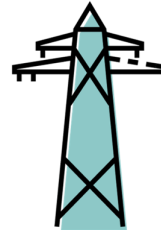
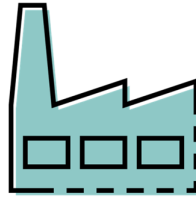
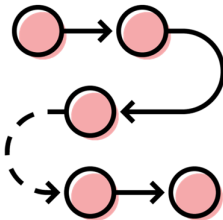
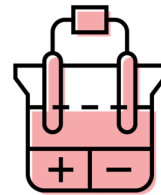
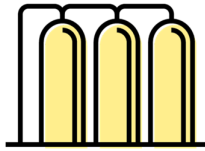


SAMHÄLLSBYGGNAD ENERGISYSTEMANALYS



Future hydrogen supply in Stenungsund

Pre-study of a SOEC pilot plant and analysis of large-scale integration of SOEC and ammonia cracking plants

Lovisa Axelsson, Maria Edvall (RISE), Simon Harvey, Tharun Roshan Kumar (Chalmers), Anna-Karin Jannasch (Uniper), Johan Westin, Fredrik Starfelt (Vattenfall), Lars Pettersson, Alma Pira Edman (Borealis), Fredrik Hellesöy (Preem)

RISE Rapport 2024:78

Abstract

To enable the chemical industries in Stenungsund achieve climate neutrality, large amounts of fossil-free hydrogen will be required. Producing all hydrogen through electrolysis will demand large amounts of electric power, but the current grid capacity in Stenungsund is limited, making less electricity-intensive hydrogen production solutions essential. This study investigates the technical and commercial prerequisites for a Solid Oxide Electrolysis Cell (SOEC) pilot plant in Stenungsund. It also analyzes various scenarios to understand how SOEC and ammonia cracking can complement each other from a techno-economic perspective and enhance security of supply.

The interviews that were conducted to gather insights from relevant stakeholders showed that they anticipate a significant increase in future hydrogen demand, highlighting the need for scalable and cost-effective production methods. There is strong interest within the industry cluster to learn more about SOEC technology and gain practical experience through the establishment of a pilot plant.

A concept for a SOEC pilot plant has been outlined in the current study including a description of the possible integration with existing infrastructure in Stenungsund. The intention with such a pilot plant is to test and gain experience from commercially available equipment of a size that is relevant for large scale hydrogen production projects. Two different plant sizes were considered, corresponding to approximately 5 MW (case 1) and 10 MW (case 2) electric power demand. There is a clear scale benefit for the larger plant which makes it the preferred choice, but the investigation showed that the CAPEX for the SOEC pilot plant is higher than initially expected. To proceed with a project, a viable business case needs to be presented.

This study also examines the technical and economic synergies between SOEC and ammonia cracking, focusing on cost optimization and operational flexibility to meet the hydrogen demand of existing Borealis steam cracker plant at the site. The analysis points to that the integration of both technologies enhances security of supply and reduces costs assuming favorable long-term low-carbon ammonia supply contracts and favourable Power Purchase Agreements (PPAs). Comparing the levelized cost of hydrogen (LCOH), the study finds that SOEC offers a lower LCOH than ammonia cracking under the assumed input costs (400 €/tNH₃), provided competitive PPAs are secured (45 €/MWh). The integrated system's LCOH ranges from 3.7 to 6.5 €/kg, depending on ammonia and electricity prices, with flexible operation potentially reducing costs to 3.7–4.5 €/kg by leveraging spot market prices.

Current EU regulations mandate temporal and geographical correlation for PPAs used in renewable fuel production, which complicates flexible operation aligned with the electricity market. Full-load, year-round operation achieves the lowest LCOH, though it limits peak demand response. The sensitivity analysis suggests that exporting excess hydrogen to the industrial cluster could offset costs in low full-load scenarios. In the near term, ammonia cracking can mitigate grid constraints, while future expansion of SOEC capacity, as grid capacity grows, promises further cost reductions and enhanced operational flexibility.

Key words: large-scale hydrogen supply, SOEC, ammonia cracking, integrated SOEC-ammonia cracker system, chemical cluster

RISE Research Institutes of Sweden AB

RISE Rapport 2024:78

ISBN:978-91-89971-39-4

2024

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Preface

This project was carried out within the *Klimatledande Processindustri*¹, as a step towards achieving the goals within the area of Process technology; to establish a concerted effort around hydrogen where a coordinated strategy for the cluster around hydrogen has also been developed, to investigate the industry's opportunities to contribute to reducing climate impact through increased electrification with regard to, for example, flexible consumption and efficiency measures, identify industrial residual streams beyond carbon dioxide with the potential to contribute to industrial symbiosis.

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The project was financed by Vinnväxtinitiativet Klimatledande Processindustri that is financed by Vinnova, Västra Götalandsregionen and members in Västsvenska Kemi- och Materialklustret.

¹ <https://klimatledande.lindholmen.se/sv>

1 Introduction

To enable the chemical industries in Stenungsund to achieve climate neutrality, large amounts of fossil-free hydrogen will be needed. The hydrogen demand in the industry on the Swedish west coast is currently 6.4 TWh/year (192 kton/year) and a number of studies indicate that the demand could more than double in future scenarios [1]. If all hydrogen is to be produced via electrolysis in the future, large amounts of electricity will be needed. However, the capacity of the transmission grid in the Stenungsund area is currently a limiting factor and alternative, less electricity-intensive hydrogen production solutions are necessary to bridge the gap.

Low-temperature electrolysis is the current benchmark technology for industrial hydrogen projects. A technology under development that has the potential to significantly reduce electric power demand by approximately 20-30% [2] is so-called high-temperature electrolysis (hereafter denoted SOEC – Solid Oxide Electrolyser Cell). Assessing the maturity of the technology requires a thorough evaluation of both opportunities and investment risks, and a pilot plant provides valuable insights into these factors. The present pre-study investigates the technical and commercial pre-requisites (feasibility) and evaluates the benefits of a SOEC pilot plant in Stenungsund.

However, the uncertainty concerning grid expansion, and the availability of fossil-free electric power necessitates investigating alternative hydrogen production technologies, such as ammonia cracking technology. Using low-carbon² and/or renewable ammonia as a hydrogen carrier could potentially bridge the supply-demand gap for hydrogen. In the present pre-study, analyses are carried out for a number of different scenarios with the aim of understanding how SOEC and ammonia cracking can best complement each other from a techno-economic perspective and with regard to security of supply.

1.1 Overview of the chemical cluster in Stenungsund

The chemical cluster in Stenungsund is Sweden's largest chemical cluster. Together the industries accounts for approximately 2% of Sweden's CO₂ emissions which mainly originates from firing fuel to generate heat necessary in the processes.

The majority of the feedstock entering the chemical cluster passes through Borealis cracker that produces ethylene amongst other products, that in turn are feedstocks for other industries in Stenungsund. The cracker products are distributed to Borealis polyethylene plant, Perstorp, Ineos and Nouryon in an integrated pipeline network.

The cracking process is an endothermic reaction and requires a lot of heat. Today Borealis has a permit to use 1,7 million tons of feedstock. When heating the feedstock, a fossil fuel is used, which generate CO₂ when fired. Borealis cracker accounts for about 600 kt CO₂ emissions per year. One way to reduce the emissions is to replace the fossil

² Low-carbon ammonia must achieve a 70% emissions savings compared to the defined emissions intensity comparator. This definition includes both blue ammonia (i.e. *from fossil energy sources (with carbon capture and storage, CCS)* and synthetic ammonia produced from non-renewable electricity, water and nitrogen that meet the emission reduction criteria of 70 %.

fuel used in heaters with low-carbon/renewable hydrogen. Hydrogen can also replace fossil fuels used to generate steam in the cluster. A prerequisite for Borealis to integrate more hydrogen into their processes is that they find a new application for the existing fuel gas.

1.2 Aim and scope

The main objectives of the project were:

1. Investigate the technical and commercial pre-requisites (feasibility) and the benefits of a SOEC pilot plant in Stenungsund. This implies development of a conceptual proposal for the design of a pilot plant for high-temperature electrolysis and make an initial cost estimate for building and operating the plant (CAPEX/OPEX).
2. Conduct interviews with relevant stakeholders to map their interest in SOEC technology and potential use of the produced hydrogen and thereby investigate the purpose and potential benefit of a SOEC pilot plant in Stenungsund
3. Increase knowledge regarding possible synergies between SOEC and ammonia cracking for large-scale hydrogen supply to the chemical cluster in Stenungsund and how these technologies can best complement each other over time
4. Formulate recommendations for continued work in a possible next phase

1.3 Method and limitations

An interview study was conducted with relevant stakeholders to gather insights regarding the potential pilot plant, focusing on the maturity of the technology, investment risks, the expected use of the produced hydrogen, and identified knowledge-raising activities desired by the stakeholders. This is presented in Chapter 2 together with an overview of other SOEC pilot plants highlighting their capacities, locations, and the organizations behind these projects.

To outline the main components necessary for the pilot plant, including support systems, a Request for Information (RFI) was sent to suppliers of SOEC technology. The RFI specified two potential plant sizes, 5 MW (Case 1) and 10 MW (Case 2). The responses have been evaluated, although specific supplier information remains confidential and is not discussed in this report; instead, aggregated data for both cases are presented in Chapter 3. This chapter also includes an examination of how the pilot plant can integrate with existing infrastructure, such as electric power connections, steam pipelines, demineralized water supply, and hydrogen delivery systems. A preliminary cost estimate (CAPEX/OPEX) for the pilot plant was developed, incorporating insights from the SOEC suppliers alongside internal cost engineering expertise.

Additionally, the project investigates the technical and economic interplay between SOEC and ammonia cracking technologies, focusing on optimizing cost and operational flexibility with Borealis steam cracker plant's hydrogen needs as case study. This integrated approach aims to provide a comprehensive understanding of the technical and economic viability of the proposed pilot plant, as detailed in Chapter 4 of the report,

facilitating informed decision-making for future hydrogen production initiatives in the region.

2 Operating scenarios, hydrogen use and the purpose of a SOEC pilot plant

The following chapter presents the identified interest in a pilot plant, mainly with the perspective of potential use of the produced hydrogen. Aspects of the plant's design and insights into the kind of knowledge-raising activities different stakeholders wish to pursue through the pilot plant is also presented. Additionally, different stakeholder perspectives regarding ammonia cracking are presented. The chapter also includes a compilation of similar pilot plants, both existing and planned, where such information is publicly available.

Interviews have been held with relevant stakeholders, including Perstorp, Nouryon, Inovyn, Linde Gas, AB Volvo, Borealis, Preem and Uniper with the aim to gather their interest and insights regarding a SOEC pilot plant in Stenungsund. The interview questions are included in Appendix 1. The material is compiled with the aim of forming a basis for decisions on continued activities after the completion of the pre-study. Section 2.1. - 2.2. presents the interview results regarding the SOEC pilot plant and 2.3. the interview results for the ammonia cracking while Section 2.4 presents other SOEC pilot plants.

2.1 Interest in a SOEC pilot plant and hydrogen use

All stakeholders expressed interest and curiosity regarding a possible pilot plant, where increased understanding of the technology was the dominant aspect highlighted. Both regarding the technology itself and how it can be integrated within the chemical cluster in Stenungsund. The future price of hydrogen was highlighted as very important as well as whether SOEC could be a technology that could produce fossil-free hydrogen at a lower cost than other technologies. The interviewed stakeholders came with different perspectives since there is a wide range of the role of hydrogen for their processes and businesses, both today and in the future. Some of the interviewed stakeholders already have a demand for hydrogen while others foresee a future demand, while some are producers of hydrogen without any demand in their process. Depending on the location of the stakeholders within this study, it is not possible for all of them to be off-takers for the hydrogen produced in a pilot plant located in Stenungsund. However, some stakeholders located in Stenungsund see the possibility to use the hydrogen for replacing existing fossil-based hydrogen used in their processes with fossil-free hydrogen whereas others see an opportunity to use it as an energy carrier for combustion to reduce CO₂-emissions replacing other fossil-based energy carriers.

This pre-study did not include any compilation of hydrogen usage today or in the future in Stenungsund but within the project Vätgas på Västkusten [1], which included 13 companies within the region involving most of the stakeholders from this pre-study, two scenarios were developed for future demand for hydrogen which indicated that the hydrogen demand in Stenungsund could be more than four times as large in a maximum

scenario compared to the demand today and more than twice as large in a minimum scenario.

Since this is a pre-study for a pilot plant, the size of the plant is not decided but as a reference point in the interviews, a size of 5-10 MW electrolyser was discussed resulting in hydrogen production of approximately 0.96-2.3 kton/year. 5 and 10 MW are also the two potential plant sizes specified in the RFI to the suppliers. With this level of hydrogen production it is not a problem to find off-takers in Stenungsund. Two of the stakeholders expressed interest in using that amount or even several times as much in the future. However, the importance of a competitive price of the hydrogen was again highlighted here. The increased future demand for hydrogen also shows a possibility for upscaling of a pilot plant. The stakeholders not located in Stenungsund see the pilot plant in Stenungsund as a possibility to evaluate the technology while their interest in investing would be on a larger scale directly.

The flexibility of off-takers to adjust their hydrogen demand from the pilot plant appears to correlate with their usage intentions. Those intending to combust hydrogen expressed more flexibility compared to those who would use the hydrogen as a feedstock in their processes. Depending on the operational pattern of the pilot plant, some degree of storage or alternative source of hydrogen might be necessary.

The stakeholders were asked about the possibility to integrate an SOEC within their existing process since high-temperature steam is a prerequisite for the electrolyser. Some stakeholders have high temperature steam and use it in their processes, but only one stakeholder stated that they have excess heat available at this high temperature level. Existing processes might have to be adjusted to be able to integrate an SOEC, but it is not considered a major obstacle. However, further investigation is needed to determine what changes would be required. Some of the stakeholders also raised the aspect of how the transition to reduced CO₂-emissions and less use of fossil fuels might lead to a change in how they generate steam and a large uncertainty about how their processes would develop accordingly and if there would be available steam and at what temperature levels in the future. The interviewed stakeholders have not made any deeper analysis about how an integration could affect the overall steam balance for their processes but the need for investigation of different scenarios for production and development and the effects on the steam balance was highlighted.

2.2 Areas of interest for operation of a SOEC pilot plant

There is an interest from the stakeholders in a SOEC pilot plant in Stenungsund. Even if some interviewees are not possible off-takers of the hydrogen produced they expressed interest in gaining operating experience for SOEC technology. The interviewees point out the need for this concept to be tested and the operation to be evaluated over time to be able to compare it with other electrolyser technologies. This is not unexpected since the TRL is lower for this technology than for other technologies.

Based on the interviews, the following key areas of interest for operation of a pilot plant were identified.

Table 2-1. Areas of interest for operation of a SOEC pilot plant in Stenungsund.

Area of interest	Description
Concept testing	Evaluate SOEC performance over time. Assess operational stability and lifespan. Impact of different operational conditions on SOEC performance.
Practical technology evaluation	Advantages of SOEC compared to other types. Information required for investment decisions. Lifespan. Maintenance costs.
Operational patterns	SOEC operation under variable conditions. Startup/turn-down and ramping up/down, what is the operating window. Parallel operation with ammonia cracking. Level of wear and tear and demand for maintenance depending on operational patterns.
Integration with industrial streams	Steam requirement.
Purity levels	Hydrogen purity levels required for various applications

2.3 Hydrogen production through ammonia cracking

The interviewees all expressed interest in a SOEC pilot plant in Stenungsund whereas the interest expressed for hydrogen production through ammonia cracking was less unanimous. In order to handle and store ammonia at an industrial site a permit is required, which is widely perceived as complicated and time consuming. One actor in Stenungsund that has such a permit which makes this stakeholder important in the discussions and future plans for ammonia cracking.

Security of supply and redundancy were highlighted as the most important advantages of hydrogen produced through ammonia cracking in Stenungsund, since this additional source of hydrogen avoids being solely reliant on the electricity grid and electricity supply. Before the electricity grid is further strengthened ammonia cracking offers a feasible solution for large scale hydrogen production. However, the interviewees had different opinions regarding whether ammonia cracking should be seen as a transition solution or not. Some interviewees perceive it as a transition solution, until the grid is strengthened and will prefer hydrogen produced through electrolysis since that is more resource efficient, whereas other actors emphasize that since it is a large investment it cannot be seen a transition solution and has to be operated over a longer time period. Since it will increase the security of supply this is seen as something positive by these actors.

The cost of hydrogen is highlighted as very important if it is to be used to a larger extent. One question raised by the interviewees is about the production cost for ammonia-based

hydrogen compared to hydrogen produced through SOEC, and how possible synergies may arise over time. This comparison is modelled and evaluated for different scenarios of electricity and ammonia prices within this pre-study and the results for this is presented in chapter 4.

2.4 Overview of similar ongoing SOEC pilot plant projects

The SOEC technology is being developed and tested at various pilot plants worldwide, showcasing its potential and scalability for future commercial applications. This section provides an overview of significant SOEC pilot plants, highlighting their capacities, locations, and the organizations behind these pioneering projects. Ongoing SOEC pilot plants are primarily characterized by the following:

- Small scale plants – 0.25 – 8 MW
- Mainly industrial integration for industrial processes
- Emphasis on long operational hours to showcase reliability and stability
- Geographic diversity with locations in Europe, USA and India
- Most have been installed or plan to be installed and commissioned in the first half of the 2020's

A summary of the identified pilot plants can be found in Table 2 with a short description of each plant below.

Table 2-2. Existing or announced pilot plants of SOEC.

SOEC manufacturer	Size [MW]	Existing (e), Announced (a)	Location
Bloom Energy	4	e	Moffett Field, US
Ceres	1	a	Bangalore, India
FuelCell Energy	0.25	a	Idaho, US
Sunfire	2.6	e	Rotterdam, Netherlands
	0.25	e*	Lingen, Germany
	1	a**	Salzgitter, Germany
	1	a***	Leuna, Germany
Thyssenkrupp Nucera	8	a	Arnstadt, Germany
Topsoe	0.35	e	Fredrikssund, Denmark

*delivered in 2022 (can't find public information if it is commissioned), **set to be commissioned in 2024,

***announced in 2021 (can't find public information if/when it was commissioned)

Bloom Energy has established a 4 MW SOEC pilot plant at the NASA Ames Research Center. The project aims to demonstrate the efficiency and commercial viability of solid

oxide technology for large-scale hydrogen production; the plant delivers the equivalent of 2.4 tonnes H_2 /day. The electrolyzer has been operational for approximately one year, showcasing its potential for high-efficiency hydrogen production and contributing to research on renewable energy storage and industrial decarbonization[3].

Ceres has partnered with Shell to establish a 1 MW SOEC pilot plant at the Shell Research Center in Bangalore, India, where the hydrogen will be used in industrial processes on site. This collaboration is aimed at validating the scalability and efficiency of SOEC technology in producing hydrogen, with initial results indicating successful hydrogen production [4].

FuelCell Energy has also ventured into the SOEC domain with a 250 kW demonstrator linked to the Idaho National Laboratory. The status of the project is uncertain since detailed public information and visual documentation of this project remain sparse [5].

Sunfire is engaged in multiple SOEC projects across Europe. In Rotterdam, as part of the MultiPLHY project, Sunfire has installed a 2.6 MW electrolyzer at Neste's refinery, consisting of twelve electrolysis modules. It operates at 850 °C utilizing industrial excess heat and is designed to produce over 60 kg H_2 /hour with the aim to integrate renewable hydrogen into the refinery's processes for renewable product production [6]. The commission phase started in July 2023 [7]. In addition to Sunfire, the MultiPLHY consortium includes Neste, the French research center CEA, SMS Group company Paul Wurth and ENGIE. The project is funded by the EU Clean Hydrogen Partnership.

Sunfire has deployed a 0.25 MW electrolyzer at RWE's hydrogen site in Lingen where the hydrogen is fed directly into RWE's test pipeline at the power plant [8]. This is part of the TransHyDE [9] project Get H_2 Nucleus [10].

Sunfire and Salzgitter AG, in collaboration with TU Bergakademie Freiberg, has integrated the SOEC stack technology into the hydrogen network of Salzgitter Flachstahl GmbH steel mill, as part of the GrInHy project. The capacity is 1 MW, aiming to produce 16.5 kg H_2 /hour to be used in processes such as the direct reduction of iron ore. The project, set to be commissioned in 2024 and running until 2027, seeks to gather data for future serial production [11].

