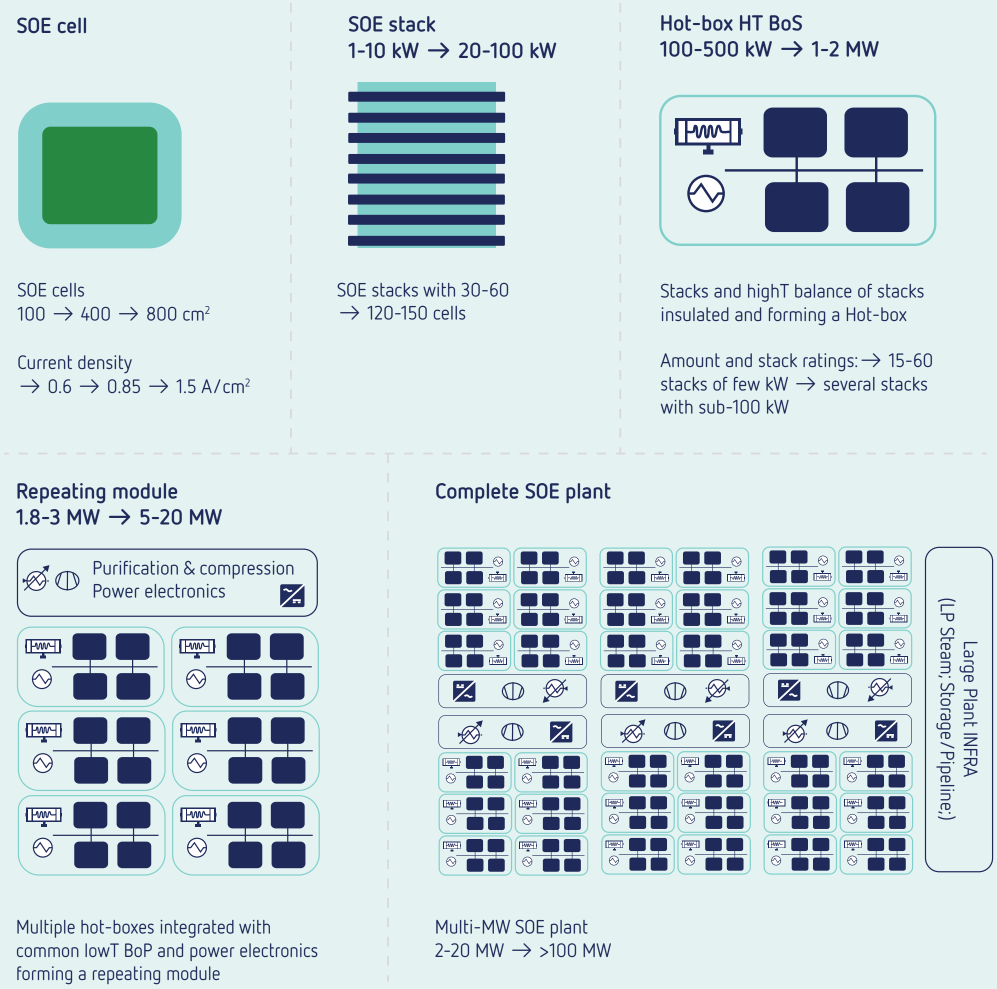

Figure 13. SOE scale-up towards multi-MW plant

A suggested envisaged scaled-up SOE design comprises a typical stack size up to 100 kW and a sizable upscaled repeating module of 9 MW. Figure 14 highlights two upscaled options of a 94 kW stack. One option is a 94 kW stack with 120 cells of 400 cm^2 and the other is with 60 cells of 800 cm^2 area. In Figure 15, three concepts of stack arrangements and heat exchangers for heat recovery of the product gas and air streams are indicated. A hot-box of 1.5 MW is proposed for a hot-box HT BoS design, see also Table 8. Further bundling of 6 hot-boxes leads to a repeating module of 9 MW (with all the required supporting-systems as power electronics, purification, compression, etc.).

