Techno-Economic Assessment of Hydrogen Generation and Storage in a Future Swedish Energy System

An investment and dispatch analysis for an electrified industry and society

Master's thesis in Sustainable Energy Systems

Felix Hörnfeldt

DEPARTMENT OF ENVIRONMENTAL AND ENERGY SCIENCES
DIVISION OF ENERGY TECHNOLOGY
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2026
www.chalmers.se

MASTER'S THESIS 2026

Techno-Economic Assessment of Hydrogen Generation and Storage in a Future Swedish Energy System

An investment and dispatch analysis for an electrified industry and society

Felix Hörnfeldt

Department of Environmental and Energy Sciences
Division of Energy Technology
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2026

Techno-Economic Assessment of Hydrogen Generation and Storage in a Future Swedish Energy System
An investment and dispatch analysis for an electrified industry and society
FELIX HÖRNFELDT

Supervisors:	Erik Rosengren, Vattenfall
	Pandu Nugroho Prianto, Chalmers, Energy Technology
	Sofia Rosén, Chalmers, Energy Technology
Examiner:	Lisa Göransson, Chalmers, Energy Technology

Master's Thesis 2026
Department of Environmental and Energy Sciences
Division of Energy Technology
Chalmers University of Technology
SE-412 96 Gothenburg
Telephone +46 31 772 1000

Cover: Conceptual visualization of wind power, solar power, nuclear power, hydropower, batteries and hydrogen-tank storage. Created by Microsoft Copilot generative AI.

Typeset in LaTeX
Printed by Chalmers Reproservice
Gothenburg, Sweden 2026

Techno-Economic Assessment of Hydrogen Generation and Storage in a Future Swedish Energy System
An investment and dispatch analysis for an electrified industry and society
FELIX HÖRNFELDT
Department of Environmental and Energy Sciences
Chalmers University of Technology

Abstract

Sweden's ambitions to reach net-zero emissions by 2045 requires an electrification of industry and society. One key factor in driving the decarbonization of sectors is hydrogen. Today, hydrogen is produced using fossil fuel technologies, but there are fossil free alternatives, such as hydrogen production through electrolysis. Hydrogen production through electrolysis requires electricity, which, if implemented, will drive up Swedish electricity demand. To investigate the impact of hydrogen generation, a Swedish energy system model, aiming to minimize total system costs, was created. The model was created with a bottom-up approach, where existing hydropower and nuclear power were expected to have the same capacities in the target year of 2040 as today. The study investigated three cases, where one was used as a reference. The first case, called base case, investigated how a future Swedish energy system could look like. Here, the total system cost amounted to 4.88(4.36) G€ with electricity production mainly coming from weather dependent technologies, onshore wind being the largest national producer. The second case investigated the impacts of removed ability to invest in hydrogen storage. The results showed an increase in total system cost by 6-7% and increased average electricity prices, in a perfect energy-only market, across all Swedish electricity price regions, compared to reference case. Larger investments and generation in onshore wind and solar PV were also seen. In the third case, the impact of electrolyser investment cost was studied. The results showed that total system costs could increase with 15%, for a 170% higher electrolyser investment cost, compared to reference case, and that average electricity prices increase with higher electrolyser investment cost. The results shows that hydrogen production will have a large impact on a future electrified Sweden and that hydrogen storage will be essential to incorporate with green hydrogen production to minimize total system costs.

Keywords: hydrogen production, hydrogen storage, energy system modelling, linear optimization, decarbonization, electrification

Acknowledgements

First and foremost, I would like to thank my supervisors Erik, Pandu and Sofia. Thank you Erik for introducing me to Vattenfall and making me feel as a part of the team from day one. Thank you to Pandu and Sofia, without your support in the modelling phase I would not have gotten as far as I have done. I would also like to thank my examiner Lisa for your support throughout this thesis. Thank you for contributing with your expertise and knowledge in energy system analysis and trusting me to take on this big challenge.

Next, I would like to say thank you to all the people at Vattenfall R&D. Thank you for welcoming me and giving me a great introduction to your work environment. Thank you to all that have lent me their time and knowledge whenever I had questions. A special thank you to my thesis worker colleagues within the department for the companionship throughout the thesis period and in the study visit to Älvkarleby.

Lastly, I would like to say a big thank you to my family. Thank you for always believing in me and giving me strength in my toughest moments, I would not have been here without your support and belief. A huge thank you to my aunt, with family, for letting me live with them during my time in Stockholm. And a big thank you to my friends for giving me some of my best moments in life during my university studies, you will all be remembered.

Felix Hörnfeldt, Gothenburg, June 2026

List of Acronyms

Below is the list of acronyms that have been used throughout this thesis listed in alphabetical order:

AGG	Aggregated Vehicle Profile
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat-and-Power
CO_2	Carbon Dioxide
CRF	Capital Recovery Factor
DH	District-heating
DWY	Dry weather year
ECC	Electrolyser Cost Case
EU ETS	European Union Emissions Trading System
EV	Electric Vehicle
FLH	Full-Load Hours
H_2	Hydrogen
HOB	Heat-Only-Boiler
IEA	International Energy Agency
LHWT	Large Hot-Water Tank
Li-Ion	Lithium-Ion
LMA	"Långsiktig Marknadsanalys"
LRC	Lined Rock Cavern
$Na\text{-}NiCl_2$	Sodium Nickel Chloride
Na-S	Sodium–Sulphur
NoH2S	No Hydrogen Storage Case
OCGT	Open Cycle Gas Turbine
O&M	Operation and Maintenance
PEM	Proton Exchange Membrane
PTES	Pit Thermal Energy Storage
PV	Photovoltaic
SEA	Swedish Energy Agency
SEmLa	"Svenska Energisystemmodellen för Lagringslösningar"
SOC	State-of-charge
SVK	"Svenska Kraftnät"
TSO	Transmission System Operator

UHS	Underground Hydrogen Storage
V2G	Vehicle-to-Grid
VMS	Variation Management Strategies
VRE	Variable Renewable Energy
WWY	Wet weather year

Nomenclature

Below is the nomenclature of indices, sets, parameters, and variables that have been used throughout this thesis.

Indices

p	Indices for technologies
r	Indices for regions
t	Indices for timestep
k	Indices for start-up interval timestep

Sets

K	Set of start-up interval timesteps
P	Set of technologies
P^{BAT}	Set of battery technologies
P^{CHP}	Set of Combined Heat-and-Power technologies
P^{ELEC}	Set of electricity generating technologies
P^{ESOC}	Set of electricity storage technologies
P^{H_2SOC}	Set of hydrogen storage technologies
P^{HEAT}	Set of heat generating technologies
$P^{HeatElec}$	Set of heat generating technologies driven by electricity
P^{HSOC}	Set of heat storage technologies
P^{SOC}	Set of all storage technologies
P^{THERM}	Set of thermal generation technologies
P^{VRE}	Set of weather-dependent technologies
R	Set of price regions
R^{SE}	Set of Swedish price regions

R^{INT}	Set of neighbouring price regions to Sweden
T	Set of timesteps

Parameters

C_p^{inv}	Investment cost of technology p
C_p^{run}	Running cost of technology p
C_p^{on}	Startup cost of thermal technology p
C_p^{part}	Part-load cost of thermal technology p
$C_{r,t}^{trade}$	Trade price in region r at timestep t
$D_{r,t}^{elec}$	Electricity demand in region r at timestep t
$D_{r,t}^{H_2}$	Hydrogen demand in region r at timestep t
$D_{r,t}^{heat}$	Heat demand in region r at timestep t
η_p	Efficiency of technology p
η_p^{charge}	Charge efficiency of storage technology p
η_p^{dis}	Discharge efficiency of storage technology p
CF_p	Power-to-storage factor of storage technology p
$W_{r,t,p}$	Weather profile for VRE technology p, in region r at timestep t
$RR_{r,p}$	Max capacity for VRE technology p in region r
$I_{r,t}^{hyd}$	Inflow into hydro reservoir in region r at timestep t
$HydP_{r,t}$	Max generation capacity for hydropower in region r at timestep t
$HydL_{r,t}$	Max hydro reservoir capacity in region r at timestep t
$HydRamp_{r,t}$	Max ramping of hydropower generation in region r at timestep t
L_p^{min}	Minimum load level of technology p
α_p	Power-to-heat ratio of technology p
CC_{r_1,r_2}	Transmission capacity between national region r_1 and region r_2