As part of the e-CO₂Met project, Sunfire has installed a 1 MW systems at TotalEnergies' refinery facility in Leuna, Germany, with the ambition to produce climate-neutral methanol on site [12].

Topsoe has an SOEC demonstration facility in Frederikssund, where a 350 kW system, composed of 12 stacks and 1200 cells, has operated over 2250 hours under industrial conditions. This demonstration, which began in autumn 2023, has operated with high stability and achieved a consistent electrolyzer efficiency of around 93% with electricity consumption of the core below 36 kWh/kg H_2 [13]. Furthermore, Topsoe has announced plans for a larger 5 MW pilot plant in Denmark, although details and information about progress on this project are very limited.

Thyssenkrupp Nucera has partnered with Fraunhofer IKTS to develop SOEC technology for hydrogen production. The aim with the partnership is to take the final steps in SOEC toward industrial manufacturing and application [14]. Thyssenkrupp are currently investing in an 8 MW pilot plant for SOEC in Arnstadt, Germany [15].

The information compiled here of the pilot plants reflects the growing global interest and investment in SOEC technology, showing the potential of hydrogen production through higher efficiencies and availability of renewable energy sources. These pilot plants serve as testbeds for refining SOEC technology, providing valuable data and insights that will shape the future of clean hydrogen production.

The economic feasibility of SOEC technology is crucial for widespread adoption. Competitive hydrogen pricing remains a primary concern for stakeholders, with many emphasizing the need for cost-effective production to ensure market viability. Policies and subsidies play a vital role in supporting the initial phases of pilot plant projects. Projects such as MultiPLHY benefit from EU funding, which is essential for mitigating financial risks and encouraging technological advancements.

3 Conceptual design of a SOEC pilot plant in Stenungsund

The intention of the present chapter is to outline a conceptual design of a potential SOEC pilot plant in Stenungsund. Focus is to identify possible prerequisites that can impact the size of the plant, and to describe how the plant can be integrated with existing infrastructure such as connection to electric power, steam pipelines, demin water supply and delivery of hydrogen to existing hydrogen pipelines. The information provided is primarily based on internal sources within Vattenfall and Borealis.

3.1 Method and scope of work

An important objective is to outline the main components including support systems (Balance of Plant) that is needed for a complete pilot plant. To receive input a Request for Information (RFI) was submitted to three suppliers of SOEC technology. Since the intention with the pilot plant is to test and gain experience from commercially available equipment of a size that is relevant for large scale hydrogen production projects, the RFI specified two possible plant sizes corresponding to an electric power demand of approximately 5 MW (Case 1) and 10 MW (Case 2) respectively. No exact hydrogen demands were specified for the two cases in order to give the suppliers the flexibility to propose optimal solutions based on their respective technology and standard module sizes.

All three suppliers responded to the RFI and provided information for both cases. However, the scope of supply differed quite substantially among the suppliers, ranging from only providing the SOEC core equipment to a proposal including support systems and hydrogen compression. Due to confidentiality reasons specific information from individual suppliers are not discussed in the present report, instead aggregated numbers for the two cases are provided.

Part of the scope is also to provide a first cost estimate (CAPEX/OPEX) for a pilot plant. The information provided by the three SOEC suppliers are important input, but significant contributions to the CAPEX-estimate origins from internal sources and cost engineering expertise within Vattenfall and Borealis. The cost estimate will be input to coming assessments of the economic feasibility of a pilot plant (not part of the present study).

3.2 Plant description

3.2.1 Key numbers

A selection of key numbers for a possible pilot plant with an electric input of approximately 5 MW (Case 1) and 10 MW (Case 2) are provided in Table 3-1. The key numbers are given as ranges reflecting the different technical solutions proposed by the suppliers. It should be mentioned that the total power demand and the specific electricity consumption include the power needed for the entire plant, i.e. estimates for additional

consumption not included within the SOEC-suppliers scope have been added (for example power for hydrogen compression).

Since the suppliers use different terminology when describing their SOEC-systems a few comments regarding the terminology used in Table 3-1 might be needed. What is here described as an *electrolyser module* refers to a set of hydrogen producing units that are connected to common systems such as power distribution and rectification (conversion of alternating current (AC) to direct current (DC)), gas processing, module control system, etc. The electrolyser module would thus be a typical building block if a large scale electrolyser plant is to be realized. Each electrolyser module typically consists of a number of hydrogen producing units that can have different names, e.g. cores, hot boxes or hydrogen modules.

As can be seen in Table 3-1 the larger pilot plant would consist of 1 to 4 electrolyser modules with module sizes ranges from 2.5 to 10 MW depending on supplier. The supplier with the largest system (10 MW) thus need to make a special solution if the smaller pilot plant size is chosen.

Table 3-1. Selected key numbers for the two considered plant sizes.

Selected key numbers		Unit	Case 1 "5 MW"	Case 2 "10MW"
General				
Nominal H ₂ production		Nm ³ /h	1350-1600	2700-3200
Nominal H ₂ production		kg/h	121-144	243-288
Outlet pressure, SOEC		bar,g	0.025 - 1.7	
Stack exchange interval		years	3 - 7	
No. of electrolyser modules ⁽¹⁾			0.5 - 2	1 - 4
Operating temp., SOEC cells		°C	600-850	
Power and heat demand				
Total electric input (excl. steam gen.)		MW	5.0 - 5.8	10-11.5
Steam input		MW	0.85 - 1.3	1.7 - 2.6
Total energy input (electric + heat)		MW	5.9 - 7.1	11.8 - 14
Cooling demand				
Cooling demand		MW	0 - 0.65	0 - 1.3
Demin water demand				
Demin water to steam generator		kg/h	1200-1700	2300-3400
Specific consumption				
Electrical input		kWh/Nm ³	3.6 - 3.7	
Steam input		kWh/Nm ³	0.6 - 0.8	
Total energy input		kWh/Nm ³	4.3 - 4.5	

⁽¹⁾ Refers to the size of an individual electrolyser building block in a plant

The specific consumption is quite similar for all suppliers, and the steam input to the SOEC make up about 15-18% of the total energy input. Consequently, access to waste heat is crucial in SOEC applications. The figures in Table 3-1 can be compared with the total specific consumption of low temperature electrolysis which has an energy demand of about 5.3 kWh/Nm³ including balance of plant.

A difference between SOEC and low-temperature electrolysis is the impact of degradation. Low-temperature electrolyzers continuously degrade over time causing a slowly increasing specific electricity consumption, but the hydrogen production can be kept constant by increasing the input power. SOECs typically operate at thermoneutral conditions with a constant specific energy consumption. However, the production capacity will start to decrease after some time of operation, and it is desirable with more frequent stack exchanges than for low-temperature electrolyzers. The suggested stack exchange intervals in the table should only be considered as indicative, and a plan for stack exchanges should be determined based on case specific optimizations.

Regarding cooling, Table 3-1 specifies the cooling capacity that should be provided as cooling water at the battery limit. One supplier does not request cooling water, i.e. the default solution is that energy losses are transferred to the ambient air.

3.2.2 Process description

A simplified block flow scheme of a SOEC plant is shown in Figure 3-1. The preferred scope of supply varies between suppliers, and the indicated scope and battery limits should only be considered as a possible example. The blue boxes are typically included in the scope of supply of an SOEC supplier (denoted as Inside Battery Limit, ISBL), the green boxes describing various utilities and plant specific equipment are typically in the scope of the project owner (Outside Battery Limit, OSBL) and the grey boxes could belong to either ISBL or OSBL.

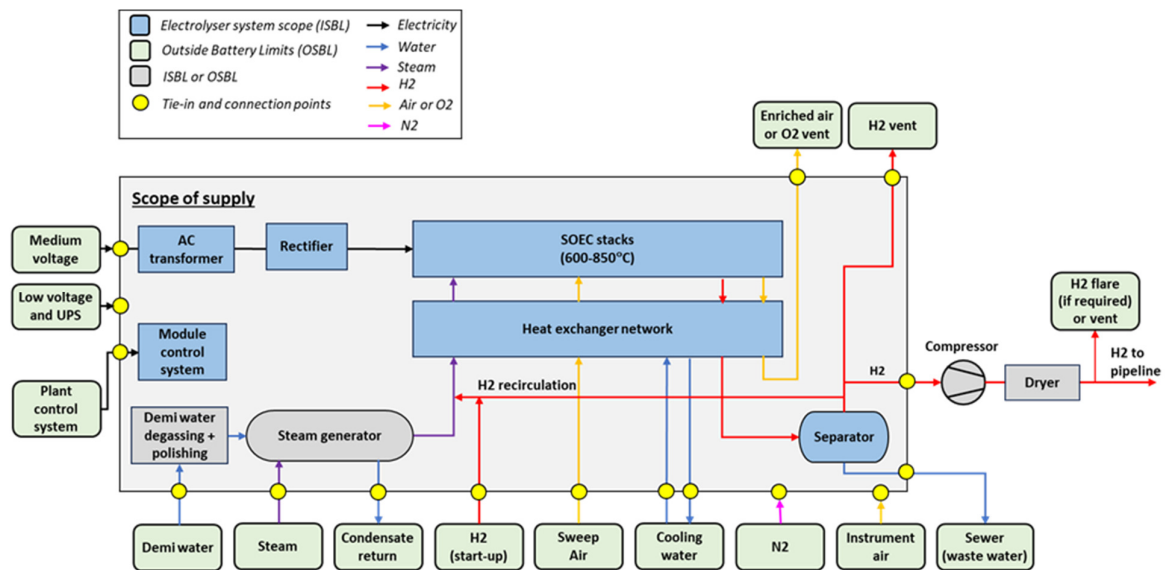


Figure 3-1. Simplified block flow scheme of a SOEC plant.

A medium voltage (typically 10-32 kV) power supply is provided to the battery limit which is then transformed to lower voltages and rectified before entering the SOEC. The main components of the electrolyser module are the SOEC stacks that operate at high temperatures (600-850°C), a heat exchanger network, equipment for gas separation and a module control system. The heat exchanger system is used to heat incoming gases to temperatures close to the SOEC operating temperature by heat exchanging with the outgoing gas streams. To reach the operating temperature of the SOEC stacks the incoming gas streams also need to pass through electrical heaters.

Water is supplied to the SOEC as steam typically specified as 150-200°C and approximately 5 bar(g). In the present case the plan is to supply the plant with demineralized water that will be boiled in a steam generator. The steam generator will be heated with an existing steam source (see sections 3.2.4 and 3.2.5 for more details about the demi water supply and the steam generation). Before entering into the cathode side of the SOEC the steam is mixed with small quantities of hydrogen that are either recirculated from the hydrogen outlet, or supplied from a hydrogen bottle during startup.

The anode side is typically fed with air (sometimes called sweep air or ventilation air) during operation. The specified air supply requirements vary between the suppliers and can be anything from zero to quite high flow rates. The outgoing stream from the anode thus consists of enriched air with an oxygen content from 23% to nearly 100% (if no sweep air is used).

The possibility to use alternative sweep gas instead of air has been discussed with SOEC suppliers. Carbon dioxide could be an option in case the oxygen stream is intended for oxyfuel combustion, however, it is important to make sure that the carbon dioxide is sufficiently clean.

Most SOEC systems operate close to the ambient pressure, and thus there is a need for a hydrogen compressor to reach the delivery pressure at 30 bar(g). The hydrogen will also be dried before entering the hydrogen pipeline. Deoxo is not needed since any possible cross-over of oxygen to the hydrogen stream will immediately react with hydrogen due to the high operating temperature of the SOEC. The same applies for possible cross-over of hydrogen to the oxygen side.

Additional utilities needed are cooling water, instrument air and nitrogen for purging the system after shut down and during certain operational modes. For a public reference on SOEC, see e.g. [16].

3.2.3 Site

A suitable location for a SOEC pilot plant is Vattenfall's site in Stenungsund, see Figure 3-2. The indicated area is a greenfield located in the south west region of the site, with short distance to existing pipelines containing steam, hydrogen and demineralized water. Available maps show a soil depth of the order of 5 m, but the soil depth and the ground conditions need to be verified through drilling tests.

A first draft of a possible layout is shown in Figure 3-3 which is also used as basis for the estimation of site preparation costs. A paved area of 45 x 70 metres is assumed which should be well enough also for the larger pilot plant (Case 2, 10 MW) that is considered. The SOEC modules and part of the supporting systems (Balance of Plant) are assumed to be skid mounted and/or enclosed in containers, i.e. there is no building surrounding the core equipment delivered by the SOEC suppliers.

The compressor and the dryer are assumed to be installed in a separate building. Moreover, a service building will be needed that contains a small control room, meeting room for visitors, workshop, storage area as well as space for possible demi water polishing equipment. An electrical substation will also be needed within the site area.



Figure 3-2. Suggested location of a SOEC pilot plant at Vattenfall's site in Stenungsund.

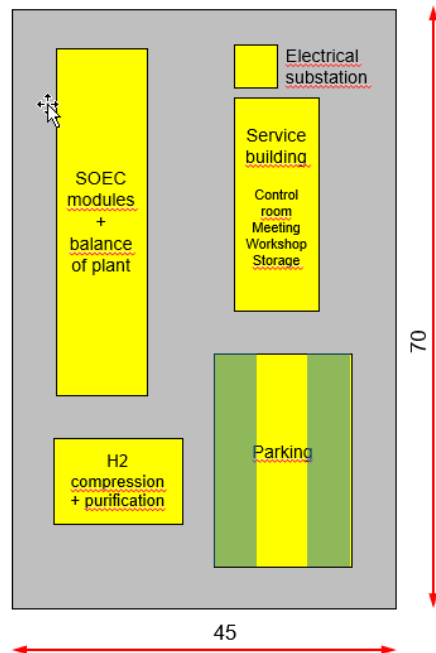


Figure 3-3. Outline of a possible layout for a SOEC pilot plant.

3.2.4 Demin water supply

A pipeline between Borealis Cracker and Borealis Polyethylene Plant which also are connected to a pipeline from Vattenfall will support the SOEC Plant with demineralized water. The pipeline track is located close to the location for the SOEC Plant with a normal flow of 40 to 50 m³/h at 12 bar pressure. To ensure proper water quality to the SOEC units (the suppliers specify either 0.1 µS/cm or 0.2 µS/cm as maximum acid conductivity), a degassing unit, a polishing unit and a conductivity meter will be installed. The maximum flow to the SOEC is approximately 3.4 m³/h for a 10 MW unit

which is a small amount of water compared to normal production of demineralized water at Borealis and Vattenfall make up water treatment plants.

3.2.5 Steam generation

The SOEC requires a supply of saturated steam at about 5 bar(g) which is equivalent to about 160 °C. In order to make sure that the quality of the steam that is supplied to the SOEC always has the correct purity, available steam from Borealis will be used as a heat source to generate fresh steam from demineralized water. There are commercially available steam/steam generators on the market that can be used for this purpose. Those steam/steam generators require steam of about 8-9 bar(g) on the primary side for a suitable temperature difference. Steam is available from Borealis at two different pressure levels, high pressure (HP) steam and medium pressure (MP) steam. The HP steam is available close to the site of the SOEC and the MP steam at the same location has a limited flow that would only be sufficient for Case 1. Due to that, the HP steam is chosen as steam supply for the SOEC. Table 3-2 shows the pressures and temperatures of the available steam nearby the site.

Table 3-2. Available steam properties nearby the site of the SOEC.

	Pressure (bar(g))	Temperature (°C)	Superheating (°C)	Massflow (kg/h)	
				Case 1	Case 2
High pressure (HP) steam	44	270	10	1750	3500
Medium pressure (MP) steam	8,8	240	60	1750	3500

The HP steam is close to the saturation point while the MP steam is more superheated. However, independent of which stream that supplies the SOEC with steam, it requires some pre-processing to lower temperature and pressure. A simplified flow scheme of the steam generation system is shown in Figure .

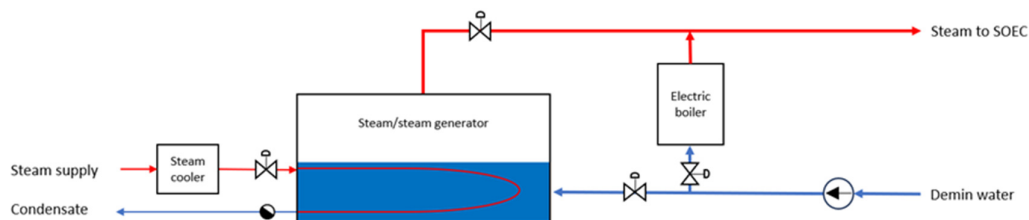


Figure 3-4. Flow scheme of the steam generation system with steam as heating source for SOEC.

As Figure shows, the steam temperature is reduced in a cooler before entering the steam/steam generator as saturated steam. If the option with 44 bar(g) steam is utilized, the steam cooler will include a pressure reducing station in order to supply the steam/steam generator with steam at 8 bar(g). The steam cooler requires cooling water.

An electric boiler will be installed as a backup with automatic start in case the steam supply has interruptions so the steam supply to the SOEC remains constant.

3.3 Power supply

3.3.1 Potential connection points

There are several possibilities to connect the SOEC facility to the grid, unfortunately every option needs reinforcement of the system, takes time and comes with a cost. Three possible connection points have been identified as seen in Figure 3-5 below:



Figure 3-5. Map of possible connection points close to the SOEC facility.

1 West of Uddevallavägen, 40 kV switchgear

2 Old heat power plant, 6 kV cable “Malte”

3 Vattenfall Eldistribution 130/40 kV Switchgear ZT12

3.3.1.1 West of Uddevallavägen, 40 kV system

There are no known available feeders at the existing 40 kV switchgear. Many of the industrial plants have a lot of motors and power electronics and this could cause voltage sag/swell, harmonics and might disturb electric equipment. Using this as a possible connection point, cables and a new switchgear are required. This is the least preferred option.

3.3.1.2 Old thermal power plant, 6 kV cable “Malte”

There are existing cables that were connected between the old thermal power plant and a back-up gas turbine that can be used. Most likely the cables have a low limitation and cannot distribute more than 10 MW of load. The cables and the switchgear at the plant are old and need to be replaced and relocated if they shall be used. The old plant is being decommissioned and will not be used again. Using this as a possible connection point, cables, new switchgear and likely a new transformer are required.

3.3.1.3 Vattenfall Eldistribution 130/40 kV Switchgear ZT12

Vattenfall Eldistribution's 130/40 kV ZT12 substation is old and has passed the technical lifetime and needs to be fully replaced. The TSO will most likely build a new 400/130 kV substation close to the existing ZT12 substation. Using this as a possible connection point, the ZT12 substation needs to be fully replaced. This connection possibility is the most preferred, and the estimated CAPEX for the power supply is based on this option.

3.3.1.4 SOEC switchgear

A switchgear (substation) will also be needed at the SOEC site in order to distribute the medium voltage power to the electrolyser modules. The requested voltage level at the battery limit is typically in the range 10-32 kV.

Depending on above stated solution there might be additional equipment needed such as transformer to the required voltage level.

The switchgear layout contains at least:

- 2 transformer feeders
- 1 feeder for metering
- 1 feeder for filter
- 2 electrolyser feeders
- 1 feeder for power supply
- 1 feeder for compressors
- 2 spare feeders

3.3.2 Power availability

The energy/power demand in the area is growing due to new companies as well as existing companies that are expanding. The DSO (Distribution System Operator) is having a hard time to fulfil all the requests and the system, that is grid and substations, has reached its limits regarding possible distribution of power. The TSO (Transmission System Operator) also need to reinforce their system due to increased load on the west coast.

An inquiry has been made to the DSO and they indicate that it is not possible to connect a 5-12 MW load within the next 6 years, even with terms that the electricity demand from the SOEC process is flexible and adaptable to the DSO's capacity. The DSO needs to do more investigations to get a more accurate cost to connect to the system and a more reliable timeline.

There is a queue with applications for new connections or to get more power/energy to existing customers. Vattenfall Eldistribution is currently reviewing the applications to assess the maturity of the projects and to investigate the probability of implementation according to the requested timelines. Projects that cannot show a presumptive timeline of implementation or seems to be too good to be true, will be removed or moved backwards in the queue. Hopefully this review by Vattenfall Eldistribution will open up opportunities to access the required power earlier than 2030.