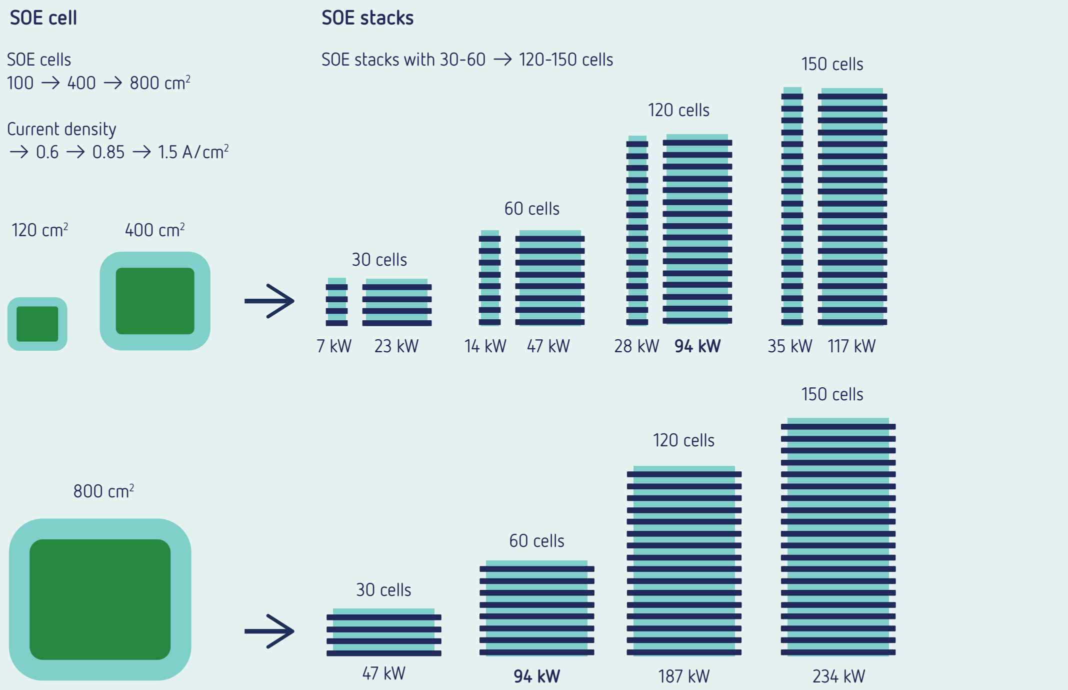

Figure 14. Scaled-Up SOE Stacks. Two upscaled options are emphasized: 94 kW stack of 120 cells of 400 cm^2 at 1.5 A/cm^2 thus 156 V @ 600 A and 94 kW stack of 60 cells of 800 cm^2 at 1.5 A/cm2 thus 78 V @ 1,200 A