Variables

C^{tot}	Total cost of the system
$i_{r,p}$	Capacity investment in technology p in region r
$g_{r,t,p}$	Electricity generation from technology p at timestep t in region r
$SOC_{r,t,p}$	State of charge in storage technology p at timestep t in region r
$SOC_{r,t,p}^{ch}$	Charging of storage technology p at timestep t in region r

$SOC^{dis}_{r,t,p}$	Discharge of storage technology p at timestep t in region r
$i^{SOC-cap}_{r,p}$	Battery capacity investment in technology p in region r
$s_{r,t,hydropower}$	Hydropower reservoir storage level in region r at timestep t
$z_{r_1,r_2,t}$	Transmission between region r_1 and region r_2 at timestep t
$\zeta^{active}_{r,t,p}$	Active generation in thermal technology p at timestep t in region r
$\zeta^{on}_{r,t,p}$	Started capacity in thermal technology p at timestep t in region r
$C^{cycl}_{r,t,p}$	Cycling cost for thermal technology p at timestep t in region r
$g_{r,t,electrolyser}$	Hydrogen generation from electrolyser at timestep t in region r
$g^{heat}_{r,t,p}$	Heat generation from technology p at timestep t in region r

Contents

List of Figures

List of Tables

1

Introduction

According to the International Energy Agency (IEA) the world electricity demand in 2035 will be about 40% higher than in 2025 and in the last decade the demand for electricity has increased twice as fast as the need for energy [1]. With more focus being put on reaching the 2050 climate goals worldwide, we see an increased need for electricity. Behind the increasing electricity demand are many factors and new initiatives, such as an increasing worldwide electric vehicle fleet and new high-speed datacentres.

In Europe there is a transition towards sustainability and meeting the 2050 net-zero climate goals. The EU is at the frontline of this transition, writing into law that the EU will be climate-neutral by 2050 [2], requiring their members to take action both on EU and national level to meet the targets. According to IEA [3], in 2023, renewables stood for approximately 42% of Europe's power generation and CO_2 emissions in Europe had dropped with 26% between 2000-2023, marking a significant shift towards renewable and net-zero technologies.

With an increasing demand for renewables, in order to meet the climate goals, new challenges arise due to the weather dependency of renewable technologies such as wind power and solar PV. Weather dependent technologies encounter challenges such as unpredictability, uncertainty, intermittency, and more [4]. One way to handle the variability of weather dependent technologies is to integrate flexibility solutions, for example batteries or hydrogen storage, into the system. These flexibility solutions can ensure that a system with a high share of weather dependent technologies can make use of all available energy, reducing the total system losses from, for example, curtailment.

1.1 Aim and Scope

The aim of the thesis is to analyse how storage and flexibility solutions can enable and facilitate the transition to more renewable power production. To investigate the integration of such solutions, an optimisation model was used. The model was created from the ground up, with inspiration from an existing model, and used to evaluate how an energy system with a proposed high electrification can supply electricity at a low total cost.

The model evaluates the energy system in Sweden for the target year 2040 and aims to help understand the impacts of an increased electrification in an energy system. The thesis evaluates the system from a techno-economic perspective with an aim to minimize cost for the whole society. The questions investigated are as follows:

Q1. Which technologies are invested in to support an electricity system with high electrification, resulting in a large electricity demand?
  - In which regions are technologies invested in?
  - What is the electricity price in a future system?

Q2. What storage and flexibility solutions are invested in and what role do they take?
  - What is the system impact if hydrogen storage technologies are not available?
  - How do different costs of electrolyser impact hydrogen production? What is the impact on hydrogen storage?

1.2 Limitations

The thesis scope of study has been constructed with some boundaries as specified below.

The thesis and model are limited to investigate Sweden and the effects on the Swedish electricity production system. The scope is limited to Sweden's existing electricity price regions, SE1-SE4, and will not consider or discuss the effects of other proposed electricity price regions. This is mainly due to the uncertainty of how the new regions will be constructed and that data is available for the existing regions.

Transmission between Sweden and neighbouring regions are considered for existing infrastructure and the model will not be able to build new transmission infrastructure. Predicted transmission capacities for 2040 are considered, with predicted completion of proposed new infrastructure such as NordSyd [5].

Vehicle-to-Grid (V2G) is not implemented in the model or considered as an available technology.

2

Background

This section includes an overview of the key aspects of the thesis and aims to give an introduction into the background of the thesis work. Section covers the Swedish energy system, role of hydrogen in the energy system, energy system modelling and basics of optimization.

2.1 Sweden's energy system

Sweden has been one of the global leaders in decarbonization with their efforts to reduce their climate footprint [6]. In 1991, they were one of the first to introduce a carbon tax, with a ”polluter pays” principle [7]. The initiative has served as a key factor in climate objectives and has provided incentives to, among others, increase the share of renewable energy technologies [7]. The carbon tax has since been complemented with the European Union Emissions Trading System (EU ETS), which is a carbon market where polluters in the EU pay for their emissions [8].

In 2024, emissions of carbon dioxide (CO_2) equivalents amounted to 47.5 MtonCO_2e, a decrease by a third since the introduction of the Swedish carbon tax in 1991 [9]. Of the total emissions in 2024, almost 2/3 came from transport and industry sectors. Therefore, large focus has been put on decarbonizing these sectors, for example with the introduction of the reduction obligation in petrol and diesel [9] and ear-marked subsidies for bio-CCS (Carbon Capture and Storage) initiatives [10].

In 2024, Sweden's energy mix consisted of approximately 20% renewable energy, 26% nuclear energy, 25% biofuels, 26% fossil energy and 3% other energy [11], were Biofuels and fossil energy are mostly used within industry and transportation. The electricity production in Sweden comes mainly from nuclear power and renewable energy technologies, standing for approximately 93% of production in 2024, the rest coming from biofuels, waste incineration and fossil sources [6].

Renewable energy technologies stood for approximately 64% of Sweden's electricity production in 2024, with hydropower as the largest producer at 38% [6]. But the share of wind- and solar power has increased exponentially in the last 10 years, with wind power production increasing with 260% from 2014 to 2024 and solar power increasing with 8700% in the same time span, according to IEA [6]. With the increasing share of weather-dependent technologies comes the need for shifting and complementing technologies when the plants can't produce at required capacity.

Hydropower's flexible ramping capabilities have acted as a complementing strategy to wind power, while simultaneously producing a lot of base power for the northern regions. Simultaneously, batteries have been incorporated in households with solar panels, acting as a shifting strategy to the regular solar production.

The future electrification in Sweden, required to reach net-zero emissions by 2045, have been investigated by Swedish energy agency (SEA) [12], Swedish TSO (Transmission system operator) [13] and in independent reports [14]. SEA and Swedish TSO, ”Svenska Kraftnät” (SVK), have presented four different scenarios for future electricity need in Sweden in 2050. The projections for electricity demand in 2050 range between 210-365 TWh [12, 13], where the span is constructed based on future electricity use and share of renewable energy sources. Models used for investigating the future Swedish electricity need have shown that Sweden is equipped to facilitate an electrified society [14] but is dependent on clear energy policy initiatives that sets the guide-path for production actors. One actual energy policy today, is the decision on providing subsidies for construction of new nuclear reactors. In SVKs LMA (”Långsiktiga marknadsanalys”) the main differentiation between their highest demand levels, is the incorporation of nuclear power [13], marking the importance of the strategic decision. Furthermore, both SEA and SVK have declared that hydrogen could be a key factor in the ambitions of Sweden's net-zero emission goal, as it could help decarbonize multiple sectors.

