Optimal electricity source mix for hydrogen production in an electrolyzer

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Abstract

Green hydrogen is seen as one of the most potential ways to reduce greenhouse gas emissions and contribute to a fully renewable energy system. Green hydrogen can replace the current fossil hydrogen which is used widely in industry. Replacing fossil hydrogen with green hydrogen offers an opportunity for a fast green hydrogen scale up and emissions reductions. The upcoming EU legislation will set a framework for green hydrogen production which needs to be fulfilled. Especially the possible strict temporal correlation requirements make green hydrogen production challenging.

The goal of this thesis is to find the most optimal VRE generation portfolio for an electrolyzer producing green hydrogen in Finland. Due to additionality requirements wind power and solar PV will be the only potential electricity generation technologies for green hydrogen production. Battery storages' potential in green hydrogen production is also studied.

The research has been conducted by first gathering all the relevant information on legislation, renewable electricity generation and electrolyzer technologies through literature review and data collection. The gathered information is applied into data models. VRE portfolio optimizations are done in annual and hourly correlation environments. Optimizations include green hydrogen profit maximization (in annual and hourly correlation), green hydrogen production maximization (in hourly correlation) and green hydrogen + Elspot electricity profit maximization (in annual correlation). Batteries' effect on green hydrogen production output and profits are analyzed.

It was found that wind power is the dominant generation technology in all cases. When profits are maximized wind power represents nearly 100% of the total VRE capacity. Multiple MW solar PV power plants are included if green hydrogen production is maximized in hourly correlation. Additional small scale solar PV power plants which can be located onsite can increase profits in all cases. Halting green hydrogen production during high Elspot price hours in annual correlation environment is an effective way to increase profitability. Producing non-green hydrogen in hourly correlation environment with Elspot electricity can increase profits greatly. Battery storages are not competitive in green hydrogen production with current price levels. Batteries can increase green hydrogen output in hourly correlation, but not significantly. Green hydrogen prices need to increase or battery costs decrease considerably for batteries to be economically viable.

Keywords Green hydrogen, Electrolyzer, Temporal correlation, VRE

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Tiivistelmä

Vihreä vety on yksi potentiaalisimmista tavoista vähentää kasvihuonekaasupäästöjä ja osaltaan mahdollistaa täysin uusiutuva energiajärjestelmä. Vihreä vety voi korvata teollisuudessa laajasti käytetyn fossiilisen vedyn. Fossiilisen vedyn korvaaminen vihreällä vedyllä mahdollistaa vihreän vedyn tuotannon nopean kasvattamisen ja suuret kasvihuonekaasupäästöjen vähennykset. Tuleva EU-lainsäädäntö asettaa määritelmiä vihreän vedyn tuotannolle, jotka tulee täyttää. Erityisesti mahdolliset tiukat ajallisen korrelaation vaatimukset tekevät vihreän vedyn tuotannosta haastavaa.

Diplomityön tavoite on löytää optimaalisin uusiutuvan sähkön tuotantoportfolio vihreän vedyn tuotantoon Suomessa. Tuuli- ja aurinkovoima ovat käytännössä ainoat mahdolliset sähköntuotantotavat vihreän vedyn tuotannossa. Akkuvarastojen potentiaali vihreän vedyn tuotannossa tutkitaan. Teoriaosuudessa käsitellään erilaisia elektrolyyseriteknologioita, uusiutuvan sähkön tuotantotapoja, sekä vihreän vedyn lainsäädäntöä. Uusiutuvan sähkön tuotantoportfolio optimoidaan vuosi- ja tuntikorrelaation vaatimuksien mukaan. Tuotantoportfolio optimoidaan vihreästä vedystä saatavan liikevoiton maksimoimiseksi (vuosi- ja tuntikorrelaatiossa), vihreän vedyn tuotannon maksimoimiseksi (tuntikorrelaatiossa), sekä vihreän vedyn ja Elspot-sähkönmyynnin liikevoittojen maksimoimiseksi (vuosikorrelaatiossa). Akkujen vaikutus vihreän vedyn tuotantomäärään ja liikevoittoihin analysoidaan.

Päälöydöksenä on tuulivoiman ylivoimaisuus sähkön tuotannossa kaikissa optimointiskenaarioissa. Mikäli liikevoitto halutaan maksimoida, tuulivoiman tulisi käytännössä olla ainoa sähköntuotantomuoto. Isot aurinkovoimalat ovat hyödyllisiä mikäli vihreän vedyn tuotantomäärä halutaan maksimoida tuntikorrelaatiossa. Pienikokoinen aurinkotuotanto, joka voidaan sijoittaa vetytuotantolaitoksen yhteyteen lisää kannattavuutta kaikissa tapauksissa. Liiketoiminnan kannattavuutta voidaan parantaa merkittävästi vuosikorrelaatiossa, mikäli korkeiden Elspot-hintojen aikana vedyn tuotanto lopetetaan. Tuntikorrelaatiossa ei-vihreän vedyn tuottaminen ostetulla Elspot-sähköllä nostaa liiketoiminnan kannattavuutta huomattavasti. Akut eivät ole kannattavia vihreän vedyn tuotannossa nykyisillä hinnoilla. Akut voivat hieman nostaa vihreän vedyn tuotantomäärää tuntikorrelaatiossa. Vihreän vedyn hinnan tulisi kallistua tai akkujen kustannusten laskea, jotta akut olisivat kannattavia.

Avainsanat Vihreä vety, Elektrolyyseri, Ajallinen korrelaatio, Vaihteleva sähköntuotanto

Preface and acknowledgements

This thesis was done in collaboration with Helen Oy. Helen has a long history of supplying Helsinki with reliable energy. Currently, Helen is facing a challenge like many utilities to switch away from fossil fuels. During my time at Helen, it has been remarkable to notice how everyone in the company is driven by the mission to achieve carbon neutrality and at the same time prioritize customers' needs. In my thesis, I wanted to focus on a topic that can play a major role in the future energy system. During my master's studies, green hydrogen had received increasing interest among investors and it started to have strong momentum. I had studied the current green hydrogen market for months on my own time while working at Helen. Therefore it was an extremely pleasant surprise when my colleagues had identified a specific problem regarding green hydrogen and suggested that I would focus on this problem in my thesis. I strongly believe that green hydrogen will help multiple industries to achieve carbon neutrality during the next decade.

I would like to thank my advisor Tuukka Hartikka who supported my work. I especially enjoyed our weekly calls where we talked about the thesis but more importantly about the current drivers and obstacles in the green hydrogen market. I gained many new insights from those conversations and Tuukka's wide-ranging knowledge helped me to understand better the big picture. I'd also like to thank my other colleagues from Helen who have supported my work and learning during my time at Helen. This thesis was supervised by Assistant Professor Annukka Santasalo-Aarnio. I want to thank Annukka for her support and ideas that made me consider the topic from various different angles which I wouldn't have thought of without her comments. Finally, I'd like to thank my family, friends, and especially my parents who have supported my education throughout my life.

Helsinki, 25.4.2022

Sakari Huhtanen

Contents

Symbols and abbreviations

Symbols

dist.	Electricity distribution cost
E_{Elspot}	Elspot purchase volume
$E_{solarPV}$	Solar PV generation volume
E_{wind}	Wind power generation volume
$LCOE_{solarPV}$	LCOE of solar PV
$LCOE_{wind}$	LCOE of wind power
$Price_{Elspot}$	Elspot hourly price
r	Interest rate
t	Number of periods
tax	Electricity taxes

Abbreviations

AEM	Anion Exchange Membrane
CAPEX	Capital Expenditure
CCUS	Carbon Capture, Utilization and Storage
CO_2	Carbon dioxide
e^-	Electron
EAC	Equivalent Annual Cost
EC	European Commission
EIA	Environmental Impact Assessment
EU	European Union
EU ETS	EU Emissions Trading System
GHG	Greenhouse Gas
Gt	Gigatonne
GW	Gigawatt
GWh	Gigawatt hour
FWCA	Finnish Wind Power Association
H^+	Proton
H_2	Hydrogen
H_2O	Water
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
ISP	Imbalance Settlement Period
kgH_2	Kilogram of hydrogen
KOH	Potassium Hydroxide
kt	Kilotonne
kW	Kilowatt
kWh	Kilowatt hour
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Hydrogen
LCOS	Levelized Cost of Storage

LHV	Lower Heating Value
m^2	Square meter
MGHP	Maximized Green Hydrogen Production
MJ	Megajoule
Mt	Megatonne
MW	Megawatt
MWelec	Megawatts electric
MWh	Megawatt hour
MWmonth	Megawatt per month
NaOH	Sodium Hydroxide
O_2	Oxygen
OH^-	Hydroxide anion
OPEX	Operational Expense
OEM	Original Equipment Manufacturer
PPA	Power Purchase Agreement
PEM	Proton Exchange Membrane
RED II	The European Union's Renewable Energy Directive II
SMA	Simple Moving Average
SOEC	Solid Oxide Electrolyzer
SMR	Steam Methane Reforming
TWh	Terawatt hour
VRE	Variable Renewable Energy

1 Introduction

The global demand for hydrogen was 90 Mt in 2020 (IEA, 2021b). It is widely used in different industrial processes e.g. in oil refining and ammonia production. Refineries consume almost 40 Mt of hydrogen annually. The chemical industry is a major hydrogen consumer having an annual consumption of 45 Mt. About 75% of the chemical industry's hydrogen consumption is consumed in ammonia production and 25% in methanol production. The steel industry consumes the remaining 5 Mt of hydrogen. A hydrogen economy is seen as one solution which could lead to a zero-carbon economy. However, the current hydrogen industry can't be labeled as environmentally friendly. Hydrogen itself does not cause Greenhouse Gas (GHG) emissions, but hydrogen production can cause significant emissions. The global emissions originating from hydrogen production were 900 Mt of CO_2. In comparison, the total estimated emissions originating from fossil fuel usage globally were 34.8 Gt, meaning that hydrogen production emissions accounted for 2.6% of the total global fossil fuel-based GHG emissions (Ritchie and Roser, 2020).

The color mentioned before hydrogen describes how hydrogen is produced. The different colors and their meaning are presented in Table 1. The feedstock which is used to produce hydrogen mandates what kind of production methods are possible. In this thesis, we focus on green hydrogen. Green hydrogen is produced in an electrolyzer which consumes renewable electricity and water. Regulators might create stricter rules for green hydrogen which need to be fulfilled in hydrogen production for the output to be considered green. It is highly possible that also other things than production method and feedstock need to be taken into account in green hydrogen production. Currently, 72 Mt (79%) of hydrogen is produced from fossil fuels and the remaining 21% is a by-product of different industrial processes. Natural gas is the most important feedstock in hydrogen production, accounting for 60% of global hydrogen production. Natural gas is usually processed into hydrogen in a Steam Methane Reforming (SMR) process and it is the most dominant production method. In Europe, 96% of hydrogen is produced from natural gas (Erbach and Jensen, 2021). The dominant fossil feedstock can be different in different countries, e.g. China relies heavily on coal. Coal-originated hydrogen accounted for 19% of global hydrogen production. In 2021 there were 16 projects which produced blue hydrogen and the total blue hydrogen production was 0.7 Mt. It is estimated that by 2030, blue hydrogen production would be 9 Mt annually. Hydrogen produced in electrolyzers is still marginal compared to the total hydrogen production, having a 30 kt annual production (IEA, 2021b).

Table 1: Different hydrogen colors, their main feedstock, and production methods (Jokinen, 2021 - data from IEA, 2021b and Lappalainen, 2020)

Color	Feedstock	Production method
Green	Renewable electricity	Electrolysis
Gray	Natural gas	Steam methane reforming
Brown	Lignite	Coal gasification
Black	Coal	Coal gasification
Blue	Fossil	Fossil hydrogen production and CO_2 capture
Turquoise	Natural gas	Pyrolysis
Pink	Nuclear power	Electrolysis
White	Industrial byproduct	Byproduct of other processes
Yellow	(Mixed) grid electricity	Electrolysis

The electrolyzer capacity for hydrogen production in mid-2021 was 300 MW. The current electrolyzer projects which are under development could increase the electrolyzer capacity to 54 GW by 2030. An additional 35 GW of electrolyzer capacity is under the earliest project development phases. In total, the 89 MW electrolyzer capacity which is divided into different project development phases, could produce 8 Mt of hydrogen by 2030. While it would be a significant increase, it would still cover only 9% of the current hydrogen demand. Europe is leading the electrolyzer capacity scale and its share of the global installed capacity is 40%.

1.1 Thesis aims and scope

The goal of this thesis is to construct an optimal renewable electricity generation portfolio for green hydrogen production. The portfolio can be different depending on what aspects of the production are prioritized and what are the legislative requirements. The main goal is to give recommendations on how much of different renewable electricity generation technologies should be included in the electricity procurement portfolio for green hydrogen production.

The thesis specifically seeks to answer four research questions:

- What is the optimal combination of different renewable electricity sources for green hydrogen production?
- What are the legislative requirements concerning the renewable electricity procurement for hydrogen to be considered green?
- How different renewable electricity generation methods can supplement each other?
- What are the production costs for different hydrogen production methods?

The thesis is focused on the Finnish market. Hydrogen end usage and utilization are out of the scope and we focus only on the hydrogen production side. The focus is on hydrogen production through electrolysis, therefore fossil hydrogen is out of the scope. Fossil hydrogen is analyzed briefly to get a better understanding of the current fossil hydrogen price levels, trends and emissions that can affect the scale-up of the green hydrogen market.

1.2 Thesis structure

This thesis is divided into seven sections. Section 2 explains the methodology. Section 3 focuses on the current hydrogen market and especially on fossil hydrogen costs and emissions. Section 4 analyzes electrolyzer technologies that are the most suitable for implementation in the short to mid-term and the costs associated with these electrolyzer technologies. Section 5 dives deeper into the current and possible future EU legislation regarding green hydrogen production. The goal of the legislation review is to understand what limitations there are for renewable electricity procurement in green hydrogen production. Section 6 analyzes the current wind power and solar PV capacities in Finland and the near future capacity additions. We also analyze their capacity factors and how their generation supplements each other in different time frames. Renewable electricity generation and battery energy storage costs are also studied in this Section and the values are later used in the empirical part of the thesis.

Section 7 is the empirical part of the thesis. Data sets of electricity generation and consumption in an electrolyzer are constructed and coupled with cost parameters. The model is optimized according to different optimization goals in different legislative environments. The results of these optimizations are the optimal renewable electricity generation portfolios for green hydrogen production. Battery storages' potential to increase green hydrogen production and batteries' commercial viability in green hydrogen production is analyzed. Section 8 states the conclusions.

2 Methodology

Both qualitative and quantitative methods are used. The theoretical part is written based on existing literature. Optimizations and calculations in the empirical part are done based on data from electricity generation simulations, realized electricity Elspot prices and realized electricity generation in the Finnish electricity grid.

The literature review is done based on peer-reviewed scientific literature, EU legislation and reports from the energy and hydrogen industries. In most cases, reports from the industry offered the most recent information on technologies and costs. Many sources in the literature review used US Dollars as currency. When US Dollars were converted into Euros we used a currency exchange rate from the 6th of January, 2022. The currency exchange rate was \$1 = €0.8828. The literature review is done on the current and expected future electrolyzer, hydrogen and renewable electricity generation technologies and markets. The goal of the literature review is to identify the most suitable technologies and important parameters (e.g. costs) which are used later in the empirical part. The EU legislation regarding green hydrogen production is analyzed in the literature review because the upcoming legislation will set the framework for what needs to be taken into account in renewable electricity procurement.

The empirical part is built around a model which optimizes the renewable electricity generation portfolio in different circumstances. The main inputs for the model are simulated electricity generation, Elspot price data, electrolyzer's technical properties, hydrogen price levels, and batteries' technical properties in cases where batteries are involved. Data was handled in Excel and the optimizations were done with Excel Solver add-in using non-linear optimization.

Electricity generation was simulated for every hour from 2018 to 2020. Wind generation simulation was based on wind measurements in a site where Lakiakangas 3, a 20 wind turbine wind farm is being constructed. The Lakiakangas 3 site is located in Isojoki and Kristiinankaupunki municipalities in Western Finland in South Ostrobothnia and Ostrobothnia regions. The western part of the wind farm is about 16 kilometers from the shore of the Gulf of Bothnia which is the northernmost part of the Baltic Sea. The Lakiakangas 3 site is expected to be fully operational in Q1 2022 and its maximum generation capacity will be 86 MW. Solar PV generation was simulated for a 1 MW solar PV plant in Helsinki. The simulation results were based on Helsinki's climate data from 1990 to 2010. The annual yield for the simulated solar PV plant was 1007.07 kWh/kWp. The wind generation data is different for each year since it was based on actual wind measurements during those years. The solar PV generation is identical every year. The solar PV generation during a leap day in 29.2.2020 is duplicated from the 28.2. simulation values.

The green hydrogen demand for one hour was determined to be 1000kg. Based on the values from the literature review, the electrolyzer's electric capacity needs to be 50 MW for it to produce 1000kg of hydrogen during one hour when it is operated at its maximum capacity. The electrolyzer's electric capacity is 50 MW in every optimization case.

We used mainly 2021 Elspot prices in the Finnish market area as hourly electricity price data. During the model construction phase (late 2021), the Elspot prices started to be systematically higher than during the same time in previous years. Bottlenecks in transmission between different market areas, higher commodity and carbon prices were increasing electricity prices across the whole Europe. Other reasons contributed to the higher electricity prices as well and the price increase can be seen as a result of multiple things combined. We decided to use the 2021 Elspot prices instead of the realized yearly prices as price data to anticipate the short and mid-term prices and to better capture the effect of volatility increase in a power market with relatively high VRE penetration. The 2021 Elspot prices are used across all three years. Comparisons are made for profits and costs between the 2021 and the 2018-2020 prices. If not stated otherwise, the Elspot prices are corresponding to the 2021 prices. For the leap day in 2020, the prices were duplicated from 28.2.2021 when using the 2021 Elspot prices.

3 Gray hydrogen's emissions and costs combined with the EU ETS costs

Gray hydrogen is used as a benchmark for green hydrogen in this thesis since it is currently the most dominant hydrogen type. It is highly likely that in the short term green hydrogen needs to compete against gray hydrogen, especially in terms of prices. Even if green hydrogen production would be costlier currently, future developments can make it a cheaper alternative for gray hydrogen. If the external costs of emissions are taken into account more in the future, the price of gray hydrogen could increase significantly. Moving away from gray to green hydrogen offers significant emissions reduction possibilities. As mentioned in Section 1 in Table 1, gray hydrogen is hydrogen produced from natural gas using SMR. In gray hydrogen production, CO_2 is a by-product and it is emitted into the atmosphere. If the CO_2 is captured and stored, the produced hydrogen would be called blue hydrogen. The production methods are the same in gray and blue hydrogen cases, only the emissions are treated in different ways. In this Section, the prices and emissions of gray and blue hydrogen are analyzed, but the main focus is on gray hydrogen due to its dominance in the market.

3.1 Gray hydrogen emissions and EU ETS price effect

The EU has determined that gray hydrogen production results in 9.3 $kgCO_2/H_2$ of emissions (Erbach and Jensen, 2021). With Carbon Capture, Utilization and Storage (CCUS) the capture rate is usually 90% which means that blue hydrogen produces about 0.93 $kgCO_2/H_2$ of emissions. However, there are uncertainties about the actual capture rate in CCUS. The EU Emissions Trading System (EU ETS) is a cap and trade system and it is the largest emissions trading system globally. Industry, power generation and flights within the European Economic Area are included in the EU ETS scheme. The sectors which are required to participate in the EU ETS scheme, need to possess one EU ETS emission allowance for every ton of CO_2 equivalent emissions they emit. The term cap in "cap and trade" refers to the fact that the amount of emissions allowances is capped, i.e. there are only a fixed amount of allowances available. The emission allowances are traded in the market freely (hence the term trade), which determines the market price for one ton of CO_2. Some emission allowances are allocated freely to emitters, but the emissions which can't be covered with the allocated allowances, need to be purchased. The EU ETS was first introduced in 2005. The EU ETS prices were low for many years (below 20 €/ton), which raised the question if it is an effective tool to combat the emissions. During the last years, the prices have started to increase and emitters have had more incentives to reduce their emissions. The EU ETS allowance prices doubled from January 2021 (32€/tons) to October 2021 when they were roughly 60 €/tons. In February 2022 the EU ETS prices have been moving around 90 €/tons (Ember, 2022). It is estimated that capturing one ton of CO_2 with CCUS costs 50 - 70 € in blue hydrogen production (van Hulst, 2019). When the EU ETS prices are more than the CO_2 capture cost, blue hydrogen is more cost-competitive than gray hydrogen in Europe.

As mentioned, the EU ETS prices are determined freely by the market and the prices can change rapidly without any policy actions if the market actors forecast changes in the future supply and/or demand. One example is the fast EU ETS future price decrease after Russia invaded Ukraine on the 24th of February 2022. On the 23rd of February, one day prior the invasion, the EU ETS future price was at 95.07 €/tons. Two and half weeks later on the 7th of March, EU ETS future prices reached a temporary low point of 58.3 €/tons. Since then the prices have bounced back to 78-79 €/tons (as of 20th of March 2022). It is not possible to explain why the market has reacted in a certain way. But it can be speculated that the market actors predicted that Russian oil and gas consumption will decrease drastically in the EU, therefore the demand for emissions allowances would be reduced. The future prices of emissions allowances are difficult to predict. 90€/ton is the EU ETS price level which is used in this thesis because that was the price level in February 2022 and the supply of emissions allowances will reduce in the future which creates pressure for allowance prices to increase (European Union, 2015).

Based on the gray hydrogen emissions determined by the EU, 108 kilograms of gray hydrogen can be produced with one EU ETS allowance. 1/108 of one EU ETS allowance price should be added on top of the price of one gray hydrogen kilogram if the carbon price is not already taken into account. With a 90 €/ton EU ETS price the emissions allowance price for one gray hydrogen kilogram is 0.83 $€/kgH_2$. With 150 €/ton allowance price the allocated EU ETS price would be 1.39 $€/kgH_2$ and with 60 €/ton 0.56 $€/kgH_2$. 90 €/ton was determined to be the EU ETS price level used in this thesis, which means the EU ETS cost in this thesis is 0.83 $€/kgH_2$ for gray hydrogen. As it can be seen, the EU ETS price affects the gray hydrogen price levels greatly. From the gray hydrogen's point of view, there can be a negative feedback loop regarding the EU ETS prices. The EU ETS prices are higher when the demand for emissions allowances is strong which often happens when fossil fuel, including natural gas, consumption is high. Simultaneously natural gas prices increase. In this kind of environment, both the natural gas and the EU ETS emissions allowances prices are high which can make the gray hydrogen non-competitive against green hydrogen relatively quickly.

3.2 Gray hydrogen price, a benchmark for green hydrogen

The price of natural gas and investment costs are the most important cost components in gray hydrogen production. Natural gas is the variable cost component and investment costs are fixed, therefore the natural gas price determines gray hydrogen price levels in the short and medium-term. Globally 240 billion cubic meters of natural gas were consumed in hydrogen production in 2020 which corresponds to 6% of the total natural gas consumption globally (IEA, 2021b).

From 2011 until the beginning of 2021, natural gas prices in Finland have been rather steady. During these 10 years the natural gas price, taxes included, has been in range of 40 €/MWh - 50 €/MWh. Excise taxes (value-added tax not included) for natural gas are in total 23.354 €/MWh in Finland (as of March 2022). During 2021 natural gas prices experienced a sharp increase when the natural gas price for power plant users quadrupled. The tax free price for natural gas in Finland in December 2021 was 87.22 €/MWh when in January 2021 it was 21.39 €/MWh (Tilastokeskus, 2021). The values are calculated for the biggest natural gas consumers. With excise taxes, the natural gas price in December 2021 was 110.57 €/MWh. Natural gas prices vary between different regions since natural gas is not traded globally in relatively large quantities. Regions which export natural gas usually have lower natural gas prices than regions which import it. Europe exports the majority of its natural gas and the price is constantly higher in Europe than e.g. in the US, which has 10% higher natural gas production than consumption (EIA, 2021b). In 2020, natural gas cost 1.84 times more in Europe than in the US. In March 2022, the European natural gas benchmark price Dutch TTF (116 €/MWh) was six times more expensive than the US benchmark price of Henry Hub (18.9 €/MWh) (Statista, 2022). Gray hydrogen is more competitive in the US than in Europe and high natural gas prices are a driving factor for switching to green hydrogen in Europe.