3.4 Plant integration

One advantage with the SOEC pilot plant in Stenungsund is the utilities available in a chemical cluster. With Borealis two plants in Stenungsund there is the possibility to connect to already existing pipelines. From the existing network there is demin water, steam and hydrogen available within less than 1 km.

3.4.1 Steam

There is steam available at different pressures. Depending on the size of the SOEC there are different alternatives.

For the larger SOEC connection to the high pressure steam is available. The connection is close, albeit the condensate also needs to be handled. The condensate connection is further away at the cracker but still within less than 1 km.

If medium pressure steam is preferred it can also be provided, but then at the same position as the condensate connection, thus a longer pipe line needs to be built for that purpose.

In the next study phase it can also be investigated if low pressure steam from polyethylene plant can be used, by relocating a let down valve so that a higher pressure can be utilized closer to the SOEC location.

3.4.2 Demin water

There is a demin water pipe rack between Borealis cracker and polyethylene side. A tie in can be made in the pipeline and there is enough technical capacity to provide the SOEC with 3.4 t/h demin water which is the highest expected demand.

The water outtake from the nearby lake Hällungen is at the upper limit. If more water is needed, water saving projects need to be identified and further investigated in the next phase.

3.4.3 Hydrogen

Hydrogen is produced in the Borealis cracker process and Ineos Inovyns electrolyser already today, therefore there is an extensive pipe network in the cluster today. Connection is possible at two positions depending on the SOEC size. If a smaller size is selected, the connection can be done to pipe rack close by. If however the larger size is selected, the connection needs to be done inside the cracker, thus further away but still within 1 km.

3.5 Operation

There are different possible setups for the operation of a pilot plant, but the current idea is that the existing organisation at Vattenfall's site in Stenungsund will be responsible for the operation of the pilot plant. Vattenfall Services already have daytime personnel at the site with on-call duty 24/7, and it is possible to extend their responsibilities to include operation and maintenance of the pilot plant. It will require training of existing

personnel combined with recruitment of a few resources with appropriate competence, but much of the existing organisational setup will be fit for purpose.

The pilot plant will have a small control room at the site, but this is not intended to be manned on a daily basis but rather used during specific tests campaigns. Moreover, it is currently assumed that the plant does not need remote operation from an operations center with staffing 24/7. Instead it is assumed that the plant will be running unmanned most of the time, and if there is a disturbance this will trigger an alarm that will be handled by on-call duty personnel. Whether this setup is appropriate will be further assessed later in the project.

3.6 CAPEX/OPEX estimations

3.6.1 CAPEX

A first CAPEX estimate for a pilot plant has been made based on the assumptions described in previous sections. The CAPEX estimate is based on a number of cost items that are listed in Table 3-3, and the source of information used to assess each cost item varies. For the SOEC system (item 1) indicative (non-binding) cost figures were obtained from the contacted suppliers. For the steam generation equipment (i.e. steam/steam generator and electric boiler) budget quotations (non-binding) were obtained from suppliers. All other cost items are estimated based on available information among the organisations participating in this pre-study. The contingency was set to 20%.

Table 3-3. List of cost items / categories included in the CAPEX estimate.

No	Cost item
1	SOEC system (transformers, rectifiers, SOEC core system)
2	Balance of plant excl. compression and steam generation (e.g. knock-out drums, static mixers, blowers, pumps, heat exchangers etc.)
3	Compression and purification
4	Steam generation including electrical back-up boiler and feed water system
5	Pipes above ground including tie-ins (steam supply, condensate return, hydrogen, demin water)
6	Pipelines below ground (sanitary water, sewer, drinking water, fire water)
7	Site prep, civil works, buildings
8	Cooling towers (heat sink)
9	Power supply (connection to grid)
10	I&C
11	In-direct costs and owner's costs (permits, FEED study, project management, procurement etc.)

No	Cost item
12	Contingency

The estimated total CAPEX for the pilot plant is 35 M€ for case 1 (5 MW) and 45 M€ for case 2 (10 MW). Due to the early stage of the project the accuracy of the cost estimate is assumed to be in the range -30%/+50%.

The fact that many cost items are more or less the same for case 1 and case 2 implies that there is a clear scale benefit for the larger plant. Both cases require large investments, and it is expected that there will be a need for substantial investment support to succeed with a pilot project. However, assessment of potential financing alternatives is not within the scope of the present pre-study.

When comparing with other electrolyzer technologies, such as PEM and ALK, which are more mature, there are no significant differences in CAPEX between the technologies. It's worth mentioning that SOEC requires more frequent stack replacements, but this cost is in general included as an OPEX item. This means the comparison needs to be based on the achievable LCOH including both CAPEX and OPEX for each technology, as comparing their CAPEX alone does not provide an accurate comparison.

3.6.2 OPEX

OPEX excluding costs for electricity and steam has been estimated. As mentioned in section 3.2.1 SOEC systems require more frequent stack exchanges than low-temperature electrolysis, and the cost for stack exchanges is here included in the annual maintenance cost. Indicative figures for annual SOEC maintenance cost were obtained from suppliers. For the compressor the maintenance cost is set to 5% of the compressor CAPEX.

Regarding operation it is assumed that the plant will require personnel corresponding to three full time equivalents (FTE), with one full time plant manager and part time support from resources with electrical, mechanical and instrumentation/test competence. Additional costs for on-call duty have been added.

All the above cost items are assumed to be fixed and independent on the plant utilization rate. The variable OPEX (excluding electricity and steam costs) is expected to be small and consists mainly of costs for demin water, nitrogen and hydrogen for startup.

The total annual OPEX is estimated to be 1-1.2 M€/year for case 1 (5 MW) and 1.5-2 M€/year for case 2 (10 MW), except for the first 2-3 years when OPEX might be somewhat higher.

3.7 Time schedule

An indicative time schedule for a SOEC pilot plant project is shown in Figure 3-6. Next steps after the present pre-study are investigations of potential financing alternatives, partnerships and possible business setup. More clarity on these topics will be necessary in order to get a tollgate 1 (TG1) decision to proceed with a project. If a positive TG1 decision is obtained, it is expected that one can proceed quite quickly into a FEED study.

The time interval from a decision to start FEED (TG2) until final investment decision (FID) is here set to 9 months. The assumed time interval from FID until start of operation (COD) is 27 months.

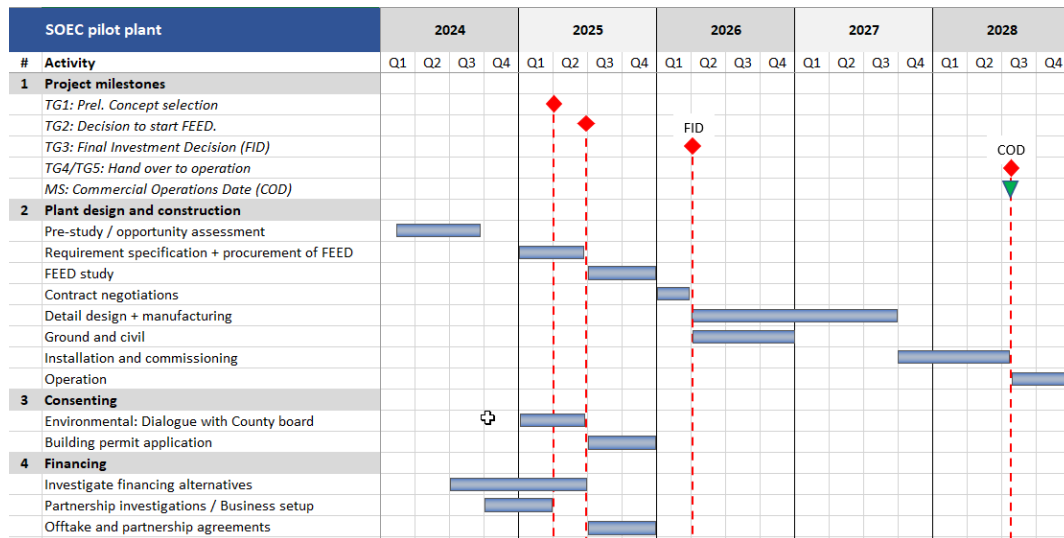


Figure 3-6. Indicative time schedule for a SOEC pilot plant project.

The early phases of the suggested time schedule is probably quite optimistic and depend on a number of tollgate decisions. However, there might be some possibilities to reduce the time interval between FID and COD. It should also be stressed that the time schedule does not consider the time needed to get a power connection from the DSO.

The main purpose of the pilot plant is to test the performance and equipment of SOEC in a controlled environment before investing in larger-scale production. The pilot plant can for example be used to test the flexibility of the operation, such as varying the input power and study the degradation of the electrolyser stacks, which are a critical component of the process. By testing these factors on a smaller scale, it is possible to optimize the production process and reduce the risk of costly mistakes when scaling up to a larger plant. After the COD shown in Figure 3-6, long term operations of the pilot plant will be carried out with a continuous delivery of hydrogen to off-takers to test the durability and flexibility of the SOEC technology. The delivered hydrogen will also generate an income even though it is a pilot plant. A more detailed operational plan and off-take agreements will be studied in the coming phase.

3.8 Summary and next steps

In the current pre-study, a concept for a SOEC pilot plant has been outlined including a description of the possible integration with existing infrastructure in Stenungsund. The intention with such pilot plant is to test and gain experience from commercially available equipment of a size that is relevant for large scale hydrogen production projects. Two different plant sizes were considered, corresponding to approximately 5 MW (case 1) and 10 MW (case 2) electric power demand.

The main takeaways are as follows:

- There are SOEC suppliers that can offer systems based on module sizes in the range 5-10 MW_e, i.e. scales that are relevant for future large-scale projects. However, these systems are new (under development) and remain to be tested.
- A location on Vattenfall's site in Stenungsund has been evaluated and is judged to be a feasible alternative. The local ground conditions should however be investigated to make a better estimate of construction costs.
- The site is located close to existing pipelines running between Borealis cracker and polyethylene plant. Possible integration with pipelines for steam, demin water and hydrogen have been assessed with positive outcome, and there should be sufficient capacity to supply also the larger pilot plant considered (case 2).
- Access to electric power is currently a limiting factor and a first response from the DSO indicates that power cannot be obtained before 2030. This is independent whether a smaller (5 MW) or a larger (10 MW) pilot plant is chosen. The DSO is reviewing the applications that are currently in the queue with respect to project maturity, and this might open up possibilities for earlier access to power.
- A first cost estimate resulted in a total CAPEX of 35 M€ for case 1 (5 MW) and 45 M€ for case 2 (10 MW). Several cost items are more or less the same for the two plant sizes, which implies that there is a clear scale benefit for the larger plant.

Based on the above conclusions the larger plant size (case 2, 10 MW) appears to be the preferred choice. However, in order to proceed with a project a viable business case and business setup need to be presented. This is also the main focus in the suggested next steps:

1. Investigate financing alternatives
2. Investigate possible partnerships, offtake and business setup
3. Continue the dialogue with the DSO regarding the timeline for power supply

The outcome from the above actions will be crucial to get the tollgate decisions that are needed in order to proceed with a FEED study.

4 Ammonia cracking as a complementary source of hydrogen and synergy effects with a SOEC plant

As mentioned in the Introduction chapter, the chemical industries in Stenungsund are expected to need substantial amounts of fossil-free or low-carbon hydrogen to decarbonize their processes. In the short term, the demand for fossil-free hydrogen stems from the need for fuel switching in their existing fired process heaters and furnaces (e.g., Borealis), large-scale carbon capture and utilization (CCU) (e.g., Project Air [17]), and the replacement of fossil-derived hydrogen in the region (e.g., Preem) to achieve net-zero emissions targets. In the longer term, these industries will require significantly more hydrogen for complete defossilization, i.e., decoupling from fossil-derived feedstocks, which may include using captured CO₂ to produce carbon-based fuels and materials.

As highlighted in section 3.3.2 the available capacity in the electricity grid is a limiting factor to meet the growing demand for fossil-free hydrogen through electrolyzers in the near future. The uncertainty concerning grid expansion and the availability of electric power necessitates investigating alternative hydrogen production technologies, such as ammonia cracking technology. This chapter presents the methodology applied and the corresponding results for the technical and cost interplay between the SOEC and ammonia cracking technologies and how they could complement each other to satisfy the future hydrogen demand at Stenungsund. This chapter does not focus on the SOEC plant at the pilot plant scale, the focus is instead on hydrogen production at a scale that could achieve decarbonization of one of the larger future H₂ off-takes in Stenungsund, i.e. Borealis' steam cracker furnaces. Thus, the selected case for the analysis herein corresponds to a hydrogen demand³ of 12 t/h from the integrated SOEC-NH₃ cracking system.

4.1 Ammonia cracking technology

Figure 4-1 shows a simplified schematic of the ammonia cracking process. The ammonia cracker consists of fired-catalytic tubular reactors, similar to commercially available steam-methane reforming reactors. Anhydrous liquid ammonia is evaporated, compressed, and preheated up to 500°C before the reactor. The ammonia decomposes into nitrogen and hydrogen under high pressure (20–50 barg) and temperatures close to 800°C. Subsequently, heat is recovered from the cracked product gas for preheating combustion air and ammonia feed. The cracked product gas consists mainly of hydrogen, nitrogen, and unconverted ammonia, some of which are recycled back to the ammonia cracker as fuel to provide energy to the endothermic ammonia cracking, ensuring zero CO₂ emissions from the cracking process. The remaining cracked product gas can be

³ The byproduct fuel gas at the cracker plant could yield 3.5–4.0 t/h of hydrogen. If this hydrogen is recovered using PSAs, it could reduce the hydrogen demand from the integrated SOEC-NH₃ system to 8.0–8.5 t/h.

directed to fired process heaters and furnaces with compatible burners in co-located process plants.

Alternatively, to deliver hydrogen with high purity, the process includes a hydrogen purification (pressure swing adsorption) unit downstream. The off-gas from the purification unit contain mainly hydrogen and nitrogen and could also be recycled as fuel for the ammonia cracker. Fuel gas externally sourced from the co-located process plant could be combusted in the ammonia crackers to increase overall hydrogen recovery from the ammonia feedstock. However, if the fuel is fossil-based, this would result in CO₂ emissions. Finally, the operating pressures of the ammonia cracker depend on the end product i.e., hydrogen-rich cracked gas or high-purity hydrogen product, and their associated delivery pressures. More information on the ammonia cracking technology can be found elsewhere [18–21].

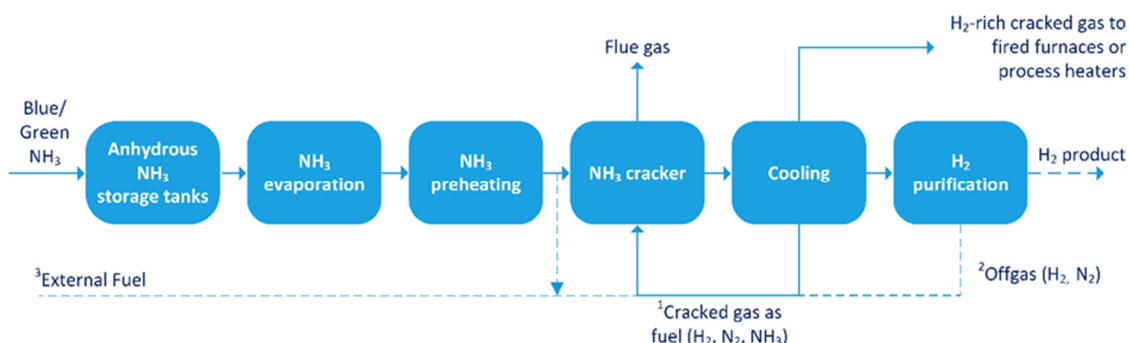


Figure 4-1. Process schematic of the ammonia cracking process.

4.2 Possible synergies between an ammonia cracker and a SOEC unit

Ammonia cracking ensures a reliable source of low-carbon and/or renewable hydrogen without being heavily dependent on the availability of renewable electricity or the timely expansion of the grid capacity, which may not align with the timelines for achieving net-zero emissions. In this context, co-locating and integrating an ammonia cracking plant with a SOEC unit could therefore offer several key advantages.

SOEC as the sole producer of hydrogen would likely be operated on PPA aligned with current regulations for renewable fuels of non-biogenic origin (RFNBO) [22]. However, if the SOEC were to operate flexibly in relation to variable electricity prices, it would necessitate capital-intensive hydrogen storage and transportation infrastructure. Consequently, ammonia cracking could provide a reliable complementary supply of low-carbon and/or renewable hydrogen, complementing the SOEC to efficiently meet the hydrogen demand during varying electricity prices without the need for hydrogen storage. In this work, we consider both low-carbon⁴ (blue) ammonia and renewable (RFNBO) ammonia, which will be referred to as ‘ammonia’ hereinafter.

⁴ Low-carbon ammonia must achieve a 70% emissions savings compared to the defined emissions intensity comparator. This definition includes both blue ammonia (i.e. from fossil energy sources with carbon capture and storage, CCS) and synthetic ammonia produced from non-renewable electricity, water and nitrogen that meet the emission reduction criteria of 70 %.

Depending on the process design and the extent of heat integration in the ammonia cracking process, excess heat could be recovered to supply low-cost steam to the SOEC. This would increase the efficiency of both the ammonia cracking process and the SOEC unit. Specifically, it would raise the SOEC's efficiency from 75% without steam import to 85% (LHV) with steam import [23]. In addition, the existing ammonia import terminals, storage capacities, and operational and handling experience at the cluster could facilitate the faster deployment and expansion of ammonia storage in relation to the required ammonia cracker capacity. Thereby, ammonia cracking technology could offer operational flexibility to the SOEC and serve as a lower-cost alternative for energy storage.

Furthermore, a continuous supply of low-carbon hydrogen could be maintained throughout the year by planning non-concurrent annual maintenance shutdown periods for each technology. The co-location and integration of the SOEC and ammonia cracker technologies could also potentially reduce the net emissions intensity of the hydrogen produced, depending on the location of the installation, the emissions intensity of the electricity grid, and the emissions associated with ammonia production, transport, and cracking. Finally, an integrated SOEC-NH₃ system could be scaled up as a shared infrastructure in the cluster, leveraging increasing grid capacity and the availability of electric power over time.

Such an expansion could involve transitioning from meeting the current hydrogen demand of the initial off-takers, such as the steam cracker plant, to addressing their future hydrogen demand and subsequently expanding to export via pipelines to other potential off-takers in the chemical cluster. However, beyond these practical benefits, the economic viability of this system is highly dependent on various uncertain economic parameters, which include electricity prices, the prices of low-carbon and/or renewable ammonia, capital and operational costs for both early-stage technologies and other site-specific constraints, such as the available grid transmission capacity and the potential for expanding ammonia storage capacity, contingent on the space available within the cluster. In this work, the interplay between the technical and cost factors was investigated using process and cost optimization models across various scenarios, both conservative and optimistic, as described in the following section.

4.3 Method

This section presents the method used to investigate the technical and cost interplay between the SOEC and ammonia cracking technology and how they complement each other to satisfy the future hydrogen demand at Stenungsund. As described in Ch. 4.1, the scope of this work is limited to Borealis' steam cracker plant, with the objective of decarbonizing its steam cracker furnaces. The existing steam cracker furnaces currently emit 553 ktCO₂ annually, resulting from the combustion of fuel gases containing methane (CH₄) and hydrogen recovered from the steam cracking process. The existing cracker furnaces have a total fired duty of approximately 400 MW corresponding to a hydrogen demand of 12 t/h. In this work, it was assumed that this demand must be met by the integrated SOEC-NH₃ cracking system. However, the by-product fuel gas at the cracker plant could yield 3.5–4.0 t/h of hydrogen. If this hydrogen is recovered using PSAs, it could reduce the hydrogen demand from the integrated SOEC-NH₃ system to 8.0–8.5 t/h. The hydrogen demand at the steam cracker plant is used as a key design

parameter in the process models, and demand constraint in optimization models developed in this work. In this context, this work focuses on addressing the following key questions:

- i. Under what price conditions would the co-location and installation of SOEC and ammonia cracking technology present an attractive hydrogen supply solution for the steam cracker plant, compared to relying solely on either of the two technologies as stand-alone options for hydrogen supply?
- ii. How would future price conditions, such as electricity prices, ammonia prices, and CO₂ emissions allowance prices, influence the technology mix?
- iii. Does the flexible operation of the SOEC in the integrated SOEC-NH₃ system offer any benefits in minimizing the total system cost, and consequently, the levelized cost of hydrogen produced?