2.2 The role of hydrogen in the energy system

In the last couple of years, the role of hydrogen has gone from a small actor in the aim for net-zero emissions, to one that can create opportunities for a more secure energy and industry infrastructure [15]. Hydrogen is an important product within refining and production industry, where it is used in critical parts of their manufacturing processes. Hydrogen demand amounted to 100 Mton in 2024, an increase with 30 Mton compared to 2019 [16], with demand being driven by industry needs.

The reason that hydrogen is now considered as a key factor in the goal to reach climate neutrality, is because of its large possibility to help decarbonize large industry and transportation sectors. As such, EU has classed its hydrogen strategy as essential to reach their 2050 carbon neutrality goal [17]. Decarbonizing of hydrogen mainly consists of decarbonizing its manufacturing process, of which in 2024 generated roughly 980 Mton CO_2 [15].

2.2.1 Hydrogen production

Today, 99% of hydrogen production comes from unabated fossil fuels and by-product, of which unabated fossil fuels stood for more than 80% of production in 2024 [15]. Hydrogen production can be categorized into different categories, with grey, blue and green being relevant in this thesis [18]. Hydrogen production through steam methane reforming, which uses natural gas as fuel, is categorized as grey hydrogen [18]. Production of hydrogen using natural gas as fuel can also be produced through

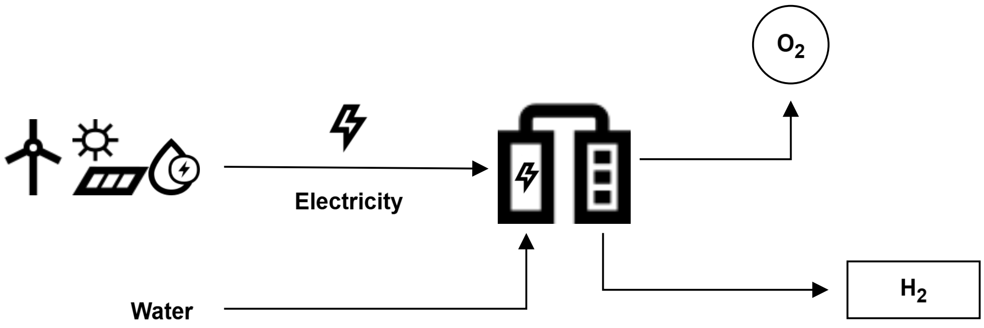


Figure 2.1: Schematic of green hydrogen production using electrolysers.

partial oxidization, auto-thermal reforming and gasification. All 4 processes generate CO_2 as a bi-product and is rarely equipped with carbon capture to reduce emissions. Grey hydrogen production benefits from the established industry infrastructure and access to low-cost natural gas [15]. These benefits locks-in the hydrogen production to the grey alternative, rather than enabling a pathway for blue and green alternatives.

Blue hydrogen and green hydrogen are two pathways to reduce emissions in the hydrogen supply chain. Blue hydrogen stems from grey hydrogen but with the addition of carbon capture and storage (CCS) [15, 18]. The incorporation of CCS can largely reduce emissions from the hydrogen production and is seen as a transitional pathway from grey to green hydrogen. Blue hydrogen is beneficial for existing hydrogen production infrastructure, where there is a low share of renewable energy infrastructure. Thus, allowing for renewable energy technologies to mature in the area before transitioning to green hydrogen production technologies [18].

Green hydrogen is produced using water and electricity, where hydrogen is gathered by separating hydrogen and oxygen in the water through an electrochemical process [19], see example schematic in Figure 2.1. This electrochemical process is done with electrolysers, where the most common types are Proton Exchange Membrane (PEM), Alkaline and Solid Oxide [16]. For green hydrogen to be considered green, the electricity used in the electrochemical process needs to originate from renewable energy sources, such as wind, solar and hydropower. With this the hydrogen production becomes CO_2 neutral, with no emissions in its production chain, and could lead to a full reduction in emissions from the hydrogen supply chain.

2.2.2 Hydrogen storage

In combination with green hydrogen production, hydrogen storage is being considered as a complement to handle the intermittency of the hydrogen production. Due to the variability of renewable energy sources, that provide the needed electricity in the electrochemical process in electrolysers, hydrogen storage can be used to shift hydrogen production to balance variable production and simultaneously bring down costs. [15]. To make use of hydrogen storage an investment in a hydrogen production technology larger than the hydrogen demand is needed. Thus, because the hydrogen production needs to meet the hydrogen demand and additional hydrogen to be stored. An investment in hydrogen production larger than demand is referred to as overcapacity investment.

Hydrogen storage technologies can be divided into physical- and chemical storage [20]. In this thesis physical storage of hydrogen is considered. Physical storage of hydrogen is either done in its gaseous or liquid form. Liquid storage of hydrogen consists of cooling down the hydrogen below its boiling point, turning it to its liquid state [20]. This form of storage can store large densities of hydrogen in a compressed space, but requires lots of energy in the liquefying process, making it less preferable for large scale storage [20]. In its gaseous form, hydrogen can be stored at different pressures which requires different amounts of compression. Thus, there is different technologies that can be used for physical storage.

For large physical storages of hydrogen, the following technologies have been proposed as alternatives: Salt cavern storage, Lined Rock Cavern (LRC) storage, hydrogen tank storage and storage in porous rocks [21, 22, 23]. For all 4 technologies the gas is compressed to a certain pressure and then stored inside the medium. Of the 4, storage in hydrogen tanks, above ground, is best for short-term storage, where it is important to access the hydrogen in a short time-period [22]. Therefore, it has been used for transportation and space travel, where access is needed quickly. For industrial applications, hydrogen storage tanks could add short-term flexibility to hydrogen production at an industry plant. For large storage of hydrogen, it is better to make use of underground hydrogen storage (UHS).

As mentioned, UHS is mainly concentrated to caverns and porous rocks. UHS in salt caverns have been used for large projects in the US for some time, while pilot studies have been completed in the last years in some European countries [15]. Projects in Europe, and US, have shown that salt caverns could offer high flexibility, with possibility to operate with frequent cycles [15, 21]. The downside of salt cavern storage is that it requires geographical conditions to operate, that are not found in all locations where large hydrogen storage is of interest [24]. Therefore, have LRC emerged as a UHS technology for use in geographical locations without conditions for salt caverns. However, no large projects with LRC as UHS have been done and therefore the costs, and feasibility, is not fully established. A LRC pilot in Sweden, part of the HYBRIT project [25], have shown it is possible to use LRC for UHS. However, the pilot had a limited storage size of 100 m^3, 70 MWh_{H_2} [15], which is far from proposed sizes of large UHS [26]. Lastly, UHS in porous rocks have been proposed as method, but is less appealing due to its limitations in cycles and possibility to inject/withdraw from the storage [26].

2.2.3 Hydrogen in Sweden

In Sweden, hydrogen is used in refinery-, plastic- and chemical industries, with an annual consumption amounting to roughly 6 TWh$_{H_2}$ [27]. The biggest production of hydrogen is done using natural gas, grey hydrogen, with a third coming as a by-product from industries. The hydrogen usage is concentrated to the west coast of Sweden, where refinery- and chemical industries are mainly located [28]. As said, hydrogen in Sweden is mainly grey and with established infrastructure the supply chain is locked in. But, with Sweden's ambitions to reach net-zero emissions by 2045 [29], and with a growing industry, hydrogens role is becoming more important.