Producing one hydrogen kilogram requires 4.5 normal cubic meters of natural gas (US DoE, 2009). One normal cubic meter of natural gas equals 10.74 kWh (EIA, 2021a). The price of natural gas is usually reported in euros per megawatt-hours in Europe. The natural gas cost per produced gray hydrogen kilogram is equal to the price of 0.04831 MWh natural gas. If natural gas costs 100 €/MWh, the cost of natural gas per produced hydrogen kilogram is 4.83 $€/kgH_2$. With 40 €/MWh natural gas price, the allocated cost is 1.93 $€/kgH_2$ and with 20 €/MWh 0.97 $€/kgH_2$. These costs don't take investment costs into account, only the natural gas cost in gray hydrogen production.

According to Longden et al., the gray hydrogen price in normal situations has been 1.48 $€/kgH_2$ (Longden et al., 2022). The cost of producing blue hydrogen in the North-Western Europe is estimated to be 1.9-2.1 $€/kgH_2$ (IEA, 2021c). Most likely the prices for both gray and blue hydrogen are significantly higher currently due to the very high natural gas prices. We use historical values for gray hydrogen prices in this thesis and not the extremely high prices which have realized during the last year. The goal of this thesis is not to compare the green and gray hydrogen prices with each other, but to find the most optimal way to procure electricity for electrolyzers. Therefore the gray hydrogen costs are not extremely important for the analyses but they are used as a benchmark for green hydrogen and especially for non-green hydrogen which can also be produced in an electrolyzer. Natural gas prices in the mid-term are difficult to predict and they can also decrease to previous low levels.

The natural gas and EU ETS prices determine the gray hydrogen price levels in the EU. When the unabated gray hydrogen cost of 1.48 $€/kgH_2$ and the 0.83$€/kgH_2$

EU ETS price are added together we get the total gray hydrogen cost of 2.31 €$/kgH_2$. This is the gray hydrogen price level with the historic natural gas prices and the current EU ETS costs. To counter the uncertainty of the current natural gas market, the gray hydrogen price is assumed to be at 2.50 €$/kgH_2$ in this thesis. This is still a relatively conservative value for gray hydrogen. As it can be seen, natural gas prices have a great impact on gray and blue hydrogen prices. Even if green hydrogen is currently considered to be less competitive than fossil alternatives, these significant price increases can make gray and blue hydrogen quickly less competitive than green hydrogen. S&P Global assessed the cost of producing hydrogen from unabated fossil fuels at 4.93 €$/kgH_2$ including CAPEX and carbon costs in October 2021 (S&P Global, 2021). This would mark a significant shift in the hydrogen market.

4 Electrolyzer technologies

There are multiple different technologies that produce hydrogen through water electrolysis. The basic principle is the same in all of these technologies: direct electric current is used to break down a water molecule into hydrogen and oxygen. The direct current flows between two electrodes: an anode and a cathode. The anode is positively charged and the cathode negatively. Oxygen is formed on the anode and hydrogen on the cathode. Between these two electrodes, there's a diaphragm or a separator that prevents the recombination of hydrogen and oxygen molecules into water (Ursua et al., 2012)

The global reaction which happens in water electrolysis is the same in all of the technologies:

$$H_2O \rightarrow H_2 + \frac{1}{2}O_2$$

In this thesis and Section, we focus on Alkaline and Proton Exchange Membrane (PEM) electrolyzer technologies since these technologies are the most probable ones to be implemented in the case study later on. This is because they are the most mature electrolyzer technologies currently. Other alternatives such as Solid Oxide Electrolyzers (SOEC) and Anion Exchange Membrane (AEM) have not reached the commercial state yet and many of their components are still in lab-scale and/or are not manufactured on an industrial scale. These technologies currently only have stacks at a few kilowatt scales. The SOEC technology has shown potential in its efficiency and potential to utilize waste heat in the process. It is operated at significantly higher temperatures (700-850°C) than other technologies (IRENA, 2020). The waste heat utilization could be very beneficial in terms of total economics if suitable utilization sources e.g. district heating are nearby.

4.1 Alkaline electrolyzer

In an alkaline electrolyzer, a cathode and an anode are submerged in a liquid alkaline electrolyte. This alkaline solution is usually potassium hydroxide (KOH) at a 25-30 % concentration. Also, sodium hydroxide (NaOH) solutions are used with the same range of concentration. Electrolytes are mixed with water and their purpose is to increase the conductivity of the solution. The diaphragm separates the cathode and anode and keeps the formed hydrogen and oxygen gases separate. (Carmo et al., 2013) An alkaline electrolyzer is connected to a DC source which maintains the electricity balance in the system. Water (H_2O) is split at the cathode to form hydrogen (H_2) and hydroxide anions (OH^-). Hydroxide anions pass through the diaphragm to the anode where they form oxygen (O_2) and water. At the same time hydroxide anions give away electrons that return to the DC source. The ionic charge carriers are the hydroxide anions. (David et al., 2019). The reaction in an alkaline electrolyzer, flow of electrons, and the forming of hydrogen and oxygen gases are shown in Figure 1

Reaction at the cathode: $2H_2O(l) + 2e^- \rightarrow H_2(g) + 2OH^-(aq)$

Reaction at the anode $2OH^-(aq) \rightarrow \frac{1}{2}O_2(g) + 2e^- + H_2O$

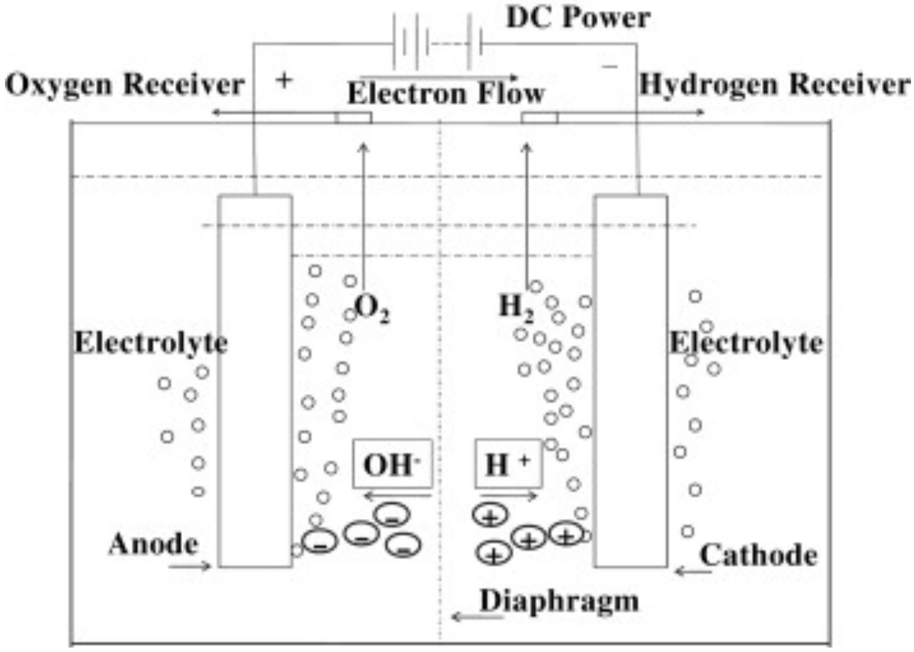

Figure 1: A schematic illustration of a reaction in an alkaline electrolyzer (Zeng and Zhang, 2010)

4.1.1 Alkaline electrolyzer system

Oxygen and hydrogen gases are produced in the electrolyzer. Some electrolyte solution, also called lye, is still mixed into these gases and it needs to be separated. These gas-electrolyte mixes go to gas-water separators (both oxygen/lye and hydrogen/lye separators) straight after the electrolyzer stack. The water phase is removed at the bottom of the separator and the gas at the top. The electrolyte is separated from the produced gases and is pumped back into the electrolyzer. Alkaline electrolyzer systems can be operated at atmospheric pressure which leads to a need for compression of produced gases. A compressor increases the hydrogen gas pressure to a level, which is suitable for storage and end-users. Alkaline electrolyzer systems can also be operated at higher pressures, in the range of 1-30 bar but the anode and cathode sides need to be at the same pressure level. Recirculating the electrolyte back into the electrolyzer stack is a special requirement for alkaline electrolyzers due to the liquid electrolyte being used in this technology. If the alkaline electrolyzer system is operated at higher pressures than the atmospheric pressure, the pressure drop in gas-water separators needs to be compensated by pumps which affects the overall efficiency of the system negatively. However, the power consumed by pumps is not significant, usually less than 0.1 % of the stack's total consumption. Some alkaline electrolyzer systems are also operated without pumping. Alkaline electrolyzers are operated at low temperatures (60 - 80 °C) (IRENA, 2020) (Chi and Yu, 2018). A typical alkaline electrolyzer system design is shown in Figure 2.

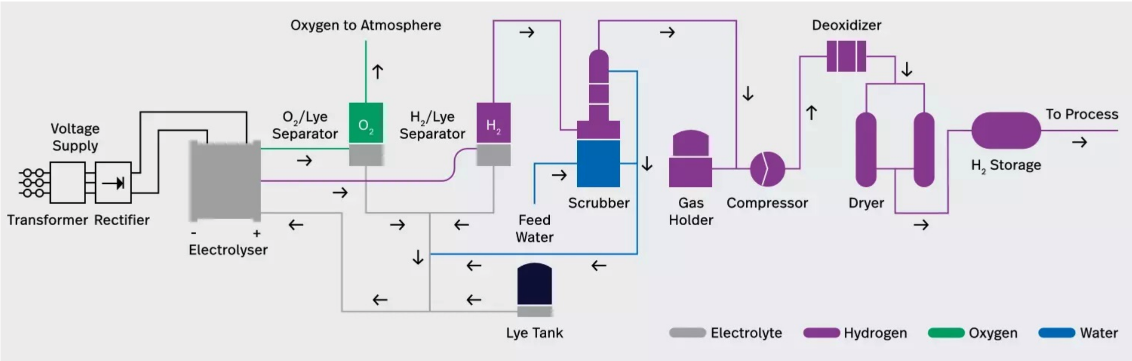

Figure 2: A typical alkaline electrolyzer system design (NEL, 2021)

4.1.2 Alkaline electrolyzer cost structure

The International Renewable Energy Agency (IRENA) has conducted a thorough analysis of the cost structures of different electrolyzer technologies in 2020. IRENA stated that creating accurate cost estimates was difficult mainly because of two reasons: lack of available data and inconsistent cost classification systems between different entities. The electrolyzer manufacturers want to retain their competitive advantages and are not willing to share information about their costs freely which is the main reason for the lack of data. Since hydrogen electrolyzers are not yet mainstream in the industry, reliable Capital Expenditure (CAPEX) estimations are especially difficult to find. IRENA performed a thorough literature review and consulted multiple leading manufacturers which gave information about the cost structures. The same problems apply also when defining PEM technology's cost structure (IRENA, 2020).

Currently, alkaline electrolyzers' CAPEX ranges from 800 to 1300 €/kW according to different industry and academic experts. Schmidt et al. interviewed different experts and the median 50 percentile value for the alkaline electrolyzer CAPEX in 2020 was 988 €/kW (Schmidt et al., 2017). Some studies suggest that even a 750 €/kW value can be achieved already today. Nel Hydrogen expected the investment costs to be as low as 400 €/kW when scaling up to 100MW plants. 988 €/kW is used in this thesis as a baseline when comparing alkaline and PEM technologies' costs. But in the case optimization, lower values are used due to the large MW-scale of the electrolyzer. Operational Expense (OPEX) values are usually given as a share of the CAPEX. In 2017 atmospheric alkaline electrolyzer had a 3% OPEX out of the CAPEX value. This 3% value is used frequently as an estimation for OPEX in different electrolyzer sizes. With the baseline CAPEX value, 3% corresponds to a 29.6 €/kW yearly OPEX. With larger electrolyzer capacities (+20 MWelec) the OPEX value is estimated to drop to 2%. These OPEX values don't include electricity or water treatment, but all the other O&M-related activities, e.g. maintenance for the whole system, spare parts and replacing auxiliary services. Alkaline electrolyzer's OPEX is usually divided into fixed and variable values, where variable OPEX increases when the operating hours are increased. In the analyzes in Section 7, a conservative 3% OPEX value for a 50 MW electrolyzer is used in the calculations. OPEX does not include stack replacement. The lifetime of an electrolyzer stack is determined to be around 85 000 hours. The system lifetime is greater, usually achieving 20+ years. This means that when investment decisions on electrolyzers are made, the need for stack replacement needs to be considered usually once during the lifetime of the system. The stack replacement costs depend on the future stack CAPEX costs, but it is assumed to be 300-420 €/kW. The alkaline electrolyzer system's lifetime is not considered to achieve major advances since the majority of the R&D investments are directed towards the CAPEX reductions of stack components. These R&D activities are crucial when the goal is to decrease the investment costs of electrolyzers, but the adoption of mass production is expected to contribute even more to the cost reductions. Solar PV panels also experienced rapid cost reductions when China started to mass-produce panels. It is expected that by mass production, the costs for alkaline electrolyzer systems can decrease to 66% of their current value by 2030. In 2030, without a significant scale-up in manufacturing, the CAPEX is forecasted to drop to 750 €/kW according to Schmit et al. which is used as a value for the 2030 costs in this thesis. However, there are multiple different views in the scientific literature on future costs which makes it hard to forecast the future prices accurately. Some studies suggest even a 400€/kW CAPEX value in the medium term. The most critical aspect of cost reductions is the scale-up in electrolyzer manufacturing. By monitoring the volume of global manufacturing capacity improvements, more precise estimations can be made in the near future (FCH 2 JU, 2017) (Bodner et al., 2015).

The technical properties for alkaline electrolyzers are shown in Table 2 and economical properties in Table 3 together with PEM electrolyzer values in the subsection 4.3 Comparison between Alkaline and PEM electrolyzers for easy comparison.

4.2 Proton Exchange Membrane electrolyzer (PEM)

In PEM electrolyzers only water is pumped to the anode where water molecules are split into oxygen, protons (H^+) and electrons (e^-). Protons which are the charge carriers, face a pulling force by an electric field that moves the protons through the membrane to the cathode where hydrogen is formed. The membrane has two functions: it's a proton conductor and a gas separator. The electrolyte is located in the membrane and it is in solid form, instead of liquid form as in alkaline electrolyzers. A DC source supplies electric power and electrons from the anode to the cathode where they are consumed during the formation of hydrogen. The DC source provides the needed force (cell voltage) for the reaction. (Kumar and Himabindu, 2019) The basic functioning principle and the structure of a PEM electrolyzer are shown in Figure 3

Reaction at the anode: $H_2O(l) \rightarrow \frac{1}{2}O_2(g) + 2H^+(aq) + 2e^-$

Reaction at the cathode: $2H^+(aq) + 2e^- \rightarrow H_2(g)$

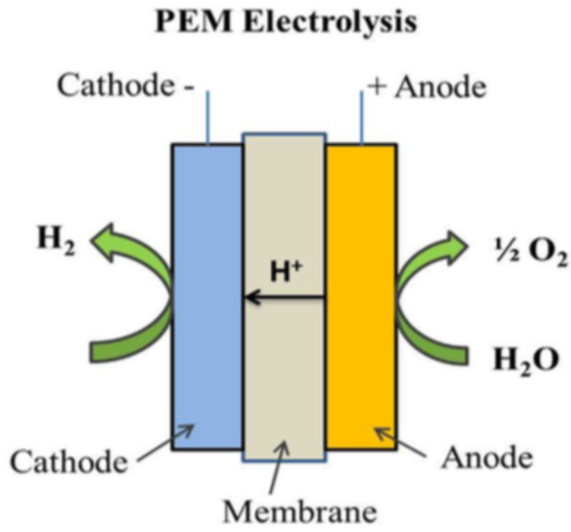

Figure 3: A schematic illustration of a reaction in a PEM electrolyzer (Kumar and Himabindu, 2019)

4.2.1 PEM electrolyzer system

PEM electrolyzer systems are simpler than alkaline electrolyzer systems. Since the electrolyte is in solid form, PEM electrolyzer systems don't need solution mixing before the electrolyzer stack. The water used in a PEM electrolyzer needs to be de-ionized which is done before the water is fed into the electrolyzer stack. This requires an ion exchanger. After the reaction, water is removed from oxygen and hydrogen gases in two different water-gas separators for both hydrogen and oxygen. PEM electrolyzers can be operated at atmospheric, differential, or balanced pressures. Balanced pressure means that the anode and cathode are operated under the same pressure, whereas in differential pressure operation, the cathode side faces higher pressure than the anode side. The current membrane electrolytes allow operation between 30 and 70 bars. If the PEM electrolyzer is operated in high pressures, the need for a compressor after the stack is reduced, in some cases, it's not needed at all if the pressure is already at the desired level from the end-user's point of view. The PEM electrolyzer systems can be operated with loads between 0% and 160% of their designed capacity which means they can, for a fixed amount of time, be overloaded if the parts are designed accordingly. In some recent experimental operations, the PEM electrolyzer has managed to produce hydrogen momentarily at a 200% load. This enables the flexible operation of PEM electrolyzers (IRENA, 2020). In Figure 4 a typical PEM electrolyzer system is shown. The high-pressure side relates to the cathode (hydrogen) side.

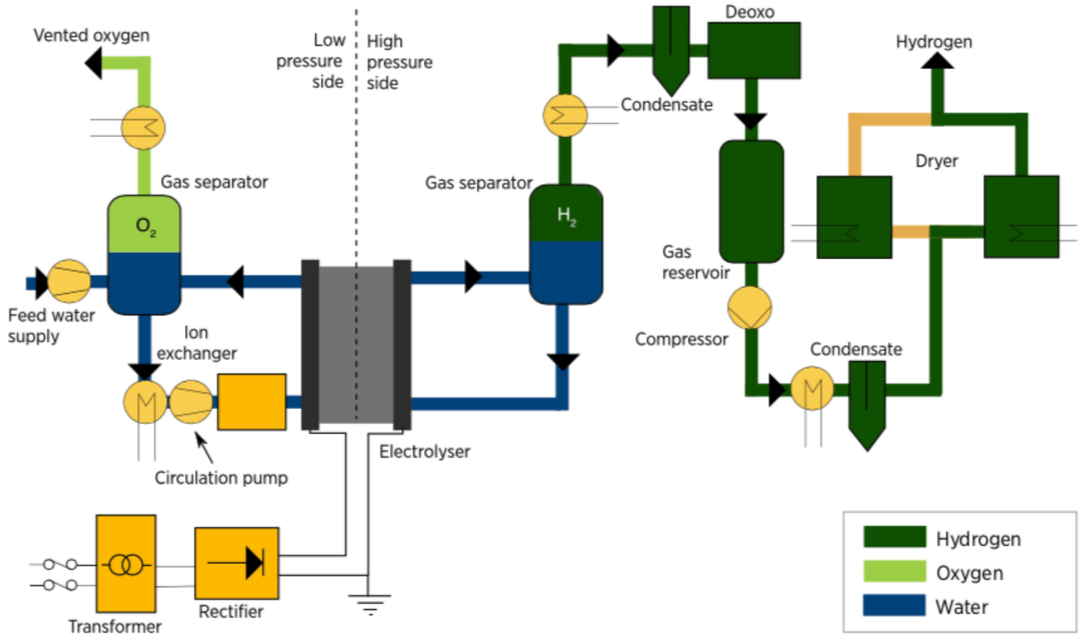

Figure 4: A typical PEM electrolyzer system (IRENA, 2020)

4.2.2 PEM electrolyzer cost structure

Similar to the alkaline electrolyzer costs, PEM electrolyzer's investment and operation costs are not widely available due to the low usage of the technology. According to Schmidt et al. the range of CAPEX values in 2020 vary between 1000 and 1950€/kW while the median 50 percentile was 1125 €/kW which is used as today's PEM electrolyzer system investment cost in this thesis. The OPEX is estimated to be 3% of the CAPEX value, which in this case corresponds to 33.8 €/kW. In 2030 the CAPEX is estimated to be 1038 €/kW (50 percentile) and OPEX to drop to 2%. Electricity usage is not included in these operational costs. PEM electrolyzers can experience more drastic cost reductions if R&D activities are successful especially in finding new ways to use less expensive materials in the PEM electrolyzer stack. The lifetime of the PEM electrolyzer stack is estimated to be around 50 000 hours and it is expected to reach 60 000 hours by 2030. (FCH 2 JU, 2017) (Schmidt et al., 2017)

4.3 Comparison between Alkaline and PEM electrolyzers

Technical specs for both alkaline and PEM electrolyzers in 2020 and 2030 estimations are presented in Table 2. The same is done for economical properties in Table 3. The electricity consumptions are calculated based on the average electrical efficiencies presented in Table 2 and hydrogen's lower heating value (LHV) of 120.1 MJ/kgH_2. The electrical efficiency is an LHV-based value. The CAPEX values in Table 3 are current estimates without any major advances by the electrolyzer manufacturing industry in R&D activities or in large-scale manufacturing. The CAPEX estimations vary and the estimation range is presented in parentheses. The median value of the CAPEX estimations is the number that is presented outside of the parentheses on the System CAPEX row. With doubling the R&D activities and scaling up the electrolyzer manufacturing capacities, bigger cost reductions can be achieved by 2030.

Table 2: Techincal properties of Alkaline and PEM technologies in 2020 and 2030 estimations (Startup time and ramp up/down speeds from Bertuccioli et al., 2014, other data from IEA, 2019)

	Alkaline electrolyzer		PEM Electrolyzer	
	Today	2030	Today	2030
Electrical efficiency (%, LHV)	66 (63-70)	68 (65-71)	58 (56-60)	65 (63-68)
Electricity consumption (kWh/kgH2 (LHV))	50	49	57	51
Operating pressure (bar)	1-30		30-80	
Operating temperature (°C)	60-80		50-80	
Load range (% relative to nominal load)	10-110		0-200	
Startup time (from cold to min load)	20min-several hours	20min-several hours	5-15min	5-15min
Ramp up speed (from min load to full load) (full-load%/sec)	0.13-25% (17%)	0.13-25% (17%)	10%-100% (40%)	10%-100% (40%)
Ramp down speed (from full load to min load) (full-load%/sec)	25%	25%	10%-100% (40%)	10%-100% (40%)
Plant footprint (m^2/kW)	0.095		0.048	

Table 3: Economical properties of Alkaline and PEM technologies in 2020 and 2030 estimations (CAPEX and stack lifetime data from Schmidt et al., 2017, OPEX data from FCH 2 JU, 2017)

	Alkaline electrolyzer		PEM Electrolyzer	
	Today	2030	Today	2030
System CAPEX (€/kW)	988 (800-1300)	750 (700-1000)	1125 (1000-1950)	1038 (850-1650)
OPEX excluding electricity (% of CAPEX)	3%	2%	3%	2%
Stack lifetime (hours)	85 000	85 000	50 500	66 000

Electricity costs are the main operating cost with electrolyzers especially when the operating hours are high. The share of electricity costs out of the total costs with different full load hours is shown in Figure 5. As it can be seen from Table 2 the alkaline electrolyzers have better electrical efficiency (63-70%) compared to PEM electrolyzers' efficiency today (56-60%). Alkaline electrolyzers are expected to retain this advantage also in 2030.