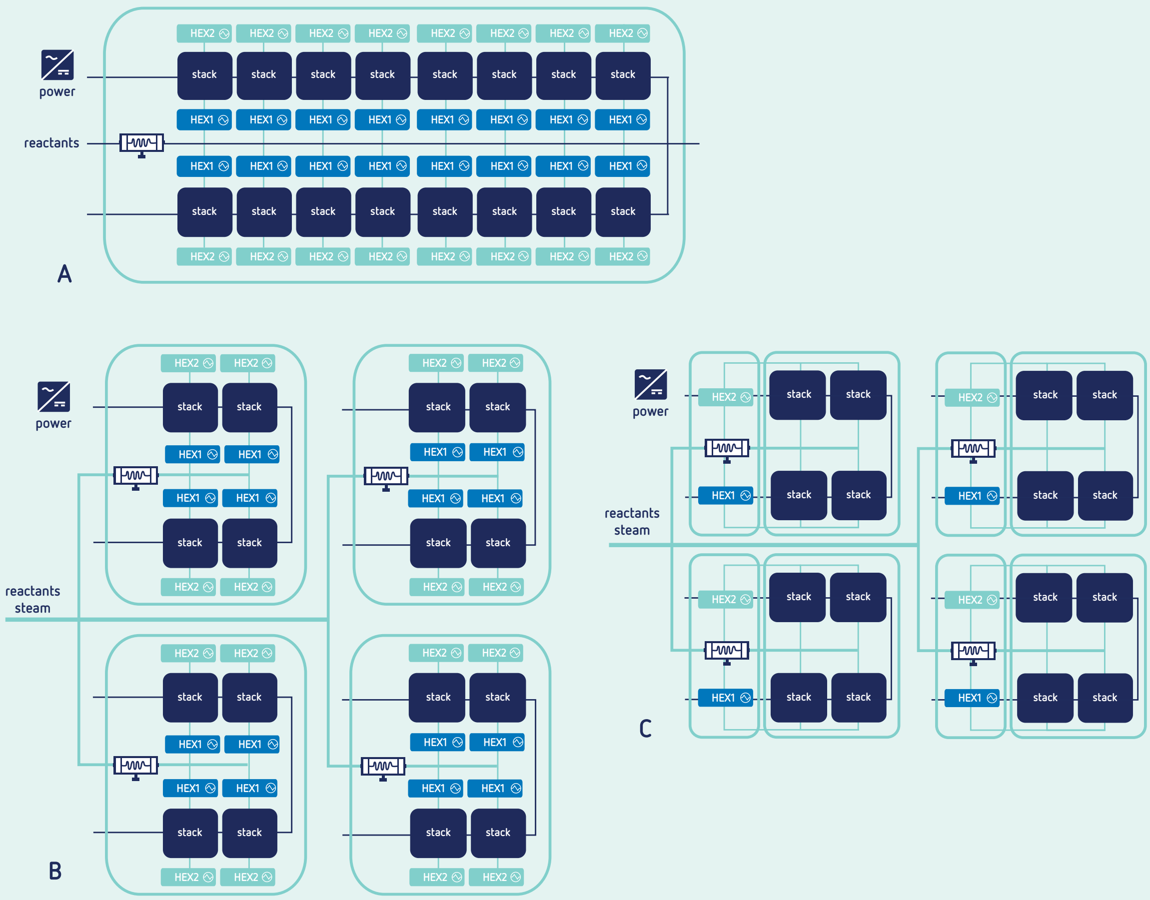

Figure 15. Scaled-up SOE towards a sizable hot-box HT BoS design with:
A. 1 hot-box of 1.5 MW with 16 of 94 kW stacks with integrated HT BoS
B. 4 hot-boxes of 0.4 MW (i.e. 4 of 94 kW stacks per hotbox) with integrated HT BoS
C. 4 hot-boxes of 0.4 MW (i.e. 4 of 94 kW stacks) with separate stack-box and HT BoS-box

Figure 15B and C depict envisaged configuration of stacks with related HT BoS for potentially simplified serviceability. The large hot-box with 16 of 94 kW stacks (as in Figure 15A) is subdivided into four separate hot-box sections, each containing four 94 kW stacks with integrated HT BoS, while still all connected to one steam header. A potential advantage of such a design is that for a replacement/service of a faulty stack only one section (i.e. 0.4 MW) needs to be disconnected and cooled down, while the other three hot-boxes can remain in a hot stand-by prolonging the stack lifetime.

Table 8. Suggested envisaged scaled-up SOE design

Cell voltage	**Cell area**	**Current density**	**Cell power**	**Amount of cells**	**Total cell area per stack**	**Stack current**	**Stack voltage**	**Stack power**
V	cm^2	A/cm^2	W	#	cm^2	A	V	kW
1.3	800	1.5	1560	60	48000	1200	78	93.6

Stacks per Hot-box HT BoS	**Hot-box power**	***Total voltage stacks in series***	**Hot-box per repeating module**	**Module**
#	kW	V	#	MW
16	1498	*1248*	6	9.0

For a 800 MW conceptual electrolysis plant, as the one that would be needed for the BP use case 2 (see paragraph 3.2), 89 blocks of 9 MW each would be needed (provided with SOE plant specific infrastructure as transformers, steam/heat lines, storage/pipelines, etc., see Figure 13). For a 100 MW plant, as in OCI case (see paragraph 3.1), 11 blocks of 9 MW would be needed. For 20 MW plant, as in AL case, at least two 9 MW block would be needed (see paragraph 3.3).

The feasibility of such proposed upscaled 1.5 MW hot-box, comprising 16 stacks of 94 kW as assumed in this study, has been discussed with several suppliers. Consistent feedback of a need of scaling to large stacks was received (from current 1-10 kW towards 20-100 kW). However, there is no general agreement on the ideal upscaled size of a hot-box based on pragmatic maintenance requirements (serviceability; flexibility for partial downtime/turndown; etc.). As a result of this feedback, an alternative conceptual scaled-up SOE design is also included in this study.

5 Techno-economic evaluation

5.1 Technical assessment

5.1.1 Design, performance and operability

The upscaling potential is a result of technology improvements leading to cost reduction. This can be achieved through:

- higher current densities;
- higher scale of manufacturing;
- increased sizing of cells, stacks, hotbox and modules.