The Swedish hydrogen demand is projected to increase to 20-25 TWh$_{H_2}$ by 2030, and estimates are projecting a hydrogen demand of 90 TWh$_{H_2}$ by 2045 [27]. The projections for both 2030 and 2045 is largely based on industry increases, especially a decarbonization of the steel industry in the north, that also has the ambition to grow its industry in the coming years. Decarbonisation of the steel industry in Sweden focuses on the transition to usage of electric arc furnaces instead of blast furnaces, which would increase electricity demand by 15 TWh, together with hydrogen-based direct reduction of iron ore, which if paired with green hydrogen production through electrolysis, could increase electricity demand substantially [27]. Similarly, there are ambitions to grow the chemical industry in the west-coast of Sweden, leading to a future hydrogen demand of 4.9-14 TWh$_{H_2}$/year [28].

The ambition to grow Swedish industry, while aiming for net zero emissions by 2045, means that if the additional hydrogen demand should be covered with the use of electrolysis, the electricity demand could increase by as much as 160 TWh, assuming electrolyser with 65% efficiency. This increase is larger than the annual usage in Sweden in 2024 [30] and it would require significant investments in new electricity production to power the green hydrogen production. To investigative what is needed to cover the additional electricity demand from green hydrogen production, energy system modelling can be used.

2.3 Energy system modelling

To evaluate and analyse complex energy systems, energy system models are used. Energy system models are a simplified representation of a complex energy system with the aim to be suitable for comprehensive analysis of consequences from policy changes related to the energy system [31]. Energy system models can be used for analysing different kinds of systems, from a single household to the whole EU. The models are usually a simplified, but representative, version of the actual system, but could also be very detailed if required. A principle is that a more detailed model is good for analysis of a small system, where the aim of the investigation is to see more detailed changes in the system, at the cost of increased complexity and in return increased computing-time. For large systems, for example the whole of EU, the system needs to be simplified to reduce complexity and computing-time.

The benefits of energy system models are that it enables actors and policy makers to evaluate the system consequences of policy changes. Models also give a better understanding of the system which makes it easier to evaluate the future of the system [31]. It also gives actors a chance to test and analyse the changes of certain parameters and the effect on the complete system. Thus, it is easier to project how the system will act and what could be a bottleneck in the system after the change, instead of seeing the consequences after actual implementation.

The formulation and use cases of the models can differ depending on the investigative case. Some models are descriptive, for example simulation models, and some are normative, for example optimization models [31]. Some models can also make use of different formulations to give a full comprehensive overview of the system [32]. Furthermore, models make use of a bottom-up or top-down approach for their description of the system [31], in this thesis bottom-up approach is used. Bottom-up models are generally used when the focus of the study is to investigate technology changes within the system, for example what technologies are needed to meet the energy demand within a system with net-zero policy.

As mentioned, models can be descriptive or normative, in this thesis a normative approach is taken. A normative approach aims to find what should be done to achieve a certain outcome, for example what technologies should be used to minimize costs. Optimization models are therefore a good approach for normative models, as the aim of the optimization model is to find the optimal solution. Two common energy system optimization approaches are investment and dispatch models. Investment models consider the investments in new technologies to meet demand. The aim is commonly to minimize the costs of meeting the demand. Dispatch models instead consider the production capabilities of technologies to meet demand. Here, the aim is to find the optimal solution to meet the demand, for example when and if a storage should be discharged during a certain time-period. A combination of the two is called an investment and dispatch model, in which the goal is related to costs and dispatch of supply to meet demand. Optimization models usually make use of a linear optimization approach, in which the energy system is described using linear functions.

2.4 Linear programming

Linear programming (LP), or linear optimization, is the practice of finding an optimal solution to a linear objective function constrained by other linear functions [33]. The objective function is either minimized or maximized, for example minimizing costs or maximizing profits, and is the goal of the problem. The optimal solution to the objection function is found in a corner point created by an intersection of constraints. The constraints are linear functions that constrain the problem within certain given parameters. Constraints can either be explicit, for example that no CO_2 emissions are allowed, or implicit, for example that hydrogen production from an electrolyser must be positive. The constraints that bind the optimal solution, in other words the constraints that make up the corner point, are called active constraints, while the others are called inactive constraints. Solutions to LP problems can have different status, generally the solution is either optimal, infeasible or unbounded. An optimal solution is the best feasible solution to the LP problem. An infeasible solution means that the region of feasible solutions is empty and that there exists no corner point of intersecting constraints. Finally, an unbounded solution is a feasible solution, but where the objective function can go to infinity [33]. A simple linear optimization formulation is seen below, where the constraints are explicit constraints and there exist an implicit constraint that $x_1, x_2 \geq 0$. The optimal solution to the LP problem is $(x_1, x_2) = (2, 3)$.

$$\begin{aligned} \max \quad & 10x_1 + 4x_2 & \\ \text{s.t} \quad & x_1 & \leq 2 \\ & x_2 & \leq 4 \\ & x_1 + x_2 & \leq 5 \end{aligned}$$

2.4.1 Shadow price

Furthermore, if the right-hand-side of one of the constraints, in the formulation above, were to change by a small amount, the resulting change in the objective function is called shadow price [33]. Shadow price represents the value of the constraint and is very useful when doing energy system analysis. For example, the shadow price on an electricity demand constraint for a given hour, is the marginal cost of electricity which is the electricity price at that given hour in a perfect energy-only market. The shadow price therefore also indicates which technology that is on the margin, setting the price, in the energy system. For the example LP problem above, changing the right-hand side of the third constraint to 6 would increase the objective with 4. Therefore, the shadow price of this change is 4 and the variable x_2 is on the margin.

3

Method

To investigate the impact of storage and flexibility solutions for a future electricity production system, a linear optimization model was developed. The model is a cost-minimizing investment and dispatch model of Sweden for a given year at hourly time resolution with the objective of minimizing the total system costs, hereby referred to as *SEmLa* (”Svenska Energisystemmodellen för Lagringslösningar”). The model covers the four existing Swedish electricity price regions, SE1-SE4 [34] shown in Figure 3.1, and includes transmission from, to and within Sweden.

SEmLa is created from the ground up, taking inspiration from the eNODE model originally developed by Göransson et al. [35], and further developed by, among others, Walter et al. [36]. The model includes transmission, similarly as Walter and Göransson [37], but with an alternative formulation and notation.

The eNODE model has previously been used to evaluate different variation management strategies (VMS) for a large system, many times for multiple countries in Europe, for example by Walter et al. [38]. The focus has not been on the impacts of singular country but rather the whole system. In the instances where Sweden has been the focus of the case study using the eNODE model, it has mostly been concentrated to a singular electricity price region [38] or as a concatenation of the north and south price regions [36].

The aim of SEmLa is instead to focus on a singular country, in this case Sweden, and analyse the impact that storage and flexibility solutions have on the national electricity production system. With Sweden’s four electricity price regions the model also aims to optimize where the solutions are most cost-effective and their needed capacity. The purpose is to give insights on what technologies are needed, in the studied regions, to meet net-zero emission targets, while satisfying an increased demand through electrification of, among others, industry and transportation. The model uses a bottom-up approach, where existing hydropower, nuclear power and expected transmission infrastructure is pre-set, and assumes that no new investments are made in technologies that release CO_2, with exception of biogenic CO_2 emissions.

SEmLa makes use of an hourly time resolution and is run for one specified weather year, further discussed in Section 3.2.1. The model makes use of a discount rate of 5% for the calculation of the Capital Recovery Factor (CRF) to investigate investments from a societal perspective. The model is run for a target year of 2040, for which cost and technical data are taken. Data is presented in Section A.