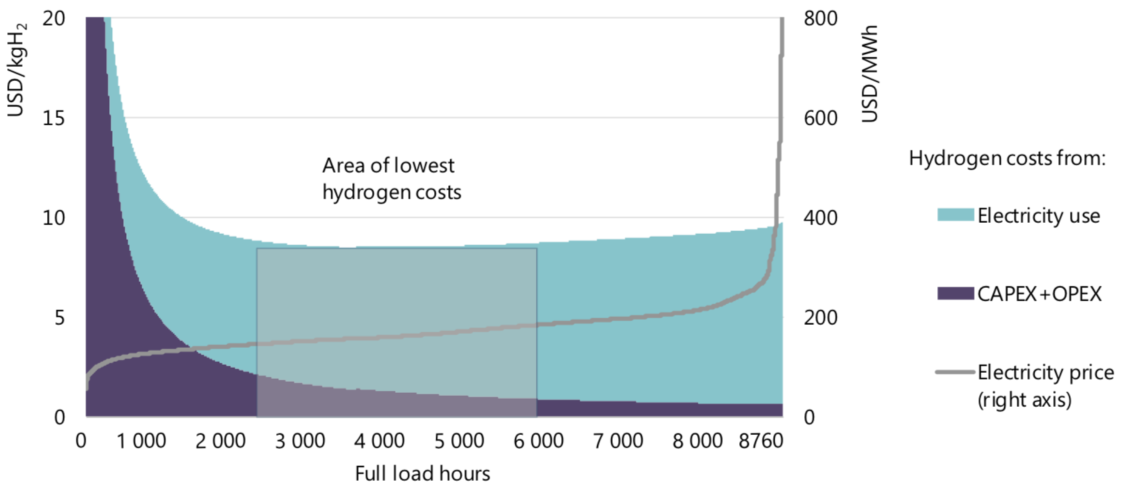

Figure 5: Relationship of CAPEX + OPEX and electricity costs out of the total costs as a function of full load hours (IEA, 2019)

PEM technology is especially superior in flexibility compared to the alkaline technology. PEM electrolyzers are able to operate in a wide load range, even a temporary load of 200% has been achieved in operation today, and the smallest operational load is just over 0% out of the rated power input. Alkaline electrolyzers can also be overloaded (max load 110%), but significantly less than PEM electrolyzers. PEM technology's minimum operational load is significantly less than alkaline technology's which is about 10%. Also, PEM electrolyzers' ramp up and down speeds are faster than alkaline electrolyzers'. Development is done by the alkaline electrolyzer manufacturers to improve flexibility. Even though alkaline technology is not as flexible as PEM technology, alkaline electrolyzers' load can still be adjusted between different hours if SPOT prices or electricity supply encourage adjustments. Combining all of these flexibility characteristics together it can be concluded that the PEM technology is more flexible than alkaline technology which is more suitable for stable loads. This enables the flexible operation of PEM electrolyzer plants. Flexible operation is a competitive advantage in today's, and especially in the future electricity markets. Electricity volatility will increase due to more Variable Renewable Energy (VRE) generation in the grid. See more about the VRE generation in Section 6. If the electrolyzer operators can switch their electricity consumption from the high price hours to low price hours, the main operating expense, electricity cost, can be reduced. If the plant is coupled with VRE production, the load switching is essential to capture and utilize the maximum value of the VRE generation. Short-term flexibility also provides possibilities to offer grid balancing services which, if implemented without disrupting the hydrogen production, can provide additional revenue streams for the electrolyzer. Depending on the site where the electrolyzer is operated, plant footprint can become a limiting factor. If the site is for example a densely built industrial site or an urban area, there can be trade-offs that need to be made in terms of the electrolyzer systems capacity and technology. Alkaline electrolyzer systems require double the area as PEM electrolyzer systems with the same capacity. When excluding all the other factors, PEM electrolyzer systems are easier to locate than alkaline electrolyzer systems in terms of the area required.

Alkaline electrolyzers have a long lifetime, while other electrolyzer types are struggling with long-term durability. The alkaline technology is well established and the first commercial system was installed already in 1927 by Norsk Hydro, the predecessor of NEL Hydrogen. Alkaline electrolysis is a well-known technology, especially in the fertilizer and chlorine industries (Bodner et al., 2015). It is the most mature electrolyzer technology. This also means that the potential cost reductions especially in terms of CAPEX are less significant in alkaline technology than in PEM technology. PEM electrolyzer stacks have more potential to reduce their costs from the costs of today. From the economic point of view, alkaline technology gains an advantage over PEM technology in economic terms if the system is operated at a relatively constant load. This is due to the lower CAPEX costs as can be seen in Table 3.

The CAPEX costs are correlating with the module sizes. As mentioned before in Subsection 4.1.2 NEL Hydrogen expects to achieve 400€/kW CAPEX costs when scaling to 100 MW plants. In Figure 6 the expected investment costs are presented as a function of the module size in MWs. Note that the currency is US Dollars. From Figure 6 it can be seen that the biggest cost reductions happen when scaling the size of the electrolyzer from 1 MW to 10 MW. After the 10 MW point is surpassed, CAPEX reductions face diminishing returns.

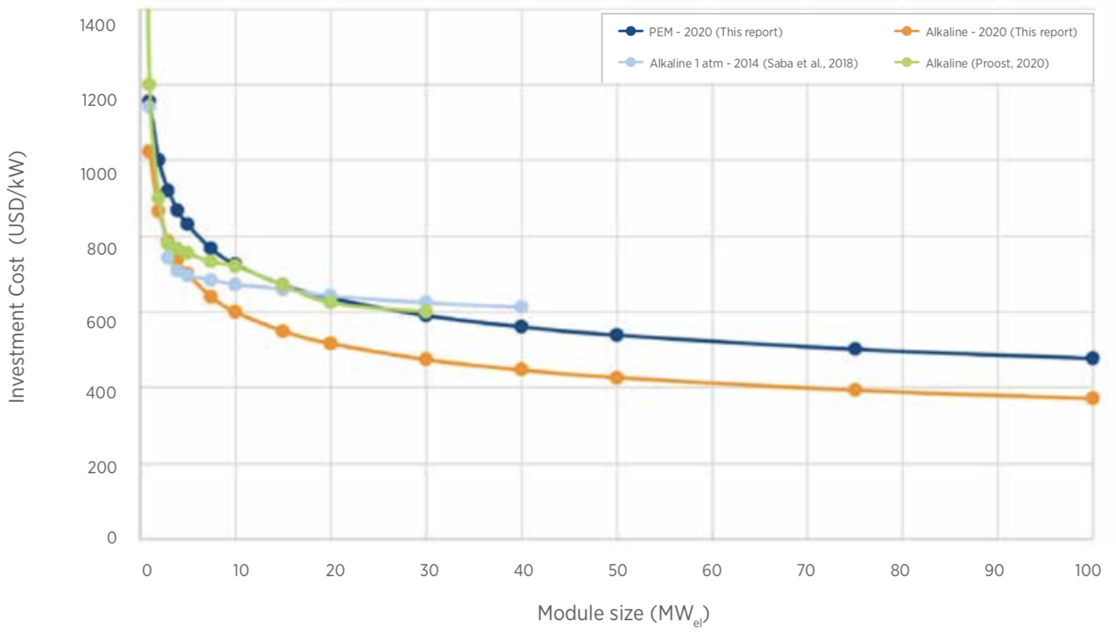

Figure 6: Electrolyzer investment cost as a function of module size for various technologies (IRENA, 2020)

Different electrolyzer manufacturers focus on different aspects on their product development roadmap. Some manufacturers might prefer to increase the efficiency of the system, while others focus more on cost reductions or flexibility improvements. At least in the short term improving one parameter leads to deteriorating other parameters. Therefore the total effect on the cost for produced hydrogen kilogram should be analyzed when deciding where to focus on electrolyzer technology improvements (IRENA, 2020).

5 Legislation

The European Union (EU) creates a legal framework for energy production and consumption in Europe. From the green hydrogen's point of view, Renewable Energy Directive II (RED II) is the most important legislative action in the EU. RED II entered into force in December 2018 and it is an updated directive from RED I which was established in 2009. RED II is created to ensure that the EU will meet its emissions reductions targets under the Paris Agreement. RED II established a new binding target for the EU to achieve a 32% share of renewables in the final energy consumption mix in 2030. In 2019, renewable energy represented 19.7% of the energy consumed in the EU. (European Commission, 2021)

The European Commission (EC) proposed a revision of the RED II in July 2021. In that revision, the 2030 renewable goal is proposed to be raised from 32% to 40% of the final energy consumption. The RED II revision is often considered as RED III and it is part of the Fit-for-55 package which aims to achieve 55% GHG emissions reduction by 2030 compared to the 1990 levels. From green hydrogen's point of view, the most important concrete sub-targets for emissions reductions in the RED III are:

- 50% share of renewables in hydrogen consumption in industry
- 2.6% Renewable Fuels from Non-Biological Origin (RFNBO) share of the transport fuels
- 1.1% annual increase in the industry's renewables use

The EC's proposed revision is now being considered by the European Council and the European Parliament. The final form of the RED III is certain only after all of these three branches have reached a mutual understanding.

The EC is also expected to provide a delegated act supplementing the RED II by the end of 2021. In RED II it was stated that the EC should provide delegated acts complementing the RED II which will ensure the additionality of renewable energy when green hydrogen production is scaled up. The most important points for green hydrogen in the delegated act, are the points supplementing article 25 and especially article 27 in RED II. Article 25 focuses on the minimum GHG emissions reduction targets for synthetic fuels and article 27 defines what needs to be taken into account in hydrogen production for hydrogen to be considered green hydrogen. In this Section, we will focus on the effects of different delegated act outcomes concerning article 27 for the green hydrogen production. Article 27 is the most important legislative act for green hydrogen production in the EU. And because of the green hydrogen rule setting, it is very essential for the implementation of case examples in this thesis.

5.1 Temporal correlation

Temporal correlation in the green hydrogen production's case considers in what timeframe the energy quantity of green electricity generation and electrolyzer's electricity consumption need to match. In other words, what is the length of an accounting period when the matching needs to be done. For instance, with a 15-minute temporal correlation requirement, an electrolyzer can't consume more electricity during a 15-minute period than what is generated by the green electricity sources during that 15-minute period where it procures its electricity. In one year accounting period, the matching needs to be done within one year. It doesn't matter when exactly the electricity is generated inside that accounting period, but the quantities need to match during that period. In the case of a one-year temporal correlation requirement, theoretically, all of the electricity can be generated during one month, and still the electrolyzer could produce green hydrogen every hour of that year if the amount of generated electricity is large enough to cover the operation for the whole year.

According to different researches conducted and ordered by the hydrogen industry the different accounting periods which are under validation by the EC are 15 minutes, one day, one month and one year. Many organizations argue that the strictest timeframes would limit the possibilities of green hydrogen production and even make green hydrogen noncompetitive against gray and blue hydrogen. It is not yet clear what is the length of the periods the EC will propose, but the ambition of the EC has been to introduce even the shortest 15-minute period. The backlash from the industry for the proposal of the shortest time period has been speculated to have affected the EC's upcoming proposal which would lead to the EC proposing longer accounting periods at least during the scale-up phase of the green hydrogen industry (Aurora Energy Research, 2021). These are still purely speculative considerations and most likely during the time of this thesis, more information is provided on this matter.

In the research conducted by Frontier, a one-hour accounting period is not considered. One hour can also be seen as one of the most likely timeframes which the EC will mandate. Currently most of the European power markets operate under a 60-minute Imbalance Settlement Period (ISP) but are moving in the near future to a 15-minute ISP operation. In the Nordics, the 15-minute ISP is expected to be operational in Q2 2023. The day-ahead market will continue with a 60-minute resolution, but the intraday and balancing markets will operate with a 15-minute resolution. Since the 15-minute resolution is not operational in many European countries, the 60-minute resolution for green hydrogen production can be seen as the strictest time resolution option which is ready to be deployed widely. This is the reason why a one-hour temporal correlation requirement can also be expected (The Nordic Balancing model, 2020). During writing this thesis, we expect a one-hour temporal correlation requirement to be enforced.

Shorter periods increase the cost of green hydrogen mainly due to lower operating hours. In Figure 7 it is demonstrated how the different accounting periods affect the price. The values used in the calculations are German power prices and profiles in 2019. The cost effect of newly built renewable plants which can also be seen in Figure 7 is analyzed more in the next Subsection 5.2. It should be noticed that especially the 15-minute but also the one-day accounting period increases the costs substantially. Shortening the timeframe from one year to one month doesn't have as significant cost-increasing effect as moving from one month to one day. This is expected since the VRE generation can fluctuate inside one month greatly, but usually the VRE assets can level off the fluctuation within one month which is not possible within one day. From Figure 7 it can be seen that the 15-minute accounting period leads to 43% higher costs than one year accounting period when calculating with the existing renewable plants' values. This is a significant increase in production costs.

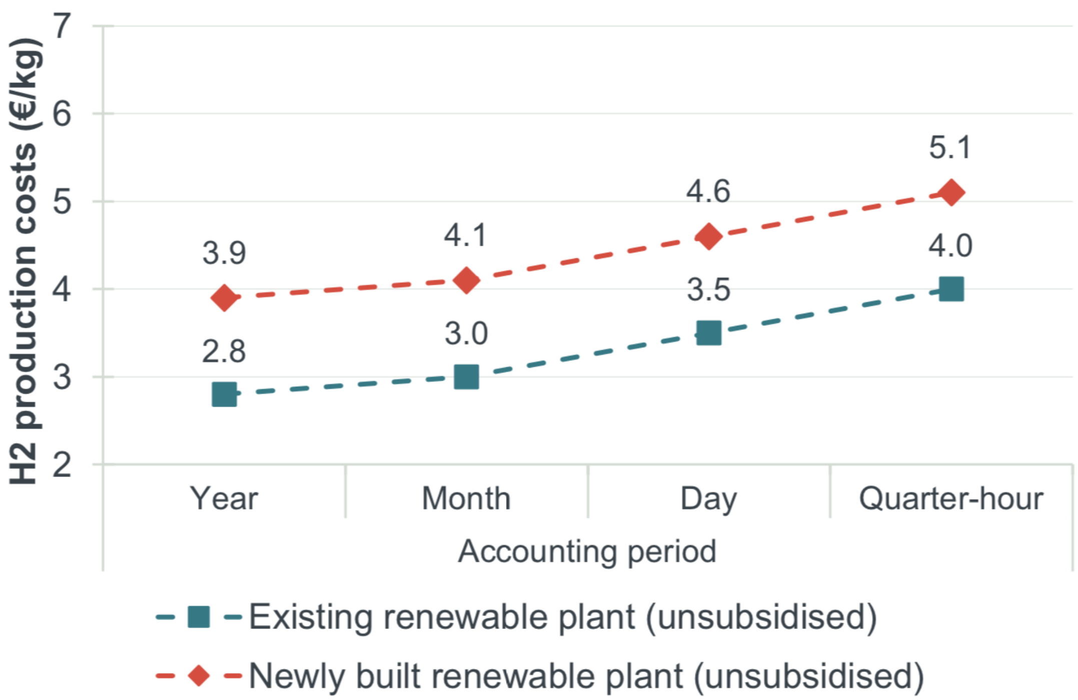

Figure 7: Different accounting periods' effect on green hydrogen costs (Frontier Economics, 2021)

Optimizing the VRE generation assets which are used for green hydrogen production becomes increasingly more important when moving to shorter accounting periods. The main cost-increasing factor with shorter timeframes is the limitation of possible operating hours. This factor can be reduced to some extent by optimizing electricity procurement. The goal of the optimization is to find assets that have different generation profiles. Different generation profiles enable the electrolyzer operation during different hours which increases the operating hours and therefore reduces hydrogen production costs. With longer accounting periods the need for asset portfolio optimization is not as significant as with short accounting periods, but cost reductions can also be achieved there. More of this is in Section 7 VRE portfolio and battery storage optimization where the optimal asset portfolios are analyzed for different accounting periods.

5.2 Additionality

In the EU's green hydrogen legislation additionality means, whether the electrolyzers are allowed to utilize VRE generation from existing (unsubsidized) assets or are they required to procure electricity from newly built assets. The goal of the additionality framework is to increase the overall system's VRE generation capacity. The goal is also to prevent the electrolyzers' electricity consumption from displacing the current renewable electricity consumption. If the electrolyzers' VRE consumption would displace some other VRE consumption, the grid system would become more dependent on carbon-intensive generation. On the other hand, if the additionality requirements are too strict, the electrolyzer capacity scaleup inside the EU market can be substantially slower than it would be without the strict additionality requirements. The main reason for this is that in some cases e.g. the wind farm projects can take even seven years from the start of planning to turbines generating electricity. Even in the fastest VRE projects, the project length is measured in years.

Currently, the expected rule for the additionality timeframe is 12 months. This means that the electrolyzer operator needs to procure its electricity from a VRE asset that hasn't been operational more than 12 months before the electrolyzer operation begins. Figure 7 shows in addition to the accounting period's cost effect, the difference in green hydrogen production costs when the electricity is procured from newly built or existing renewable plants. If renewable electricity is required to be generated by a newly built plant, the production cost increases by 1.1€/kg. The cost effect of newly built plant requirement compared to the existing plants is the same with different accounting periods. In 2030 the average levelized cost of hydrogen (LCOH) can be reduced by 18% if all renewable and decarbonized electricity sources are allowed, compared to the case when only newly built VRE assets are allowed. (Aurora Energy Research, 2021)

5.3 Geographical correlation

Geographical correlation means that the renewable electricity generation units and the consumption need to be located relatively close to each other. It is not yet stated what the location requirements are exactly, but the EC's delegated act is expected to provide concrete framework in this matter. In recital 90 of the RED II, it is stated that produced fuels can be counted as fully renewable only if the electricity generation unit and the fuel production plant (electrolyzer in this case) are located on the same side of a grid bottleneck. (European Commission, 2021) This would most likely mean that the consumption and generation units need to be inside the same power market bidding zone. Since Finland consists of only one bidding zone, the electrolyzer operator in Finland would be allowed to procure their electricity anywhere from Finland.

It is not expected that bottlenecks in a distribution grid or other local bottlenecks inside a bidding zone would be a limiting factor in the EC's delegated act. However, the geographical correlation requirement would most likely remove the possibility to procure electricity e.g. from Sweden. If two bidding zones wouldn't systematically have bottlenecks between each other then it could be possible to procure electricity from another bidding zone. It is also possible that the electricity can be procured from another bidding zone during the electrolyzer market scale-up phase, only when there is free capacity in the transmission capacity between the two zones. Strict geographical correlation rules could increase the green hydrogen production costs, especially if the correlation is regulated also inside a power market area. The exact price increasing effect is not determined as precisely as in temporal correlation and additionality cases and it is likely to have a smaller effect than those two. But it can limit the possible sites where renewable electricity can be procured. The geographical correlation issue is more important in countries that have multiple power market areas e.g. in Sweden and Norway. In these countries, the green hydrogen production should most likely be located closer to the renewable generation sites than in Finland.

5.4 Power supply concepts

The definition of how green electricity can be procured for it to be counted as 100% renewable electricity in green hydrogen production is still unclear. Currently, the RED II provides two different ways to procure electricity that can be counted as renewable. These are stated in the article 27 and they provide different computational renewable shares for the electrolyzer operator. The first one is procuring electricity with a grid connection, where the share of renewables in the national grid two years before the year in question determines the computational share of renewable electricity for green hydrogen production. In RED II it is determined that the RFNBOs can be counted as renewable energy only if the GHG emissions savings from the use of these fuels are at least 70% compared to fossil alternatives. To achieve the 70% threshold when the electrolyzer consumes grid electricity, the average carbon intensity of the grid needs to be at a level that corresponds to under 3.4 $kgCO_2/kgH_2$ of emissions. Currently, only a few European countries achieve this threshold e.g. France, Austria, Norway, Sweden and Iceland. In 2020 producing hydrogen with the average grid electricity in Finland would've caused 3.8 $kgCO_2/kgH_2$ emissions. By increasing the carbon-free generation, Finland should be able to have a low enough carbon intensive grid in the near future to achieve the required 70% GHG reductions with the grid electricity (Aurora Energy Research, 2021). As mentioned, the renewable share of the grid two years prior to the electrolyzer operation determines the share of renewable electricity. But to achieve a 100% renewable electricity share, the electrolyzer operator needs to procure their electricity only from renewable sources, not only utilize the grid electricity without any other measures. The second option in addition to the grid electricity is to have a direct connection to a renewable electricity generation asset. The generation assets should not be connected to the grid and if they are connected, evidence needs to be provided that the electricity has been supplied without taking electricity from the grid (European Commission, 2021).

In addition to these two rules established in RED II, a third renewable electricity procurement possibility is expected to be introduced in the EC's delegated act. The delegated act would allow the use of bilateral power purchase agreements (PPA). A PPA is an agreement between a power producer and buyer, where they agree on a fixed price level for a certain period of time. Usually the buyer agrees to purchase electricity for 10-20 years. This is beneficial for both the producer and the buyer. The producer can leverage PPAs when acquiring financing for building the power plant by showcasing stable revenues in the long term. The buyer also can hedge against electricity price volatilities with PPAs. PPAs are already an industry standard in VRE projects, and acquiring renewable electricity supply through PPAs is business as usual in the energy sector. As mentioned, PPAs are a valuable tool for renewable electricity project developers, which means that the PPAs are often agreed upon before the construction phase begins. This makes the additionality requirement when PPAs are utilized a minor issue.

There are different kinds of PPA contract types, a physical and a virtual PPA being the most common ones. Physical PPA means that the generated electricity is moved directly to the buyer's electricity balance sheet. The buyer pays the agreed price to the power producer and the electricity is transmitted to the buyer's location either through a third party electricity grid or through a direct connection. If electricity transmission is needed, transmission costs need to be paid. In almost all cases direct connection is feasible only with small-scale power plants, for instance, if the generation unit consists of solar panels on the buyer's rooftop. In virtual PPAs the power producer sells the generated electricity to the power market and the buyer purchases electricity from the power market. After the power market activities, the difference between the realized market price and the agreed PPA price is calculated. If the power market price is higher than the PPA price, the power producer will pay the difference to the buyer, and the buyer will pay the difference to the power producer if the market price is lower than the PPA price (Afry, 2019).

The PPA contract parties will agree on what PPA pricing model is used. Pay-as-produced is the most straightforward model. It means that the buyer buys all electricity generated by the power plant. The generated electricity amount will fluctuate which means the purchased electricity amount at different hours will vary. The buyer needs to balance its electricity balance sheet every hour. If the generation is less than the buyer consumes, it needs to purchase electricity from other sources, usually from the power market, to match its purchases and consumption. If the generation is more than the consumption, the buyer needs to sell the excess electricity to the power market. In the pay-as-produced model, the imbalance risk is carried by the buyer. In the baseload PPA model the parties will agree, in addition to the price, on the amount of electricity which is supplied by the power producer to the buyer every hour. Baseload refers to a constant power supply. Since the buyer is entitled to a constant electricity supply, the power producer is responsible for balancing the imbalances in generation and the agreed electricity supply and does the required power market transactions. In baseload PPAs the power producer bears the imbalance risk. In both the pay-as-produced and baseload model, it is also possible that the buyer buys a part of the electricity generated by the power plant (e.g. 20% of the total generation) and the remaining part of the generation is sold to other PPA buyers or to the power market. Third parties are often used for balancing the electricity balance sheets especially if neither of the parties possesses the required expertise for imbalance settlements (Afry, 2019). Because of the temporal correlation requirements stated earlier, it is assumed that only the pay-as-produced model is eligible for green hydrogen production.

Power supply concepts are one part of the equation which needs to be matched. Additionality, temporal and geographical correlations need to be taken into account as well. The EC could also make a difference between the grid and direct connection in terms of the additionality requirements. A less strict requirement for grid-connected assets could be possible to ensure the VRE assets are operating and generating renewable electricity to the grid even if the electrolyzer wouldn't be ready to be operated yet. This would reduce the risk of wasting potential electricity generation from operationally ready VRE assets due to bureaucracy. If the electrolyzer operator would procure their electricity through grid-connected VRE assets, in most cases they wouldn't be the only one utilizing the electricity generated by those assets. This is because the economies of scale benefit big VRE projects and usually it wouldn't make sense for one operator to build their own assets. This of course can be different if electricity generation is the primary business for the VRE operator which is the case for utilities but often not for small-medium-sized industry players. VRE assets' generation can be distributed to multiple different end-users, which in general own or in other ways are entitled to a specific share of the VRE generation e.g. through a PPA. Therefore the electrolyzer operator couldn't by themselves determine when the VRE asset should start its operation and it would be difficult for them to match the additionality requirements very strictly. Direct connection assets are usually smaller in terms of capacity than grid-connected assets which makes scheduling the construction of direct connection VRE assets easier. Therefore the operational start of direct connection assets is easier to match with the electrolyzer's operational start and stricter additionality requirements are easier to fulfill. During writing this thesis, purely speculative industry expert assumptions are made that with a grid connection the additionality requirement would be 24 months and with a direct connection, the assets should start their operation during the same calendar year as the electrolyzer.

6 Renewable electricity generation and battery storage

Because of the additionality requirements described in Section 5.2, wind and solar PV generation are the only focus areas of this thesis from the electricity generation point of view. These additionality requirements exclude existing hydropower plants from the potential electricity procurement mix for green hydrogen production. Hydropower would complement the fluctuating VRE generation sources greatly. Hydropower could be used indirectly if the carbon intensity of the grid falls to a level that enables the use of grid electricity. This Section's focus is on understanding the current deployment of VRE assets in Finland and their costs which are done in Sections 6.2 and 6.3. Wind power and solar PV generations' temporal variation and their potential to supplement each other are analyzed in 6.4. Battery energy storages can be used to store generated renewable electricity for later use in electrolyzers. The requirements for electricity that is stored in the batteries are the same as they would be if the renewable electricity would be consumed immediately by the electrolyzer. Especially the battery storage costs are analyzed in 6.5. The feasibility of batteries to supplement the electricity procurement mix is studied later in Section 7. Before focusing on the current states of wind power and solar PV, levelized cost of electricity is analyzed. LCOE is an essential concept when determining the costs related to a specific electricity generation technology. LCOE concept is used in both wind power and solar PV analyses.