A major cost reduction factor is upscaling through:

- larger cell areas and larger stacks;
- more cells and stacks per hotbox;
- bigger modules.

The current density is a main cost driver (CAPEX), as with higher current densities, less SOEC surface area is needed for the same output. It is assumed that current density can be doubled before 2030, so increasing from typically 0.7-0.8 to 1.5 A/cm^2. The operating temperature and stack efficiency will not change and remain at thermo-neutral voltage 1.3 V, which means steam electrolysis efficiency of 100% LHV, only allowing for electricity consumption to compensate for temperature losses to environment and hot stand-by.

More reduction of stack costs is expected to be achieved through increasing scale of manufacturing capacity and automation. The evaluation of this learning rate is out of the scope of this study.

Larger cell areas of 800 cm^2 result in 4 to 8 times larger cell areas than those currently available on the market. The main technological challenges for these larger cells are gas tightness, acceptable pressure drop, controlled thermal profiles, degradation and manufacturability.

The number of cells per stack can be increased to have larger stack power rating and less manifolds, piping and BoS equipment, such as heat exchangers. Bigger hotboxes can be sized based on the larger stacks. The hotboxes can be grouped together outdoors or in containers and should be accessible for maintenance. The size of a module is market driven and should be transportable. The modules can be designed in a standardised arrangement of several modules in one system. For large-scale applications, multiple systems are needed depending on required size of the plant. The balance of plants (e.g. electricity supply, water treatment, gas purification, utilities) is usually on plant level. The plant size will depend on the application and can range from tens of MW to GW as seen in the use cases of this study.

The stack power rating depends on the number of cells per stack and current density. The hotbox design is limited to typical 800 V DC by the voltage applied from the transformer-rectifiers. For the scaled-up stack, 1,200 V are assumed (having more cells/stacks in series), meaning that the power input and hydrogen output per hotbox increases with a factor of 1.5. Two stack design options have been considered in this study. A first option of stacks with 60 cells; and a second option of stacks with higher cell number of 146, therefore scaling up the stacks and saving on stack assembly and manifolds costs. The system configuration for both options with these stack sizes is assumed to have the same number of hotboxes, modules, systems.

Table 9. Stack design

Design parameters	Unit	Value		Comments
Current density	A/cm^2	1.5		
Cell voltage	V	1.3		
Cell area (effective)	cm^2	800		
Nr of cells per stack	#	60	146	2 options
Nr of stacks per hotbox	#	15	6	Limited to 1,200V DC rectifier output
Stack capacity	kW	94	250	
Hotbox capacity	kW	1,500	1,500	
Module	MW	9		
Cell degradation	% V	10%		Assumption for replacement at end-of-life
Stack hydrogen production efficiency for steam electrolysis	kWh/kg	33		Steam electrolysis
System efficiency (excl. steam generation)	%	84%		2 kWh/kg compression and 3.2 kWh/kg e-heaters and AC-DC 97%
Hydrogen production per stack	kg/h	3.0	7.5	per stack

The operating strategy for all cases is similar. Load variation with green electricity profile, assuming flexible operating following wind (and/or solar) profile, typically 4,000 full load hours. Ramping up and down is possible instantaneously based on intermittency and flexible demand. The operation strategy is based on ramping up/down of the entire plant through equal distribution up to a load set-point (e.g. 80%). Below this set point switching-off hotboxes is necessary. Therefore, the number (and size) of hot boxes should be such that the full operating window is covered for a typical plant size, which is possible with the proposed sizing for all three uses cases. Hot stand-by is needed for hotboxes in periods of low or no load with renewable electricity. Prolonged times of low or no load (or renewable power) may require to put some hotboxes in cold stand-by and purged with nitrogen. This decision is normally driven by economic criteria. This is an economic decision. Start-up of the hotbox takes typically 24 hours, and consequently should be planned well in advance according to the forecast of available power and required product demand.

Based on the above considerations, the proposed scaling-up to 1 GW plants leads to components sizes as summarized in Table 10.