4.3.1 Process integration

The existing steam system of the cracker plant [24] has three steam headers—high-pressure (HP) steam (85 barg), medium-pressure (MP) steam (8.8 barg), and low-pressure (LP) steam (1.8 barg). HP steam is generated in the natural gas (NG) fired steam boilers and from recovering heat from the product gases from the steam cracking furnaces. Some of the HP steam is expanded (40barg) and exported to Borealis' polyethylene (PE) plant. Surplus LP steam is typically condensed in the dump condenser, which handles both excess steam at the cracker plant and imported LP steam from the PE plant. The surplus LP steam at the PE plant is typically available when the LD5 unit is running, at 4.5 barg, and is expanded⁵ to 1.8 barg before being sent to the steam cracker plant. The surplus steam is highly discontinuous, ranging from 0–37 t/h during specific hours, with an annual average flow of 2.4 t/h.

The SOEC includes the SOEC stacks, a standby electric boiler, and a dedicated demineralized water (DM) steam generator that is supplied with demineralized water (see Figure 3-1). Here it is assumed that the steam generator is driven by MP steam (8.8 barg) recovered from the NH₃ crackers, and surplus LP steam at the steam cracker plant (1.8 barg). A mechanical vapor recompression (MVR)⁶ unit is integrated to upgrade the surplus LP steam, which is supplied at 5 barg to the steam generator.

⁵ This expansion could be avoided to reduce the pressure ratio in the MVR or thermocompressor, thereby reducing the electricity demand in the electrically driven compressors or the HP motive steam demand in the thermocompressor.

⁶ An alternative to the MVR is a thermocompressor, which could use high-pressure steam (45 barg) from the steam cracker plant to upgrade the surplus LP steam.

Table 4-1. Relevant ammonia cracking process data

Parameters		Unit
Operating pressure ^a	20	bar
Overall hydrogen recovery ^b	81	%
Multi-stage feed compressor discharge temperature	250	°C
MP steam generation potential ^c	2.67	t _{MPsteam} /t _{H₂}
Cracked product gas—recycled as cracker fuel	18	%
Cracked product gas composition		
H ₂	74.1	vol.%
N ₂	24.7	vol.%
NH ₃	1.2	vol.%

^a Ammonia cracking technologies are typically based on commercially available steam methane reforming technologies, which generally operate between 20–50 bar. In this work, the lower bound was chosen since high-pressure and high-purity hydrogen was not required for its end use as cracker fuel.

^b Thyssenkrupp UHDE and Topsoe's H2Retake™ process report a hydrogen recovery of 78% using ammonia as fuel.

^c Topsoe's ammonia cracking technology reports that it requires neither cooling nor steam generation units. Their process flowsheet indicates that the remaining excess heat is utilized in a pre-converter to enhance hydrogen recovery. Consequently, depending on the chosen process technology, the potential for MP steam generation could range from 0 to 2.67 tonnes of MP steam per tonne of hydrogen produced from the ammonia cracker. Here, the upper bound corresponds to the recoverable heat (~1500 kW, Figure 4-3) estimated from the developed ammonia cracking model, where the latent heat of MP steam is 2017.3 kJ/kg.

Figure 4-2 shows the process flowsheet of the ammonia cracking system with a hydrogen production capacity of 1 t/h. Table 4-1 lists the relevant process data for the ammonia cracking system. In this work, the cracked product gas is used as the fuel for both the ammonia cracker (18% recycled) and the steam cracking furnaces (82%). The existing burners in the steam cracking furnaces combust hydrogen-rich fuel gas (CH₄/H₂) and retrofits to the burners may be required to combust the cracked product gas, which mainly consists of H₂, N₂, and residual NH₃. Although hydrogen purification units are not required in this configuration, the additional capital costs associated with hydrogen purification are kept included in the assumed total capital costs of the ammonia cracker (Table 4-2). Heat is recovered from high-temperature flue gases and the cracked product gas for air and feed preheating. The maximum discharge temperature of the final stage of the multi-stage feed compressor is set to 250°C to retain the heat of compression and preheat the feed before it enters the feed preheater. Any remaining excess heat in the cracked product gas is recovered to generate saturated MP steam to drive the steam generator in the SOEC, as shown in Figure 4-3.

Alternatively, co-firing an NH₃/H₂ fuel gas mixture could be considered for the steam cracker furnaces, wherein a stream of pre-heated vapor ammonia could bypass the cracker and be mixed back with the cracked product gas stream to achieve a desired composition. This co-firing option could potentially reduce the invested capacity and operational costs of the NH₃ cracker system in a SOEC-NH₃ configuration, as significantly less ammonia would need to be cracked. The extent of ammonia cracking, for blending hydrogen with an NH₃ feed, would depend on the trade-off between improving fuel characteristics and reducing NO_x emissions compared to the direct

combustion of ammonia in the steam cracker furnaces. However, this option was outside the scope of this work and was therefore not investigated.

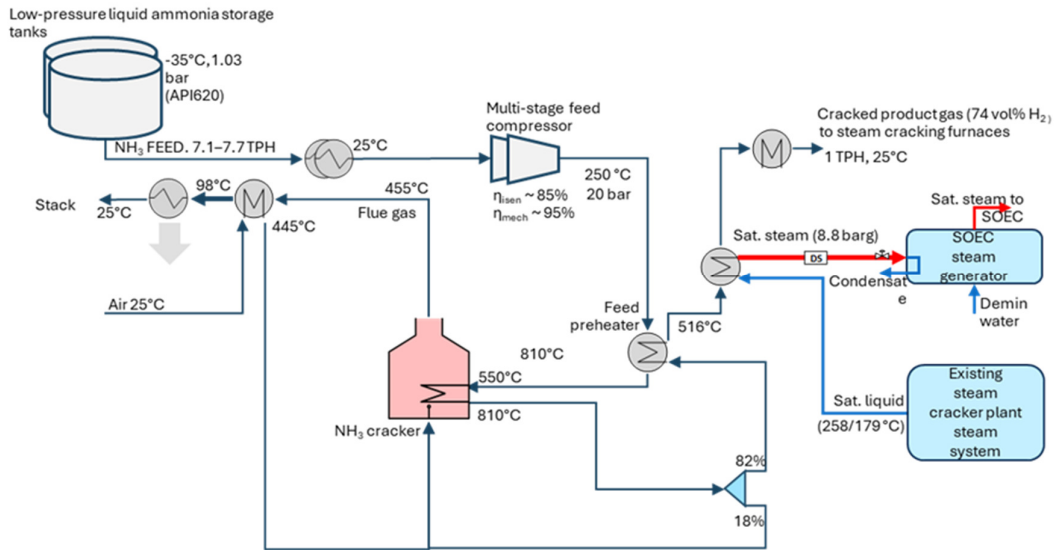


Figure 4-2. Process flow diagram of the ammonia cracking system, integrated with the steam system of the steam cracker plant.

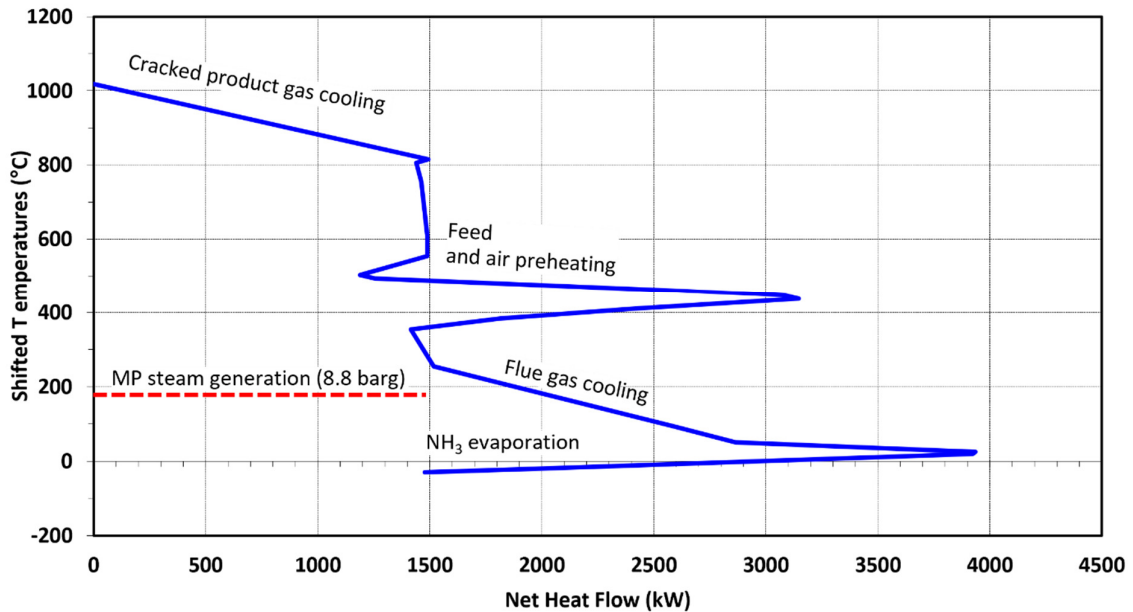


Figure 4-3. Grand composite curve (with $\Delta T_{min} = 5^\circ\text{C}$) of the ammonia cracking system with a hydrogen production capacity of 1 t/h. The solid red line indicates the hot utility curve i.e., the heat recovered from the ammonia cracking system as MP steam (8.8 barg)

4.3.2 Cost optimization model

A multi-period mixed-integer linear programming approach is taken to identify an optimal technology mix and hydrogen dispatch strategy for the SOEC-NH₃ system. The model is developed and implemented in the General Algebraic Modeling System

(GAMS), aiming to minimize the total system cost over the year for a given hydrogen demand, subject to the technical constraints of hydrogen production technologies. The total system costs include the annualized capital costs and annual operational costs of hydrogen production technologies, including the annualized capital costs of additional ammonia tank capacity, new steam generators i.e., standby electric boiler and the MVR, and annual emissions costs. Table 4-2 presents a summary of input data, assumptions, and other relevant parameters used in the optimization model. It is important to note that all process technologies included in the model assume fixed specific capital expenditures (CAPEX) expressed in EUR/MW. As a result, the optimization model does not take economies of scale into account.

Equation 1 shows a simplified equation of the levelized cost of hydrogen⁷ produced, which accounts for the annualized capital investment of the process technology⁸ and the yearly operational costs (energy and maintenance costs). Equation 2 shows the weighted average (WA) LCOH produced by the integrated SOEC-NH₃ system⁹. For a given scenario, the model determines the optimal invested capacities of the SOEC and the ammonia cracker and optimizes their operation within the integrated SOEC-NH₃ system on an annual basis with hourly resolution. The description of the optimization model can be found elsewhere [25]. Figure 4-4 shows the overview of the SOEC-NH₃ system with its main constraints associated with the availability of electricity, ammonia, and steam. The possibility of storing pure hydrogen was not considered in the model, as there is no hydrogen storage facility on-site and limited feasibility for such an installation in the future.

$$\text{LCOH} = \frac{\text{CAPEX}_{\text{annualized}} + \text{OPEX}_{\text{yearly}}}{\text{Annual hydrogen production}} \left[\frac{\text{€}}{\text{kg}} \right] \quad (1)$$

$$\text{LCOH}_{\text{WA}} = \frac{(\text{LCOH}_{\text{SOEC}} * H_{2,\text{SOEC}}) + (\text{LCOH}_{\text{NH3cracker}} * H_{2,\text{NH3cracker}})}{(H_{2,\text{SOEC}} + H_{2,\text{NH3cracker}})} \left[\frac{\text{€}}{\text{kg}} \right] \quad (2)$$

⁷ Note that the model optimizes for the lowest system costs. The technology-specific levelized cost of hydrogen (LCOH) and the weighted average LCOH are subsequently calculated for the least-cost system.

⁸ The cost contributions of the electric steam boiler and the MVR are computed and included separately for comparability between the hydrogen production technologies in different scenarios.

⁹ Symbols $H_{2,\text{SOEC}}$ and $H_{2,\text{NH3cracker}}$ represent the total annual hydrogen produced by each respective technology.

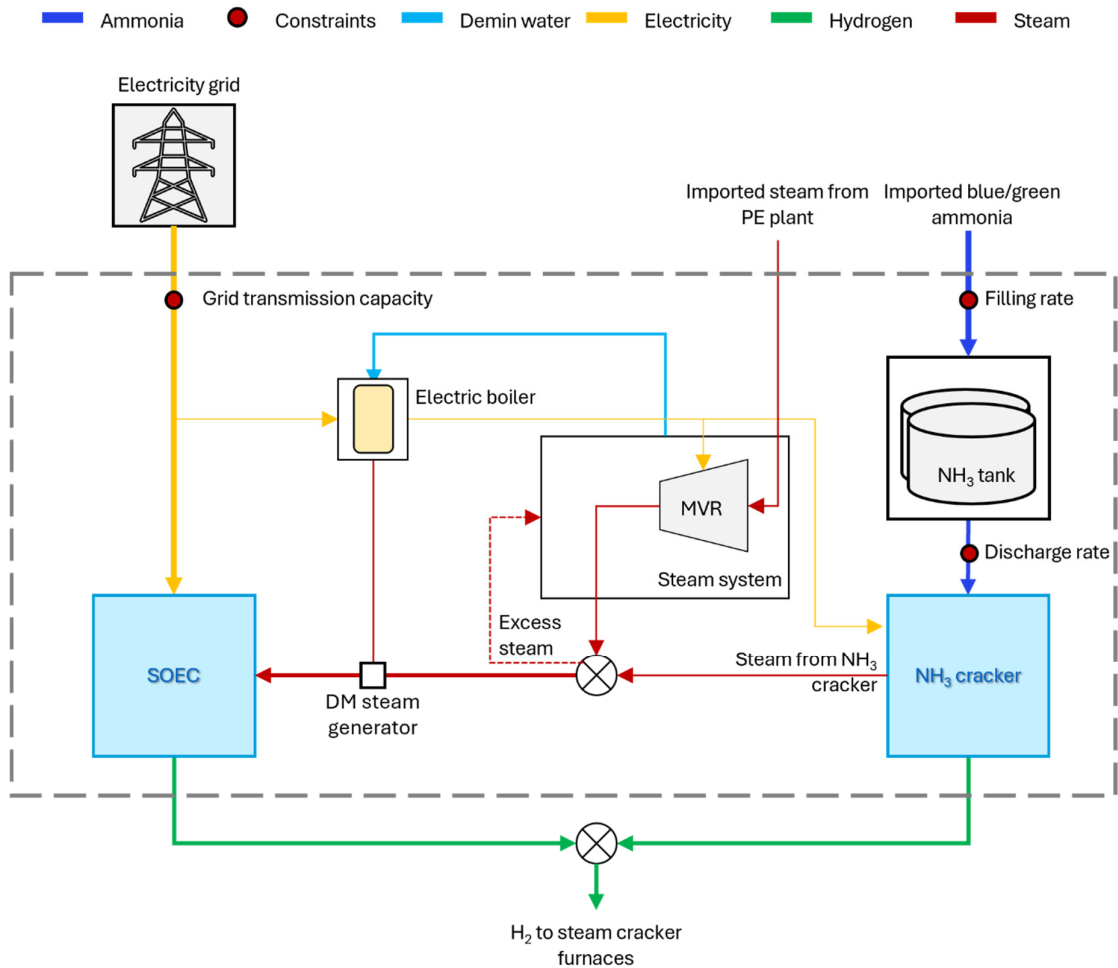


Figure 4-4. Schematic overview of integrated SOEC-NH₃ system with its main constraints. The hydrogen production technologies are highlighted in blue. The steam system of the cracker plant is included within the system boundary, where a mechanical vapor recompression (MVR) unit is used to upgrade imported steam from the polyethylene (PE) plant. Note that the excess steam (red dashed line) offsets steam generation and the corresponding CO₂ emissions from natural gas boilers in the cracker plant. This is only relevant in scenarios where more steam is available than required by SOEC.

4.3.2.1 Electricity

The system imports electricity from the grid and has no direct connection to a co-located renewable electricity producer. The overall system is limited by the available transmission capacity between the SOEC-NH₃ system and the local grid. The current transmission capacity at the cracker plant is estimated to be 100 MW [26], which is less than one-tenth of the total estimated transmission capacity to the regional grid in the Stenungsund region (850 MW [27,28]). The electricity imported from the grid is assumed to be bought and delivered at a constant PPA price compliant with the Delegated Act 27/REDIII and < 18 mg CO₂eq/MJ electricity. Additionally, a grid tariff is assumed for the imported electricity to represent transmission fees and taxes (4 €/MWh [29]).

4.3.2.2 Ammonia

The system is limited by the available ammonia tank capacity at the existing site (5 kt [30]). Scenarios with larger ammonia tanks account for investments in additional tank capacity. These tanks are further constrained by their maximum filling and discharge rates. The ammonia tank is assumed to be filled at the start of each month, with a maximum filling rate of 4% of the total tank capacity per hour. The maximum discharge rate is set to match the ammonia demand in the ammonia cracker at any given hour. Additionally, the model includes a constraint for the minimum tank capacity, requiring it to be always maintained at a level equivalent to 1.5 times the maximum expected ammonia demand in any given hour. It should be noted that there is no constraint on the installed capacities of the ammonia crackers, as most scenarios require capacities that exceed the reported minimum of 10 tonnes per day of hydrogen [20,21].

4.3.2.3 Steam

In a given hour, the steam demand in the SOEC is met by surplus LP steam, upgraded by an MVR, and the MP steam generated from the recovered heat of the ammonia crackers. During hours when the total steam demand is not fully met by these two sources, an electric steam boiler acts as a standby unit to supply the remaining steam required by the SOEC. Since an investment in MVR is necessary to utilize the surplus LP steam (1.8 barg), the model prevents steam dumping in the dump condenser throughout the year. Instead, it assumes that an equivalent amount of steam is displaced from the NG boilers, thereby reducing natural gas consumption and associated emissions. The avoided cost of CO₂ emissions from the NG boilers is deducted from the total annual emissions cost of the integrated SOEC-NH₃ system.

Table 4-2. Technology, economic data, and assumptions.