6.1 Levelized Cost of Electricity

The Levelized Cost of Electricity (LCOE) is the total lifetime cost of electricity generated per generated energy amount for a certain generation technology. LCOEs for the same generation technology can also vary, e.g. between different geographical locations. LCOE can also be understood as the average electricity price that is required to cover the full lifetime costs. It is a very useful and highly utilized concept when comparing different generation methods' lifetime costs with each other. It includes all the costs which are involved from the start of planning to the asset's retirement. These different costs include e.g. CAPEX, OPEX, profit margins of the whole value chain, installation, project development, manufacturing and decommissioning. The lifetime of the project affects the LCOE as well. LCOE focuses only on electricity generation and the scope of LCOE ends when the electricity is generated. Therefore it does not include electricity distribution and transmission costs. VRE generation units like wind power and solar PV don't have fuel costs since they are powered by natural forces. By examining only the marginal costs and making decisions based on them, the total cost of these VRE assets would be dismissed and the investment decisions would be wrongfully justified, potentially leading to economically negative decisions. Especially with CAPEX-heavy assets like VREs, but also with other assets, it is crucial to focus on LCOE and not on marginal costs when making investment decisions. (**irena2020projected_costs**)

LCOE is a fictitious electricity price that is needed on average to make the present value of the sum of all costs and all revenues over the entire operational life of the unit equal to zero. Low LCOE by itself can't justify investments and on the other hand, high LCOE does not necessarily rule out investments. It is important to compare the LCOE to the revenue potential. Different electricity market areas have different price levels and the price levels can be driven by different factors. A systematically high electricity price level can encourage investments into assets that wouldn't be profitable in low price areas. The factors which determine the electricity price levels between different hours are as important as the price level when making investment decisions. In the future, they can be even more important when volatility in the electricity markets increases. One example of this is the so called duck curve effect in the Californian electricity market. California has abundant solar resources and solar PV generation is rather cheap there. But the high penetration of solar PV has led to the point, where the attainable revenue is lower for solar PV than for other generation technologies. This is due to the very high electricity supply during the solar PV generation hours, which is caused by a very high amount of installed solar PV capacity. High supply and relatively static demand lead to decreasing market prices. The duck curve in California Independent System Operator's market area during a typical spring day is demonstrated in Figure 8. The y-axis presents net demand, which is the actual demand minus VRE generation i.e. the electric energy amount which needs to be satisfied with other than VRE generation at every hour. The data was gathered in 2016 and we can see that the duck curve effect is expected to escalate when more solar PV capacity installations are done. When the solar PV generation starts to decrease during the late afternoon, other generation sources face the need for a fast generation ramp up which can be problematic.

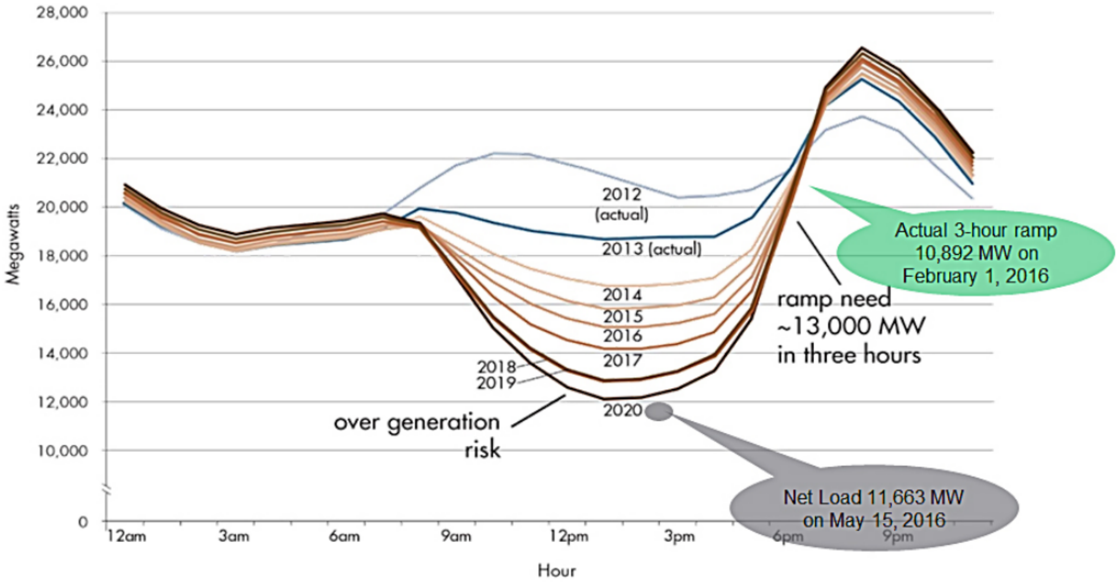

Figure 8: Duck curve effect in California electricity market during a typical spring day. Good solar resources and significant installed solar PV capacity can lead to electricity oversupply during the daytime. On the y-axis net demand, which is demand minus VRE generation (CAISO, 2016)

6.2 Wind power

At the end of 2020 total installed wind power capacity in Finland was 2586 MW and generation was 7.8 TWh. 67 new wind turbines were installed which increased the capacity by 302 MW (Finnish Wind Power Association, 2021a). Based on these numbers the average capacity of a new wind turbine was 4.5 MW. The generation capacities of new wind turbines have been growing steadily during the last years and decades due to improvements in technology and the increase in wind turbines' hub height and blade diameter. Wind resources are more abundant in higher altitudes which encourages increasing the hub height. With bigger blade diameters, wind turbines swept area increases. With bigger swept areas, the wind turbines can utilize more wind energy due to larger areas are covered by the blades. Wind power capacity is expected to grow rapidly in Finland in the near future. The Finnish Wind Power Association (FWCA) predicts that the yearly capacity additions are 793 MW in 2021, 1 320 MW in 2022 and 1 206 MW in 2023 (Finnish Wind Power Association, 2021b). These numbers are based on the project phases, where different wind projects are currently. The different phases are in order from the first project phase to the last phase:

- Pre-screening
- Land use plan process started
- Environmental impact assessment (EIA) process ongoing
- Land use plan proposal

- EIA done
- Land use plan done
- Fully permitted
- Under construction

The projects which are in the first project phases are less likely to realize and if they end up being constructed, these projects take significantly more time to be operational than the projects which are in the last phases. The equivalent of 2 435 MW was in the construction phase and 3 607 MW was fully permitted when the report was previously updated (Q1/2021). The majority of these new projects are onshore wind projects. There aren't any new offshore wind projects which would be fully permitted or under construction. In the development pipeline across all different project phases, there are equivalent to 2 847 MW of offshore projects and 18 561 MW of onshore projects. The electricity generation by wind turbines is estimated to be approximately 10 TWh in 2022 and 13 TWh in 2023 (Finnish Wind Power Association, 2021c).

The LCOE of wind power plants, both for onshore and offshore, has been rapidly declining during the past decades. The global LCOE for onshore wind was 78.56 €/MWh in 2010 and 34.43 €/MWh in 2020 which means that during the 2010-2020 period the cost reduction was 56% (IRENA, 2021). The International Energy Agency (IEA) has gathered a database of different electricity generation technologies installed across the Globe. In that database a Finnish 30 MW onshore wind project had an LCOE of 28.88 €/MWh with a 3% discount rate. CAPEX accounted for 22.75 €/MWh and OPEX 6.13 €/MWh. With a 7% discount rate, the total LCOE was 39.65 €/MWh. In comparison, a Norwegian 130 MW onshore plant's LCOE was 21.24 €/MWh and a Dutch 50 MW onshore plant's LCOE was 29.25 €/MWh. Both the Norwegian and Dutch power plants' LCOEs were estimated with a 3% discount factor. Pexapark, a software company based in Zurich which has supported over 10 GW of PPA deals, reported a 22.74 €/MWh onshore PPA price in the Nordics (IEA, 2020). The low prices in the Nordics are especially driven by big onshore capacity additions in Southern Sweden where there is currently an oversupply of onshore PPA deals. PPA prices in Finland can be assumed to be a bit higher than in the oversupplied Swedish market (Pexapark, 2021). In the calculations in Section 7 a 25 €/MWh LCOE is used for onshore wind. The PPA prices can be considered as an opportunity cost for the electrolyzer operator which could've been obtained from multi-year PPA deals. The same factors which are increasing the capacity of new wind turbines are driving down the costs. The technological improvements which enable the increases in the capacities of new wind turbines make turbines cheaper per installed capacity and generated electricity. Also, the economies of scale, learning by doing in manufacturing and in operation decrease the costs. The LCOE of wind power is expected to decline by 15% from 2020 to 2025 globally. Based on this estimation the 2025 global LCOE would be 29.27 €/MWh and the Finnish wind power LCOE in 2025 would most likely be 20-25 €/MWh.

6.3 Solar PV

Solar PV generation plays a minor role in the current Finnish electricity generation portfolio. At the end of 2020, 293 MW of solar PV capacity was connected to the grid. The annual capacity additions in 2020 were 91 MW, which is a significant increase compared to the total installed capacity. Compared to the 2019 installed capacity the capacity increase was 45%. In 2020, the solar PV capacity's share of the total electricity generation capacity in Finland was 1.6%, but solar PV generation accounted only for 0.4% of the total electricity generation in Finland (Energiavirasto, 2021). Solar PV capacity grows rapidly in percentages, but still, the absolute increase is not close to the wind power capacity additions. Solar PV generation is usually small-scale in Finland. Distributed rooftop solar takes a major share of the total installed solar PV capacity. Under 1 MW small-scale generation units accounted for 98% and over 1 MW generation units for 2% out of the total installed solar PV capacity. The number of grid-connected solar PV plants in Finland is between 20 000 – 25 000. The total capacity of off-grid installations is difficult to determine precisely. In 2019 the off-grid installations accounted approximately for 11.3 MW (Ahola, 2019). Because the majority of solar PV generation is done by small-scale rooftop solar PV plants, it is much more difficult to estimate the near future capacity additions for solar PV than it is for wind power capacity. In wind power's case, the power plants have rather standardized project development models and they require official permits. Whereas with solar PV, the small-scale capacity additions don't require such extensive bureaucracy and therefore are not as precisely documented, making future capacity additions difficult to predict. It can be assumed that solar PV capacity in Finland will continue to increase, because of decreasing panel costs and the latest developments in the energy market which have caused an increase in consumers' and businesses' electricity bills.

Solar PV electricity generation potential across Europe is presented in Figure 9. In the bottom left corner, the solar irradiation (kWh/m^2) and yield parameter (kWh/kW) scales are presented. The yield parameter means how much electricity can be generated annually per installed capacity. The solar generation potential is much higher in Southern Europe than in the Nordics. The solar PV generation potentials in South and Southwest Finland are better than in other parts of Finland. The Helsinki region has approximately a 900 kWh/kW yield parameter and 1200 kWh/m^2 of solar irradiation according to this map. According to European Technology Innovation Platform, a rooftop solar PV power plant had a yield parameter of 960 kWh/kW and a ground-mounted solar PV power plant had a 1010 kWh/kW yield parameter in Helsinki. In comparison, ground-mounted solar PV power plants had a yield parameter of 980 kWh/kW in London and 1680 kWh/kW in Malaga. The generation potential is not much better in the northern part of Central Europe than in Southern Finland. Solar PV generation in Finland is more focused on the summer months, due to long day times during the summer. 90% of the irradiation energy in Southern Finland is realized between March and September. The generation variation within a year is stronger in Finland than in Central Europe, where solar PV generation is distributed more evenly across multiple months. Based on Figure 9, solar PV assets in Finland should be installed either to the South or Southwest areas.

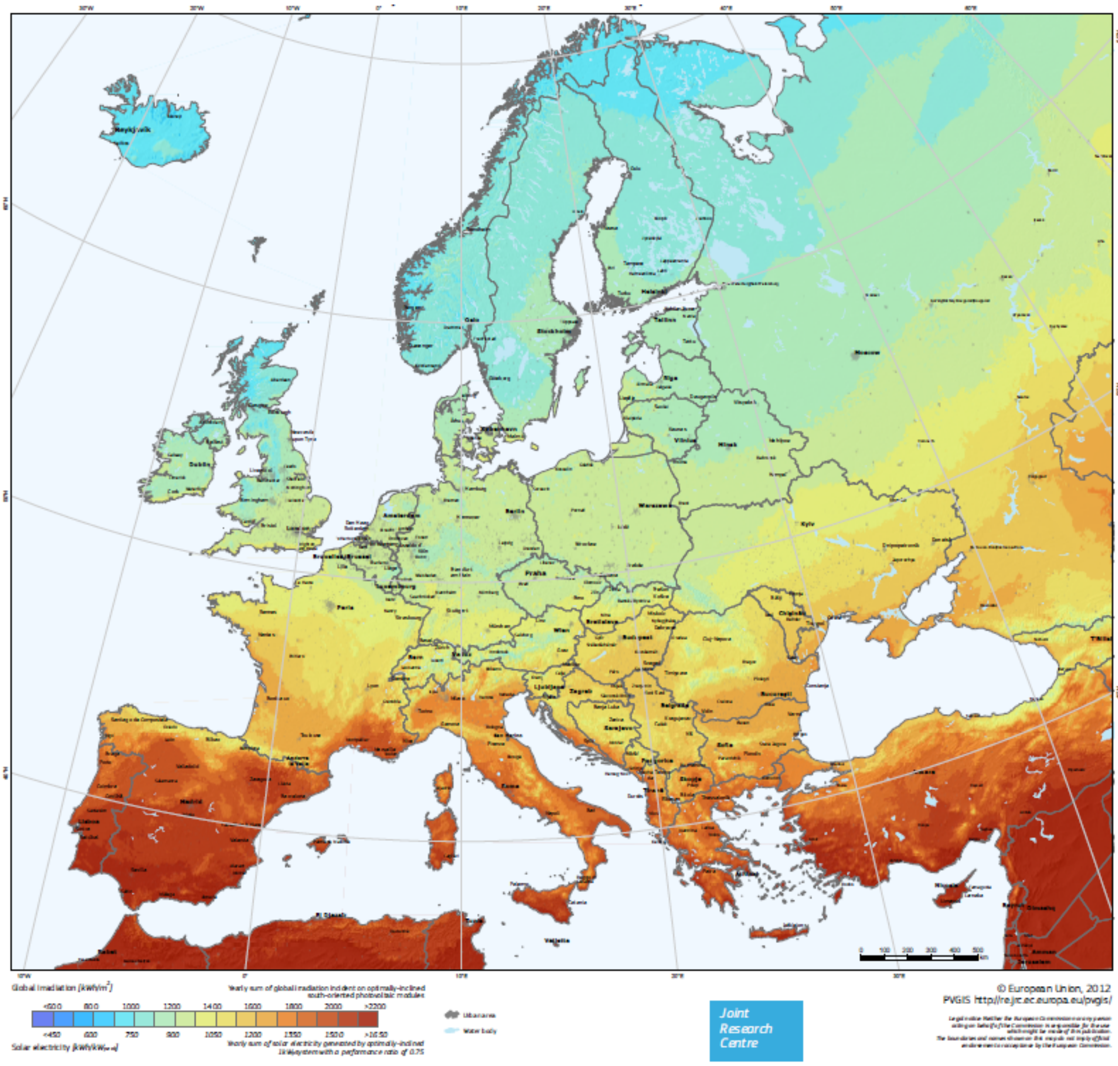

Figure 9: Solar PV electricity generation potential in Europe (European Commission, 2012)

Solar PV's global LCOE has fallen by 85 % from 2010 to 2020, outpacing the wind power cost reductions. The mass manufacturing of solar PV panels started in the 2010s which enabled drastic cost reductions. The decline in solar module cost contributed 46% of the total LCOE reduction in utility-scale solar PV between 2010 and 2020. In 2010 the global LCOE was 336€/MWh and in 2020 50€/MWh which makes it still more expensive globally than wind power (IRENA, 2021). The solar PV's LCOE varies greatly between different regions since favorable solar irradiation conditions can increase the generation greatly and therefore decrease the LCOE. Also, other regional differences can affect the prices, for example if a country has a well-established solar PV market, costs are lower than in underdeveloped markets. The stated global prices are most likely too pessimistic. European Technology Innovation

Platform has estimated solar PV LCOEs for different locations, power plant sizes and interest rates. We focus only on utility-scale solar PV plants. The smallest utility-scale power plant which is analyzed in European Technology Innovation Platform's report is 1 MW. In Helsinki, with a 2% interest rate, the LCOE would be 32 €/MWh and with a 4 % interest rate 38 €/MWh. With the biggest interest rate of 10%, the LCOE would be over 60 €/MWh. This demonstrates the interest rate's effect on required future cash flows generated by the investment. In comparison, a 1 MW utility-scale solar PV plant in Malaga has an LCOE of 22 €/MWh with a 4% interest rate. For a 100 MW solar PV plant in Helsinki, the LCOE with a 2% interest rate is 25 €/MWh and with a 4% interest rate, it is 30€/MWh. The LCOEs are expected to decrease in the future. In 2025 a 1 MW utility-scale solar PV power plant in Helsinki with a 4% interest rate is expected to have an LCOE of 30€/MWh. In the case analysis in Section 7, we assume the solar PV's LCOE to be 37€/MWh, which is close to the 1 MW solar PV plant's LCOE in 2020 with relatively low interest rates. Future and current solar PV plants' capacity would most likely be closer to 1 MW than 100 MW in Finland.

6.4 VRE capacity factors

VRE generation profiles and capacity factors in Finland were calculated based on the Finnish Energy's (Energiateollisuus) hourly generation data, the FWCA's wind power capacity data, and the Finnish Energy Authority's (Energiavirasto) solar PV capacity data. The analyzes were done for three years: 2018, 2019 and 2020. Based on the installed capacities and generated electricity calculations, average hourly capacity factors were calculated. The generation data presented the generation in the Finnish grid by different sources, including wind power and solar PV. The data is not location-specific but it gives information about the grid's total wind and solar PV generation at every hour. Therefore the calculated capacity factors for different timeframes can be used as indicative, and more precise data would be needed if and when the VRE procurement is done from specific wind power and solar PV power plants.

The average monthly capacity factors for wind power across the Finnish electricity grid in 2018-2020 are presented in Figure 10. The installed capacity is different for every year and the annual capacity additions are diversified equally for every month. For example, in January 2019 the installed capacity was 2041 MW and the calculative monthly additions were 20.3 MW which means the calculative capacity in February 2019 was 2061.3 MW. This monthly capacity addition is done for every month equally. At the beginning of 2018, the installed capacity was 2041 MW and there were no capacity additions during that year. At the beginning of 2020 the installed capacity was 2284 and the annual capacity installations were 302 MW (25.2 MW monthly additions). From Figure 10 we can notice that usually during the spring and summer months, wind generation decreases compared to the winter and autumn months. The average capacity factor from these three years achieve its peak value in February when the capacity factor is 43.3%. The lowest average capacity factor is 19.7% in July. The daily variations can be significant and daily wind generation can be extremely low during high generation months and vice versa for the low generation months. This annual variation is important to notice when designing a VRE portfolio which should provide a stable electricity supply across the whole year.

Figure 10: Wind power average monthly capacity factors in the whole Finnish electricity grid in 2018-2020. Generation data from Energiateollisuus, 2021

The average monthly capacity factors for solar PV across the Finnish electricity grid in 2018-2020 are presented in Figure 11. The capacity factors and installed capacities are calculated similarly for every month as in wind power's capacity factor case. The starting solar PV capacity in 2018 was 66 MW, in 2019 125 MW and in 2020 202 MW. The monthly calculative capacity additions were 4.9 MW in 2018, 6.4 MW in 2019 and 7.6 MW in 2020. Since the annual capacity additions in 2018 (59 MW) were almost as big as the starting capacity, the monthly capacity additions during May, June and July in 2018 were doubled to give a more realistic view of the capacity factors during high generation months. To counter the double additions, during October, November and December there weren't any calculative capacity additions. The capacity factors are low during winter, early spring and late autumn months and capacity factors are high from the late spring to early autumn. The average capacity factor from these three years peaks in July, achieving a 32.4% capacity factor. This is still less than the wind power's maximum capacity factor. During both January and December, the average capacity factor is less than 1%. The variability within a year is significant for solar PV generation.

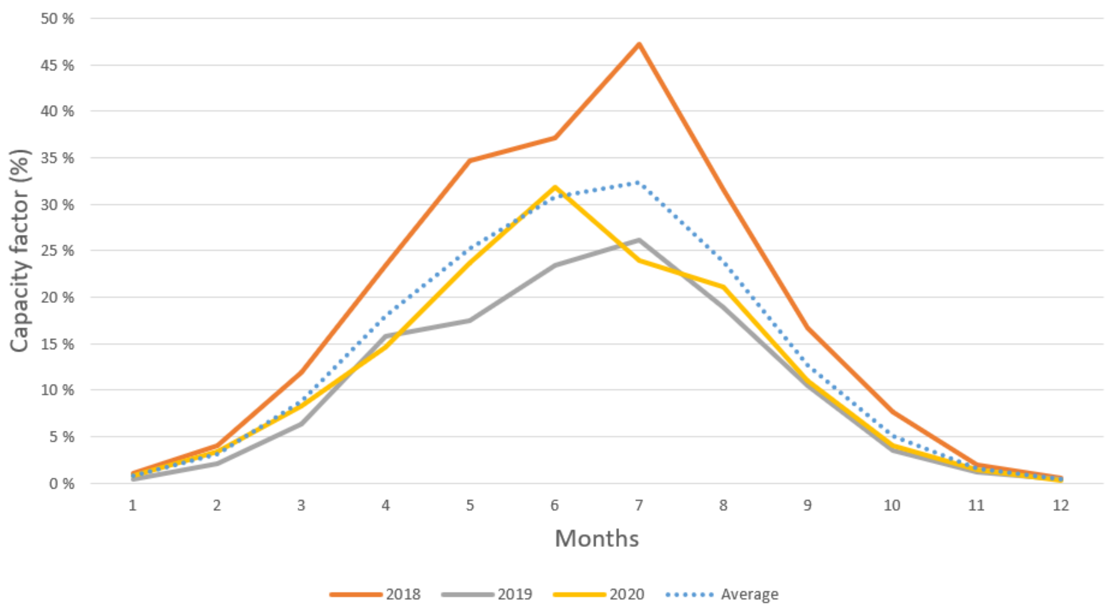

Figure 11: Solar PV average monthly capacity factors in the whole Finnish electricity grid in 2018-2020. Generation data from Energiateollisuus, 2021

The average capacity factors for wind power and solar PV from 2018 to 2020 in the Finnish electricity grid are presented in Figure 12. The average values are the same as presented in Figure 10 and Figure 11. They are presented together in an additional Figure 12 to demonstrate their different capacity factor characteristics within a year. As it can be seen, wind power's average capacity factor drops during the summer months when the solar PV's average capacity factor peaks. When the wind power's capacity factor is at its highest annual value during the winter and autumn months, the solar PV's capacity factor is at its lowest. These two different variable generation technologies supplement each other at the annual scale. This is one crucial factor that enables the VRE portfolio (consisting of only wind power and solar PV) optimization to provide a stable electricity supply across a whole year. If the two generation technologies would share similar capacity factor characteristics, the VRE portfolio optimization would not bring as much additional value as is possible with different capacity factor characteristics.