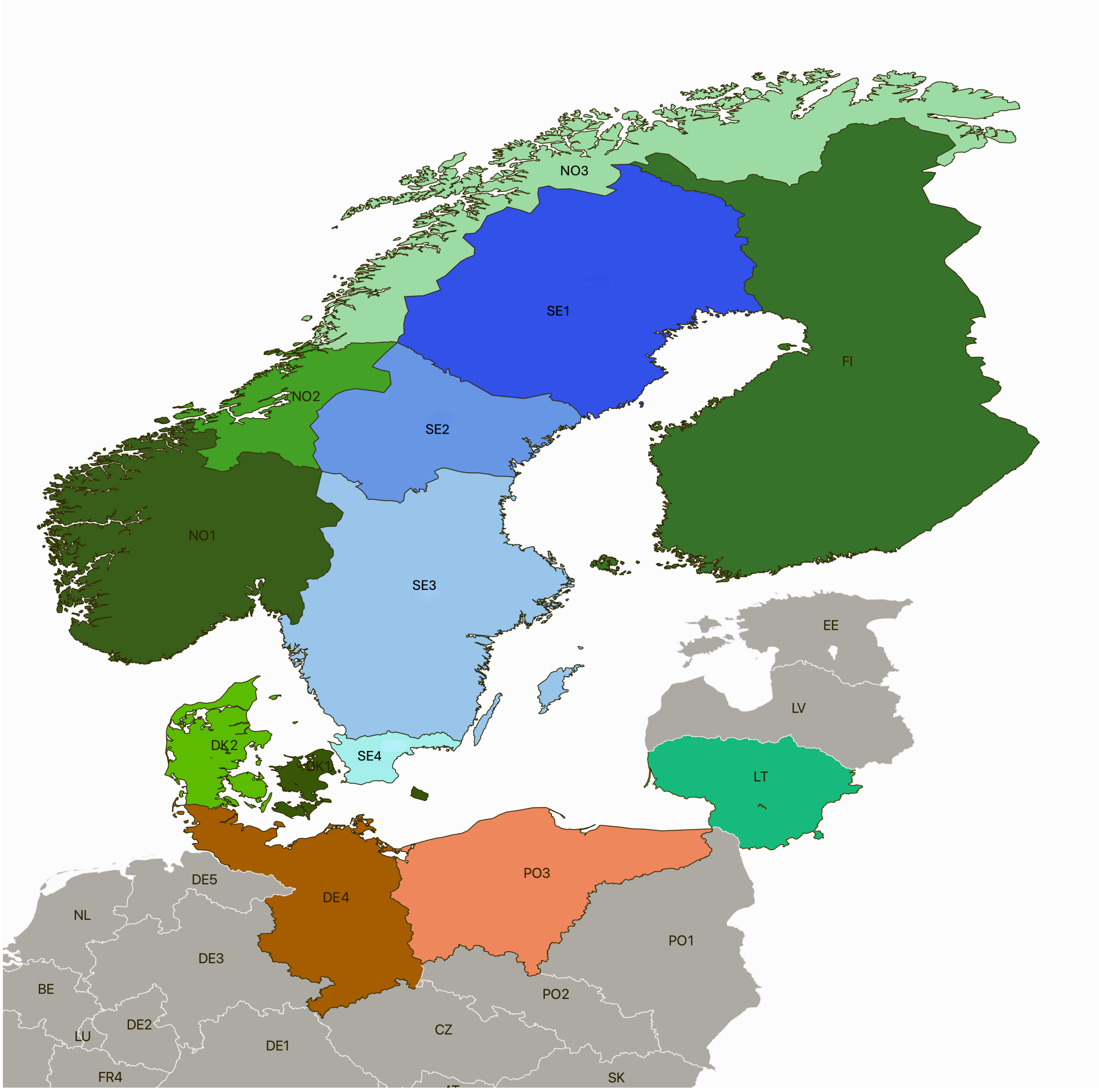


Figure 3.1: Map of electricity price regions used in model, produced by Simon Öberg at Division of Energy Technology at Chalmers University of Technology [39].

3.1 Model description

SEmLa is a linear investment and dispatch optimization model with the objective to minimize the total cost, C^{tot}, of a system given by Eq. (3.1).

$$\begin{aligned}\min C^{tot} = &\sum_{r\in R^{SE}}\sum_{p\in P} C_p^{inv} i_{r,p} + \sum_{r\in R^{SE}}\sum_{t\in T}\sum_{p\in P}\left(C_p^{run} g_{r,t,p}/\eta_p + C_{r,t,p}^{cycl}\right)\\ &+ \sum_{r_1\in R^{SE}}\sum_{r_2\in R^{INT}}\sum_{t\in T} C_{r_2,t}^{trade} z_{r_1,r_2,t}\end{aligned} \tag{3.1}$$

Here the investment cost C_p^{inv}, annualized using 5% discount rate, for technology p is scaled by the invest capacity $i_{r,p}$ in technology p in region r. The running cost C_p^{run} for technology p is scaled by the generation $g_{r,t,p}$ in region r at all timesteps t, and then added together with the cycling costs $C_{r,t,p}^{cycl}$, from cycling technologies p. The generation is divided with the efficiency η_p to account for fuel usage. Lastly, the cost of import/export with external regions $C_{r_2,t}^{trade}$ is scaled by the transmitted electricity $z_{r_1,r_2,t}$ between national region r_1 and neighbouring region r_2 for all timesteps. The transmission between Swedish regions is not considered as a cost to the system, but acts as flexibility measure to meet the demand in each region.

The electricity generation, $g_{r,t,p}$, from all technologies p in a region r at each timestep t needs to meet the electricity demand, $D_{r,t}^{elec}$, in each region r at each timestep t. The inclusion of storage technologies and transmission in the model constructs the demand balance as in Eq. (3.2),

$$D_{r,t}^{elec} \leq \sum_{p\in P^{ELEC}} g_{r,t,p} + \sum_{p\in P^{ESOC}} (SOC_{r,t,p}^{dis} - SOC_{r,t,p}^{ch}) + \sum_{r_2\in R\setminus r} z_{r,r_2,t}, \quad \forall r\in R^{SE},\ \forall t\in T, \tag{3.2}$$

where $SOC_{r,t,p}^{ch/dis}$ denotes the discharge and charge of a state-of-charge (SOC), storage, technology and $z_{r,r_2,t}$ denotes the transmission between two regions. The electricity generation is constrained by the installed capacity $i_{r,p}$ for each electricity generating technology p in region r, as in Eq. (3.3).

$$g_{r,t,p} \leq i_{r,p}, \qquad \forall r\in R^{SE},\ \forall t\in T,\ \forall p\in P^{ELEC} \tag{3.3}$$

For weather-dependent technologies, solar and wind, the production each hour is also limited by their weather potential $W_{r,t,p}$ and the available regional resources $RR_{r,p}$, as in Eqs. (3.4)-(3.5).

$$g_{r,t,p} \leq i_{r,p} W_{r,t,p}, \qquad \forall r\in R^{SE},\ \forall t\in T,\ \forall p\in P^{VRE} \tag{3.4}$$

$$i_{r,p} \leq RR_{r,p}, \qquad \forall r\in R^{SE},\ \forall p\in P^{VRE} \tag{3.5}$$

The weather profiles and regional resource capacities are produced using Mattsson et al. [40] GlobalEnergyGIS tool and is further discussed in section 3.2.5.