Table 10. Configuration upscaling potential

Design	Unit	Upscaling		Comments
Stack power, max	kW	100	250	
Hotbox	kW	1,500		smallest unit to switch off
Module	MW	9		
Plant	MW	1,000		
Nr of stacks per hotbox	#	15	6	Limited to 1200VDC rectifier output
Nr of parallel hotbox per module	#	6		Transportable
Nr of modules per system	#	10		Assumed 90 MW
Nr of systems per plant	#	11		
Total nr. of rectifiers per plant	#	50		Assumption for replacement at end-of-life
Total nr of hotboxes	#	660		
Total nr of stacks	#	10,000	4,000	
System efficiency	%	83		See Table 12
Nr of Balance of Plant	#	3		Compressors and downstream processing (e.g., drying) per plant, typical turn down ratio 25-30%
Hydrogen production per stack	Nm^3/h	33	83	
Hydrogen production per hotbox	Nm^3/h	420		
Hydrogen production per module	Nm^3/h	2,520		
Hydrogen production per system	Nm^3/h	25,200		
Hydrogen production per plant 1 GW size	Nm^3/h	277,200		

The proposed scaling-up design is a direction to achieving costs reduction. Whether this will be practically feasible regarding manufacturability, mechanical design and operational performance needs to be proven in a next step.

Concerning the three use cases, the configuration would be as follows (see Table 11).

Table 11. Modules and systems for use cases with upscaling

Design	Unit	Unit size	OCI	AL	BP1	BP2
Electricity consumption stacks	MW		80	17	460	760
Nr. of hotboxes	#	1.5 MW	54	12	312	504
Nr. of modules	#	9 MW	9	2	52	84
Nr. of systems	#	90 MW	1	<1	5	8

5.1.2 System efficiency

The system efficiency for the three use cases has been calculated (see Table 12). The assumption is that with higher current density, larger cells and higher power ratings the stack and system efficiencies do not change. The system efficiency is defined as Energy (in product)/Total energy consumption. In case of SOE and 100% stack efficiency, the system efficiency can be simplified to stack electricity consumption divided by the total electricity consumption. The efficiency losses are due to electricity consumption for compression (and air blowing) and e-heaters and losses at AC-DC transformer-rectifiers. The conversion is based on LHV and corresponding electro-neutral point. The steam and heat supply are not considered as we assume that this is excess steam. Also heat integration is included and optimised to avoid steam consumption for preheating.

Table 12. Efficiencies GW scale SOE systems based on use cases

Based on use case		**OCI and BP1**	**Air Liquide**	**BP2**
		Steam electrolysis	CO_2 reduction to CO	Co-electrolysis to syngas
Conversion	kWh/kg product	33.3	2.7	7.1
Compression	kWh/kg product	2	0.2	0.5
e-heaters	kWh/kg product	3.2	0.3	0.6
AC/DC (97%)	kWh/kg product	1.5	0.1	0.2
Total	kWh/kg product	40.0	3.3	8.4
System efficiency	LHV (%)	83%	82%	92%

On system level, the efficiency (LHV) is 83% for hydrogen production, 82% for CO_2 reduction and slightly higher to 92% for syngas production. The difference in specific electricity consumption is mainly due to the differences in properties and single pass conversion rate. Thus, the electricity consumption required for electric heating of the different feed gases, recycled product flows and air (after heat integration with inlet-outlet heat exchangers).

For low temperature water electrolysis with AWE and PEM, the system efficiency could be 76% resp. 77% (HHV), assuming 80% of stack efficiency. This corresponds to a specific electricity consumption of resp. 52 resp. 51 kWh/kg hydrogen.[3] The SOE specific electricity consumption on system level for steam electrolysis is 40 kWh/kg. The efficiency would be therefore more than 20% higher. If liquid water is used as feed to SOEC for steam generation (HHV), the specific energy consumption is 8kWh/kg higher. We would need about 47 to 48 kWh/kg, as calculated in OCI and BP1 use cases. The SOE system efficiency gain would largely disappear.

5.1.3 Stack lifetime

The stack lifetime is mainly determined by degradation of the electrode materials. As limited data on lifetime is available, it is difficult to get guarantees from technology providers. The degradation depends

[3] Gigawatt green hydrogen plant: design and capital costs (ispt.eu)

on the technology, steam and/or CO_2 quality, operating temperature and current density. This does not change with upscaling. The assumed higher current densities, however, can result in higher degradation, but data is missing. Most of the available degradation data has been obtained at lab-scale conditions, some suppliers report duration of these tests up to 2 years. The stacks operate at thermoneutral point, at temperatures between typically 550 and 750°C depending on the technology. Usually, degradation is higher at higher temperatures, so reducing temperature can be a strategy to slow-down the degradation rate, but this is at the expense of the hydrogen production rate.