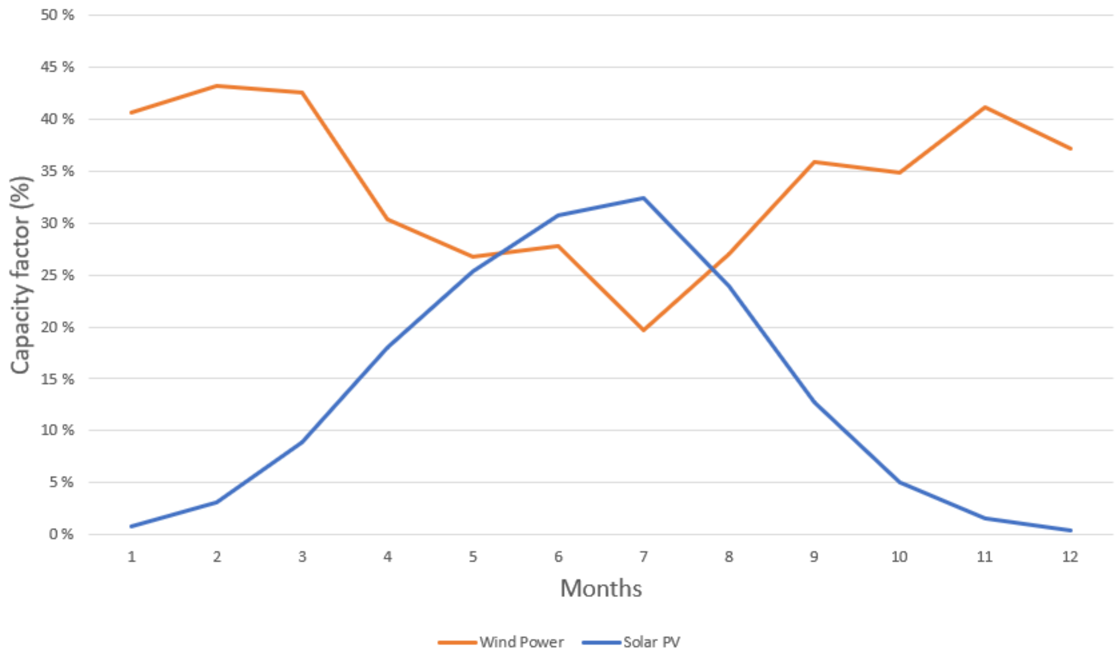

Figure 12: Wind power and solar PV average monthly capacity factors in the whole Finnish electricity grid. Average values from 2018 to 2020. Generation data from Energiateollisuus, 2021

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Average hourly capacity factors for solar PV and wind power from 2018 to 2020 in the Finnish electricity are presented in Figure 13. As mentioned previously, VRE generation can fluctuate a lot within a week and a day. Solar PV's daily fluctuation is usually easier to forecast than wind power's. From Figure 13 we can see that wind power and solar PV supplement each other also at the daily scale. There is on average more wind generation during the night time than during the day, and quite self-evidently there's more solar PV generation during the daytime. It should be kept in mind that the presented values are averages. The daily generation can differ greatly from the average values. Based on the average monthly and hourly capacity factors it can be concluded that solar PV and wind power generation could supplement each other even in Finland.

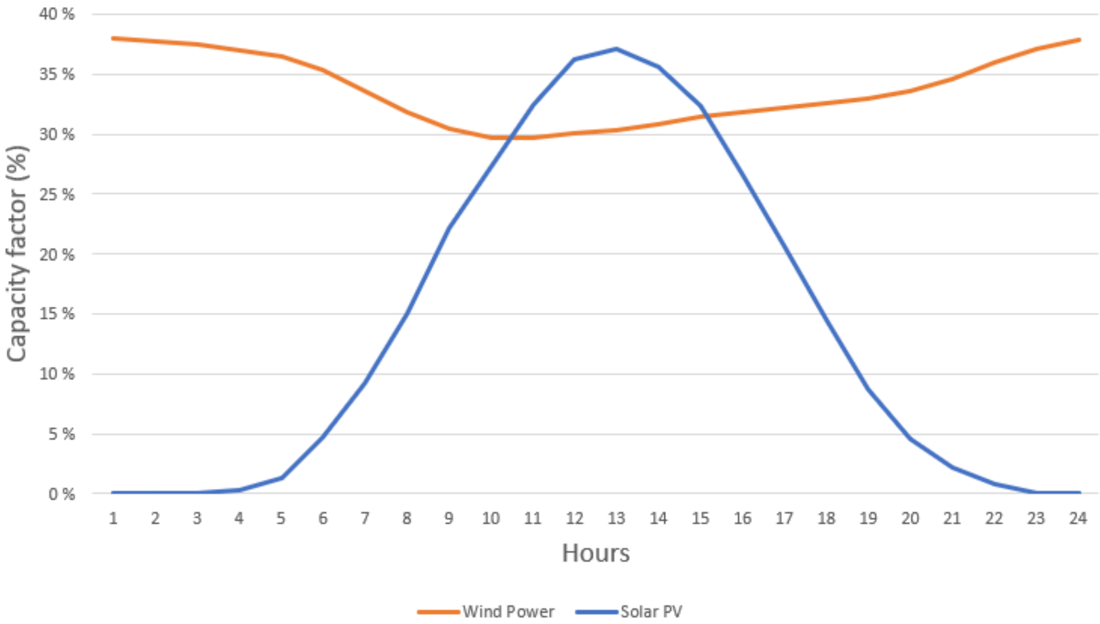

Figure 13: Wind power and solar PV average hourly capacity factors in the whole Finnish electricity grid. Average values from 2018 to 2020. Generation data from Energiateollisuus, 2021

6.5 Battery energy storage

The selected battery technology is lithium-ion because it is by far the most dominant battery technology globally. In 2020, lithium-ion batteries represented 93% of the total new energy storage capacity additions. In 2020, 5 GW of energy storage capacity was added globally. Lithium-ion batteries are very capable in terms of fast response and energy discharge. The discharging and charging powers will not be a limiting factor when the batteries are coupled with an electrolyzer. But their energy storage capacities are a limiting factor, if and when the investment costs need to be realistic. Lithium-ion batteries are compact, and battery storages are easy to scale up because of their modular nature. Currently, the biggest installed battery in Finland is 30 MWh with a 30 MW discharge power. The battery was the biggest battery unit in the Nordics during its installation in 2020. Globally there have been bigger battery installations that provide ancillary services for electricity grids and store excess VRE generation for later use. For example, Tesla has supplied a 450 MWh / 300 MW battery to Australia which consists of 210 Tesla Megapacks. This Victorian Big Battery project illustrates how battery storage capacity can be easily scaled to the optimal storage capacity by modular battery units (Fingrid, 2020) (IEA, 2021a).

The cost of batteries depends on the output power and capacity of the selected battery. Increases in energy storage capacities and output power will lead to additional investment costs. Different utility-scale batteries have different cost characteristics, especially in terms of maximum (dis)charge power (€/kW). But in energy storage capacity terms (€/kWh) they are rather close to each other which is selected as the cost parameter for batteries in the calculations. This is because during the calculations in Section **??**, the storage size is variable, but the discharge capacity is fixed. The battery should provide enough energy storage capacity to sustain electrolyzer operations for multiple low VRE generation hours. A battery with 20 MW discharge power and 4 hours of discharge capacity (80 MWh) is estimated to cost 1005$/kW - 1535 $/kW and 251 $/kWh - 384 $/kWh (Electric Power Research Institute, 2020). In calculations, we use the average value of 318 $/kWh which equals 281 €/kWh. OPEX for 4-hour batteries is in the range of 2$/kW - 6 $/kW per year. In the calculations, we use the median value of 4 $/kW which translates to 3.5 €/kW per year.

The Levelized Cost of Storage (LCOS) aims to adapt the well-known LCOE concept into energy storages. LCOS can be described as the average discharging price required to cover the full lifetime costs of a storage plant. For example, a 6 MWh battery installed in Finland had an LCOS of 177 €/MWh with a 3% interest rate according to IEA (IEA, 2020). In Denmark, a 6.3 MWh battery had an LCOS of 38 €/MWh. Because the LCOS data is scarce and fragmented, we can't conclude precisely the LCOS levels. LCOS is not as established concept as LCOE and it is more limited in terms of straightforward applications than its electricity counterpart. Generation assets only have to deal with the power market prices when they are selling the generated electricity, while storages need to take both the charging (buying) and discharging (selling) prices into account. A certain price level does not tell the whole story of whether storages would be profitable in a specific market since the electricity storages are taking advantage of energy arbitrage. Arbitrage happens when an operator buys a good at a low price and sells the exact same good at a higher price usually in a different market. In the electricity market's case, energy arbitrage can be utilized in the same market but during different hours. In the case analysis in Section 7, the electrolyzer consumes 50 kWh of electricity per one produced hydrogen kilogram. When the green hydrogen price is at 3 $€/kgH_2$, the revenue from one MWh of discharged electricity that is consumed by an electrolyzer is 60 €/MWh. Therefore with a 177 €/MWh LCOS, the average charging price leading to zero profits in green hydrogen production is -117 €/MWh. With a 38 €/MWh LCOS, the break-even charging price is 22 €/MWh. The break-even charging price can be increased if green hydrogen is more expensive. In this case the potential revenue would be greater. These break-even charging prices are simplifications to demonstrate the required price levels. They should not be treated as precise values since many things affect the LCOS values. The latter charging price of 22 €/MWh is realistic, but still difficult to attain systematically. Even if the current LCOS values are not accurate, most likely the VRE LCOE values need to decrease from the current levels to enable even the cheapest batteries to be profitable in green hydrogen production.

7 VRE portfolio and battery storage optimization

The model was constructed first for the year 2020. After all different data variables and calculations were defined, the model was duplicated for 2019 and 2018. The model is similar between different years. Wind generation simulation and yearly Elspot prices are the only data sets that can change between the years. The yearly Elspot prices are used only when comparing to results with the 2021 prices. 2021 Elspot prices are used in every case if not stated otherwise. More about the used inputs and values in the next Section 7.1. The model uses hourly price and generation data for every year. It should be noted that 2020 was a leap year, which means it had 8 784 hours when other years had 8 760 hours. The 24-hour increase is not significant, since the length of a leap year is only 0.3% longer than a normal year's length. But it should be kept in mind if the results between a leap year and a normal year are minor.

The goal is to find the optimal VRE generation mix and battery size for different cases in green hydrogen production. The different temporal correlation cases which are analyzed are annual and hourly correlations. These two temporal correlation requirements were chosen because they are seen as the most extreme cases. The 15-minute temporal correlation which would be stricter than the one-hour correlation, wouldn't be possible to simulate with the current data which is in hourly resolution. The optimal generation mixes for both the annual and hourly requirements with 150 MW and 300 MW total capacities, are analyzed in Subsection 7.2. 150 MW was chosen as the smallest total capacity to be analyzed by finding the smallest capacity which could meet the annual correlation requirement with a safety margin when the electrolyzer is operated every hour of the year. Wind generation has a higher capacity factor in Southern Finland than solar PV. Therefore the lowest total generation capacity to meet the annual correlation is analyzed with only wind power. With 150 MW wind capacity the annual generation is 13.9 GWh in 2018 and 9.3 GWh in 2019 more than the consumption when the electrolyzer (50 MWelec) is operated every hour of the year. The year 2020 was exceptionally good in wind power generation and the 150 MW wind power capacity generated 163 GWh more than what was the electrolyzer's consumption. Since 2020 was abnormally good in terms of wind generation, long-term planning shouldn't be made based on that year's generation. Therefore 150 MW is the lowest total capacity which is analyzed for an electrolyzer with a 50 MW electrical capacity. The minimum total capacities with different battery sizes in case of an hourly correlation requirement to reach a 95% utilization rate are analyzed in 7.3. Based on these analyzes we can compare the optimal VRE mixes in different cases and conclude from what sources the electricity should be procured. The role of small-scale solar PV generation is studied in Subsection 7.5. The optimal battery size with different battery CAPEX and green hydrogen prices are analyzed in Subsection 7.4.

7.1 Cost inputs for optimization

Since many of the costs associated with green hydrogen production are overnight investment costs, they need to be proportionate for one year when calculating annual profits and costs. Calculating the Equivalent Annual Cost (EAC) makes it possible to study the economic performance of an electrolyzer for one year. The EAC is calculated for one year by dividing the total CAPEX with an annuity factor and adding other annual costs e.g. OPEX. Equation 1 presents how the annuity factor is calculated.

$$\text{Annuity factor} = \frac{1 - \frac{1}{(1+r)^t}}{r} \tag{1}$$

Where:
t = number of periods
r = interest rate

The annuity factors are different for electrolyzer and battery in the case study. For the electrolyzer, the project lifetime is 20 years and for the battery it is 15 years. After 15 years it is estimated that the battery's energy storage capacity will drop significantly which leads to its retirement from primary operation. The cost of capital which acts as the interest rate in the annuity factor formula is 5% for both the electrolyzer and the battery. With these values, the annuity factor for the electrolyzer is 12.46 and for the battery 10.38. The EAC is used in the case studies when calculating other than electricity costs (Investopedia, 2020).

The electricity distribution costs are calculated with Helen Electricity Network's values for an industrial customer connected to a 110 kV line. The basic tariff is 950 €/month, power charge 990 €/MWmonth, winter daytime distribution 11.75 €/MWh and other time distribution 3.99 €/MWh. These values don't include value-added taxes (VAT). Winter daytime distribution cost is paid during December, January and February from 7.00 to 21.00 during weekdays (Helen Sähköverkko, 2021). Distribution costs are paid based on the consumed electricity. Wind generation and SPOT purchases require distribution networks. Small-scale solar PV generation could potentially be located on the same site as the electrolyzer. In that case, distribution is not needed for solar PV generated electricity. In the model, 1 MW is the upper bound for a solar PV plant that could be located onsite.

Electricity taxes are divided into two different categories in Finland. The manufacturing industry, data centers and greenhouse farming are required to pay a smaller tax than other actors. This smaller tax is 0.063 c/kWh and it is paid from the consumed electricity. An exemption is made for small-scale power plants. If a small-scale power plant generates less than 800 MWh during a calendar year, the generation is tax-free (Verohallinto, 2021). With the simulated solar PV generation values, a 0.79 MW solar PV power plant is the biggest solar PV plant that doesn't exceed the tax boundaries. A 0.79 MW solar PV plant generates 797 MWh of electricity. This can be calculated with the annual yield of 1007.07 kWh/kWp.

The chosen electrolyzer technology is alkaline since the hydrogen output was desired to be as constant as possible. With relatively stable output and loads, alkaline is preferred over PEM technology as explained in Section 4.3. The desired output was 1000 kgH_2/h. With the current alkaline electricity consumption per produced hydrogen kilogram (50 kWh/kgH_2), a 1000 kg hydrogen demand corresponds to 50 MWelec electrolyzer capacity. The electrolyzer capacity is held constant between different cases to enable better comparison. The used electrolyzer CAPEX is 800 €/kW which is the lowest value in Table 3 for alkaline electrolyzers. Due to the large scale of the electrolyzer, this lower bound value is chosen. It can be seen as a conservative estimation for an electrolyzer with 50 MWelec capacity. In Figure 6 it was seen that 50 MWelec capacities could see CAPEX values even under 400 €/kW (note that in Figure 6 currency is in US Dollars). The total CAPEX is €40 M. Electrolyzer's annual OPEX is 3% out of the CAPEX which equals €1 200 000. The annualized CAPEX when calculated with the EAC is €3 209 703. The total annual cost for the electrolyzer is €4 409 703.

Electricity is the main cost component of an electrolyzer with high operating hours. High operating hours is the goal in every case, due to the high CAPEX costs associated with electrolyzers. For wind generation, the chosen LCOE is 25 €/MWh and for solar PV 37 €/MWh. The investment costs of newly built renewable VRE assets are not considered mainly because of two reasons: 1. the EU legislation regarding the additionality requirements is not clear yet, therefore both newly built and existing VRE assets could potentially be viable electricity generation sources 2. procuring electricity through PPAs is a very popular method in many industries. PPAs are a potential electricity procurement method also for an electrolyzer and LCOEs can act as a benchmark when PPA prices are negotiated. Because of these reasons studying the generation costs through LCOEs was chosen. Solar PV generation is given priority in the electrolyzer's electricity consumption which means that first all of the available solar PV generation is consumed and the electricity demand which is not fulfilled by solar PV is supplied by wind generation. If SPOT purchases are allowed (in annual correlation) the SPOT purchases are used to supplement the designated VRE generation to match the whole electricity demand (50 MWh) for every hour. The used battery CAPEX value is 281 €/kWh and the annualized costs are calculated based on the realized battery size. For example with a 10 MWh battery, the total CAPEX would be €2 810 000 and the EAC €270 722 with the 10.38 annuity factor. The inputs which are used in the analysis are presented in Table 4.

Table 4: Inputs used in the analysis

Cost of Capital	5%
Nr of periods (electrolyzer)	20
Nr of periods (battery)	15
Distribution cost	3.99 €/MWh
Distribution cost (winter day)	11.75 €/MWh
Basic distribution tariff	950 €/month
Distribution power charge	990 €/MW, month
Electricity tax	0.63 €/MWh
Upper limit for tax free generation	800 MWh
Upper limit for onsite solar PV capacity	1 MW
Electricity consumption per kgH2	50 kWh/kgH2
Electrolyzer electrical capacity	50 MW
Electrolyzer CAPEX	800 €/kW
Electrolyzer annual OPEX (out of CAPEX)	3%
Wind generation LCOE	25 €/MWh
Solar PV generation LCOE	37 €/MWh
Battery CAPEX	281 €/kWh
Battery max discharge/charge power	50 MW
Green hydrogen price	3 €/kgH2

7.1.1 Electrolyzer's electricity consumption cost calculation

The electrolyzer's electricity consumption cost is calculated by multiplying the amount of solar PV and wind power generation consumed in the electrolyzer with the corresponding LCOE. The Elspot expenses are added also to the electricity costs if Elspot purchases are allowed. Electricity taxes and distribution costs are included. The electricity cost calculation is demonstrated in Equation 2. In this case it is assumed that solar PV generation is under the tax free and onsite limits, therefore those costs are not included in solar PV generaion. Electricity taxes and distribution costs need to be paid from the wind power generation and Elspot purchases in every case and also from the solar PV generation if it isn't under tax-free or onsite limit. The temporal correlation is annual correlation which enables the Elspot purchases if the VRE generation can't match the whole demand.

$$\begin{aligned} &E_{solarPV} * LCOE_{solarPV} + E_{wind} * (LCOE_{wind} + tax + dist.) + E_{Elspot} \\ &\quad * (Price_{Elspot} + tax + dist.) = \text{Electricity consumption cost} \end{aligned} \tag{2}$$

Where:
$E_{solarPV}$ = Solar PV generation volume
$LCOE_{solarPV}$ = LCOE of solar PV
E_{wind} = Wind power generation volume
$LCOE_{wind}$ = LCOE of wind power

tax = Electricity taxes
dist. = Electricity distribution cost
E_{Elspot} = Elspot purchase volume
$Price_{Elspot}$ = Elspot hourly price

If the temporal correlation requirement is hourly correlation, Elspot purchases can't be done. Elspot purchases are not done also if the VRE generation can match the whole electricity demand. If Elspot market revenues are included, the revenue and costs related to electricity sold to the Elspot market are calculated. The distribution costs and electricity taxes are paid only from the consumed electricity (if the generation is not tax-free or onsite), not from the electricity sold to Elspot. More info on what revenue streams and costs are included in different cases can be found in Section 7.2.

7.2 Annual and hourly correlation

In Section 5.1 different studies conducted by the hydrogen industry proposed that with short temporal correlation requirements, green hydrogen production would be more expensive than with longer temporal correlations. It is expected since short accounting periods limit the number of possible electrolyzer operation hours compared to longer accounting periods. In this Section, hourly and annual correlation requirements are compared and the goal is to find the optimal VRE generation mix for both requirements. Different optimal VRE mixes are found by optimizing the VRE capacities in relation to different economical values and electrolyzer's operation in a given legislative environment. The variables in optimization cases are wind and solar PV capacities and the total VRE capacity is fixed. Battery storage capacity was also one of the variables, but in all cases when optimizing the electricity procurement in relation to economic performance, the optimal battery size was always 0 MWh. More about battery's potential and reasoning why it isn't currently competitive in Section 7.4. The constraints which need to be satisfied in optimizations are:

- solar PV capacity + wind capacity <= 150 MW or 300 MW
- annual electrolyzer electricity consumption <= annual VRE generation
- in hourly temporal correlation: hourly electrolyzer electricity consumption <= hourly VRE generation

In both, the annual and hourly correlation requirement cases the operational profit maximizing VRE portfolio is analyzed. In the operational profit case, only the electricity costs which are corresponding to the electricity consumed in the electrolyzer are taken into account and the only revenue source is hydrogen. Also, electrolyzer OPEX and annualized investment costs are included in the costs. When focusing on operational profit maximization in annual correlation, the optimal VRE mix is equal to the case when green hydrogen production costs are minimized. This is because the amount of hydrogen produced and the price for green hydrogen are constant. Therefore only the costs can change in profit calculations. But in hourly correlation, profits might not be maximized when the production costs are minimized since the hydrogen production amount can change as well.

Also, the case where the profits from excess electricity sales to Elspot are added on top of the operational profit from hydrogen is studied for annual correlation. The operational profit + Elspot profit means that in addition to the green hydrogen revenue, the revenue generated by excess electricity sales to the power market is taken into account. Instead of only calculating the electricity costs associated with the electrolyzer's consumption, the total generation cost needs to be calculated. This is easy since the total generation from solar PV and wind generation is multiplied by their LCOEs.

For hourly correlation, the VRE mix which leads to the Maximized Green Hydrogen Production (MGHP) in an electrolyzer is studied. Green hydrogen production is maximized when the electrolyzer's utilization rate is maximized. This happens when sufficient amounts of VRE generation are available across multiple hours and the hours when VRE generation availability is restricted are minimized. When maximizing the electrolyzer's utilization rate, it is more valuable to have a steady supply of electricity across multiple hours than to have great amounts of electricity supply during a limited number of hours. If the VRE generation is more than the electrolyzer's maximum electric capacity during a given hour, the electricity supply potential is wasted from the electrolyzer's point of view. It would be better to shift the supply from these excess generation hours to the hours when VRE generation is limited. Different energy storages are capable of shifting the supply from high supply to low supply hours. Batteries function as energy storage in our analyzes, but as mentioned before they weren't economically competitive. Batteries are not utilized in MGHP optimization cases to enable better VRE portfolio and performance indicator comparisons to operational profit and operational+Elspot profit cases. Batteries would certainly increase the utilization rate and it is analyzed more in Section 7.4.

7.2.1 Annual correlation

The optimal VRE mixes with a total capacity of 150 MW for operational profit and operational + Elspot profit optimizations can be seen in Table 5. Profits are calculated with the 2021 SPOT prices. Wind power is clearly a dominant generation source by taking a 100% share of the total capacity every year in both cases. This is due to wind power's superior capacity factor. What is significant is the amount of electricity generated in 2020 compared to the other years which is due to the extremely favorable wind conditions. The capacity factor for wind power in 2020 was 45.71%, while it was 34.39% in 2018 and 34.04% in 2019. The solar PV's capacity factor was 11.5% across all years since the same simulated values are used for solar PV every year. In annual correlation, the importance of having a steady supply of electricity from VRE assets is not as important as in hourly correlation. When the steady supply is not very highly valued, solar PV's importance is minimal at latitudes where solar irradiance is limited. The electrolyzer's consumption was the same in 2018 and 2019: 438 GWh, but 2020 was a leap year, therefore the consumption was 1.2 GWh more in 2020. When taking the consumption increase into account, in 2020 the same wind generation capacity generated 150 GWh and 155 GWh more electricity than in 2018 and 2019 respectively. On average during these three years, the optimal VRE mixes for operational profit maximization led to 0.18 $€/kgH_2$ of profits and the generation exceeded the consumption by 62 GWh. Since the VRE portfolio was identical between the operational profit and operational + Elspot profit cases, the generation and consumption values are the same. The profits in operational + Elspot profit maximization cases were on average 1.59 $€/kgH_2$.

It can be seen from Table 5 that profits change significantly between different years in both operational profit and operational + Elspot profit optimizations. The changes in profits are caused by changes in the VRE portfolio's generation. The costs per produced green hydrogen kilogram can be calculated from the values in Table 5 by subtracting the profit from the green hydrogen price (3 $€/kgH_2$). This hydrogen production cost calculation method is more suitable when focusing only on hydrogen operational profit values. Elspot sales revenues are significant in operational + Elspot profit cases and they affect the profits greatly. The operating margins in operational profit maximization were 5% (2018), 1% (2019) and 12% (2020). The operating margin is calculated by dividing the operating income (profit) by the total revenue (green hydrogen price). Even though the produced amount of green hydrogen and generated electricity are exactly the same in both optimization cases, the differences in profit per produced hydrogen kilogram are significant. This reflects the importance of choosing the right accounting method. The operational profit values could be used when determining the green hydrogen pricing and the operational + Elspot profit values when making investment decisions in the electrolyzer and the VRE assets.

Table 5: The optimal VRE portfolio with a 150 MW total VRE capacity in annual correlation, 2021 Elspot prices.