Generation technologies that are thermal based, such as turbines, take on additional constraints in accordance with Göransson et al. [35]. Eqs. (3.6)-(3.7) limits the generation to the available active generation $\zeta_{r,t,p}^{active}$ and the required minimum load L_p^{min}, given for each thermal technology p. The amount of started capacity is controlled by $\zeta_{r,t,p}^{on}$, as per Eq. (3.8), while Eq. (3.9) controls that the capacity is deactivated for at least the required start-up time interval K which encompasses all the start-up timesteps k.

$$g_{r,t,p} \leq \zeta_{r,t,p}^{active}, \qquad \forall r \in R^{SE},\ \forall t \in T,\ \forall p \in P^{THERM} \tag{3.6}$$

$$\zeta_{r,t,p}^{active} \cdot L_p^{min} \leq g_{r,t,p}, \qquad \forall r \in R^{SE},\ \forall t \in T,\ \forall p \in P^{THERM} \tag{3.7}$$

$$\zeta_{r,t,p}^{active} - \zeta_{r,t-1,p}^{active} \leq \zeta_{r,t,p}^{on}, \qquad \forall r \in R^{SE},\ \forall t \in T,\ \forall p \in P^{THERM} \tag{3.8}$$

$$\zeta_{r,t,p}^{on} \leq i_{r,p} - \zeta_{r,t-k,p}^{active}, \qquad \forall r \in R^{SE},\ \forall k \in K,\ \forall p \in P^{THERM} \tag{3.9}$$

The total cycling costs $C_{r,t,p}^{cycl}$ is given by Eq. (3.10) and is scaled based on the start-up cost C_p^{on} and part-load cost C_p^{part} of each thermal technology. Both costs are calculated using methods by Göransson [41].

$$C_{r,t,p}^{cycl} \geq \zeta_{r,t,p}^{on} \cdot C_p^{on} + (\zeta_{r,t,p}^{active} - g_{r,t,p}) \cdot C_p^{part}, \quad \forall r \in R^{SE}, \forall t \in T, \forall p \in P^{THERM} \tag{3.10}$$

Next, SEmLa incorporates transmission within the country and with neighbouring regions, where there is existing transmission infrastructure. No investments in new infrastructure is considered. Export and import of electricity is done at the same point, therefore one transmission cable can only import or export electricity during each hour. Export of electricity is negative as it decreases the available electricity, while import is positive as it increases the available electricity. The transmission between two regions at a given timestep t is described by $z_{r1,r2,t}$ and is limited by the installed capacity, as seen in Eq. (3.11).

$$-CC_{r_1,r_2} \leq z_{r_1,r_2,t} \leq CC_{r_1,r_2}, \quad \forall r_1 \in R^{SE},\ \forall r_2 \in R \setminus r_1,\ \forall t \in T \tag{3.11}$$

For transmission within Sweden the following constraint, controlling that the import from one region is the same as the export from the other region [37], is added.

$$z_{r_1,r_2,t} = -z_{r_2,r_1,t}, \quad \forall r_1, r_2 \in R^{SE},\ \forall t \in T \tag{3.12}$$

3.1.1 Storage

Storage solutions, such as batteries and heat storage, are implemented in the model with the following energy balance:

$$SOC_{r,t+1,p} \leq SOC_{r,t,p} + SOC_{r,t,p}^{ch} \cdot \eta_p^{ch} - SOC_{r,t,p}^{dis}/\eta_p^{dis}, \ \forall r \in R^{SE}, \forall t \in T, \forall p \in P^{SOC} \tag{3.13}$$

where $SOC_{r,t,p}$ is the storage level for technology p, in region r at time t. Although not all storage technologies are batteries the SOC notation is used for simplicity. η_p is the dis-/charge efficiency of the given technology, $SOC_{r,t,p}^{ch}$ is how much the technology is charged with at timestep t and $SOC_{r,t,p}^{dis}$ is how much is discharged from the storage and delivered to the grid. The storage level is limited by the installed capacity while the charge and discharge is dictated by the installed capacity and the power-to-storage factor CF_p as below. CF_p is used for all non-battery technologies.

$$SOC_{r,t,p} \leq i_{r,p}, \qquad \forall r \in R^{SE},\ \forall t \in T,\ \forall p \in P^{SOC} \tag{3.14}$$

$$SOC_{r,t,p}^{ch} \leq i_{r,p} \cdot CF_p^{ch}, \qquad \forall r \in R^{SE},\ \forall t \in T,\ \forall p \in P^{SOC} \tag{3.15}$$

$$SOC_{r,t,p}^{dis} \leq i_{r,p} \cdot CF_p^{dis}, \qquad \forall r \in R^{SE},\ \forall t \in T,\ \forall p \in P^{SOC} \tag{3.16}$$

The power-to-storage factor CF is calculated by using the energy storage capacity and input/output capacity. The capacities are given for one unit of energy and the capacity factor gives how fast one can charge or discharge the storage. The formula for CF is given by Eq. (3.17). The unit for CF is 1/h.

$$CF = \frac{\text{Input/Output capacity for one unit [MW]}}{\text{Energy storage capacity for one unit [MWh]}} \tag{3.17}$$

For battery technologies, charge and discharge is also governed by investment in their power capacity component, Eqs. (3.18)-(3.19). The power capacity component governs how fast and for how long the battery takes to charge or discharge.

$$SOC^{ch}_{r,t,p} \leq i^{SOC-cap}_{r,p}, \qquad \forall r \in R^{SE},\ \forall t \in T,\ \forall p \in P^{BAT} \tag{3.18}$$

$$SOC^{dis}_{r,t,p} \leq i^{SOC-cap}_{r,p}, \qquad \forall r \in R^{SE},\ \forall t \in T,\ \forall p \in P^{BAT} \tag{3.19}$$

3.1.2 Hydropower equivalent

Due to the magnitude and flexibility of hydropower generation, it needs a representative modelling when evaluating different storage and flexibility solutions. When modelling hydropower it is usually done using equivalent models, to limit the computational effort. Among others, Prianto [42] have shown that equivalent representations of hydropower produce accurate results with a significant reduction in computational time.

The representation of hydropower in SEmLa is based on work by Öberg et al. [43], specifically their Bi-level equivalent. This equivalent differs from the simple equivalent in that it incorporates additional constraints on up- and down-ramping with seasonal variations in generation and reservoir limits.

Eqs. (3.20)-(3.22) describes the simple equivalent constraints where the reservoir level $s_{r,t,hydropower}$ is dependent on the inflow $I^{hyd}_{r,t}$ into the hydropower reservoir and the hydropower generation $g_{r,t,hydropower}$. The hydropower generation is constrained by an upper and lower limit $HydP_{r,t}$ while the reservoir level is limited by $HydL_{r,t}$. Both limits are seasonally dependent, based on three different inflow periods.

$$s_{r,t+1,hydropower} \leq s_{r,t,hydropower} + I^{hyd}_{r,t} - g_{r,t,hydropower}, \qquad \forall r \in R^{SE},\ \forall t \in T \tag{3.20}$$

$$HydP^{min}_{r,t} \leq g_{r,t,hydropower} \leq HydP^{max}_{r,t}, \qquad \forall r \in R^{SE},\ \forall t \in T \tag{3.21}$$

$$HydL^{min}_{r,t} \leq s_{r,t,hydropower} \leq HydL^{max}_{r,t}, \qquad \forall r \in R^{SE},\ \forall t \in T \tag{3.22}$$

Öberg et als. Bi-level equivalent includes limitations on up- and down-ramping, as in Eqs. (3.23)-(3.24), where maximum up- and down-ramping during one timestep t is given by $HydRamp_{r,t}$. $HydRamp_{r,t}$ is also dependent on the inflow period in region r at the given timestep t.

$$g_{r,t+1,hydropower} - g_{r,t,hydropower} \leq HydRamp_{r,t}, \qquad \forall r \in R^{SE},\ \forall t \in T \tag{3.23}$$

$$g_{r,t-1,hydropower} - g_{r,t,hydropower} \leq HydRamp_{r,t}, \qquad \forall r \in R^{SE},\ \forall t \in T \tag{3.24}$$

The values and inflow period descriptions are taken from Öberg et al. and presented in Tables A.11-A.12.

3.1.3 Hydrogen

With increasing need for green hydrogen, produced without emissions, in industry, comes a large increased electricity demand. Green hydrogen produced using water and electricity, can be paired with hydrogen storage to shift its production from peak electricity demand hours.