Description		Value	Unit	Notes/Reference
Technology data and other assumed data				
Hydrogen demand		12	t/h	Corresponds to the hydrogen demand in the existing steam cracker furnaces.
Existing grid transmission capacity		100	MW	Estimated [26,28]
Steam demand (SOEC)		9	t MPsteam / tH ₂	[23]
Energy efficiency	SOEC	75	%	Refers to Low Heating Value (LHV). Estimated total energy efficiency including the imported steam [23].
	NH₃ cracker	81.7	%	Refers to Low Heating Value (LHV). Estimated from the ammonia cracker model. Efficiencies reported by technology providers are 78% when using ammonia as the fuel [18,19].
Specific electricity demand	SOEC	38.90	MWhe/MWh H ₂	Based on reported electrical efficiency with steam import (~85.7%) [23].
	NH₃ cracker	0.027	MWhe/MWh H ₂	~0.9 MWhe/tH ₂ . Estimated from the ammonia cracker model. Assuming $\eta_{isen} \sim 0.85$, $\eta_{mech} \sim 0.95$ for multi-stage feed compressor with a discharge pressure and temperature of 20 barg and 250°C.
Existing ammonia tank capacity		26	GWh	Lower bound equivalent to existing tank capacity at Stenungsund, 5kt [30,31].
Ammonia tank filling frequency		1	/month	Current filling frequency
Filling rate		4	% of total tank capacity/hour	2400 t/h ~ equivalent to two marine loading arms for an ammonia tank capacity of 60 kt ~4% of total tank capacity/hour. Estimated spatial footprint ~ 55,000 m ² (Sillamäe, Estonia) [32]

Description		Value	Unit	Notes/Reference
Technology-specific ramp rate	SOEC	10 (hot)	mins	[23]
	NH₃ cracker	1% of nominal load per 2 mins		Assumed similar to steam methane reformers [33]. Note that this is a conservative estimate, other publicly available sources report a ramp rate of 3%/min [34].
	Electric boiler	1.8	mins	Warm start-up [35]
	MVR	30	mins	Warm start-up assumed. 1 hour for cold start-up [35]
Technology-specific minimum load (% relative to nominal load)	SOEC	10	%	[23]
	NH ₃ cracker	50	%	Assumed similar to steam methane reformers [33]. Note that this is a conservative estimate, other publicly available sources report a load range between 20–100% [34].
	Electric boiler	2	%	[35]
	MVR	0	%	0–15 %. Lower bound assumed [35]
Economic parameters				
Value of N₂ and O₂		No value is assigned to by-product streams.		
Technology lifetime		25	year	An equivalent lifetime of 25 years is assumed for both technologies for the sake of consistency.
Interest rate		10	%	Estimated capital recovery factor ~11.01%
Operational hours		8760	Hours/year	Assumption. The actual operational hours could be somewhat lower considering annual maintenance shutdown periods.
Reported specific CAPEX	SOEC	2,500,000	€/MW	Note that the specific CAPEX used in the optimization model is based on the reported CAPEX range for SOEC [36]. The specific CAPEX presented in Section 3.6.1 is relatively higher, as it is relevant for smaller pilot plants.
	NH₃ Cracker	93,600–432,200	€/MW	Corresponds to reported specific CAPEX of 0.13–0.63 M€/MTPD [34]
	Electric boiler	100,000	€/MW	[35]
	MVR	1,200,000	€/MW	[35]
Annualized specific CAPEX	SOEC	402,916	€/MW	This value also includes a maintenance cost assumed to be 5% of the annualized CAPEX (€/y). An additional cost escalation factor of 1.4 is assumed for unaccounted CAPEX and operational costs e.g., stack replacement, and annual maintenance shutdown periods resulting in lower operation hours.
	NH₃ Cracker	50000	€/MW	Cost function obtained from [37,38]. An additional cost escalation factor of 1.4 is assumed

Description		Value	Unit	Notes/Reference
				for unaccounted site-specific costs e.g., site-preparation and permits.
	Electric boiler	11016	€/MW	-
	MVR	132,201	€/MW	-
Technology-specific cycling costs	SOEC	0	€/MWh	Assumption.
	NH₃ cracker	-	€/MWh	The actual cycling cost is unknown. The model considers the positive load difference between two steps, which is multiplied by the cost of ammonia. Therefore, the model assumes twice the cost of ammonia during specific hours with either ramp-up or ramp-down to prevent frequent cycling of the NH ₃ cracker.
Ammonia storage tank		57.4	€/MWh H ₂ product	30,000 tonne API620 tanks, 15M\$, 190 GWh HHV, or 158 GWh LHV. 0.92 €/USD. Converted to H ₂ product (LHV) [39].
Operational cost parameters				
Ammonia price		400–1000	€/tNH ₃	The assumed ammonia price range encompasses the reported price for low-carbon ammonia (420 – 564 \$/mt) and renewable ammonia (781 – 818 \$/mt) [40]
Electricity price (PPA)		50–100	€	–
Grid tariff		4	€/MWh	Represents taxes and distribution costs [41]
Gas price		60	€/MWh	This value is used to estimate the fuel costs avoided in scenarios with surplus steam from the ammonia crackers and the upgraded MP steam (MVR).
EU-ETS		100–200	€/tCO ₂	–

4.3.3 Scenarios and Sensitivity Analysis

A reference start year of 2030 was assumed. Figure 4-5 illustrates the possible scenarios for a SOEC-NH₃ system with a total hydrogen production capacity of 12 t/h. This system is primarily constrained by the ammonia tank capacity, which is subject to the space availability on-site¹⁰ and the transmission capacity between the steam cracker plant and the local grid. Figure 4-5 shows the infeasible configuration, highlighted in gray, that would be insufficient to meet the hydrogen demand of 12 t/h. To investigate scenarios that are both conservative and optimistic with respect to the tank and grid transmission capacities, three scenarios were investigated at the extremities of the broad feasible space, shown in Figure 4-5.

¹⁰ Alternatively, an ammonia barge can be docked at the port jetty of the steam cracker plant to overcome space limitations within the plant boundaries.

Given the short timeframe leading up to 2030, it is reasonable to assume that an expansion in tank capacity is more likely than an expansion in grid transmission capacity. Therefore, Scenario S1, describes a conservative yet realistic configuration, assuming that the transmission capacity remains unchanged, while the ammonia tank capacity is set equal to the minimum tank capacity (312 GWh or 60kt) required to meet the hydrogen demand. Conversely, Scenario S2 presents a conservative and somewhat unrealistic configuration¹⁰, assuming that the expansion of ammonia tank capacity due to space availability is the primary constraint, which results in no increase in ammonia tanks beyond the current capacity of 5 kt. In this case, the grid transmission capacity would need to be at least 500 MW to meet the hydrogen demand. Finally, assuming that both the expansion of ammonia tank capacity and transmission capacity are equally likely within the given timeframe, a highly optimistic scenario, S3, is investigated, where the available tank capacity and transmission capacity are 312 GWh and 500 MW, respectively. A sensitivity analysis was carried out to determine their minimum and maximum possible system costs and corresponding hydrogen production costs for the defined scenarios. Table 4-3 lists the investigated scenarios, and Table 4-4 lists the parameters considered for the sensitivity analysis. The minimum and maximum possible system costs are determined by setting the listed parameters to their respective lower and upper-bound costs. Each of the investigated scenarios is suffixed with subscripts min and max to indicate the assumed electricity, ammonia, and EU-ETS allowance prices.

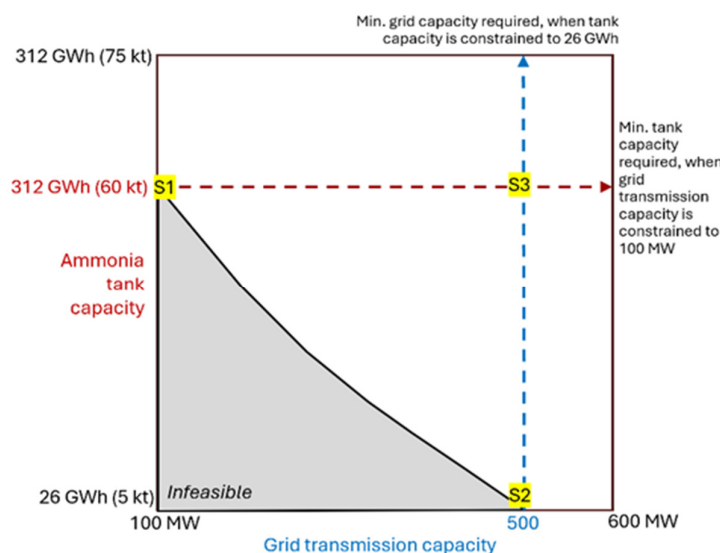


Figure 4-5. Scenarios investigated in the feasible space of the SOEC-NH₃ cracker system.

Table 4-3. Ammonia tank and grid transmission capacities assumed in the different scenarios investigated.

Scenarios	Grid Transmission Capacity (MW)	Ammonia tank Capacity (GWh)
S1	100	312 (60 kt)
S2	500	26 (5 kt)
S3	500	312 (60 kt)

Table 4-4. Parameters and their range included sensitivity analysis.

Parameters ^a	Min	Max	Unit
Electricity (PPA) price ^b	50	100	€/MWh
EU-ETS allowance price	100	200	€/tCO ₂
NH ₃ price ^c	400	1000	€/tNH ₃

^a Note that projected price developments for these economic parameters over the plant's lifetime were not considered. Instead, a max-min approach was used to determine the minimum and maximum possible LCOH through sensitivity analysis. The sensitivity results with minimum and maximum economic parameters are referred to in the text as *low price conditions* and *high price conditions*, respectively.

^b In scenarios with spot prices, only EU-ETS and ammonia price ranges are applied.

^c Note that for the minimum and maximum scenarios, ammonia is assumed to be low-carbon and renewable, respectively, corresponding to the assumed price of 400–1000 €/tNH₃, with emissions intensities set to 2.5 tCO₂/tNH₃ and 0 tCO₂/tNH₃, respectively.

4.4 Results

4.4.1 LCOH comparison under standalone operation

To understand the benefits of co-locating and integrating the SOEC-NH₃ system at the steam cracker, it is essential to first examine how these individual technologies operate as standalone hydrogen suppliers. To this end, Figure 4-6 illustrates a breakdown of the levelized cost of hydrogen produced by the SOEC and ammonia crackers under both low and high-price conditions. Assuming the SOEC operates as the sole producer of hydrogen in the cluster, the levelized cost of hydrogen¹¹ could range from 3.89–6.39 €/kg¹², while the ammonia cracker ranges from 3.68–8.18 €/kg¹³. Electricity costs could account for approximately 50–61% of the estimated LCOH for the SOEC, while ammonia costs could account for approximately 85–96% of the LCOH produced from the ammonia crackers. Comparable LCOH to that of the SOEC (~6.4 €/kg) would be attainable if renewable ammonia prices approach 800 €/tNH₃ under high price conditions. Two main differences between the two technologies are the lack of emissions costs for the SOEC, assuming consumption of renewable electricity, while the ammonia cracker could incur costs of up to 0.25–0.50 €/kg if low-carbon ammonia is used, assuming emissions cost of 100 and 200 €/tCO₂. Notably, the ammonia cracking system would be more cost-effective by relying on low-carbon ammonia as the primary feedstock and paying for supply-chain CO₂ emissions¹⁴, rather than sourcing renewable ammonia solely for hydrogen production. Moreover, it is unlikely that low-carbon and renewable ammonia will achieve price parity in the foreseeable future. In Figure 4-6a, under low-price

¹¹ Accounting for annual maintenance shutdowns and assuming 8,000 hours of operation over the year, the LCOH ranges for the SOEC and NH₃ cracker are €4.06–€6.56/kg and €3.70–€8.20/kg, respectively.

¹² These values correspond to an SOEC with an installed capacity of approximately 467 MW.

¹³ These values correspond to an ammonia cracker with an installed capacity of approximately 489 MW.

¹⁴ This inference is subject to the associated supply chain emissions that include CO₂ capture rates at the ammonia production plant, fate of captured CO₂, transport distances and type of fuel used for ammonia cracking. A specific emissions intensity of 2.5 tCO₂/tNH₃ was estimated for low-carbon ammonia in this work.

conditions (Min), it is assumed that the imported steam is derived from residual heat from a co-located plant, resulting in zero steam costs. However, if steam import is not available, the steam costs associated with the SOEC could range from 0–1 €/kg, depending on the source of imported steam and the associated energy costs. For example, if all the steam demand is met using an electric boiler with an electricity price of 100 €/MWh, steam costs could rise to as much as 0.55 €/kg. In Figure 4-6b, under standalone operation, the steam generated from the ammonia crackers is assumed to have no value, although, it could offset some of the emissions and costs associated with steam generation from NG boilers.

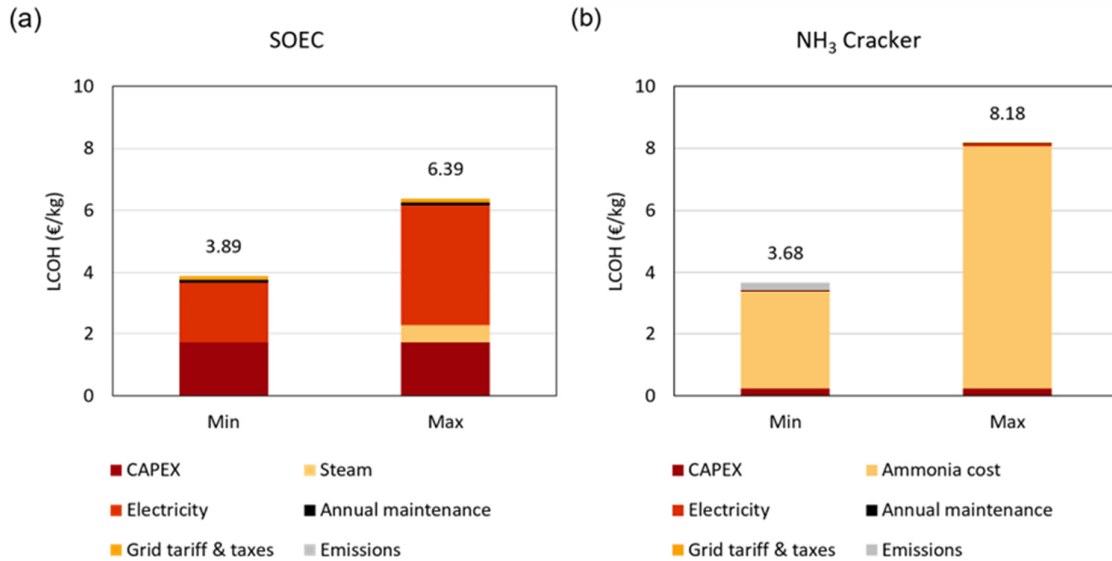


Figure 4-6. Breakdown of levelized cost of hydrogen produced from standalone operation of the (a) SOEC and the (b) ammonia cracker under low and high price conditions, as per Table 4-4.

4.4.2 Operation with fixed electricity (PPA) price

Table 4-5 lists a summary of the total system costs, LCOH, emission intensity, and installed capacities for the different scenarios investigated, assuming fixed electricity prices under a PPA. Given the fixed economic parameters and the absence of fluctuating variables, except for the intermittent surplus steam from the PE plant, which has a minor influence on the operation of the SOEC, the optimization model primarily functions as an investment model. It is constrained by the key limitations of the investigated system, namely ammonia storage and grid transmission capacities. Under low and high price conditions, irrespective of the scenario, the weighted average LCOH ranges from 3.7–4.13 €/kg and 6.48–7.7 €/kg, respectively. More specifically, the benefits of co-location and integration are evident under low-price conditions, where the weighted average LCOH remains marginally lower than the individual LCOH of either technology. An exception is Scenario S1max, where the limitation in grid transmission capacity restricts further investments in SOEC, despite the lower LCOH of 5.84 €/kg. Notably, this value is exactly 0.55 €/kg lower than the estimated LCOH for the standalone operation of the SOEC under high price conditions (6.39 €/kg), indicating that the imported steam comes from recovered excess heat at no additional cost. In general, under lower price conditions, larger investments in an ammonia cracker are expected, unless limited by ammonia storage capacity (e.g., S2min). Similarly, under high price conditions, larger

investments in SOEC are expected, provided there is sufficient grid transmission capacity e.g., S1max). The differences in low and high price conditions are visualized for the broad feasible configuration, in Figure 4-7, which shows the share of total hydrogen demand of 400 MWh met with the SOEC.

Table 4-5. Summary of total system costs, LCOH, emission intensity, and installed capacities for different scenarios investigated, assuming the fixed electricity (PPA) price range.

Grid transmission and ammonia tank capacities	100 MW, 60 kt	500 MW, 5 kt	500 MW, 60 kt	100 MW, 60 kt	500 MW, 5 kt	500 MW, 60 kt	Units
Scenarios	S1_{min}	S2_{min}	S3_{min}	S1_{max}	S2_{max}	S3_{max}	-
Total system costs	396.9	439.9	396.9	816.9	686.9	689.4	M€/y
Hydrogen production costs							
LCOH (SOEC)	3.89	4.17	3.89	5.84	6.37	6.37	€/kg
LCOH (NH ₃ cracker)	3.67	3.67	3.67	8.18	8.18	8.18	€/kg
Weighted avg. LCOH	3.70	4.13	3.70	7.7	6.48	6.48	€/kg
Weighted avg. LCOH including utilities ^a	3.75	4.18	3.75	7.75	6.53	6.53	€/kg
Specific emissions intensity of hydrogen produced							
Electrolyzers	0	0	0	0	0	0	tCO ₂ /tH ₂
NH ₃ cracker	2.52	2.52	2.52	0	0	0	tCO ₂ /tH ₂
Integrated SOEC-NH ₃ system	2.16	0.18	2.16	0	0	0	tCO ₂ /tH ₂
Annual average H₂ production							
Electrolyzers	56.9	371.4	56.9	81.50	375.5	375.5	MWh/h
NH ₃ cracker	343.1	28.6	343.1	318.5	24.4	24.4	MWh/h
Installed capacities^b							
Electrolyzers	66.35	433.3	66.35	95.07	438.19	438.19	MW
NH ₃ cracker	420.2	35.0	420.2	390.1	29.9	29.9	MW
Electric steam boiler	0.0	59.0	0.0	0.0	59.9	59.9	MW
MVR	37.0	37.0	37.0	37.0	37.0	37.0	MW
Share of H₂ demand met with SOEC	14	93	14	20	94	94	%

^a The CAPEX of the MVR and electric boiler cannot be directly attributed to steam demand in the SOEC, as they also help reduce on-site emissions during surplus steam scenarios. Therefore, these cost components (€/kg) are added to the weighted average LCOH instead of to the technology-specific LCOH.

^b Note that although the invested capacities are above the minimum possible capacities (10 t/d H₂) reported by technology providers [20,21], the model does not account for economies of scale. As a result, scenarios with relatively smaller installed capacities may incur somewhat higher LCOH than the estimates provided here. For instance, the installed capacities of the ammonia cracker in Scenarios S2_{min}, S2_{max}, and S3_{min} correspond to capacities ranging from 17.5 to 20.6 t/d H₂, which represents the scale of a demonstration plant⁵⁷.

Under low price conditions (Figure 4-7a), the optimization model predominately invests in the ammonia cracker system owing to the comparable operating costs (ammonia $\sim$ 76.9 €/MWh to 50 €/MWh electricity price) with significantly lower capital costs. Here, the investment in ammonia crackers is directly related to available ammonia tank capacity. For example, for an unchanged ammonia tank capacity of 5 kt, approximately 94% of the total hydrogen demand is met with electrolyzers. Conversely, under high price conditions (Figure 4-7b) the SOEC-NH₃ system is highly sensitive to the available transmission capacity, and thereby the model predominantly invests in SOEC which has significantly lower operational costs compared to the ammonia cracker. Specific emissions intensity is expected to range between 0–2.52 tCO₂/tH₂, depending on the capacity of the ammonia cracker operating with low-carbon ammonia. The integrated operation with SOEC could minimize the specific emissions intensity, depending on its installed capacity.

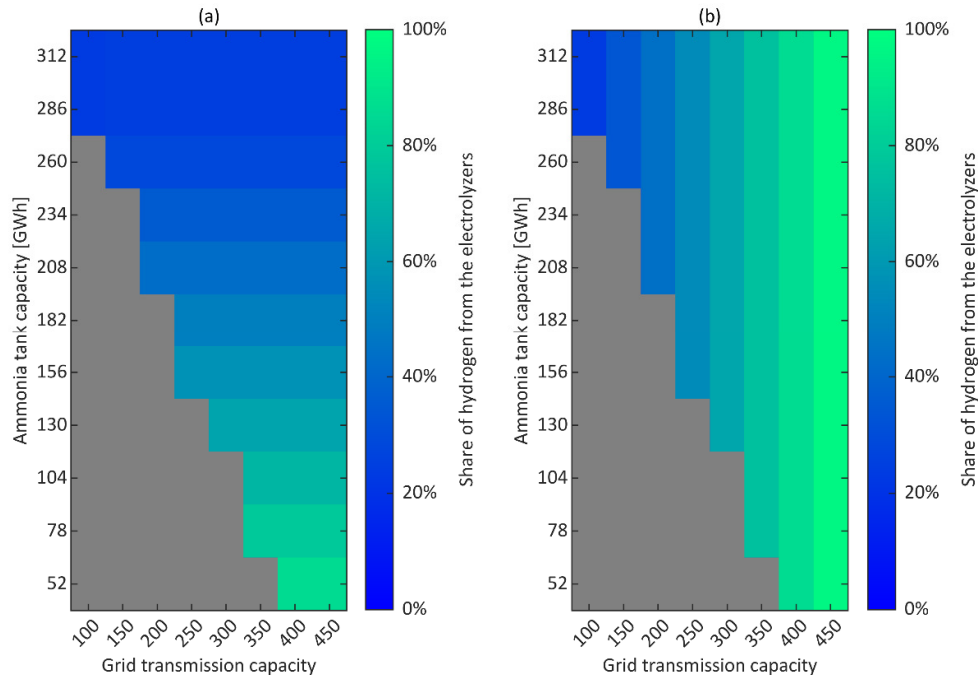


Figure 4-7. Share of hydrogen from the electrolyzers in the SOEC-NH₃ system under minimum (a, left panel) and maximum (b, right panel) price conditions.