	Operational profit maximization				Operational + Elspot profit maximization			
	Wind (MW)	Solar PV (MW)	Profit (€/kgH2)	Gen.-Con. (MWh)	Wind (MW)	Solar PV (MW)	Profit (€/kgH2)	Gen.-Con. (MWh)
2018	150	0	0.14	13 873	150	0	1.51	13 873
2019	150	0	0.04	9 345	150	0	1.12	9 345
2020	150	0	0.36	163 019	150	0	2.14	163 019
Avg.	150	0	0.18	62 079	150	0	1.59	62 079

Other than electricity costs associated with the electrolyzer are €4 409 703 and it is identical between different years. For example, the total electricity consumption cost in the 2018 operational profit maximization case was €20 678 153 and the total cost was €25 087 856. The electricity's share of the total costs was 82.4%. During the same year with the operational + Elspot profit calculation, the total electricity cost was €25 699 599 and the total cost €30 109 302 which leads to electricity costs taking an 85.4% share of the total costs. CAPEX and other than electricity OPEX costs represent only 17.6% and 14.6% of the total costs in these examples. The cost structure is similar in 2019 and 2020. This demonstrates the importance of minimizing electricity costs.

As mentioned, the 2021 Elspot prices were higher than the prices in 2018-2020. When maximizing the operational profits with the actual realized Elspot prices in 2018-2020, the resulting VRE mixes are the same in 2019 and 2020 as with the 2021 Elspot prices. In 2018 the solar PV capacity was 0.1 MW and wind capacity 149.9 MW. The operational profits increased across all years with the actual realized Elspot prices, which is expected since electricity is the most important cost factor in green hydrogen production. Compared to the 2021 Elspot prices, the profits increased by 0.33 $€/kgH_2$ (0.47 $€/kgH_2$) in 2018, 0.49 $€/kgH_2$ (0.53 $€/kgH_2$) in 2019 and 0.50 $€/kgH_2$ (0.86 $€/kgH_2$) in 2020 when using the realized Elspot prices. In parentheses are the actual profits with the realized yearly Elspot prices.

Table 6 is identical to Table 5 except the total VRE capacity is increased to 300 MW. What should be noted is that when maximizing the operational profits, solar PV is included in all three years whereas in operational + Elspot profit maximization it is not. Solar PV had tax-free generation and distribution-free boundaries. The 2018 and 2020 operational profit optimizations scale the solar PV plant to the maximum capacity which can be located onsite, thus avoiding the distribution costs. The 2019 operational profit optimization scales the solar PV plant to the tax-free generation limit. If the solar PV plant is under the tax-free generation limit, it is also under the maximum onsite capacity limit. Even though solar PV plants in Finland have significantly worse capacity factors than wind power plants, solar PV is competitive in a 300 MW VRE portfolio if it can be operated under one of those thresholds. On average the profits in operational profit maximization cases were 0.42 $€/kgH_2$ and the generation exceeded the consumption by 560 GWh. In operational + Elspot profit cases the average profit was 4.58 $€/kgH_2$ and the generation exceeded the consumption by 563 GWh. Average wind power and solar PV capacities shouldn't be considered as precise values in the operational profit optimization case since they don't give accurate information about the optimization results. This is due to the onsite and tax boundaries which were explained. Especially the average solar PV capacity does not paint the whole picture. It should be noticed that the optimal solar PV capacity is either at the tax-free limit (0.79 MW) or at the onsite limit (1 MW) and not between those values.

Table 6: The optimal VRE portfolios with a 300 MW total VRE capacity in annual correlation, 2021 Elspot prices.

	Operational profit maximization				Operational + Elspot profit maximization			
	Wind (MW)	Solar PV (MW)	Profit (€/kgH2)	Gen.-Con. (MWh)	Wind (MW)	Solar PV (MW)	Profit (€/kgH2)	Gen.-Con. (MWh)
2018	299	1	0.37	463 740	300	0	4.42	465 745
2019	299.21	0.79	0.33	455 129	300	0	3.64	456 689
2020	299	1	0.56	762 232	300	0	5.67	765 237
Avg.	299.07	0.93	0.42	560 367	300	0	4.58	562 560

With a 300MW total VRE capacity, the profits are higher than with a 150 MW VRE capacity. The reason is that with bigger generation capacities, more low-cost VRE generation can be utilized in the electrolyzer's operation. In operational profit optimization the 300 MW capacity achieved 133% more profits than the 150 MW capacity. In operational + Elspot profit optimization the 300 MW capacity achieved 188% more profits than with 150 MW. Increasing the total capacity does not remove the problem of zero wind generation hours. A lot of the extra generation with larger capacities need to be sold to Elspot and it can't be utilized in the electrolyzer's consumption. Therefore increasing the VRE capacity is not a solution which can by itself solve the electrolyzer's electricity self-sufficiency problem. Other measures like energy storages are needed, if the electricity is wanted to be supplied solely by own VRE generation assets.

7.2.2 Hourly Correlation

In the case of hourly correlation, the electrolyzer operator can't consume more electricity during a one-hour accounting period than is generated by the VRE assets. In an annual temporal correlation, the electrolyzer operator could purchase electricity from Elspot if there were deficits in its own VRE generation. The hourly correlation requirement would be a major limitation for the green hydrogen producers and therefore Maximized Green Hydrogen Production (MGHP) case is analyzed. In essence, MGHP tells how the VRE portfolio should be constructed to maximize the green hydrogen production with hourly correlation requirement. Operational profit maximization case is also analyzed for hourly correlation similar to the annual correlation case. It should be noted that the cost and revenue streams are identical in both the MGHP and operational profit maximization analyses which enables a straightforward comparison between these two cases. When in annual correlation the annual green hydrogen production was 8760 tons since the electrolyzer could operate every hour of the year, in hourly correlation the green hydrogen production amounts can vary. The produced green hydrogen amount can be calculated by multiplying the annual production potential of 8760 tons (8784 tons in 2020) with the utilization rates in Tables 7 and 8.

Table 7 presents the optimal VRE mixes for a 150 MW total VRE capacity in hourly correlation. Electrolyzer's utilization rates and profits from hydrogen sales corresponding to a specific VRE generation mix are presented. Solar PV takes a significant share of the total capacity when MGHP optimization is done. Solar PV capacity is above both the onsite and the tax-free generation limits in all three years. The optimal capacities vary quite drastically between different years, especially 2018 saw a very high optimal solar PV capacity of 32.4 MW (21.6% of the total capacity) but 2019 had only 5.4 MW (3.6%). 2020 which had extremely favorable wind conditions, still had a 12.4 MW solar PV capacity. One explanation for this could be that with high amounts of wind generation, the value of one additional wind generation capacity (MW) becomes less valuable when compared to solar PV. With extremely favorable wind conditions, less wind capacity is needed to provide the required amount of electricity. In this case, solar PV generation's temporally complementary generation becomes more valuable and less costly from the opportunity cost point of view. But these assumptions can't be made only from this data. The differences in utilization rates and profits between MGHP and operational profit maximization cases should be noted. In operational profit maximization, the optimal VRE mix during all three years consisted of 100% wind capacity. In the MGHP case, the average utilization rate across the three years was 62.35% (corresponding to 5 462 tons of green hydrogen) and the average profits were 0.61 $€/kgH_2$. In operational profit optimization, the average utilization rate was 62.11% (5 441 tons of green hydrogen) and the average profits were 0.64 $€/kgH_2$. The profits increased on average by 0.03 $€/kgH_2$ when switching from optimal MGHP mixes to optimal operational profit mixes and the utilization rate decreased on average by 0.24%. It could be stated that these differences are not significant.

Table 7: The optimal VRE portfolios with a 150 MW total VRE capacity in hourly correlation, 2021 Elspot prices.

	Maximized Green Hydrogen Production				Operational profit maximization			
	Wind (MW)	Solar PV (MW)	Utilization Rate (%)	Profit (€/kgH2)	Wind (MW)	Solar PV (MW)	Utilization Rate (%)	Profit (€/kgH2)
2018	117.6	32.4	57.84	0.52	150	0	57.31	0.58
2019	144.6	5.4	58.88	0.59	150	0	58.82	0.60
2020	137.6	12.4	70.32	0.72	150	0	70.19	0.74
Avg.	133.3	16.7	62.35	0.61	150	0	62.11	0.64

In Table 8 optimal VRE portfolios for a 300 MW total VRE capacity in hourly correlation are presented. The results are more uniform between the three years than in the 150 MW optimization case. In MGHP optimization cases, wind and solar PV capacities are in practice identical between the three years, but the profits and electrolyzer's utilization rates vary. As it has been mentioned earlier, 2020 was an extremely favorable year for wind generation, which increases the utilization rate and profits compared to 2018 and 2019 even though the three years had nearly identical

VRE portfolios. The 2018 and 2019 years reflect more normal conditions. The profits in MGHP cases during 2018 and 2019 differ only by 0.01 €$/kgH_2$ and the utilization rate by 1.36%. In MGHP optimization results, the average utilization rate across the three years was 75.67% (6 629 tons of green hydrogen) and the average profits were 0.67 €$/kgH_2$. With the operational profit maximization results, the average utilization rate was 73.52% (6 440 tons of green hydrogen) and the average profits were 0.78 €$/kgH_2$. The profits increased on average by 0.11 €$/kgH_2$ when switching from optimal MGHP VRE portfolio to optimal operational profit portfolio and the utilization rate decreased on average by 2.15%.

Table 8: The optimal VRE portfolios with a 300 MW total VRE capacity in hourly correlation, 2021 Elspot prices.

	Maximized Green Hydrogen Production				Operational profit maximization			
	Wind (MW)	Solar PV (MW)	Utilization Rate (%)	Profit (€/kgH2)	Wind (MW)	Solar PV (MW)	Utilization Rate (%)	Profit (€/kgH2)
2018	232.6	67.4	71.95	0.64	300	0	69.34	0.74
2019	232.7	67.3	73.31	0.65	300	0	71.45	0.76
2020	232.7	67.3	81.75	0.73	300	0	79.77	0.83
Avg.	232.7	67.3	75.67	0.67	300	0	73.52	0.78

The changes in utilization rates are rather insignificant when switching from MGHP values to operational profit maximization values. It raises the question if planning the business according to MGHP would be reasonable. Wind generation is more abundant and cheaper in Finland than solar PV. It is much simpler to build a VRE portfolio that consists of only one kind of power generation technology instead of two. Most likely choosing one generation technology instead of two, would reduce the project-related costs greatly.

7.2.3 Comparison between annual and hourly temporal correlation results

The annual and hourly correlation operational environments are rather different and therefore especially the cost comparisons between them are not straightforward. The profits in operational profit maximization cases between the annual and hourly correlation requirements are analyzed. The costs are better comparable in operational profit optimizations than in operational + Elspot profit optimizations. The revenue from the Elspot market is the same in hourly and annual correlations since the generation and consumption originating from the designated VRE assets are identical during every hour when the VRE portfolios are identical. This is the case with a 150 MW operational profit maximizing VRE generation mix when in both the hourly and annual correlation, the 150 MW VRE portfolio consisted of 100% of wind power capacity. The amount of excess electricity sold to Elspot and Elspot price levels are identical, therefore the Elspot revenue is also identical between hourly and annual correlations. Since in annual correlation, the electrolyzer can operate every hour of the year and in the hourly correlation it can't, the green hydrogen production amounts vary. The MGHP results in hourly correlation are compared to the production potential which is achieved in annual correlation.

Interestingly the profits are bigger in the hourly correlation operational profit maximization case than in the annual correlation operational profit maximization. The average 150 MW operational profit maximizing profits in annual correlation were 0.18 $€/kgH_2$ and in hourly correlation 0.64 $€/kgH_2$. In 300 MW case the profits were 0.42 $€/kgH_2$ (annual correlation) and 0.78 $€/kgH_2$ (hourly correlation). Especially in the 150 MW case, the profits are significantly bigger in hourly correlation. 256% more profit per produced hydrogen kilogram was achieved in hourly correlation. Whereas in the 300 MW case the profits were 86% bigger in hourly correlation. These results are contrary to the prior research provided by the green hydrogen industry. The most significant explaining factor is the high Elspot prices in 2021 which were used in the analyses. In annual correlation, the electrolyzer is run also during the hours when it needs to purchase electricity from Elspot. With a larger VRE generation portfolio, there is less need for Elspot purchases which explains the smaller difference in profits between 300 MW annual and hourly correlation than in the 150 MW cases. The hours which require Elspot purchases are the hours when VRE assets' and especially wind power's generation is low. When the designated VRE assets' generation is limited, usually the VRE generation across the whole Finnish grid is limited as well. These hours are in most cases high Elspot price hours. In Finland, low VRE hours in practice mean low wind generation hours. These low wind hours lead to high electricity costs for the electrolyzer operator. For example the average Elspot costs in the optimal 150 MW operational profit case in 2018 were 63.3 €/MWh, in 2019 69.9 €/MWh, and 65.3 €/MWh in 2020. These are significantly greater costs than the wind's LCOE (25 €/MWh).

When the marginal profit (marginal revenue - marginal costs) is positive, the total profits will increase. When the marginal profit is negative, it can be determined that green hydrogen production with Elspot electricity is not sensible during the negative marginal profit time period. The marginal cost of producing green hydrogen with Elspot electricity (150 MW of wind power) was on average 3.18 $€/kgH_2$ (2018), 3.50 $€/kgH_2$ (2019) and 3.26 $€/kgH_2$ (2020). The marginal cost is higher than the marginal revenue (3 $€/kgH_2$) which makes the additional green hydrogen production with Elspot electricity economically unjustified. The electrolyzer operator is not exposed to the Elspot price risk when it is consuming only electricity which is generated by the designated VRE assets. In the future, Elspot prices can increase permanently at least for a fixed time period. This Elspot price risk should be taken into account if the temporal correlation requirement is more than one hour. Also in the hourly temporal correlation legislative environment, Elspot prices act as an opportunity cost, but not as a direct cost for the electrolyzer operator. In hourly correlation, it is possible to forecast the future electricity costs rather precisely whereas in annual correlation the costs can change significantly between different years and other time periods. Therefore the hourly correlation would lead to a less risky electricity price environment and enables better planning and forecasting of the future costs.

When the Elspot price levels are changed from the 2021 prices to the actual realized prices for every year, the annual correlation cases become more competitive due to the lower electricity price level. Still, the hourly correlation environment is more competitive in almost every optimization case than the annual correlation. The hourly correlation profits and costs don't change if the Elspot prices are changed from the 2021 prices to the actual realized prices, because Elspot purchases are not allowed. With the actual realized Elspot prices the profits in annual correlation with a 150 MW operational profit maximizing VRE portfolio were 0.47 $€/kgH_2$ (2018), 0.53 $€/kgH_2$ (2019) and 0.86 $€/kgH_2$ (2020). Only in 2020, the annual correlation case yield higher profits with the actual realized Elspot prices than hourly correlation. The average Elspot costs were 48.0 €/MWh (2018), 45.7 €/MWh (2019) and 31.6 €/MWh (2020). The marginal costs of producing green hydrogen with the actual realized Elspot prices were 2.40 $€/kgH_2$ (2018), 2.28 $€/kgH_2$ (2019) and 1.58 $€/kgH_2$ (2020). The marginal costs, in this case, are below the marginal revenue from green hydrogen (3 $€/kgH_2$) which makes the additional green hydrogen production with the cheaper Elspot prices economically viable.

In Table 9 the total profits with three different cases for the years 2018-2020 are presented. The VRE mixes are optimized for operational profit maximization and the values presented are the total profits from the hydrogen business. The only revenue source is green hydrogen, costs include annualized electrolyzer costs and the electricity costs related to consumed electricity in the electrolyzer. The optimal capacities were 100% of wind power in all cases except in 2018 when using the 2018 Elspot prices in annual correlation, the wind capacity accounted for 149.9MW and solar PV for 0.1MW. The AC in Table 9 corresponds to annual correlation and HC to hourly correlation. The 2021 prices mean that the used Elspot prices are from the year 2021 and the actual prices mean the prices are from the corresponding year.

As it was explained, the marginal profit for green hydrogen production with Elspot electricity was positive with the actual realized annual prices but negative with the 2021 prices. It can be seen that the highest total profits are achieved in the case "AC Actual Prices" and the lowest in "AC 2021 Prices". Hourly correlation lands between these two cases in total profits, which is expected since the hourly correlation can be seen as a base case before the Elspot purchases occur. In AC 2021 Prices the marginal profit was negative compared to the hourly correlation case, which reduces the total profits. In AC Actual Prices the marginal profit was positive which increases the total profits from the base case. Electricity cost which leads to the marginal cost being equal to marginal revenue (3 $€/kgH_2$) is 60 €/MWh. It is calculated by dividing the marginal revenue of green hydrogen produced with Elspot electricity with the Elspot electricity purchase volume. Electricity taxes and transmission costs need to be considered when calculating the marginal cost. Transmission costs (summertime) and electricity taxes added together equal 4.62€/MWh. That value needs to be subtracted from 60 €/MWh to get the threshold for an Elspot price leading to 0€ of marginal profit. The Elspot threshold value is 55.38 €/MWh for 3 $€/kgH_2$ green hydrogen price. If the average Elspot price during low VRE generation hours is above the 55.38 €/MWh level, it is not profitable to produce green hydrogen with the 3 $€/kgH_2$ price level. With 4 $€/kgH_2$ the Elspot threshold price is 75.38 €/MWh and with 5 $€/kgH_2$ it is 95.38 €/MWh. A one-euro increase in the green hydrogen price allows a 20 €/MWh increase in the allowed average Elspot price.

Table 9: Total profits with 150 MW total capacity, operational profit maximizing VRE portfolios. 150 MW of wind power in all cases, except in 2018 annual correlation with the 2018 Elspot prices 149.9 MW wind power and 0.1 MW solar PV capacity.

	AC 2021 Elspot Prices	AC Actual Elspot Prices	HC 2021 Elspot Prices
2018	€1 192 144	€4 104 132	€2 927 511
2019	€308 482	€4 677 642	€3 094 339
2020	€3 183 629	€7 586 440	€4 553 690

The annual hydrogen production potential with a 50 MWelec capacity electrolyzer is 8 670 tons when it is operated at its maximum capacity all the time. With MGHP optimized values the average green hydrogen production was 5 462 tons (62.35%) with a 150 MW VRE capacity and 6 629 tons (75.67%) with a 300 MW VRE capacity. The green hydrogen volume is much smaller in hourly correlation than in annual correlation. The utilization rates represent how much green hydrogen is produced in hourly correlation compared to the output potential which is achieved in annual correlation. With 150 MW VRE capacity, the maximum average utilization rate was 62.35% which means the hourly correlation output was only 62.35% of the annual correlation output.

7.2.4 Green and non-green hydrogen production in an electrolyzer

If the end consumer needs to have a steady supply of hydrogen during all hours, the deficit of the green hydrogen production caused by the hourly temporal correlation requirements needs to be procured from other sources. One possible non-green hydrogen procurement method is to run the electrolyzer at its maximum capacity even during the hours when the green hydrogen requirements are not fulfilled. This would lead to a situation where both green and non-green hydrogen are produced in the electrolyzer. Out of the total hydrogen produced, green hydrogen's share is equal to the utilization rate percentages in Tables 7 and 8. If the green hydrogen production is prioritized and maximized, the non-green hydrogen production would account for 100% - utilization rate%. The costliest Elspot hours, which would lead to losses, can be dismissed which would reduce the non-green hydrogen production amount. For example with the average 150 MW MGHP optimized values, the non-green hydrogen production would be at maximum 3 298 tons. Non-green hydrogen prices would most likely be lower than green hydrogen prices because the end-user can't account it as green. The estimated gray hydrogen price is 2.50 $€/kgH_2$ which includes the EU ETS cost corresponding to 90 €/ton price as explained in Section 3. With 2.50 $€/kgH_2$ non-green hydrogen price, the non-green hydrogen could be produced profitably when the Elspot prices are at maximum 45.38 €/MWh.

With the 2021 Elspot prices there were 5 672 hours when the Elspot price was more than 45.38 €/MWh. In 2018 with the 150 MW MGHP optimized VRE generation mix, there were 3 346 hours when the Elspot price was more than 45.38 €/MWh and the electrolyzer's consumption could not be fully matched with own VRE generation. The Elspot purchases needed on top of the green hydrogen production to achieve a 100% utilization rate were 184 654 MWh. Out of these purchases 106 724 MWh were done when the Elspot price exceeded 45.38 €/MWh. The Elspot purchase amount leading to non-negative marginal profits is therefore 77 930 MWh which corresponds to 1 559 tons of non-green hydrogen production. In this case, the green hydrogen production is 5 067 tons and the total hydrogen production is 6 626 tons (75.6% of the potential production). The total Elspot cost for the non-green hydrogen is €2 207 860 and the revenue is €3 897 500. The maximal marginal profit which can be obtained by running the electrolyzer outside of the hourly temporal correlation requirements is €1 689 640. The green hydrogen profit is considered as a base case which would happen in any case, therefore the electrolyzer CAPEX+OPEX costs are included there and not in the non-green hydrogen costs. The green hydrogen costs are in total €12 586 295 and the revenue €15 200 749, corresponding to €2 614 454 of profit. The green + non-green hydrogen profits combined are €4 304 094.

In comparison, in 2018 with the 150 MW operational profit maximization values, there were 3 091 hours when there was a need for Elspot purchases and the Elspot price exceed 45.38 €/MWh. Even if the number of hours is smaller than with the MGHP values the total Elspot purchases during those hours was 110 885 MWh, 4 161 MWh more than with the MGHP values. This is because the Elspot purchases are distributed more evenly between different hours with MGHP optimized VRE generation. The total Elspot purchases to achieve a 100% utilization rate was 186 985 MWh. With 150 MW operational profit maximizing VRE mix (100% wind) the green hydrogen production is 5 020 tons and the non-green hydrogen production with non-negative marginal profit is 1 522 tons. In total, the hydrogen production is 6 542 tons (74.7% of the potential production), 84 tons less than with the MGHP values. The total Elspot cost is €2 162 112 and the non-green hydrogen revenue is €3 805 000. Non-green hydrogen profit is €1 642 888. The green hydrogen costs are €12 133 375 and revenue is €15 060 887, corresponding to € 2 927 512 of profits. The total green+non-green hydrogen profit is €4 570 400. The green+non-green hydrogen profits are significantly greater in 2018 than the profits in operational profit maximization cases in annual and hourly correlation cases when only green hydrogen is produced.

The green+non-green hydrogen production amounts and profits in 2018 in an hourly correlation environment with a 150 MW MGHP and operational profit maximizing

VRE generation mixes are presented in Table 10. The VRE portfolios are the same as in Table 7 and thus they are optimized for only green hydrogen production. The presented profits are maximum profits that can be obtained in an hourly correlation environment since the non-green hydrogen is produced only when the marginal profit is positive. Table 10 also includes profit comparisons to cases when only green hydrogen was produced. It should be noted that the profits can be significantly increased if non-green hydrogen production is included on top of the green hydrogen production. Available hydrogen amount is increased which is a positive outcome, especially for customers who value a steady supply of hydrogen.

Table 10: Green + Non-Green Hydrogen production with maximized total profit in hourly correlation requirement with optimal MGHP and operational profit maximizing 150 MW capacities in 2018

	G+NG Max Green H2 Production	G+NG Operational profit max
Green H2 (tons)	5 067	5 020
Non-Green H2 (tons)	1 559	1 522
Total H2 (tons)	6 626	6 542
Total profit (€)	€4 304 094	€4 570 400
Total profit per produced H2kg (€$/kgH_2$)	0.65	0.70
Difference to MGHP only-green H2 production profits (€)	€1 689 639	€1 955 945
Difference to operational profit max only green H2 production profits (€)	€1 376 583	€1 642 889
Difference to annual correlation (€) profits	€3 111 950	€3 378 256

In the annual correlation requirement, the most expensive hours can be avoided as well. The electrolyzer should be operated always when the marginal revenue is bigger than the marginal costs. This is the same principle as in the hourly correlation green + non-green hydrogen case. But now the revenue is all the time at the higher green hydrogen price level 3 €$/kgH_2$ and the operator doesn't need to consider the non-green hydrogen discounts.