Regarding steam and/or CO_2 quality, the presence of especially silica-based and sulphur-based impurities have an adverse impact on performance and lifetime of the electrodes. Also, presence of amines, ammonia and NO_x in CO_2 reduces lifetime of SOEC. The quality of the feedstock, therefore, needs to be monitored and conditioned if required and possibly purification is needed, e.g. based on an assessment of the demin water quality and steam and condensate system. In OCI use case, dedicated steam generation is considered instead of using available steam, as this is of insufficient quality. Concerning CO_2 as feedstock, also the quality is important. In the Air Liquide use cases, the CO_2 is considered available as liquefied and therefore of high quality.

5.1.4 Reliability and availability

The design, layout and configuration with number of cells per stack, stacks per hotbox and hotboxes per module have an impact on reliability, availability and maintainability. The suggested layout is with 60/146 cells per stack, 15 resp. 6 stacks per hotbox, 12 parallel hotbox per module and 4 modules per 18 MW system.

Usually in the process industry, operational reliability is well above 97%. Availability of a facility can be typically 93%, taking into account unplanned logistics and planned stops. For electrolysis, the utilisation also depends on the load variation and flexibility of the system due to intermittency of renewable electricity. For solid oxide electrolysis, operational experience is only available on pilot and demo scale, whereas for solid oxide fuel cellsmore operational experience is available. In both cases, data is missing for large-scale industrial applications, especially with dynamic operation.

Reliability mainly depends on failure rates on component and system level. For reliability calculations, a Mean Time Between Failure (MTBF) is used, which is the inverse of failure rate per year. Data is missing concerning failure rates and depends on technology. A sensitivity analysis based on a theoretical calculation has therefore been conducted to support the proposed upscaling pathways. In case of MTBF of 5 years, a sensible reliability of more than 90% can be demonstrated for 60 cells per hotbox with more than 4 hotboxes in parallel. In case of 146 cells, however, 8 or more hotboxes are required to meet the required reliability. If the MTBF were to be 1 year, 16 or more parallel units are needed for both 60 and 146 cells per stack to meet the reliability requirement of about 90%. The suggested breakdown with both configurations seems therefore logical based on these indicative calculations, but need more testing and full-scale operational data on failure rates.

5.1.5 Maintainability

Common maintenance strategies should be adopted like prescriptive and condition-based maintenance. Typically, stacks or complete hotboxes need to be replaced in case of failures on cell level or better. The stacks can be sent to the supplier workshop or serviced on site by supplier. Therefore, access to stacks should be ensured, with sufficient space and safe working place isolated from stacks and hotbox which are energized.

Options for balance of stacks with preheater and electrical process and air heaters are as follows. In addition, an option D to centralise heat exchangers on modular level is included, nonetheless the stack arrangement is similar to other options.

A. Heat exchangers inside hotbox of 16 stacks, integrated per stack of 100 kW (or 250 kW).

B. Heat exchangers inside hotbox, centralised per hotbox of 1,500 kW, or divided in 4 sections.

C. Heat exchangers outside hotbox, outdoors, centralised per hotbox of 1,500 kW, or divided in 4 sections.

D. Heat exchangers outside module, outdoors and centralised per module of 9 MW.

Regarding downtime, option A would be longest and shorter in other options due to lowering of thermal mass and simpler service. However, the reduction in production capacity is the same and amounts to 1.5 MW, due to one common steam header design (unless it can be redesigned such that once the steam header is connected again the 3 hot-boxes in case B and C can get back to production while the hot-box with replaced stack(s) is heating up). For the BP use case (760 MW), such turndown of 1.5 MW unit would mean reduced production of 0.2%, whereas for OCI use case (80 MW) this is 1.8%, which is likely to be acceptable in an industrial production environment.