4.4.2.1 System operation under fixed electricity prices

Given the likelihood of a lack of transmission capacity in the short term, and the projected increase in EU-ETS, ammonia, and electricity (PPA) prices, this section presents results for Scenario S1_{max} with a grid transmission capacity of 100 MW and ammonia tank capacity of 60 kt (312 GWh). Note that this scenario presents the most conservative scenario with no grid expansion until the start year of 2030, with an electricity price of 100 €/MWh, EU-ETS allowance prices of 200 €/tCO₂, and ammonia price at 1000 €/tNH₃ (192.3 €/MWh).

Figure 4-8 illustrates the share of hydrogen produced from the electrolyzers and the ammonia cracker, and their associated LCOH. Both technologies operate throughout the year at full load. Although the model accounts for the ramping rates and minimum loads of each technology, the overall system operates at a fixed load throughout the year due to the fixed electricity price established through power purchase agreements. The inability to operate the SOEC with spot prices, during favorable periods with low electricity prices, restricts the investment in SOECs to the minimum capacity possible dictated by the available transmission capacities. This scenario includes an MVR with an installed capacity of 37 MW, with no investments made in an electric boiler, indicating that the steam demand of the SOECs is met by surplus steam available at the cracker plant when available, while the remaining steam demand is supplied by large-scale ammonia crackers. In this case, the upgraded MP steam, produced using MVR, primarily offsets emissions from the NG boilers in the steam cracker plant, which is reflected in the LCOH of the NH_3 cracker. Figure 4-8b shows the LCOH produced from the SOEC and the ammonia crackers, along with the weighted average LCOH of the SOEC- NH_3 system. Since ammonia crackers are most sensitive to the price of imported ammonia, securing long-term contracts for low-carbon and renewable ammonia at or below 800 €/t NH_3 is necessary to close the gap between the two technologies and reduce the weighted average LCOH.

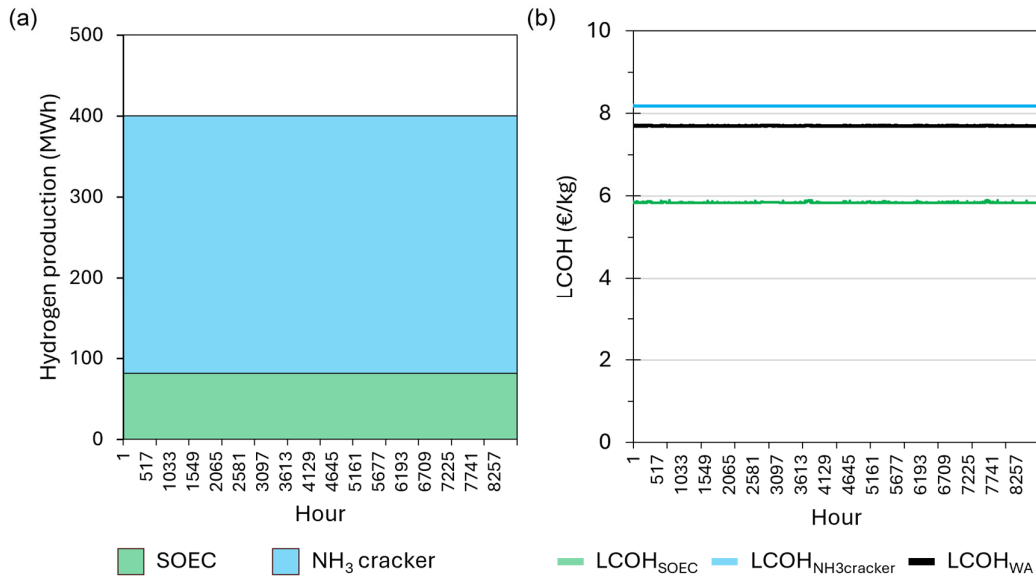


Figure 4-8. (a) Hydrogen supply from the SOEC (green shaded area) and ammonia crackers (blue shaded area) over the year ($S1_{\text{max}}$) and the (b) corresponding weighted average levelized cost of hydrogen produced by the SOEC- NH_3 system, indicated by the black solid line.

4.4.2.2 Ammonia tank level, filling, and discharging profiles

Figure 4-9a presents the ammonia tank level over the year. The tank depletes linearly throughout the month due to the constant ammonia demand in the ammonia cracker. The tank is filled every month and takes 25 hours to fill at a filling rate of 4% of the available tank capacity (2400 t NH_3 /h). Figure 4-9b illustrates the minimum tank level constraint that prevents discharging beyond the minimum tank level (red dashed line) during all hours.

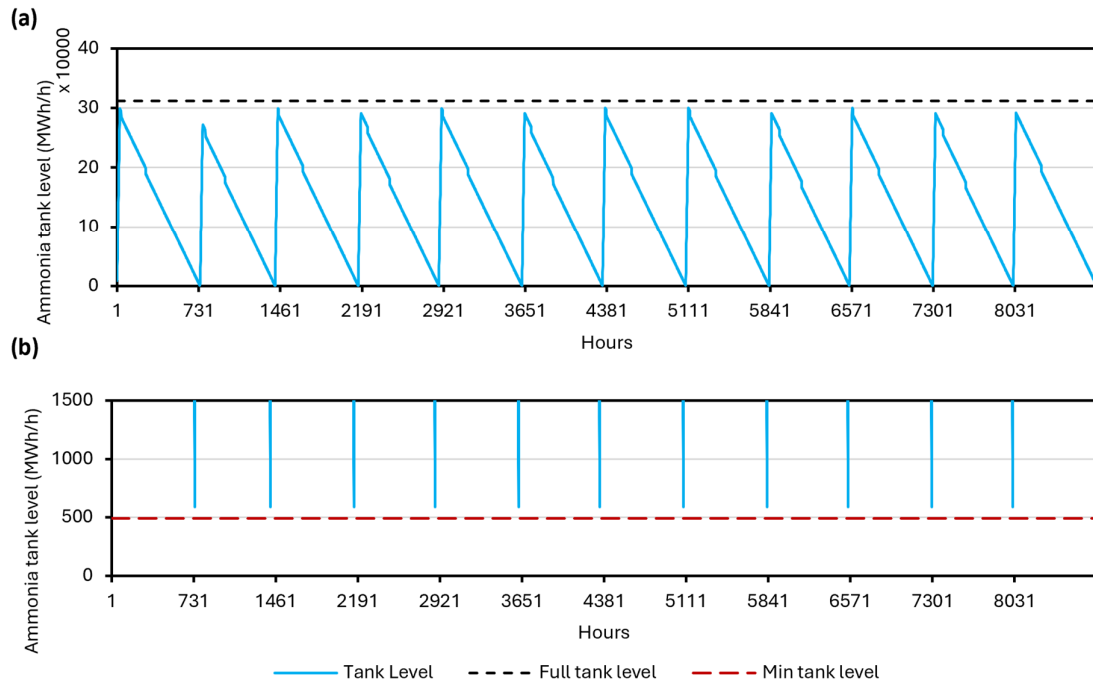


Figure 4-9. Ammonia tank level profiles over the year for Scenario S1_{max}, with fixed electricity price. The black dashed line indicates the maximum available tank capacity, and the red dashed line indicates the minimum tank level.

4.4.3 Operation with spot prices

This section presents a hypothetical scenario to demonstrate the potential for flexible operation of the SOEC–NH₃ system, specifically highlighting how the SOEC can respond to fluctuating spot prices. In the short term, such flexible operation is unlikely given that it entails significant investment and operational risks and does not meet the current requirements for the production of renewable hydrogen [22]. In the long term, however, with increased penetration of variable renewable electricity, such large-scale renewable hydrogen plants could provide a flexible load to the electricity system, utilizing renewable electricity that would otherwise be curtailed and potentially mitigating price cannibalization.

Given that grid transmission capacity is the primary limiting factor in the short term, Scenario S1 (100MW, 312 GWh) is assumed to be the most likely scenario, with increased transmission capacity expected over time. A corresponding expansion of the SOEC, in line with the grid transmission capacity while excluding the possibility for H₂ export, under high price conditions is shown in Figure 4-10. The grid transmission capacities are 100MW, 300MW, and 500MW in Figure 4-10a-c, respectively.

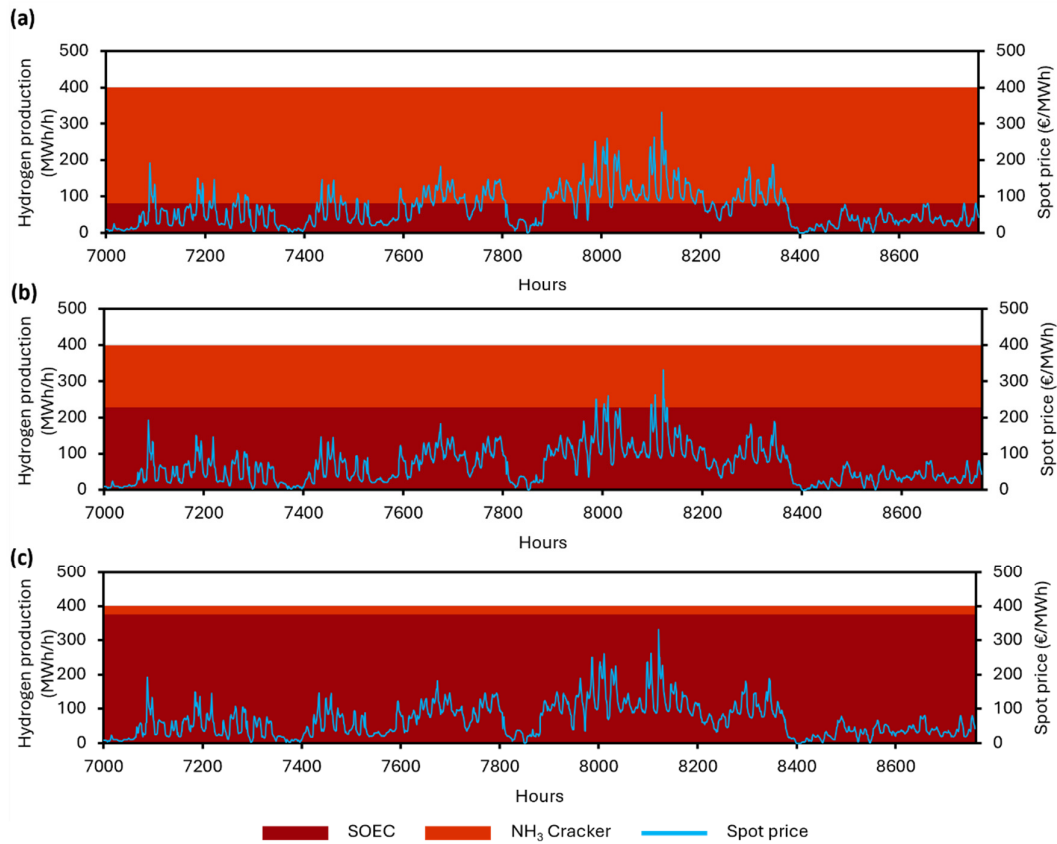


Figure 4-10. Influence of increasing access to grid transmission capacities without the possibility of hydrogen export. Hourly hydrogen supply profiles from the SOEC and the NH₃ cracker are shown for 1760 selected hours with highly volatile spot prices ranging from 0 to 332 €/MWh. This is presented for scenarios with grid transmission capacities of (a) 100 MW, (b) 300 MW, and (c) 500 MW, all with a fixed ammonia tank capacity of 312 GWh.

Figure 4-10 shows that under high price conditions, the model favors investment in larger SOEC capacities over ammonia cracking as grid transmission capacities increase. However, the lack of export capability, including the high price of ammonia limits the flexible operation of the SOEC-NH₃ system. Instead, the SOEC-NH₃ system is optimized to achieve installed capacities that allow full utilization throughout the year. Figure 4-11 shows the hydrogen supply profiles for Scenarios S_{1min}–S_{3min} where the flexible operation of the SOEC-NH₃ system is primarily influenced by low-price conditions, with electricity and ammonia prices being in a comparable price range for several hours throughout the year.

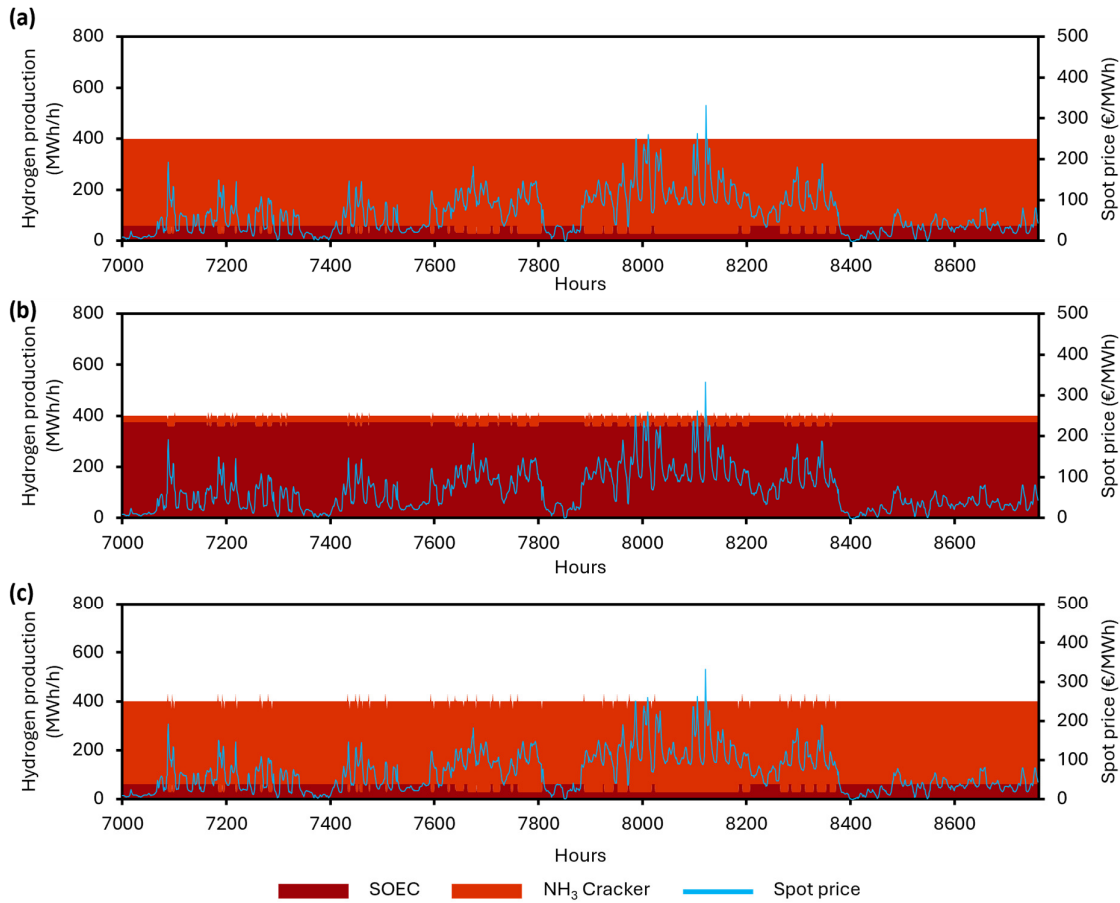


Figure 4-11. Hourly hydrogen supply profiles of the SOEC-NH₃ system under spot prices and low price conditions (100 €/tCO₂, 400 €/tNH₃) without the possibility of H₂ export, for (a) S1_{min}, (b) S2_{min}, (c) S3_{min}, for 1760 selected hours with highly volatile spot prices ranging from 0 to 332 €/MWh. Refer to Table 4-6 for the corresponding ammonia tank, grid transmission capacities, and capacity factors.

Figure 4-11a-b illustrates the limitation of grid transmission and ammonia tank capacities, respectively. In Figure 4-11c, it can be observed that during periods of high electricity prices, the SOEC operates at a constant operational load of 46%. Although the SOEC has the ability to ramp down to 10% of its installed capacity, this threshold is not met, indicating a trade-off between capital investments and high operational expenses of the SOEC. The complementary effect of the ammonia cracker on the flexible operation of the SOEC is evident in scenarios where the SOEC-NH₃ operates under spot prices with limited ammonia tank capacity (208 GWh) and grid transmission capacity (250 MW), as illustrated in Figure 4-12. In this scenario, the SOEC operates within an envelope of 48–100%, while the ammonia cracker operates within an envelope of 68–100%. The corresponding capacity factors for the SOEC and the ammonia cracker are 0.9 and 0.74, respectively. Table 4-6 lists a summary of the total system costs, LCOH, emission intensity, and installed capacities for the different scenarios investigated, assuming spot prices, without the possibility of H₂ export. Scenarios with spot prices indicate the possibility of operating the SOEC-NH₃ system flexibly in response to variable electricity prices.

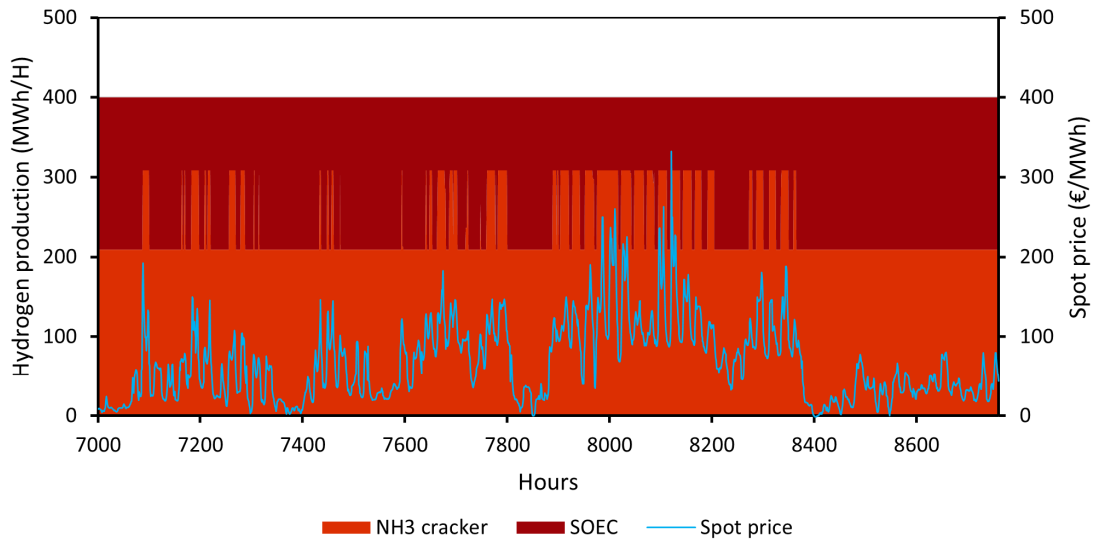


Figure 4-12. Hourly hydrogen supply profiles of the SOEC-NH₃ system under spot prices and low price conditions (100 €/tCO₂, 400 €/tNH₃) without the possibility of H₂ export for 1760 selected hours with highly volatile spot prices ranging from 0 to 332 €/MWh. The ammonia tank and grid transmission capacities are limited to 208 GWh and 250 MW, respectively.

Table 4-6. Summary of total system costs, LCOH, emission intensity, and installed capacities for the various scenarios investigated under the assumption of spot prices, without the possibility of H₂ export.