The Elspot price threshold for non-negative marginal profit in annual correlation with a 3 €$/kgH_2$ price is 55.38 €/MWh. The year 2018 with 2018 generation data and 2021 Elspot price data is analyzed here as an example of the effects on annual production. There were 4 514 hours in total when the Elspot price was over 55.38 €/MWh and 2 316 hours when Elspot purchases were done when the Elspot price exceeded 55.38 €/MWh. The total Elspot purchase volume during hours exceeding 55.38 €/MWh was 82 844 MWh and the total annual purchase volume was 186 985 MWh. Elspot purchase volumes leading to non-negative marginal profits was 104 141 MWh (corresponding to 2 083 tons of green hydrogen) and the associated total cost was €3 575 029. The production which would require Elspot purchases with more than 55.38 €/MWh price is abandoned, therefore the total green hydrogen production amount is 7 103 tons. This is calculated by deducting 82 844 MWh (1 657 tons) from the annual green hydrogen potential. The total green hydrogen revenue is €21 309 000. Other costs than the Elspot costs were in total €12 133 375. In this case the profits from green hydrogen production is (excluding Elspot sales) €5 600 596 (0.79 $€/kgH_2$). In comparison, the annual correlation profits in 2018 with the exact same VRE generation mix were €1 192 144 when the electrolyzer was operated at its maximum capacity every hour of the year. One of the best comparisons to make between hourly and annual correlation costs is achieved by comparing the hourly correlation costs when green and non-green hydrogen is produced with the annual correlation costs when the costliest green hydrogen production is abandoned. This way, annual correlation is not the only one to suffer from high Elspot price hours. In this case the annual correlation profits were 0.79 $€/kgH_2$ which means the costs were on average 2.21 $€/kgH_2$. The profits in operational profit maximizing green + non-green hourly correlation case were 0.70 $€/kgH_2$ corresponding to an average cost of 2.30 $€/kgH_2$.

It should be noted that in 2018 with annual correlation the hydrogen production amount which fulfills the green hydrogen criteria was 7 103 tons when in hourly correlation it was only 5 020 tons. With the hourly correlation requirement, the total profitable hydrogen output was 6 542 tons. The green hydrogen production is significantly smaller with the hourly correlation requirement than in the annual correlation. The total output (green + non-green) is also smaller with hourly correlation than the green hydrogen output in annual correlation. This is because in annual correlation, the hydrogen price level can be at 3 $€/kgH_2$ at all times, compared to the hourly correlation when it needs to be dropped to 2.50 $€/kgH_2$ when the green hydrogen requirements are not met. The revenue potential is greater in annual correlation. Depending on the customer preference, the output volumes can be more important than the relatively small price changes. If the hydrogen output volume is prioritized over the price, the customer might be willing to pay more per produced hydrogen kilogram which is produced during the high Elspot price hours. This would enable increasing the non-green hydrogen output volume in an hourly correlation environment.

Table 11 brings together the Elspot optimized hydrogen production values which are discussed in this subsection. The example year is 2018 and the VRE generation portfolio is 150 MW of wind power in both the annual and hourly correlation, thus the generation profile is identical. Elspot prices are from 2021.

Table 11: Hydrogen production in 2018 when the Elspot optimization is done. Hydrogen is produced only when the marginal profit is positive from Elspot electricity purchases. 150 MW wind power capacity, 2021 Elspot prices

	Annual Correlation 2021 Elspot prices	Hourly Correlation 2021 Elspot prices
Green H2 (tons)	7 103	5020
Non-green H2 (tons)	0	1 522
Total H2 (tons)	7 103	6 542
Costs (€/kgH2)	2.21	2.30
Total profit (€)	5 600 596	4 570 400

7.3 Minimum VRE capacities for 95% electrolyzer utilization rate

In this Subsection the goal is to find the minimum VRE capacities with four different battery storage capacities which would lead to a 95% electrolyzer utilization rate in an hourly correlation environment. As it was seen in Section 7.2.2, the maximum utilization rates on average were 62.35% with 150 MW and 75.67% with 300 MW VRE capacity which are much smaller than the 95% goal. Because of the windless periods, it is rather difficult to increase the utilization rate from these numbers without expanding the VRE capacity multiple times. For example in 2018 with the MGHP VRE mix, the longest continuous time period when the VRE generation was under 10 MWh was 42 hours. The longest time period with under 10 MWh of wind generation is 72 hours. Wind generation is the backbone in terms of electricity generation volume, but solar PV can supplement it as can be seen from those numbers. The continuous time periods are flawed in analyzing the low VRE generation periods. In the data, there are many cases when the VRE generation increases over 10 MWh for a couple of hours after being under the threshold for 20+ hours, which breaks the continuous time period calculation. But after those hours the VRE generation decreases under 10 MWh for multiple hours.

Simple Moving Average (SMA) calculation gives a better understanding of how the VRE generation has acted in a studied timeframe. SMA tells us the average of studied data points in the given time frame. For example, 24 SMA in hourly generation data context, the average generation from the previous 24 hours is calculated. When new data points are included, the data points which are now outside of the 24-hour window are removed, this makes the average calculation "moving". In 2018 data, the smallest 24-hour SMA for VRE generation with the 150 MW VRE capacity (117.6 MW wind, 32.4 MW solar PV) is 2.6 MWh and the biggest is 111.1

MWh. The average 24 SMA is 44.1 MWh. Figure 14 presents the daily average 24 SMAs for the 2018 VRE generation. The VRE portfolio consists of 117.6 MW wind capacity and 32.4 MW solar PV capacity, totaling 150 MW. 24 SMAs are calculated for every hour of the year, and then the average 24 SMA is calculated for every day. From Figure 14 we can see the big volatility in VRE generation which wouldn't be noticeable from the cumulative time periods when the VRE generation is below some threshold value. The average 24 SMA seems to be extremely volatile and it is often near the maximum or minimum capacities, not between these two extremes. This makes the electrolyzer operation more difficult than if the electricity supply would be steadier even if it would mean less electricity output. Especially the time periods when the 24 SMA is low for multiple days, are difficult to offset without big energy storage capacities. Increasing VRE capacity is one solution, but it can only help to a certain point. Because of these low 24 SMA periods, we don't try to achieve 100% utilization rates which would be impossible in practice.

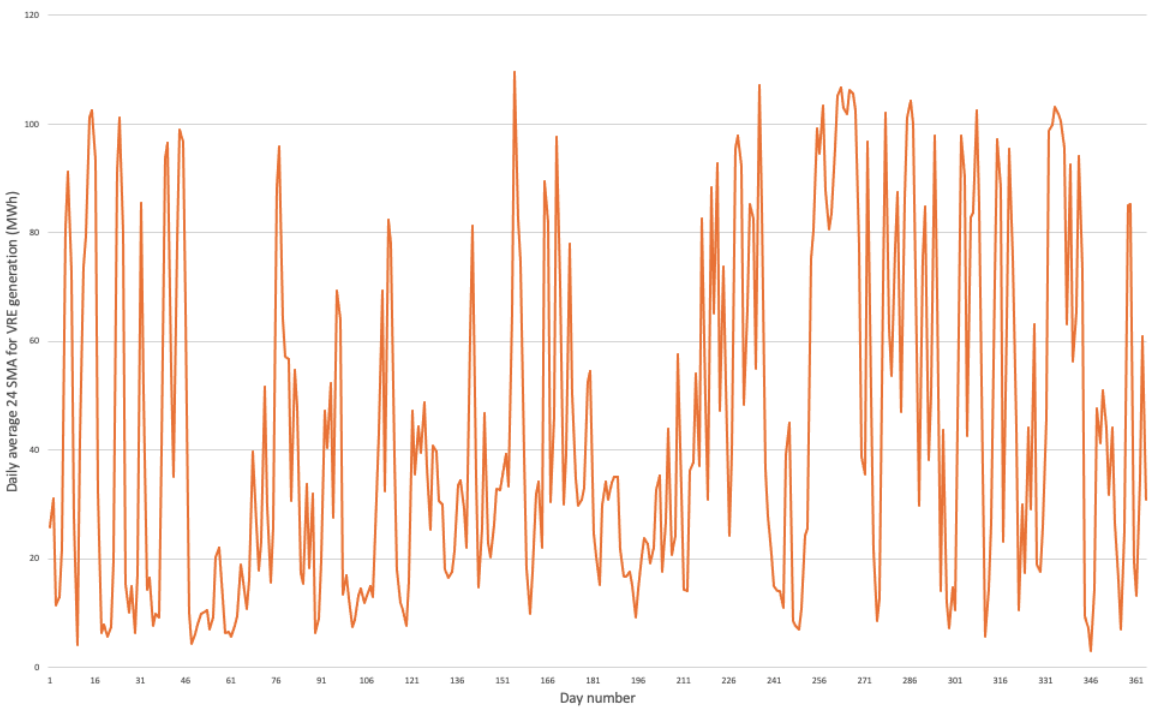

Figure 14: Daily average 24 SMAs in 2018 for 150 MW VRE generation

The minimum capacities which achieve a 95% utilization rate with four different battery storage sizes are presented in Figure 15. The values are averages from 2018-2020. In each case, the total capacity was minimized by changing the solar PV and wind capacities. The battery storage capacity was fixed either to 0 MWh, 50 MWh, 100 MWh or 200 MWh. The most important and obvious observation is that with bigger storage capacities, the required generation capacity is smaller. With a 200 MWh battery, the required VRE capacity is less than half what is needed without any battery capacity. But even with the 200 MWh battery, the required

VRE capacity is very large: 736 MW. Most likely it isn't realistic to harness that much of VRE capacity to supply a 50 MW electrolyzer. It is noted that the required capacities are unrealistic at least in the current market, but the results should be studied to understand better what is needed to achieve high utilization rates in a difficult legislative environment. The required capacities could be realistic in the future. The most significant reduction in VRE capacity requirement is achieved when scaling the battery from 0 MWh to 50 MWh. The needed VRE capacity is reduced by 27% (382 MW). When scaling the battery from 100 MWh to 200 MWh the VRE capacity reduction is 23% (218 MW), significantly less than what the first battery installation decreases the needed VRE capacity even if the battery size increase is double the size (100 MWh versus 50 MWh). The marginal increase in the electrolyzer's utilization rate is the greatest during the first energy storage capacity increases. More about the utilization rate increases and marginal profits and costs associated with batteries in Section 7.4.

Another observation that should be made, is that with larger battery storage capacities, the solar PV's share out of the total capacity increases. This is most likely due to the better excess wind generation storage capabilities which enable the use of solar PV as a complementary generation method for the long low wind periods. When the storage capacity is limited, wind generation takes a bigger share because wind generation's higher capacity factor compared to solar PV is more valuable. I.e. with large energy storage capacities, some high capacity factor wind capacity can be traded for solar PV capacity which offers generation diversification for different hours.

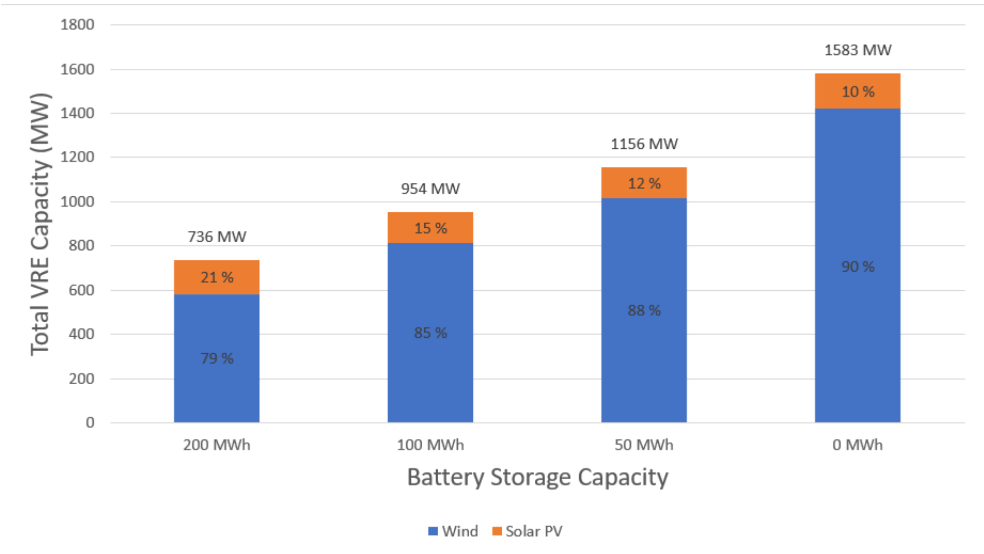

Figure 15: Minimized VRE capacities and the optimal combination of solar PV and wind power for a 95% electrolyzer utilization rate with different battery storage capacities.

7.4 Cost optimal battery capacity and battery storage's effect on the electrolyzer's utilization rate

In this Section, the benefits and costs of increasing battery storage capacities are analyzed. The only temporal correlation requirement which is considered in the analyzes is the hourly correlation because there the need for short-term energy storage is the greatest. The optimal battery storage capacities are studied for different green hydrogen prices and battery CAPEX values. The optimal battery size calculations are based on the utilization rate increases achieved by different battery sizes. The utilization rate increase leads to bigger quantities of output and revenue, but it comes with the cost of additional investments into batteries. The utilization rates are derived for an electrolyzer with a 50 MWelec capacity. The battery's charge/discharge capacities are always 50 MW, equal to the electrolyzer's maximum capacity. The electricity is supplied by a VRE portfolio which is optimized for the MGHP i.e. maximized utilization rate without a battery. In essence, we study how different battery sizes affect the electrolyzer's utilization rate when electricity is supplied either by 150 MW or 300 MW VRE portfolios.

7.4.1 Different battery storage capacities' effect on electrolyzer's utilization rate

In Figure 16 the change in electrolyzer's utilization rate as a function of battery storage capacity increase is presented. The battery storage capacity is increased by 5 MWh intervals which are shown on the x-axis. The values on the y-axis present the increase in the absolute percentage point values of the electrolyzer's utilization rate compared to the previous, 5 MWh smaller, battery capacity. The values are calculated as averages from the years 2018-2020 for both the 150 MW and 300 MW of total capacity with optimal VRE mixes for MGHP (utilization rate maximization) without any energy storage capabilities. For example, the first points on the orange line on the left-hand side mean that with a 150 MW VRE capacity, the utilization rate increases by 0.35%-points (62.35% to 62.70%) when a 5 MWh battery is installed compared to no battery case. When the battery capacity is increased from 10 MWh to 15 MWh the utilization rate increases by 0.25%-points. Even the biggest marginal increases in utilization rate are not significant. A 0.35%-point increase in the utilization rate corresponds to 31 tons of green hydrogen.

The most important observation to be made is that with the first battery capacity additions, the effect on utilization rate increase is the greatest. This is expected since even with small battery capacities during the first low VRE generation hours, some generation deficits can be compensated. On the other hand, with big battery capacities more VRE generation deficit can be compensated, but this requires that excess VRE generation is available in large amounts during the high VRE generation periods for the battery to be fully charged. Big batteries can't compensate for long periods of VRE deficit, e.g. with a 50 MW electrolyzer, a fully charged 200MWh battery can provide electricity only for four maximum load hours in case there isn't any VRE generation available. The long low VRE generation periods decrease the effectiveness of big batteries. As described in Section 7.3, VRE generation can increase momentarily during a long low VRE generation period, which doesn't enable battery charging. All of these factors decrease the overall effectiveness of big batteries. This explains the decreasing marginal effect of batteries on utilization rate when the battery capacity is increased which can be seen in Figure 16.

Figure 17 presents the absolute utilization rate of an electrolyzer with different battery sizes. It has the same data as Figure 16. The only difference is in data presentation, Figure 17 shows the absolute utilization rate where as Figure 16 shows the change in utilization rates. We can make the exact same conclusions from these two figures. Figure 17 highlights the small cumulative change in the absolute utilization rate with different battery sizes.

Small batteries have more battery charge cycles than bigger batteries. One battery charge cycle is achieved when the battery is first charged and then discharged the same amount as its maximum energy storage capacity. One cycle can be achieved through discharging a fully charged battery from 100% to 0% or discharging a partially charged battery e.g. two times from 75% to 25%. In other words, to achieve one battery charge cycle, the battery only needs to be cumulatively charged and discharged an equal amount to its capacity. Smaller batteries have more charge cycles than bigger batteries in one year. For example in 2020 with 150 MW VRE capacity, a 10 MWh battery had 326 cycles, 100 MWh 194 cycles and 200 MWh 151 cycles. This represents that the potential of small batteries is more efficiently utilized.

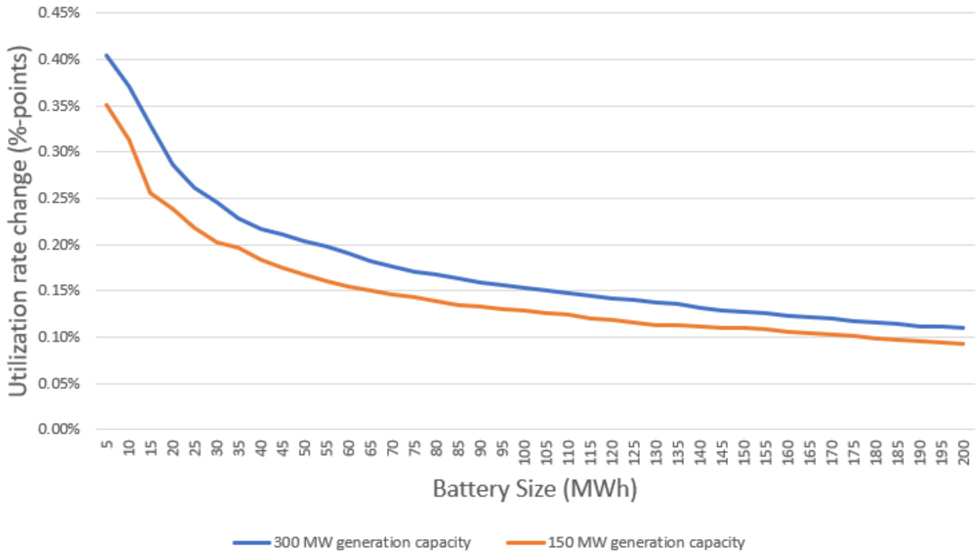

Figure 16: Electrolyzer's utilization rate as a function of battery storage capacity with 150 MW and 300 MW VRE generation. Hourly temporal correlation requirement.

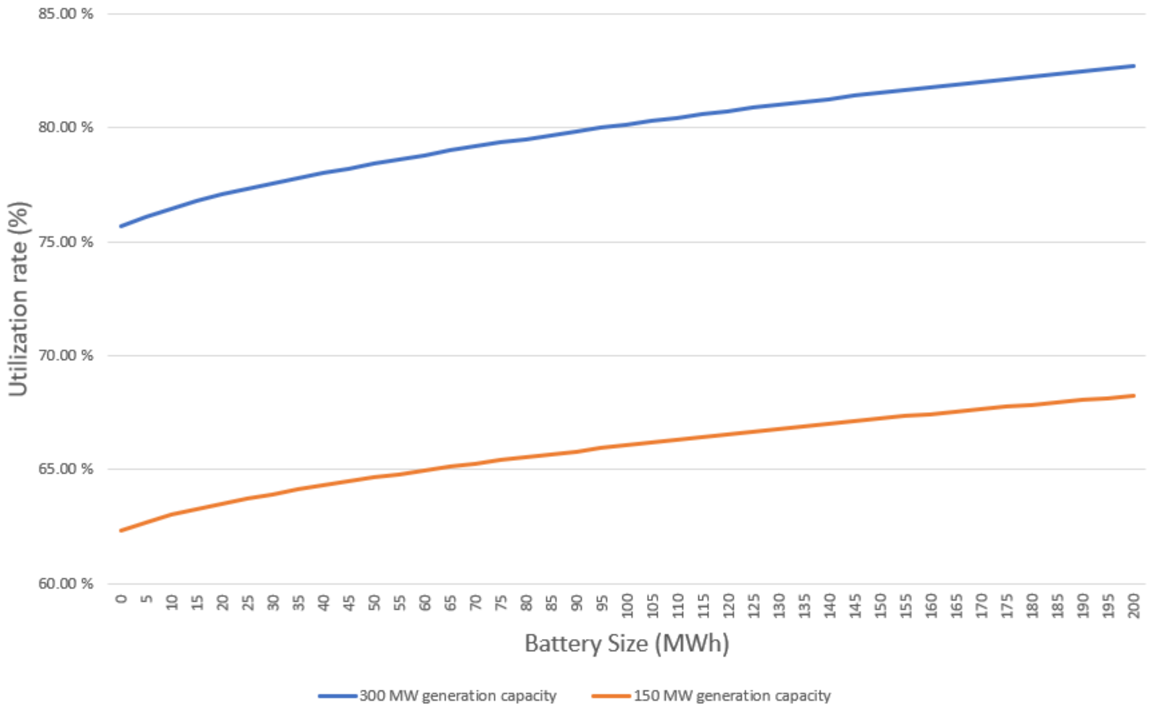

Figure 17: Electrolyzer's absolute utilization rate as a function of battery storage size with 150 MW and 300 MW VRE generation. Hourly temporal correlation requirement.

7.4.2 Marginal revenues and costs with different green hydrogen prices and battery CAPEX levels

Marginal revenue and cost are important concepts in optimal battery storage size analyzes. Marginal revenue means how much additional revenue can be achieved by additional one unit output increase. In this case the battery storage capacity is increased, which increases the green hydrogen output. The battery storage capacities are increased by 5 MWh intervals. Marginal cost means how much costs increase when the output is increased by one unit, or in our case by 5 MWh. Marginal profit is calculated by subtracting marginal costs from marginal revenues. Marginal profit is the most important value when determining whether additional investments are reasonable. It tells how much additional profit can be made if for example in this case battery storage capacity is increased. If marginal profit is positive, increasing battery storage capacity is justified and if it is negative it tells that additional investment would lead to losses.

As it was described in Section 7.2, with current battery CAPEX and assumed green hydrogen prices, the battery storage capabilities are not economically feasible. With higher green hydrogen prices it is possible to invest in energy storages. Also if the storage CAPEX costs are reduced, the current green hydrogen price levels can justify the investments.

The marginal revenue, costs, and eventually profits when coupling an electrolyzer with a battery, are based on the utilization rate changes. When the utilization rate increases, the revenue from green hydrogen is increased, thus the marginal revenue is positive. But we have to take into account the marginal costs associated with increasing the battery storage capacity. When the utilization rate is increased by 1% the green hydrogen output increases by 87 600 tons. The output increase is multiplied by the green hydrogen price to determine the marginal revenue. For example with the biggest utilization rate increase achieved in Figure 16 with a 300 MW VRE capacity, 0.40%, the marginal revenue with 3 $€/kgH_2$ price is €105 120. With 4 $€/kgH_2$ it would be €140 160 and with 5 $€/kgH_2$ €175 200. Both the green hydrogen price and the output increase affect the marginal revenue. As the utilization rate increase faces diminishing returns so does the marginal revenue. When the battery is scaled from 95 MWh to 100 MWh the utilization rate increase is only 0.15% which leads to marginal revenue of €39 420 with a 3 $€/kgH_2$ price.

Marginal costs associated with the battery storage capacities are simpler than the marginal revenues. In our case, the battery CAPEX presented in constant €/kWh values. This means that the marginal costs are constant with every battery storage capacity increase. Scaling the battery from 0 to 5 MWh has the same cost as scaling from 95 MWh to 100 MWh. Therefore a line that presents marginal cost is horizontal. The marginal cost is calculated by multiplying the costs corresponding to the additional investment by quantity. In this case, costs are battery CAPEX and quantity is additional battery storage MWh. Because the additional battery investments would yield utilization rate increases across multiple years, the additional CAPEX cost needs to be annualized to enable the comparisons between marginal revenues and costs. The battery's annuity factor is 10.38 as explained in Section 7.1. Increasing the battery storage capacity by 5 MWh leads to the annualized marginal cost of €135 356 when the CAPEX cost is 281 €/kWh. Most likely in practice the marginal costs wouldn't be constant, because bigger batteries require more space which could be a limiting factor: after a certain point, assigning more space for batteries becomes extremely costly. Small batteries are rather easy to accommodate, but MWh-scale batteries require large spaces assigned solely to them. On the other hand, economies of scale could reduce the cost of large batteries. When project development and balance of plant costs are allocated to more MWhs, the cost per MWh becomes cheaper. These are often project-specific problems and cost calculations, which need to be taken into account when optimizing the costs.