Regarding heat exchanger maintenance, the access is easier in case of separate and outdoor location of heat exchangers which can also be spatially optimised for a more convenient maintenance access and more rapid swapping of the faulty stack(s). These heat exchangers will be bigger than integrated heat exchangers part of a hotbox or stacks. This scaling-up will bring saving on equipment, piping and civil costs, especially for option D. Also, safety risks can be reduced as hotboxes do not need to be opened and disassembled. Another advantage is the physical separation of the hot compartments providing the opportunity to only cool-down for service the stack-box reducing downtime. Therefore, it is suggested to design larger systems, not to be containerised but accessible and easy maintainable, put outside like in process industry. Of course, turndown requirements, flexibility and reliability requirements should be considered in design. A disadvantage is the missing-out of savings due to mass fabrication, automation and benefits of solid oxide fuel cell technology and manufacturing.

5.1.6 Sustainability

From a sustainable point of view, the origin of the excess steam is important and should be in line with the RFNBO requirements according the delegated Acts 27 and 28 from the Renewable Energy Directive (RED) II. Lessons learned from this project show that low pressure steam can be generated from residual heat and not necessarily requires high/medium pressure steam from the processing plant. Moreover, the advantage is that the quality of steam could be tailored to the feedstock restrictions from the SOEC. Also CO_2 capture is important for calculation of overall CO_2 reduction.

5.2 Economical assessment (CAPEX)

An economical assessment has been done for 2020 and 2030 level to evaluate the upscaling and innovation potential. A level V CAPEX cost estimate was made, which is a factorised method for determining investment budgets with an accuracy of ± 50% in an early stage of a capital project. Due to limited information on stacks and balance of stacks costs a bottom-up cost estimate proved to be difficult. The estimate is expressed as Total Investment Costs (TIC), defined as all costs which are relevant from owner and investor point of view (excl. taxes). TIC include direct costs for supply of equipment and materials and contractors, indirect costs for EPC contractor and owner, and contingency to cover risks and uncertainties. Total Investment Costs (TIC) are estimated in this study at around 4,800 €/kW in 2020 and 1,200 €/kW in 2030, based on literature and engineering factors (see Table 13). This suggests that a CAPEX reduction with a factor four could be potentially achieved through upscaling, mass fabrication and technology innovation.

Table 13. Total Investment Costs (TIC) 1 GW SOE plant 2020 and 2030

	CAPEX 1 GW SOE plant		**Base case**	**Upscaling**
			2020	2030
A1	Direct costs			
A1.1	Module costs, delivery		2,130	520
A1.2	Site installation, civil, HV, interconnecting piping (30% of A1.1)		640	160
A2	Total direct costs	Euro/kW	2,770	680
B	Indirect costs (EPCm+Owners) (25% of A2)	Euro/kW	690	170
C	Total direct + indirect costs	Euro/kW	3,460	850
D	Contingency (40% of C)	Euro/kW	1,380	340
E	Total Installed Costs (Rounded)		**4,800**	**1,200**

These costs cover engineering, procurement and fabrication of SOE module including heat exchangers by technology providers. For 2030 level, a cost reduction of 80% is assumed for stacks and balance of stacks, due to upscaling, increased manufacturing capacity and higher current density. The exact scope, however, is not entirely clear. It was not possible to prepare a bottom-up estimate for the modules based on an equipment list and unit costs. Therefore, the FCH JU target of 2,130 €/kW in 2020 and 520 €/kW in 2030 have been used as a reference. These costs (2020 figures) are for supply of modules with smaller nameplate capacity (e.g. 100 MW) and a different scope. These targets exclude direct costs for site installation, HV electrical, and civil-works. Based on a GW advanced design study for AWE an PEM water electrolysis, about 30% needs to be added to these targets to include the site installation also in the costs. On top of these direct costs, another 25% EPCm + Owners costs and 40% contingency needs to be added for Total Investment Costs (TIC). These percentages are in accordance with common engineering practices.

Compared with the direct cost level for stacks and Balance of Stacks (BoS) costs as explained in paragraph 4.2, the costs for Balance of Plants (BoP) of about 130 Euro/kW have been added to these direct costs.

6 Roadmap towards SOE-application on SOE-pilot demonstration

Demonstration of the SOE-technology on pilot and near-commercial scale is an essential step in the realization of a full economical viable mature SOE-technology applicable on industrial scale. Especially when these pilots are performed on-site in an industrial environment, it creates the opportunity for both technology suppliers and end-users to learn and verify technology developments. The technology supplier gets a better idea about the system requirements with respect to integration in the industrial environment. The end-user will get more reliable data to inform their business case of the impact of the SOE-technology on their business case. Both the technology supplier and the end-user learn about the gaps in the technology and especially the integration aspects that needs to be closed on the road towards maturity; i.e. which Key Performance Indicators or system components require further improvement. The schematic figure below shows the different steps to be taken in order to realize a SOE-pilot onsite. Each step is described in more detail in the following paragraphs. Addressing step 1 to 5 forms the backbone for the actual realization of an on-site pilot.