Grid transmission and ammonia tank capacities	100 MW, 60 kt	500 MW, 5 kt	500 MW, 60 kt	100 MW, 60 kt	500 MW, 5 kt	500 MW, 60 kt	Units
Scenarios	S _{1min}	S _{2min}	S _{3min}	S _{1max}	S _{2max}	S _{3max}	-
Total system costs	397.9	447	397.9	773	476.7	479.2	M€/y
Hydrogen production costs							
Electrolyzers	4.37	4.26	4.37	4.24	4.24	4.24	€/kg
NH ₃ cracker	3.69	3.8	3.69	8.13	8.13	8.13	€/kg
Weighted avg. LCOH	3.71	4.2	3.71	7.29	4.48	4.48	€/kg
Weighted avg. LCOH with utilities ^a	3.76	4.25	3.76	7.34	4.53	4.53	€/kg
Specific emissions intensity of hydrogen produced							
Electrolyzers	0	0	0	0	0	0	tCO ₂ /tH ₂
NH ₃ cracker	2.52	2.52	2.52	0	0	0	tCO ₂ /tH ₂
Integrated SOEC-NH ₃ system	2.19	0.16	2.19	0	0	0	tCO ₂ /tH ₂
Annual average H₂ production							
Electrolyzers	53.2	371.6	53.2	80.4	375.5	375.5	MWh/h
NH ₃ cracker	346.8	28.3	346.8	319.5	24.4	24.4	MWh/h
Installed capacities							

Grid transmission and ammonia tank capacities	100 MW, 60 kt	500 MW, 5 kt	500 MW, 60 kt	100 MW, 60 kt	500 MW, 5 kt	500 MW, 60 kt	Units
Electrolyzers	69.2	437.2	69.2	93.9	438.2	438.2	MW
NH ₃ cracker	456.9	50.5	456.9	391.3	29.9	29.9	MW
Electric steam boiler	0	59.8	0	0	59.9	59.9	MW
Mechanical vapor recompression unit	37	37	37	37	37	37	MW
Share of H₂ demand met with SOEC	13	93	13	20	94	94	%
Capacity factors							
Electrolyzers	0.897	0.992	0.897	1	1	1	-
NH ₃ cracker	0.930	0.687	0.930	1	1	1	-

^a The CAPEX of the MVR and electric boiler cannot be directly attributed to steam demand in the SOEC, as they also help reduce on-site emissions during surplus steam scenarios. Therefore, these cost components (€/kg) are added to the weighted average LCOH instead of to the technology-specific LCOH.

^b Note that although the invested capacities are above the minimum possible capacities (10 t/d H₂) reported by technology providers [20,21], the model does not account for economies of scale. As a result, scenarios with relatively smaller installed capacities may incur somewhat higher LCOH than the estimates provided here. For instance, the installed capacities of the ammonia cracker in Scenarios S2_{min}, S2_{max}, and S3_{min} correspond to capacities ranging from 17.5 to 20.3 t/d H₂, which represents the scale of a demonstration plant⁵⁷.

4.4.3.1 Influence of fixed and spot electricity prices on the SOEC-NH₃ system

Figure 4-13a and Figure 4-13b show the estimated range of the weighted average LCOH and the total system costs, respectively, assuming fixed electricity prices under a Power Purchase Agreement (PPA). In contrast, Figure 4-13c and Figure 4-13d present the same estimates based on spot prices for 2023. The upper and lower bounds shown in Figure 4-13 correspond to the maximum and minimum sensitivity scenarios listed in Table 4-4.

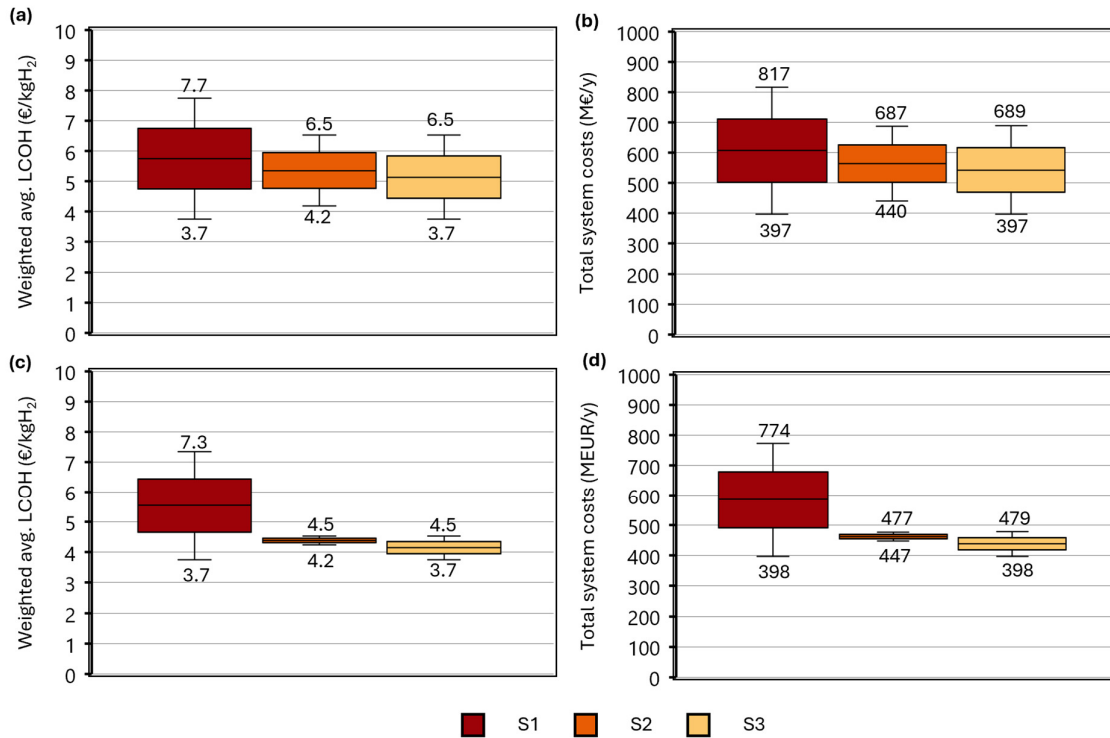


Figure 4-13. Estimated ranges of weighted average levelized cost of hydrogen and total system costs for the SOEC-NH₃ system: (a-b) when operated with a fixed electricity price and (c-d) with spot prices. The lower and upper bounds correspond to the sensitivity ranges listed in Table 4.4 for EU-ETS (100–200 €/t) and ammonia price (400–1000 €/t NH₃). Note that the bounds in subplots (a) and (b) use the fixed electricity price range (50–100 €/MWh).

In general, Figure 4-13 shows that a SOEC-NH₃ system restricted by the grid transmission capacity would have a significantly larger ammonia cracker, that in turn, would be highly sensitive to the price of ammonia over the plant's lifetime. In addition, the surplus steam from the PE plant and the ammonia cracker aid in reducing the operational cost of the SOEC system. Given the limitation of the grid, large-scale ammonia crackers could provide a transitional solution for meeting a fraction of the total hydrogen demand, particularly under low-price conditions. The remaining hydrogen demand could be met with hydrogen recovered from the fuel gases (see Section 4.5) or from an SOEC of the required capacity. However, as prices increase over time, the optimal system will involve a growing share of renewable hydrogen from the SOEC, driven by the expansion of SOEC capacity based on the availability of renewable electricity and grid transmission capacities.

4.4.3.2 System operation under spot prices

Figure 4-14 illustrates the weighted average LCOH of the SOEC-NH₃ system for Scenarios S1_{max} and S3_{max}. When comparing the weighted average LCOH between fixed and spot price conditions, it becomes clear that the flexible operation of the SOEC leads to an overall reduction in LCOH. For instance, the weighted average LCOH decreases by 0.42 €/kg in S1_{max} and by 2 €/kg in S3_{max}. In high-price scenarios (max), the reduction in LCOH is primarily due to spot prices, with an annual average of 51.7 €/MWh, which is comparable to the lower bound of PPA prices. As shown in Figure 4-14, there are very few price periods (approximately 300–400 hours) when the LCOH of the SOEC exceeds

that of the cracker. Nevertheless, during these hours, the SOEC operates at constant loads (Figure 4-12a-c), indicating a trade-off between capital costs and the operational expenses of the SOEC. In contrast, in Scenario $S3_{\min}$, where the LCOH for both technologies are comparable (Figure 4-11c), there are 3,975 hours during which the LCOH of the SOEC exceeds that of the cracker, allowing for flexible operation. The relatively low capacity factor for the SOEC in these scenarios (Table 4-6) suggests that the full potential for flexible operation is not being fully utilized. Instead, if export capability were available, the SOEC system could maximize hydrogen production during periods of low electricity prices. With larger SOEC capacities and fast ramp-up times, the system could adjust production based on volatile spot prices, such as those seen in 2023—reducing output during high electricity price hours and operating at full capacity during low-price periods. This aspect is further explored in Section 4.3.4.

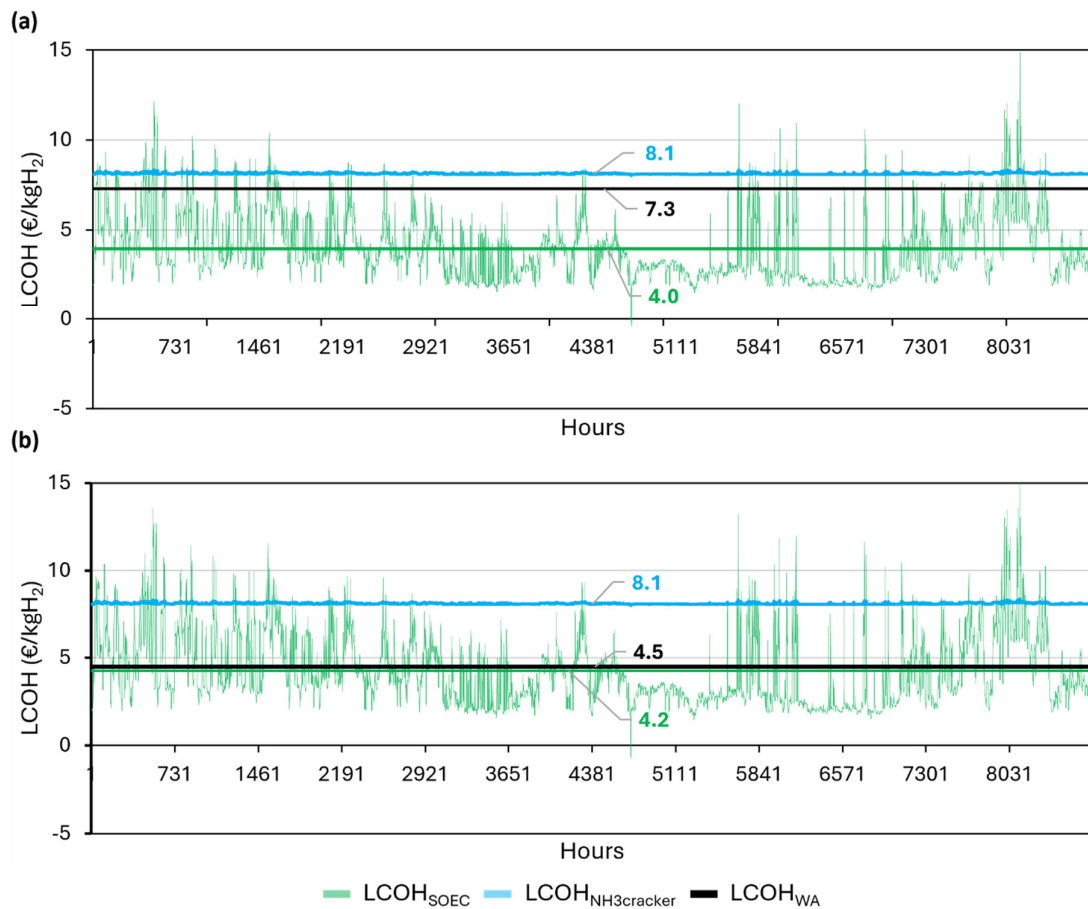


Figure 4-14. Weighted average LCOH of the SOEC-NH₃ system for Scenarios $S1_{\max}$ and $S3_{\max}$.

4.4.3.3 Steam balance profiles

Figure 4-15 shows the steam balance profiles for the Scenarios $S1_{\max}$ and $S3_{\max}$, under high price conditions.

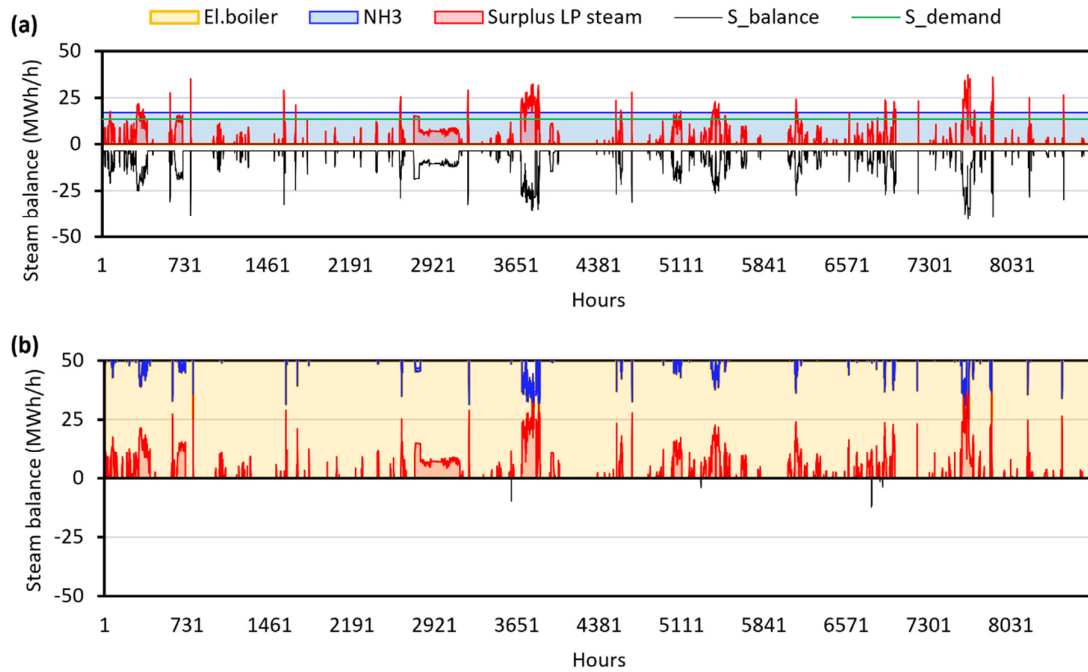


Figure 4-15. Steam balance profiles for (a) $S1_{max}$ and (b) $S3_{max}$, assuming spot price.

In Scenario $S1_{max}$, the limited grid transmission capacity results in a relatively smaller SOEC system with a fixed steam demand, which is lower than the steam generated through heat recovery in the ammonia crackers. The surplus steam available at the cracker plant (red solid line) remains unutilized. The remaining steam, indicated by the black solid line, is no longer condensed in the dump condenser, as shown in **Fel! Hittar inte referensskälla..** Instead, the model assumes that the corresponding amount of steam from the natural gas boilers is no longer required, thereby avoiding the associated CO₂ emissions. Ideally, all surplus steam should be utilized as the primary steam supply for the SOEC system. This steam balance is achieved in scenarios, e.g., $S3_{max}$, where the SOEC system is substantially larger compared to the ammonia crackers, as shown in Figure 4-15b.

4.4.4 Operation with spot prices with the possibility of hydrogen export

This section expands on the previous scenario of providing flexibility to the electricity system and explores the possibility of exporting hydrogen to other potential off-takers in the cluster during favorable electricity price hours. Given that grid transmission capacity is the primary limiting factor in the short term, Scenario S1 (100 MW, 312 GWh) is assumed to be the most likely scenario, with increased transmission capacity expected over time. A corresponding expansion of the SOEC, in line with the grid transmission capacity and allowing for H₂ export under low and high price conditions are shown in Figure 4-16 and Figure 4-17, respectively.

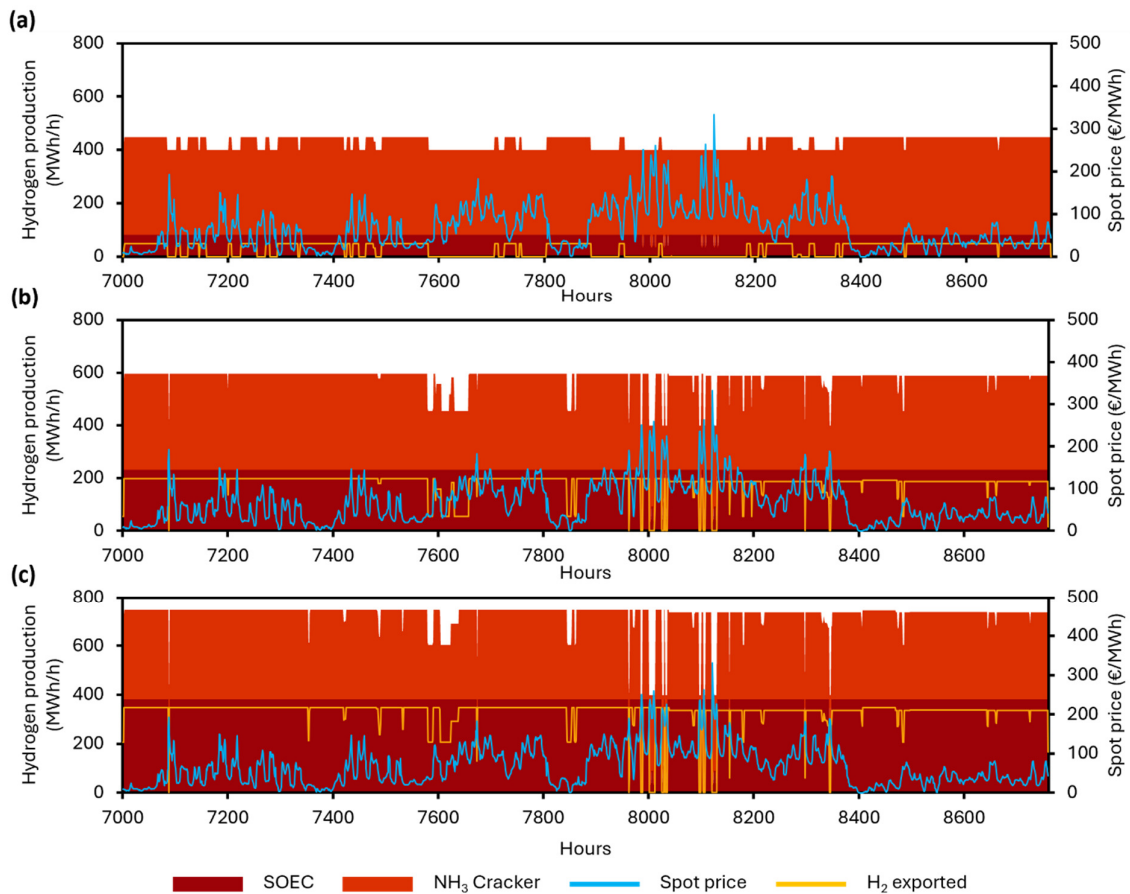


Figure 4-16. Influence of increasing access to grid transmission capacities with the possibility of hydrogen export under low price conditions. Hourly hydrogen supply profiles from the SOEC and the NH_3 cracker, along with H_2 export profiles, are shown for 1760 selected hours with highly volatile spot prices ranging from 0 to 332 €/MWh. This is presented for scenarios with grid transmission capacities of (a) 100 MW, (b) 300 MW, and (c) 500 MW, all with a fixed ammonia tank capacity of 312 GWh.

Flexible operation of the SOEC- NH_3 system is possible only when the SOEC is operated under spot prices, while the ammonia cracker responds accordingly to meet the hydrogen demand at the steam cracker plant and export hydrogen to the cluster. The choice to export hydrogen depends on price conditions and the installed capacities, which are influenced by the ammonia tank and grid transmission capacities. Comparing Figure 4-16 and Figure 4-17, the opportunity for flexible operation of the SOEC- NH_3 system diminishes under higher price conditions, indicating the sensitivity of the ammonia cracker to ammonia prices and demonstrating how the ammonia cracker complements the SOEC's operation. Figure 4-16a and Figure 4-17a illustrate how limited grid transmission capacity (100 MW) restricts the SOEC from utilizing low electricity price periods for exporting hydrogen. Figure 4-16b-c and Figure 4-17b-c illustrate how the model invests in larger capacities for both the SOEC and the ammonia cracker, well beyond what is required to meet the hydrogen demand of the cracker plant, in order to maximize the potential for exporting hydrogen to other off-takers in the cluster. However, the annual average export of hydrogen to the cluster is dependent on the assumed price for the exported hydrogen. The resulting weighted average LCOH for the

steam cracker plant, assuming a hydrogen export price of €8/kg for the cluster, is presented in Table 4-7.