Figure 18 presents marginal revenues for an electrolyzer operator with five different green hydrogen prices. The five downward sloping lines present the marginal revenues, each with a different green hydrogen price. The marginal cost associated with a 281€/kWh CAPEX cost is the horizontal line and it is presented for comparison with marginal revenue. The marginal revenue is calculated based on utilization rate increases obtained with different battery storage capacities. The VRE generation mix is the optimal 300 MW VRE generation capacity for maximizing the utilization rate of an electrolyzer without any batteries (MGHP optimal). The utilization rates are averages from the years 2018-2020, and the average optimal VRE portfolio during those years consisted of 232.7 WM wind power and 67.3 MW solar PV. The utilization rate without a battery is 75.67% which corresponds to 6 629 tons of green hydrogen. The starting point without any battery capacity leads to total revenue of €19 887 000 with 3 $€/kgH_2$ green hydrogen price. Every point on the marginal revenue lines presents the marginal revenue when the battery capacity is scaled by 5 MWh from the previous capacity. Therefore the marginal revenue achieved by scaling the battery e.g. from 0 MWh to 15 MWh is calculated by summing all the marginal revenues corresponding to 5 MWh, 10 MWh and 15 MWh together. From Figure 18 we can see that with the current battery CAPEX and green hydrogen price levels, an investment even into the smallest possible battery (5 MWh) would lead to losses due to the marginal revenues being smaller than the marginal costs. Every investment which yields higher marginal revenues than the marginal cost of €135 356, is profitable. With 4 $€/kgH_2$ the biggest profitable battery size is 5 MWh which enables €141 856 of additional revenue leading to €6 500 of marginal profit. With 5 $€/kgH_2$ the optimal battery size is 15 MWh and with 7 $€/kgH_2$ 35 MWh. If the price level is 5 $€/kgH_2$ and the battery is scaled from 0 MWh to 15 MWh the total marginal profit would be:

$$(€177320 + €162723 + €144273) - 3 * €135356 = €78248$$

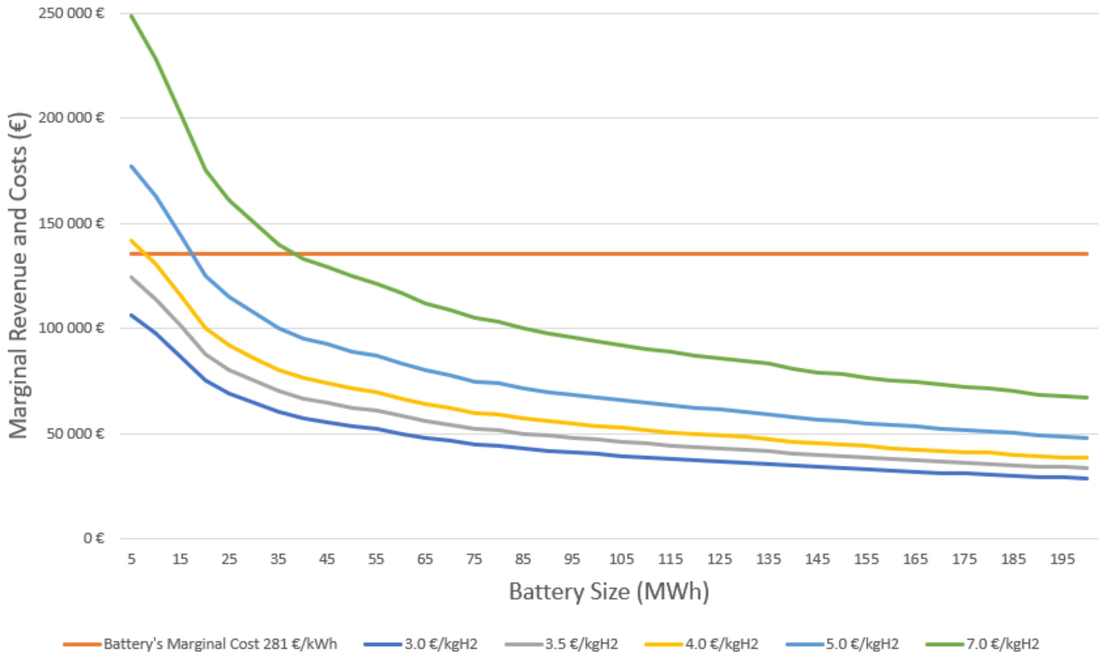

Figure 18: Marginal revenues for different green hydrogen prices based on utilization rate increases with different battery storage capacities. Marginal cost is calculated from the current battery CAPEX levels (281 €/kWh). VRE generation portfolio of 300 MW (232.7 MW wind, 67.3 MW solar PV)

In Figure 19 marginal costs of batteries with different CAPEX values compared to marginal revenues are presented. The horizontal lines present the marginal cost of increasing the battery storage capacity with six different CAPEX (€/kWh) values. The biggest value, 281 €/kWh is the value that is used in our case. This is the current battery investment cost. As it was already noted in Figure 18, the current battery CAPEX costs can't justify investments into batteries. The annualized marginal costs for different battery CAPEX values are:

- 281 €/kWh: €135 361
- 250 €/kWh: €120 428
- 200 €/kWh: €96 342
- 150 €/kWh: €72 257
- 100 €/kWh: €48 171
- 50 €/kWh: €24 086

50 €/kWh CAPEX level would enable even the biggest studied 200 MWh battery capacities. This CAPEX level is extremely optimistic and won't happen in the foreseeable future. 150 €/kWh CAPEX level would require major advances in the energy storage industry, but it is not ruled out in the mid to long term. With a 150

€/kWh CAPEX level, the biggest possible battery sizes for different green hydrogen prices leading to positive marginal profit are presented below. In the parentheses are the cumulative utilization rate increases with the specific battery storage capacity compared to the case without a battery.

- 3 €/kgH2: 20 MWh, (1.39%)
- 4 €/kgH2: 45 MWh, (2.56%)
- 5 €/kgH2: 80 MWh, (3.85%)

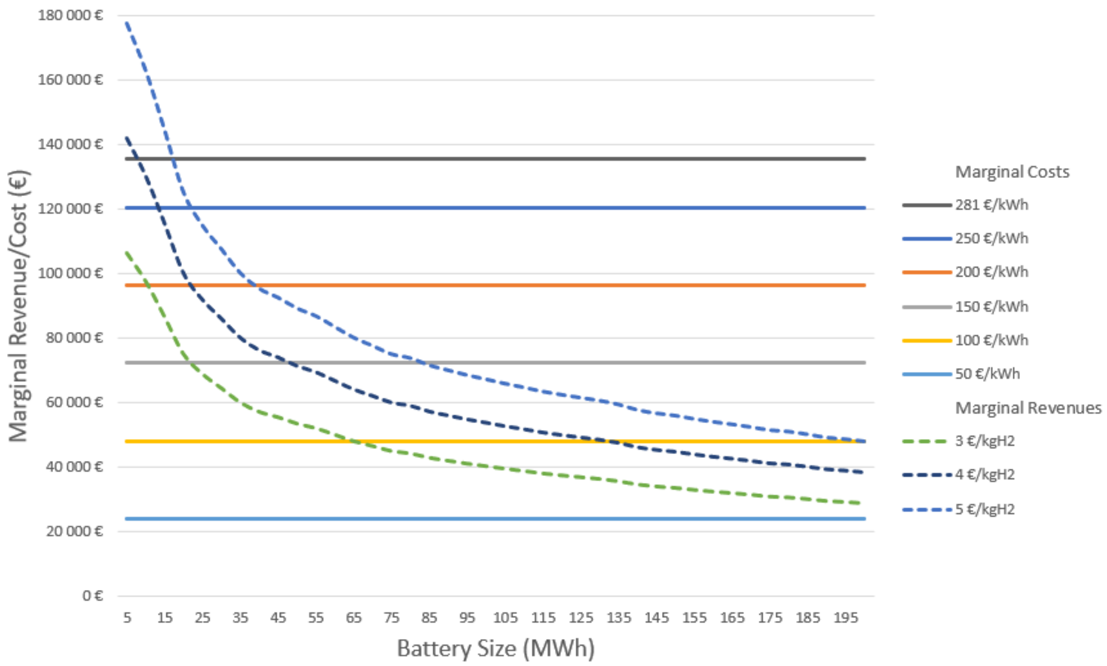

Figure 19: Horizontal lines: Marginal costs for batteries with different battery CAPEX values. Dashed lines: Marginal revenues for additional green hydrogen production with different battery storage capacities. VRE generation portfolio of 300 MW (232.7 MW wind, 67.3 MW solar PV)

It is expected that the battery costs will decrease in the future and the cheaper investment costs will be more relevant from the investment point of view. Although, any drastic reductions in energy storage investment costs are not expected in the mid-term, which could enable 100+ MWh storages to be coupled with an electrolyzer. Most likely the CAPEX reductions will enable investments in a maximum of 50 MWh batteries. As it was seen from the marginal revenues, with higher green hydrogen prices the additional battery investments would be competitive already today. The green hydrogen price is agreed between the producer and buyer of green hydrogen. If the buyer values the additional output enough, the price can be increased to levels enabling battery investments. Most likely the current industrial buyers do not value the rather small increase in output highly enough, which could make the batteries competitive.

In addition to batteries, values presented in Figure 19 apply to any storage technology if their investment costs act similarly. Similarly in this case means that every MWh increase in energy storage capacity would result in the same investment cost increase per MWh. The only question is whether the utilization rate can be increased the same amount as with the batteries. Batteries and hydrogen storages both act as energy storage from the system's point of view. Disregarding the technical aspects, the two storages' difference is in whether the energy is stored in front of or behind the electrolyzer. This is important when analyzing the total effect on the system and the required investments if a stable supply is desired. Because batteries store the energy in front of the electrolyzer, no additional investments are required in addition to the battery. Hydrogen storages store the energy behind the electrolyzer. To provide similar storage and VRE fluctuation leveling off potentials, hydrogen storage requires increased electrolyzer capacity. If the demand is 1 ton/hour (corresponding to 50 MWelec) and low VRE generation time periods need to be leveled off, the electrolyzer capacity needs to be increased to levels that enable hydrogen storage filling during the high VRE generation periods. In our case, the battery's discharging and charging capacities were 50 MW for discharging capacity not to be a constraint for a 50 MW electrolyzer. Theoretically for the hydrogen storage to achieve similar charging potentials as the battery, the electrolyzer should be scaled to 100 MWelec capacity. This would be extremely costly, doubling the electrolyzer investment cost. If the hydrogen storage would be implemented in practice, the electrolyzer capacity would be increased but not as dramatically as doubling the capacity. A 25% increase could be one estimation that corresponds to 62.5 MW in our case. This limits the charging potential of the hydrogen storage, but not the discharging potential. Overall, operating a hydrogen storage would create a more difficult operating environment than if a battery acts as the energy storage. Batteries enable better and especially faster demand response potentials which could generate additional revenue streams. In future studies, comparing the hydrogen storages' and batteries' influence on the overall system's efficiency and investments should be studied further.

7.5 Small scale solar PV generation

In Section 7.2 it was noted that the share of solar PV in the VRE mix depends on what is the most prioritized aspect of the electrolyzer operation and what are the legislative requirements. In hourly correlation, the need for solar PV is clearer than in annual correlation since the VRE generation sets the limits for the electrolyzer operation every hour. Whereas in annual correlation, the VRE portfolio only needs to be optimized in accordance to cost minimization and make sure the annual energy quantities match inside one year.

If the onsite solar PV generation is considered in the annual correlation environment as a supplementary and not a trade-off for wind generation, profits can be increased. In every optimization case in annual correlation, the optimal VRE portfolio consisted of 100% of wind when the total capacity was limited to 150 MW. With 150 MW wind capacity and 1 MW onsite solar PV capacity, the profits can be increased when compared to the cases with only 150 MW of wind capacity. Compared to the 150MW/0MW case the 150MW/1MW case delivered €18 461 (2018), €20 340 (2019), and €15 706 (2020) more profits from the hydrogen business. The profit increases in percentages were 1.5% in 2018, 6.6% in 2019 and 0.5% in 2020. Especially during the years when wind generation is limited, the additional 1 MW solar PV generation can increase the profits relatively much. But when the wind generation is plentiful, the profit increase in percentages is not significant. The absolute value of the additional profit is not big. In annual correlation, onsite solar PV generation which does not displace wind capacity can be considered as a low-hanging fruit, since the transmission costs can be avoided and the electrolyzer operator can reduce her Elspot price risk. 150MW/0MW VRE portfolio yields higher profits than 149MW/1MW, therefore also 150MW/1MW yields more profits than 149MW/1MW.

Especially in hourly correlation, choosing the priorities in electrolyzer operation is important. Before committing to a certain VRE portfolio, it should be made clear whether the profits or green hydrogen output volume are prioritized. If the profits are prioritized, with a fixed 150 MW total capacity, wind capacity should take a 100% share of the total capacity. But if the green hydrogen output is prioritized, solar PV should be included.

In Figure 20 the effect of solar PV capacity on utilization rate is demonstrated. The generation data is from 2018 and the total capacity is fixed at 150 MW. This means that increase in solar PV capacity is deducted from wind generation capacity. The optimal VRE portfolio when maximizing the green hydrogen output is 117.6MW wind power and 32.4MW solar PV capacity. Solar PV generation is costlier than wind generation. Therefore it is not justified in any case to scale the solar PV capacity over the utilization rate maximizing capacity. Similar figures can be plotted for other years. The utilization rate increases when the solar PV capacity is increased from 0 MW to the point where the utilization rate maximum is achieved. After that point, the utilization rate starts to decrease if solar PV capacity is still increased. The optimal VRE mixes for MGHP/electrolyzer's utilization rate maximization in hourly correlation for different years were presented in Section 7.2.2 in Tables 7 (150 MW) and 8 (300 MW).
If the operational profits are prioritized in hourly correlation, and the solar PV is considered as supplementary to wind generation capacity, the profits can be increased by installing an additional 1 MW onsite solar PV plant in addition to 150MW of wind generation capacity. The operational profits are not significantly increased, but the onsite solar PV capacity has a positive effect. The profits were increased by €11 289 (0.4%) in 2018, €9 714 (0.3%) in 2019 and €7 256 (0.2%) in 2020 when compared to the 150 MW of wind power and 0 MW of solar PV capacity case. Compared to the MGHP/utilization rate maximizing VRE portfolio, the 150MW/1MW yields on average €175 440 (5.9%) more profits. In the case of hourly correlation, the onsite solar PV capacity should also be considered as a low-hanging fruit that can provide

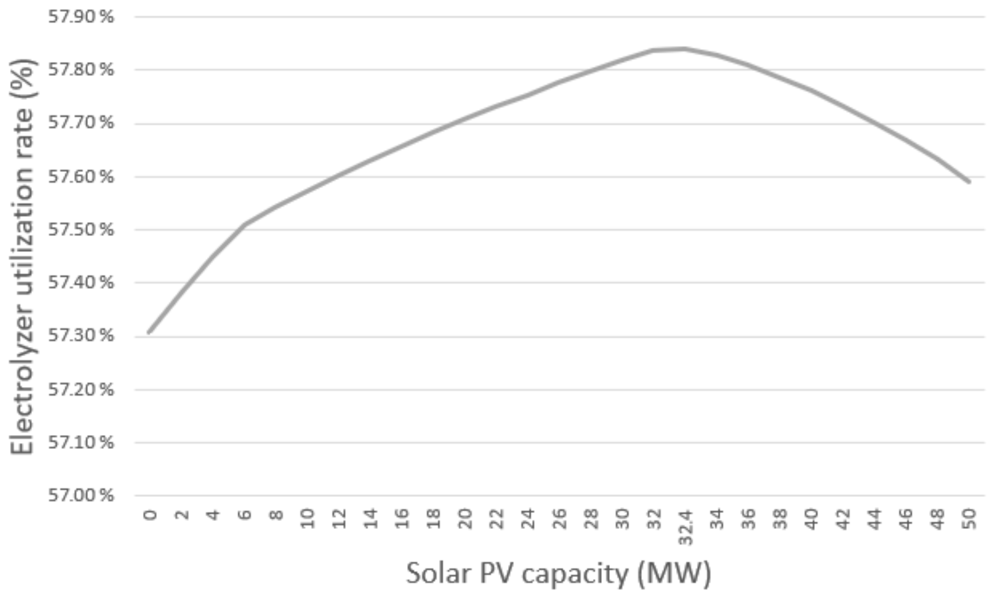

Figure 20: Electrolyzer's utilization rate as a function of solar PV capacity with 2018 generation data. 150 MW total capacity (wind power capacity + solar PV capacity = 150 MW)

rather cheap electricity without electricity transmission fees. Also, green hydrogen output can be increased with small-scale solar PV generation compared to the case without any solar PV generation capacity.

The conclusion is that solar PV in Finland should not be considered as a trade-off for wind power capacity, but as a supplementary VRE generation source if the profits are prioritized in hourly correlation. In annual correlation, onsite solar PV generation is justifiable in every case. Solar PV generation's competitive advantages should be utilized when planning the VRE portfolio. From the cost structure point of view the main competitive advantages are possibilities for an onsite and tax-free generation. In other parts of the Globe where solar irradiation is greater, this wind generation dominance is not set in stone. When the profits are prioritized in high solar irradiation areas, solar PV and wind generation capacities are optimized more evenly than in Finland. The only case in Finland when solar PV capacity can be increased at the expense of wind power capacity is in hourly correlation when green hydrogen output needs to be maximized. But it should be kept in mind that the increase in green hydrogen output is not significant when changing from profit maximizing to green hydrogen output maximizing VRE portfolio. This raises the question of whether utilization rate maximization should be prioritized in any case.

8 Conclusions

This thesis was a collaborative study with Helen to study how a green hydrogen production's VRE portfolio should be constructed in Finland. The thesis aimed to answer four key research questions that all contribute to the VRE portfolio formation. The electrolyzer's electric capacity was determined to be 50 MW in all cases. When this thesis was done (late 2021 - early 2022) the legislative framework for green hydrogen production was still unclear. Legislative requirements especially regarding the temporal correlation are important when designing the optimal VRE portfolio and legislation can have a major effect on production costs. When this thesis was written, it was expected that an hourly correlation requirement will be enforced. If the temporal correlation requirement is strict, tradeoffs need to be made between green hydrogen production volume and production costs. Therefore it is important to know what is prioritized before the VRE portfolio is optimized. In the case of less strict temporal correlation requirements, green hydrogen production volume optimization is not very important since the VRE generation fluctuations can be leveled off inside a long time period and therefore the temporal correlation requirements can be met with high certainty. This enables the electrolyzer to produce green hydrogen at its maximum capacity all the time which is not possible with strict temporal correlation requirements. Due to the additionality requirements, the electricity generation will be limited to solar PV and wind power generation. In April 2022 it is expected that the VRE plants can become operational at maximum 12 or 24 months before the electrolyzer operation starts. Different rules might apply for grid and direct connected VRE assets.

The optimal combination of different renewable electricity sources in green hydrogen production will heavily depend on the legislative requirements. When the green hydrogen production costs are minimized and the operational profits are maximized, in all temporal correlation requirement environments wind power should in practice represent 100% of the total VRE capacity due to its cheap LCOE. Solar PV generation has a higher LCOE value than wind power generation. In operational profit maximization cases, solar PV capacity can be at maximum at the onsite or tax-free level. Small-scale solar PV generation can avoid costly transmission costs and/or electricity taxes. Therefore solar PV generation will be small scale or it won't be included in the VRE portfolio at all. In the annual correlation environment, there isn't any need for optimizing the VRE portfolio according to green hydrogen output maximization since the green hydrogen output is in practice unchangeable. Therefore in annual correlation, the VRE portfolio leading to maximal operational profits should be prioritized in every case.

Wind power and solar PV generation can supplement each other. When the studied time period is long enough, wind power and solar PV assets generate electricity on average at different times. On average wind power's capacity factor is at its highest from late autumn to early spring, whereas solar PV's capacity factor is at its highest from late spring to early autumn. On average wind power generates more electricity during nighttime and solar PV during daytime. If the studied time period is short, the two generation methods might not supplement each other. Supplementary features of wind power and solar PV are especially important in strict temporal correlation environments. The structure of an optimal VRE portfolio mix in the hourly correlation environment depends on what is prioritized in the green hydrogen production. If the green hydrogen output is maximized, solar PV represents a considerable share of the total capacity but wind power will still be the primary generation technology. If the total VRE capacity is two to three times larger than the electrolyzer's electric capacity, wind power represents roughly 90% or more, of the total VRE capacity. When the VRE portfolio's total capacity is increased, the share of solar PV generation out of the total capacity should increase as well. If the operational profit is maximized in the hourly correlation environment, wind power represents 100% of the total VRE capacity.

Solar PV generation plays a major role only when the hydrogen output is maximized in hourly correlation. But it can bring small additional value also when operational profits are maximized in annual and hourly correlation. In most cases, solar PV generation needs to be considered as supplementary to wind capacity and not as an alternative to wind generation where increases in solar PV capacity would lead to decreases in wind power capacity. This way small scale solar PV power plants which can be located onsite, can reduce the green hydrogen production costs and therefore increase the operational profits. Small-scale onsite solar PV generation can be thought of as a low-hanging fruit that can increase operational profits in every case and also increase the green hydrogen output in hourly correlation. Although these increases are not significant.

It is extremely important to determine what is the electricity price level which is the zero marginal profit point in hydrogen production. If the electricity cost is higher than that specific price level, producing hydrogen would lead to losses. For example with the values which are used in this thesis, a 3 €/kgH_2 green hydrogen price would enable hydrogen production when the total electricity cost is at maximum 60 €/MWh. Electricity taxes and distribution costs need to be included in the total electricity cost when determining the sustained Elspot, LCOE, or PPA price level. The electrolyzer's electricity consumption per produced hydrogen kilogram and the price of hydrogen are the main factors that determine the cutoff electricity price level. The main idea in annual correlation is to abandon the unprofitable green hydrogen production. In hourly correlation, the idea is to increase non-green hydrogen production with Elspot electricity purchases when it can be produced with positive marginal profits. When hydrogen production is abandoned during the hours when marginal profit would be negative, costs can be decreased drastically and operational profits increased even if the hydrogen output and therefore hydrogen revenues are reduced. The sales price for non-green hydrogen needs to be cheaper than for green hydrogen. With a 2.5 €/kgH_2 non-green price level which is used in this thesis, 50 €/MWh is the zero marginal profit electricity cost level for hydrogen production. If it is possible to sell or utilize non-green hydrogen, the electrolyzer operator should produce non-green hydrogen with Elspot electricity if it leads to positive marginal profits and there is unutilized electrolyzer capacity available. This way the total hydrogen production amount and the total operational profit can be increased.

The green hydrogen production costs depend on what are the temporal correlation requirements and whether profits or total hydrogen output is prioritized. It also depends on whether hydrogen production is optimized according to Elspot prices. When an electrolyzer produces only green hydrogen, without Elspot-optimization and it produces the maximum amount of green hydrogen given the temporal correlation requirements the production costs are 2.82 $€/kgH_2$ (8 760 tons) in annual correlation and 2.39 $€/kgH_2$ (5 462 tons) in hourly correlation. The total green hydrogen production amount is in the parentheses and the total VRE capacity is 150 MW. When only green hydrogen is produced, the profits are maximized and green hydrogen is produced always when possible (no Elspot-optimization), the production costs are 2.82 $€/kgH_2$ (8 760 tons) in annual correlation and 2.36 $€/kgH_2$ (5 441 tons) in hourly correlation. As mentioned, in annual correlation the VRE portfolio is identical between production volume and profit maximization cases since the electrolyzer can be operated at its maximum capacity all the time. Therefore the production costs and production volume are identical as well. The production costs per hydrogen kilogram can be minimized further when hydrogen is produced only during positive marginal profit hours (Elspot optimization is done). In this case, the production costs are 2.21 $€/kgH_2$ (7 103 tons of green hydrogen) in annual correlation and 2.30 $€/kgH_2$ (5 020 tons of green hydrogen, 1 522 tons of non-green hydrogen) in hourly correlation. Gray hydrogen production costs have been historically 2.0-2.5 $€/kgH_2$ but the current increases in natural gas prices have increased the gray hydrogen price from the historic levels.

When battery storage is used as energy storage for an electrolyzer, the electrolyzer's utilization rate can be increased in hourly correlation. The utilization rate increase is not significant. The biggest increase in the electrolyzer's utilization rate realizes with the first battery capacity addition (0 MWh to 5 MWh). Even in this case, the utilization increase is only 0.35%-points when the VRE portfolio is 150 MW. With larger VRE portfolios, the utilization rate can be increased more per MWh but still by a relatively small amount. Battery storage capacity additions face diminishing returns. The biggest effect on the electrolyzer's utilization rate is seen with small batteries and the effect diminishes with larger batteries.

The current battery CAPEX levels are too high for batteries to be profitable in green hydrogen production. Batteries can't increase hydrogen production output enough for additional revenue to outweigh high battery investment costs. With a 3 $€/kgH_2$ green hydrogen price level, the battery CAPEX should be reduced from the current 281 €/kWh to 200 €/kWh to justify even the smallest battery storage. Increasing the green hydrogen price level to 5$€/kgH_2$ would make a 15 MWh battery economically feasible with the current CAPEX level. In annual correlation, it is even harder to justify battery investments than in hourly correlation, since the hydrogen production volume is constant and thus hydrogen production volume can't be increased.

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