Hydrogen is integrated in a similar manner as Rosén et al. [44], where demand of hydrogen is a fixed hourly profile value, calculated from a yearly demand. The hourly value is fixed as the estimate is that industry will require a constant amount of hydrogen each hour. The demand of hydrogen can either be provided from an electrolyser or from discharge of hydrogen storage. The hydrogen demand balance is presented in Eq. (3.25).

$$D^{H_2}_{r,t} \leq \sum_{p \in P^{H_2SOC}} \left(SOC^{dis}_{r,t,p} - SOC^{ch}_{r,t,p}\right) + g_{r,t,electrolyser} - \frac{g_{r,t,FC}}{\eta_{FC}}, \quad \forall r \in R^{SE},\ \forall t \in T, \tag{3.25}$$

where $D^{H_2}_{r,t}$ is the fixed hourly hydrogen demand for each region r, $g_{r,t,electrolyser}$ is the hydrogen production from the electrolyser, $g_{r,t,FC}$ is the electricity generation from fuel-cells, included as it uses hydrogen as fuel, and the hydrogen storage technologies in the set P^{H_2SOC} are constrained by Eqs. (3.13)-(3.16). For LRC, there is an additional constraint on maximum 20 allowed cycles throughout one year, described by Eq. (3.26).

$$\sum_{t \in T} SOC^{ch}_{r,t,LRC} \cdot \eta^{ch}_{LRC} \leq i_{r,LRC} \cdot 20, \quad \forall r \in R^{SE} \tag{3.26}$$

As the electrolyser is producing hydrogen using electricity, its generation increases the electricity demand. Therefore the left hand side of the electricity demand balance, Eq. (3.2), is updated as

$$D^{elec}_{r,t} + \frac{g_{r,t,electrolyser}}{\eta_{electrolyser}} \leq \ldots, \quad \forall r \in R^{SE},\ \forall t \in T, \tag{3.27}$$

while the right hand side is kept the same as in Eq. (3.2). The hydrogen production from electrolyser is constrained by Eq. (3.28).

$$g_{r,t,electrolyser} \leq i_{r,electrolyser}, \quad \forall r \in R^{SE},\ \forall t \in T \tag{3.28}$$

3.1.4 Heat

Due to Sweden's geographical position it encounters all four weather seasons, with especially cold weather in the northern parts of the country. The cold weather requires buildings and services to receive heating from heat producing plants. In the last 10 years the heat consumption in Sweden has been around 50 TWh, where multi-family dwellings stand for the majority share, according to SCB [45]. The District-Heating (DH) demand is met by combined heat-and-power (CHP) plants, fuel based heat plants, together with electric boilers and heat pumps who run on electricity.

SEmLa incorporates heat generation technologies to meet the DH demand. $g^{heat}_{r,t,p}$ is the heat generation by heat generating technology p for each region r at timestep t. The model makes use of heat producing technologies and the heat generation is governed by Eq. (3.29).

$$g^{heat}_{r,t,p} \leq i_{r,p}, \quad \forall r \in R^{SE},\ \forall t \in T,\ \forall p \in P^{HEAT} \tag{3.29}$$

For heat generating technologies with a startup time longer or equal to 1 hour is also constrained by Eqs. (3.6)-(3.10), similar to thermal technologies.

The heat demand $D^{heat}_{r,t}$ in each region r at timestep t is met by the demand balance in Eq. (3.30), where the heat storage technologies in the set P^{HSOC} are constrained by Eqs. (3.13)-(3.16).

$$D^{heat}_{r,t} \leq \sum_{p \in P^{HEAT}} g^{heat}_{r,t,p} + \sum_{p \in P^{HSOC}} (SOC^{dis}_{r,t,p} - SOC^{ch}_{r,t,p}) + \sum_{p \in P^{CHP}} \frac{g_{r,t,p}}{\alpha_p}, \quad \forall r \in R^{SE},\ \forall t \in T, \tag{3.30}$$

Heat generation from CHP plants is dictated by its electricity generation and power-to-heat factor α_p. CHPs take on cycling properties in accordance with Eqs. (3.6)-(3.10).

Heat generating technologies that make use of electricity as fuel increases the electricity demand, similarly as the hydrogen producing electrolyser. Therefore the left hand side of the electricity demand balance, updated in Eq. (3.27), is changed to

$$D^{elec}_{r,t} + \frac{g_{r,t,electrolyser}}{\eta_{electrolyser}} + \sum_{p \in P^{HeatElec}} \frac{g^{heat}_{r,t,p}}{\eta_p} \leq \ldots, \quad \forall r \in R^{SE},\ \forall t \in T, \tag{3.31}$$

with the right hand side kept the same as in Eq. (3.2).

3.2 Model Parameters

The following section describes the most important parameters used in the model and thesis work.

3.2.1 Weather year

To ensure consistency between different parameters, such as weather profiles, water inflows and demand profiles, we make use of reference weather years. For this thesis the meteorological weather years 1991 and 1992 have been used. The reason being that they have opposite characteristic for hydropower inflows. Year 1991 is considered a dry year and year 1992 is considered a wet year, according to Öberg et al. [43], where the dry year has less inflow into hydropower reservoirs compared to the wet year. In numbers, the dry year has 11 TWh less electricity generating inflow compared to the wet year. The weather year parameter is used for construction of wind and solar profiles, discussed in Section 3.2.5, for demand profiles and for predicted electricity prices from external regions, discussed in Section 3.2.4. Hereby, 1991 is referred to as Dry weather year (DWY) and 1992 as Wet weather year (WWY). Weather years are representative representations of years with different amount of hydropower inflow and results are not applicable to every year where the hydropower inflow is the same as those used in this thesis.

3.2.2 Demand

SEmLa incorporates demand on electricity, hydrogen and heat. The demands are dependent on the scenario and case of which is investigated, described in Section 3.3. This section describes how the demands are constructed. All demands have been provided by Division of Energy Technology at Chalmers University [39].

Electricity demand

Electricity demand data is divided in two parts, historical load and future load. The historical load is dependent on the reference weather year to match wind, solar and hydro behaviour. Total demand of historical load is the total demand in the given weather year. The future load comes from industry and road transport sectors and is a constant hourly load. The categories contributing to the total load is shown in Table 3.1, where demand for EVs are taken from Taljegard et al. [46] and rest from Chalmers Division of Energy Technology [39].

Electric vehicle (EV) demand is implemented using the Aggregated Vehicle Profile (AGG) method presented by Taljegard et al. [46]. Here the EV fleet, for the different categories, is aggregated into one profile and handled as one large unit with a fixed driving and charging profile. Reason for the AGG approach is to limit the complexity and computational demand of the model. Another reason is that V2G is not implemented in the model and therefore a more detailed approach is not needed, see Taljegard et al. [46].

As seen in Eq. (3.31), electricity demand is also dependent on hydrogen- and heat production from technologies using electricity as fuel. Therefore a large increase in electricity demand comes from electrification of those sectors.

Sector	Category	Region	Total yearly demand [TWh$_{el}$]
Historical load		SE1	2.8
		SE2	6.8
		SE3	89.4
		SE4	26.7
Industry	Fossil free steel	SE1, SE3	7.6
	Plastic (Chemical)	SE3	11.3
	Concrete and Cement	SE3	2.4
	Battery factories	SE1, SE3	5
Road Transport (EV)	Passenger cars	SE1-4	17
	Light trucks	SE1-4	3.6
	Heavy trucks	SE1-4	10.7
	Buses	SE1-4	1.4

Table 3.1: Electricity demand sectors, categories and applicable regions.

Hydrogen demand

Hydrogen demand is handled as a constant hourly load over each timestep of a year. Reason is that hydrogen demand in this study only comes from industry, which is assumed to have production running constantly throughout the year. The hydrogen demand is broken down into categories, similar as electricity demand, and shown in Table 3.2.

Category	Region	Total yearly demand [TWh$_{H_2}$]
Fertiliser	SE1	3.5
Refineries	SE3	3.2
Electrofuels	SE2	2.8
Plastic (Chemical)	SE3	10.7
Fossilfree steel	SE1, SE3	15.6

Table 3.2: Hydrogen demand categories and applicable regions.