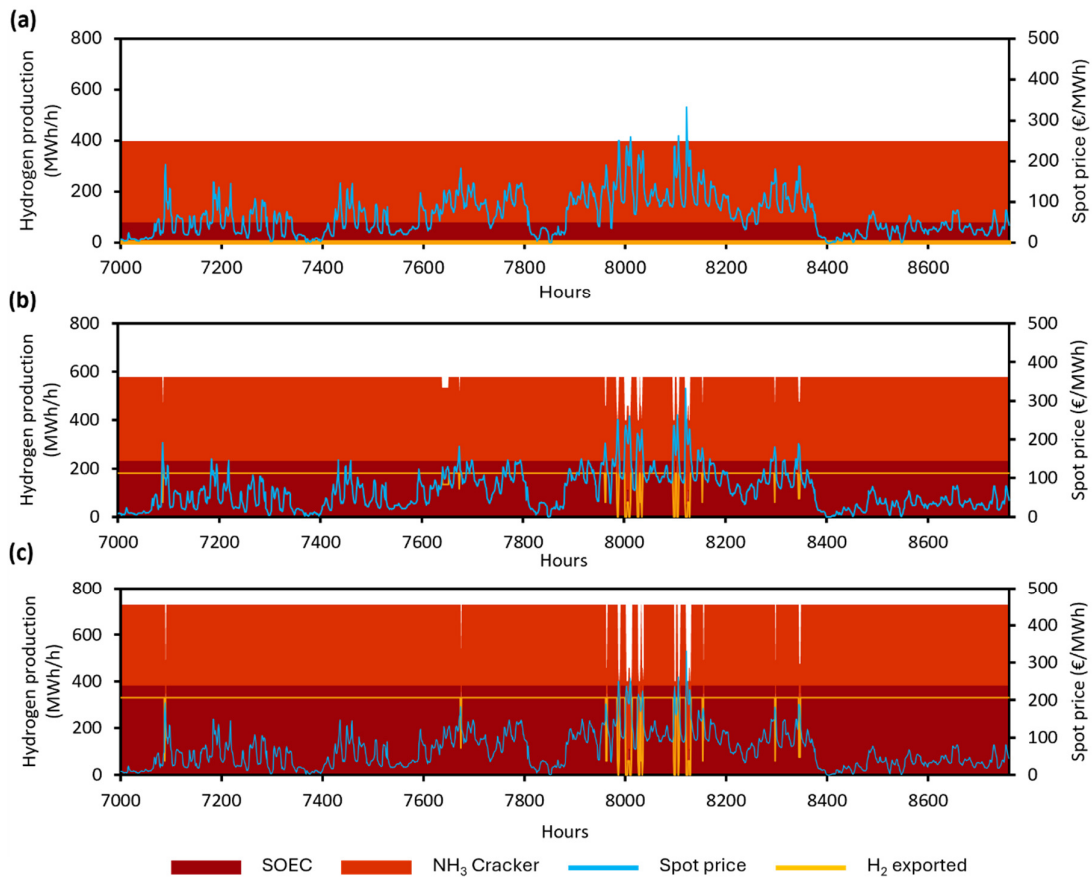


Figure 4-17. Influence of increasing access to grid transmission capacities with the possibility of hydrogen export under high price conditions. Hourly hydrogen supply profiles from the SOEC and the NH_3 cracker, along with H_2 export profiles, are shown for 1760 selected hours with highly volatile spot prices ranging from 0 to 332 €/MWh. This is presented for scenarios with grid transmission capacities of (a) 100 MW, (b) 300 MW, and (c) 500 MW, all with a fixed ammonia tank capacity of 312 GWh.

In comparing the scenarios in Figure 4-16 and Figure 4-17 with a hydrogen price of €8/kg, two key aspects can be highlighted: the spot price at which H_2 export ceases and the spot price at which the SOEC reduces its output to the minimum load. Under low price conditions (Figure 4-16b-c), hydrogen exports to the cluster cease for 95 hours over the year when spot prices exceed €176/MWh. In contrast, under high price conditions (Figure 4-17b-c), exports cease for 66 hours over the year when prices exceed €190/MWh. Under high electricity price conditions, the SOEC is ramped down, while the ammonia cracker prevents costly operation of the SOEC during these hours and meets the steam cracker plant's demand. In most scenarios, the lowest operating loads of the SOEC are observed during periods when spot prices exceed €206/MWh (Table 4-7). Nevertheless, both technologies operate at full load throughout the year, with capacity factors above 0.95, indicating that the possibility of export ensures full utilization of the invested capacities of the SOEC- NH_3 system. Comparing the operational hours of the scenarios presented in Section 4.4, it is evident that operating on a PPA gives no incentive for flexible operation of the SOEC- NH_3 system, instead the

optimal invested capacities are run at full load throughout the year. In contrast, operating the system under spot prices without the possibility of H₂ export can result in lower full load hours, particularly in configurations where both tank and grid transmission capacities are limited (e.g., 250 MW, 40 kt tank in Figure 4-12). This risk can be mitigated by either expanding the ammonia tank or grid transmission capacities or by exporting H₂ to the cluster. Finally, depending on the installed capacities, price conditions, and hydrogen prices, there is significant potential to reduce the weighted average LCOH for the steam cracker plant.

Table 4-7. Influence of H₂ export on the weighted average LCOH of the SOEC-NH₃ system.

Scenarios with H ₂ export		100 MW, 60 kt	300 MW, 60 kt	500 MW, 60kt	Units
Low price conditions (100 €/tCO ₂ , 400 €/tNH ₃)					
Installed capacities	SOEC	94.9	269.7	444.8	MW
	NH ₃ cracker	448.5	448.2	448.2	MW
Annual average LCOH	SOEC	3.97	4.17	4.30	€/kg
	NH ₃ cracker	3.69	3.69	3.69	€/kg
Lowest operating loads (SOEC) ^a	41.6		14.7	10.0	%
Number of hours without H ₂ export	3203		95	95	hours/y
Weighted average LCOH	3.79		3.88	3.96	€/kg
Annual average export of H ₂	29.85		177.87	325.71	MWh/h
Weighted average LCOH offset with exported H ₂ (at 8 €/kg)	3.21		1.41	0.35	€/kg
High price conditions (200 €/tCO ₂ , 1000 €/tNH ₃)					
Installed capacities	SOEC	93.9	270.7	445.7	MW
	NH ₃ cracker	391.3	426.1	425.9	MW
Annual average LCOH	SOEC	3.96	4.14	4.25	€/kg
	NH ₃ cracker	8.13	8.13	8.13	€/kg
Lowest operating loads (SOEC) ^b	100		22.4	13.7	%
Number of hours without H ₂ export	0		66	66	hours/y

Scenarios with H ₂ export	100 MW, 60 kt	300 MW, 60 kt	500 MW, 60kt	Units
Weighted average LCOH	7.29	6.57	6.11	€/kg
Annual average export of H ₂	0	177.34	325.12	MWh/h
Weighted average LCOH offset with exported H ₂ (at 8 €/kg)	7.29	4.12	2.54	€/kg

^a Corresponds to a spot price of 208 €/MWh (100 MW, 312 GWh), while the other scenarios correspond to a spot price of 206 €/MWh.

^b The SOEC operates at full load through the year (100 MW, 312 GWh); while the other scenarios correspond to a spot price of 206 €/MWh.

4.5 Key Considerations

Future research should explore a key site-level reality that was not evaluated in this work—the fate of by-product fuel gas at the cracker plant. Figure 4-18 illustrates a simplified schematic of the steam cracker plant, highlighting the supply of low-carbon and/or renewable hydrogen from the SOEC-NH₃ system to the steam cracking furnaces.

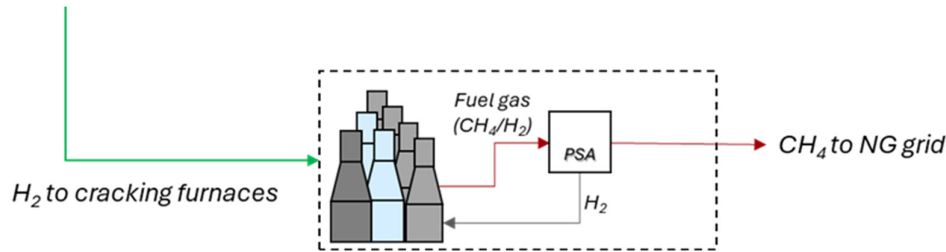


Figure 4-18: Fate of fuel gas at the cracker plant

These furnaces currently combust fuel gas, primarily composed of hydrogen and fossil methane. The fossil-derived methane in the fuel gas results from the existing fossil-based feedstock slate, which includes ethane, propane, butane, and naphtha. Supplying the steam cracking furnaces with renewable hydrogen from the SOEC-NH₃ system would imply that the combustion of fuel gas in these furnaces would cease. Consequently, the hydrogen in the fuel gas (~4 t/h) could be recovered using a pressure swing adsorption unit, reducing the hydrogen demand from the SOEC-NH₃ system to 8 t/h and possibly reducing capital investments.

The methane recovered from the fuel gas could be valorized to produce low-carbon hydrogen via steam methane reformers or autothermal reformers equipped with CO₂ capture units, or it could alternatively be exported to the natural gas (NG) grid. Selling the methane to the grid could reduce the LCOH for the renewable hydrogen producer (steam cracker plant). More importantly, the exported methane would displace, to some extent, fossil fuel gas imports to the EU, as outlined in REPowerEU [42]. It is expected that the exported methane will gradually transition to a mix of bio-derived and fossil-derived methane as the steam cracker plant implements its planned measures [43] to decouple fossil feedstock to renewable feedstock, including chemically and thermochemically recycled materials. Consequently, the nature and extent of the feedstock switch at the steam cracker plant, along with the end-use of the exported

methane, will ultimately determine the classification of the recovered hydrogen, which may range from gray to low-carbon hydrogen.

4.6 Conclusions

The ammonia cost range used in this analysis covers a wide spectrum, accounting for projected price levels for PPA (50–100 €/MWh) and low-carbon or renewable ammonia (400–1000 €/tNH₃). If the two technologies are to be compared on a standalone basis, ammonia cracking fed by blue ammonia at 400 €/tNH₃ corresponds to operating a SOEC with a PPA of 45 €/MWh. Although both hydrogen production technologies would produce hydrogen classified as renewable, they achieve emissions reductions exceeding the mandated minimum of 70% for greenhouse gas reduction [22]. However, the ammonia cracking technology would have a significantly higher specific emissions intensity (2–2.5 tCO₂/tH₂) than the SOEC operating with renewable PPA or even grid electricity in Sweden (0–1.4 tCO₂/tH₂), where the average emissions intensity is below 30 gCO₂/kWh [44]. Conversely, if comparable emissions reductions are to be achieved, long-term renewable ammonia contracts below 800 €/tNH₃ would need to be secured to achieve a comparable levelized cost of hydrogen to an SOEC with a PPA of 100 €/MWh. These technology-specific differences and site-level constraints can be effectively addressed by co-locating and integrating the two technologies. For instance, an ammonia cracker with a reasonable capacity would be necessary to compensate for limited grid transmission capacity in the short term. However, determining the optimal capacity of the ammonia cracker would depend on the projected expansion and availability of grid transmission capacity over time at the cluster. In general, the risk of an oversized ammonia cracker, or stranded assets, is minimal given the significantly higher expected hydrogen demand in the cluster compared to the steam cracker plant.

Co-location and integration of the SOEC and the NH₃ cracker ensure the security of H₂ supply, allowing for the optimization of their cost interplay by securing long-term low-carbon ammonia contracts at the lowest possible price, along with favorable PPAs for the SOEC, in line with current regulations. Results show that the integrated SOEC-NH₃ system with sufficient tank and grid transmission capacity would have an LCOH ranging from 3.7 to 6.5 €/kg, assuming a blue ammonia price of 400–1000 €/tNH₃, a PPA of 50–100 €/MWh, and an EU-ETS emissions allowance price of 100–200 €/tCO₂. In contrast, the integrated SOEC-NH₃ system would have an LCOH ranging from 3.7 to 4.5 €/kg when operating flexibly in response to variations in the spot price with similar site conditions.

The wide-ranging total annual system costs obtained from the different scenarios, excluding H₂ export, translate to a significantly high CO₂ abatement cost (>720 €/tCO₂). This indicates that using renewable hydrogen as a CO₂ abatement measure for high-temperature industrial process heat is prohibitively more expensive than other alternatives available to the steam cracker plant, such as end-of-pipe CO₂ capture [45]. The SOEC-NH₃ system, however, does not carry the risk associated with CO₂ capture technologies of becoming a stranded asset over time, as it can transition to producing hydrogen for CO₂ utilization, especially with the anticipated feedstock switch at the steam cracker plant, and possibility to export H₂ to the cluster.

Considering that current regulations [22] mandate a PPA for renewable fuel producers, the lowest LCOH occurs when the SOEC-NH₃ system operates at full load throughout the

year. Therefore, under such conditions, it is expected that the system will be unable to provide a flexible load to the electricity system, particularly during periods of high electricity demand. The scenario analysis reveals that the flexible operation of the SOEC-NH₃ system with spot prices could potentially reduce the full load hours of both technologies to some extent and have minimal impact on the LCOH, especially without the possibility of exporting hydrogen to the cluster. In contrast, the flexible operation of the SOEC-NH₃ system, combined with the possibility of hydrogen export to the cluster, offers significant potential to minimize both the total system cost and, consequently, the LCOH produced for the steam cracker plant. In the short term, a practical SOEC-NH₃ system would likely involve relatively larger ammonia crackers compared to the SOEC. These larger crackers would provide a buffer for the lack of grid transmission capacity and ensure the security of H₂ supply to the steam cracker plant. Given that regulations are expected to evolve, the integrated SOEC-NH₃ system will ultimately benefit from expanding SOEC capacity over time in relation to the hydrogen demand at the cluster. This expansion could leverage flexible operation in relation to spot prices to minimize LCOH for the steam cracker plant by facilitating hydrogen exports to other off-takers within the cluster. With the expected increase in variable renewable electricity, an SOEC-NH₃ system with relatively large SOECs could provide a flexible load to the electricity system, mitigating curtailment and price cannibalization.

5 Conclusions and suggestions for future work

This project has investigated the technical and commercial pre-requisites for establishing an SOEC pilot plant within the chemical cluster in Stenungsund. Two different plant sizes were considered, corresponding to approximately 5 MW and 10 MW electric power demand. The project also investigated stakeholder engagement as well as the potential for integrating SOEC technology with ammonia cracking for large-scale hydrogen production. The analysis highlights how these technologies can complement one another over time. A prerequisite for Borealis to integrate more hydrogen into their processes is that they find a new application for the existing fuel gas. The following conclusions summarize key findings and offer recommendations for future work.

Stakeholders in Stenungsund anticipate a significant increase in future hydrogen demand, highlighting the need for scalable and cost-effective production methods. There is a strong interest within the industry cluster to learn more about SOEC technology and gain practical experience through the establishment of a pilot plant. The results of this study indicate that there is a clear scale benefit for the larger plant (10 MW) which makes it the preferred choice. However, the investigation also revealed that the estimated CAPEX for the SOEC pilot plant is higher than initially expected. In order to proceed with a project a viable business case need to be presented.

Comparing large-scale SOEC with ammonia cracking as two separate stand-alone technologies for fulfilling the future hydrogen demand in Stenungsund, our analysis shows that very low ammonia prices are required for ammonia cracking to be economically competitive with SOEC. To exemplify, ammonia cracking fed by ammonia at 400 €/tNH₃ corresponds to operating a SOEC with a PPA of 45 €/MWh, assuming that corresponding demand for power and steam for SOEC operation are available at the site.

Co-locating and integrating the SOEC with the ammonia cracker (SOEC-NH₃) units enhances the security of hydrogen supply and provides an opportunity to decrease costs by securing both favorable long-term low-carbon ammonia contracts and Power Purchase Agreements (PPA)s. The results of this work indicate that the LCOH for the integrated system ranges from 3.7 to 6.5 €/kg, depending on assumed ammonia and PPA prices. If flexible operation is assumed, thereby enabling the SOEC unit to purchase power on the spot market, LCOH for the integrated SOEC-NH₃ system could decrease to 3.7 to 4.5 €/kg.

Given the current carbon footprint in the regional electricity mix (i.e. < 18 g CO₂eq/MJ electricity, <90% renewable share), EU regulation (Delegated Act 27/REDIII) will require renewable fuel producers to use PPAs with temporal and geographical correlation. This would in turn imply that flexible operation in relation to the electricity market would become more complicated and possibly more risky. The lowest LCOH is achieved when the SOEC-NH₃ system operates at full load throughout the year, though this limits its ability to provide load-shedding services during periods of peak electricity demand.

Flexible operation in response to spot prices results in only a minor reduction in full-load hours, even during a highly volatile price year like 2023, and does not lead to a significant increase in LCOH. However, spot price volatility can vary annually, meaning full-load hours may also fluctuate. If excess hydrogen production can be exported beyond what is required to meet Borealis's demand alone, it reduces the risk of cost escalation due to low full-load hours.

A final insight from this study is that a large scale ammonia cracker could be an interesting solution for overcoming the existing limitation in grid capacity within the near-term future. However, as the grid capacity is increased, SOEC capacity could increase over time, which will further decrease costs and support flexible operation as regulations evolve.

5.1 Suggestions for future work

In order to proceed with a project for a SOEC pilot plant, a viable business case need to be presented which requires the following steps:

- Investigate financing options
- Investigate possible partnerships, offtake and business setup
- Continue the dialogue with the DSO regarding the timeline for increasing grid power capacity and power supply

To enhance the overall viability of the SOEC plant, further work is necessary in order to investigate how the following factors could affect the business case:

- Sell or use the oxygen stream
- Possible income from balancing services to the Swedish electricity TSO Svenska Kraftnät
- Conditional grid connection agreements

Given the importance of low hydrogen prices to motivate stakeholders to develop their operations in a way that significantly increases hydrogen usage, it would be valuable for future studies to investigate hydrogen production using alternative electrolyzer technologies, such as PEM or Alkaline electrolyzers which both are much more mature technologies, and which potentially could result in lower LCOHs. This would allow for a comparison of LCOH across different technologies, providing further insights into their economic feasibility.

Given the requirement for Borealis to find a viable application for their existing fuel gas in order to integrate more hydrogen into their processes, exploring potential solutions for this challenge is recommended as a focus for future work.

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Appendix 1

Pilotanläggning – intresse och användning av vätgas

Hur ser ert intresse ut för en pilotanläggning i Stenungsund?

Vad ser ni för nyttor för ert företag med en pilotanläggning i Stenungsund? Vilka risker?

Hur skulle ert företag kunna använda den producerade vätgasen från pilotanläggningen? I vilka mängder? Kan ni ta emot den flexibelt? Vad ska vätgasen användas till (vilken värdekedja)?

Vid en framtida pilotanläggning för SOEC, finns det från din organisation intresse av att vara partner/delägare i en sådan anläggning?

Pilotanläggning – integration

Är det möjligt att koppla en pilotanläggning till er anläggning idag? Är det något ni skulle vilja?

Har ni idag ånga som går att integrera med en SOEC? (Bra med info om vad som krävs (MP/LP/tryck/ - alt vilken temp SOEC vill ha)

Ser ni risker med att integrera en SOEC med ångsystemet? Vilka? Hur kan de hanteras?

Pilotanläggning – tester

Vad skulle ditt företag vilja se att pilotanläggningen används till?

Vilka kunskapshöjande aktiviteter skulle ni vilja se? Några särskilda tester som bör genomföras? Något typ av driftmönster ni vill testa?

Framtida utveckling och uppskalning

Vad är ert intresse för framtida uppskalning av en pilotanläggning/en större vätgasproduktion?

I vilken takt, och när i tiden kan det vara intressant med en större anläggning för er?

Vilken mängd vätgas kan ni ta emot längre fram? Hur stort vätgasbehov ser ni framåt?

Ammoniak krackning och ammoniakbaserad vätgas

Hur ser ni på möjligheten till ammoniak krackning för vätgasproduktion? Är detta bara relevant till elnätet är förstärkt? Eller ser ni att detta är relevant även när elektrolysörer är på plats?

Är det något er organisation är intresserade av? Att investera i?

Vilka hinder/drivkrafter ser ni för detta?

Vilken potential finns det? Hur ser tillgången på grön ammoniak ut?

Hur flexibel är denna produktion?

Några tester/driftfall som din organisation vill ska utredas/modelleras inom detta projekt?

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