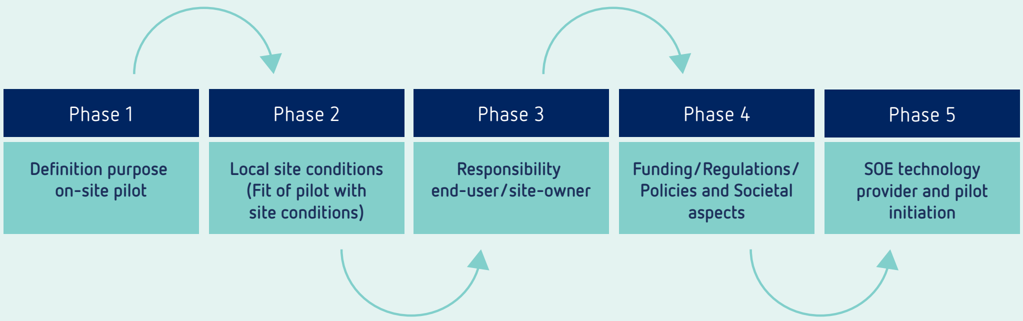

Figure 16. Schematic scheme on the different steps towards an on-site SOE pilot demonstration

1) Definition of the purpose and user requirements of the on-site pilot

2) Inventory of the local site conditions (Interaction technology supplier and end-user/site owner):

The SOE-pilot should fit with the local on-site conditions, which requires an upfront discussion between the end-user or site owner and the aimed for technology supplier. The site-related conditions include integration of electricity and gas feedstock, footprint, safety aspects and permitting.

3) Responsibility of end-user/site owner:

The responsibility of the end-user/site owner should be defined with respect to system/equipment ownership, daily operation, system maintenance, operation training and how to deal with sharing knowledge on use of SOE technology.

4) Funding/Regulations/Policies and Societal aspects:

There are several funding opportunities for large scale electrolysis demonstrations on either regional, national and European level. Regulations and policies form a driver for industries to aim for carbon-neutral production processes:

5) SOE technology provider and pilot initiation:

On basis of the aforementioned steps the final choice for a suitable SOE technology provider can be made.

7 Conclusions

In the Next Level SOE project, ISPT and TNO have performed a feasibility study on SOEC technology with Air Liquide, BP and OCI. The feasibility study focuses on three use cases from three different industrial partners with three different applications of SOEC:

- hydrogen production in an ammonia plant at OCI Chemelot site in The Netherlands;
- syngas and green hydrogen production integrated with blue hydrogen and downstream e-fuels as concept study for a potential BP site;
- carbon monoxide production at Air Liquide, Rozenburg Rotterdam site.

The process integration, upscaling potential and technical-economical aspects of brown-field applications of SOEC technology have been evaluated. Heat and material balances and process flow diagrams have been prepared for the use cases. Through process integration excess steam from up or downstream operations can be used. More attention is needed to address dynamic performance, feedstock quality, reliability and degradation of stacks and incorporate this in the design and operation and maintenance strategy. The upscaling potential is based on increase of current density with a factor 2, increased surface areas of cells with a factor 8 and bigger modules of 9 MW. A lesson learned from this project shows that steam can be generated from residual heat and not necessarily requires high/medium pressure steam from the processing plant. Based on literature and engineering factors, a capex reduction with a factor 4 could be potentially in reach through upscaling, mass fabrication and technology innovation. A roadmap is given to be able to develop and deploy the SOEC technology this decade. As a next step it is suggested to develop a pilot plant to demonstrate the technology on a 5 to 10 MW scale.

Join us!

WWW.ISPT.EU

ISPT

Groen van Prinstererlaan 37

3818 JN Amersfoort

The Netherlands

info@ispt.eu

t. +31 (0)33 700 97 97

Andreas ten Cate

Program Director System Integration

ISPT

andreas.tencate@ispt.eu

t. +31 (0)6 15874702

Hans van 't Noordende

Principal expert Hydrogen

ISPT

hans.vantnoordende@ispt.eu

t. +31 (0)6 13080753