From Table 3.2 we see that regions SE1-SE3 have an hourly demand, while SE4 does not. For SE1-SE3, Table 3.3 shows the hourly demand. Investments in electrolyser above the hourly demand will be referred to as Overcapacity as it enables generation over the constant demand. This is essential for investments in hydrogen storage technologies, as overcapacity is needed to charge the storage.

Region	Hourly demand [GWh_{H_2}/h]
SE1	1.85
SE2	0.32
SE3	1.92

Table 3.3: Hourly hydrogen demand per Swedish electricity price region.

Heat demand

Heat demand, specifically DH demand, is handled with a historical year load profile, where the total demand is given for the weather year. As previously mentioned in Section 3.1.4, the heat demand in Sweden has been around 50 TWh for the last years and comparing loads from chosen weather years with today we see a small difference. One reason for shifts in heating demand, of different years, is how cold or hot the winter period is. Looking at the total heating demand it is mostly connected to how cold or hot it is in SE3 as it stands for ∼60% of total heat demand [39].

3.2.3 Transmission capacity

Transmission between Swedish electricity price regions and with external neighbouring price regions are controlled by the transmission capacity between regions. Table 3.4 defines the cable capacities between price regions, both internally and externally for Swedish price regions. The capacities are taken from Division of Energy Technology at Chalmers [39] who bases capacities on ENTSO-E [47] for the given target year of 2040. Values are maximum allowed capacity in the transmission line at a given hour, and together with electricity prices from neighbouring regions, SEmLa decides how much to import/export for each Swedish price region. Transmission losses are not included in the model.

Region	**SE1**	**SE2**	**SE3**	**SE4**
SE1	-	3300	-	-
SE2	3300	-	10700	-
SE3	-	10700	-	2800
SE4	-	-	6200	-
DK1	-	-	-	2550
DK2	-	-	1005	-
NO1	-	-	2095	-
NO2	-	1000	-	-
NO3	600	300	-	-
FI	2000	-	1200	-
LT	-	-	-	700
PO3	-	-	-	700
DE4	-	-	-	600

Table 3.4: Cable capacities for trade between Swedish- and neighbouring electricity price regions in 2040. Values given in MW and region index from Figure 3.1.

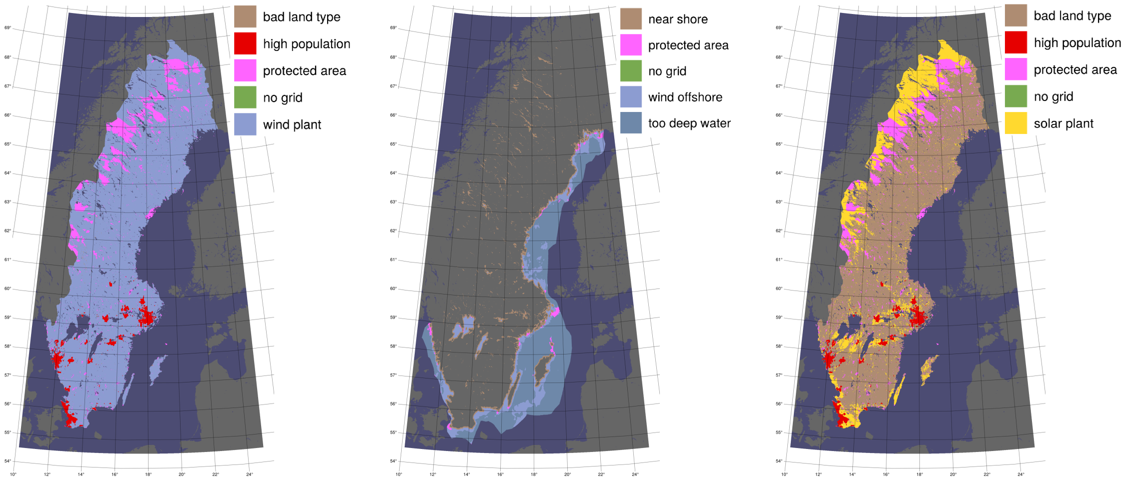
3.2.4 Electricity prices for neighbouring regions

Electricity prices for neighbouring regions are produced by the ELLI model, developed by Division of Energy Technology at Chalmers [39]. The model is a European energy system model which can model several European regions. To produce the electricity prices the model is run for the specified target year of 2040, with parameters for a given weather year. The electricity prices are handled as a parameter in SEmLa to determine the cost of trade between Swedish price regions and neighbouring regions.

3.2.5 Weather profiles - GlobalEnergyGIS tool

The GlobalEnergyGIS tool developed by Mattsson et al. [40] is used to create wind and solar PV profiles and potentials. The tool uses a specified weather year as input when creating the profiles and potentials. For this thesis onshore wind, offshore wind, utility-scale PV and rooftop PV was used. For each technology 5 different resource classes were used, which are based on annual capacity factors [40]. The tool makes use of a mask which removes protected areas, water, roads, cities and streams, similarly as in Walter and Göransson [37], therefore limiting the total available area for each technology to be installed.

For onshore wind farms a density of 5 MW/km^2 was used and 8% of total land area was assumed to be available after removal of mask, see Figure 3.2a. Full-load hours and max capacities for onshore wind classes are shown in Table A.5 and A.9.



(a) Total area for onshore wind after removal of mask, of which 8% is available for onshore wind installation.

(b) Total area for offshore wind after removal of mask, of which 33% is available for offshore wind installation.

(c) Total area for Solar PV after removal of mask, of which 5% is available for Solar PV installation.

Figure 3.2: Available area for onshore wind, offshore wind and solar PV produced by GlobalEnergyGIS [40].

For offshore wind farms a density of 8 MW/km^2 was used and 33% of total area was assumed to be available after removal of mask, see Figure 3.2b. For offshore wind the following constraints were also made: max distance of 150 km to nearest grid connection, minimum distance of 5 km to shore and a max depth of 40 m. Full-load hours and max capacities for offshore wind classes are shown in Table A.6 and A.9.

For Solar PV farms a density of 45 MW/km^2 was used and for both utility-scale and rooftop Solar PV 5% of total area was assumed to be available after removal of mask, see Figure 3.2c. Solar PV farms are constrained to be within 150 km of nearest grid connection and cannot be built in populated areas with more than 150 $persons/km^2$. Rooftop Solar PV are constricted to populated areas with at least 200 $persons/km^2$. Full-load hours and max capacities for utility-scale and rooftop PV classes are shown in Table A.7, A.8 and A.10.

3.3 Cases definition

The thesis investigates three different cases, where one is used as a base case and reference when evaluating the other two. The cases are run for two different weather years, as specified in Section 3.2.1, and demands specified in Section 3.2.2.

3.3.1 Base Case

In the base case, all technologies are available for investments and no restrictions are put on any model parameter. The base case is run for the specified weather years and is used as a reference when investigating the below cases.

3.3.2 No Hydrogen Storage Case

In the no hydrogen storage case (NoH2S), it is not allowed to invest in any hydrogen storage technologies, neither Hydrogen tanks or lined rock caverns. This forces SEmLa to only invest in electrolysers to cover the hourly hydrogen demand. This case seeks to investigate the impacts on the whole system for the continuous hourly load that comes from the required hydrogen production and the difference compared with the base case.

3.3.3 Electrolyser Cost Case

The electrolyser cost case (ECC) seeks to investigate how different investments costs for PEM Electrolysers impacts hydrogen production and storage. The case investigates 5 different investments costs, including base case cost, and is specified in Table 3.5. The Fix O&M cost of the electrolyser is set to 2% of the investment cost. All other technologies are kept the same as in base case and the model is run with the same parameters as the base case. Electrolyser investment costs are taken from the Danish Energy Agency [48].

PEM Electrolyser Investment cost [k€/MW]				
325	450	600	900	1200

Table 3.5: Investment cost for PEM Electrolyser for 5 different investigated levels. Base case cost was 450 k€/MW.

3.4 Code development

The SEmLa model is developed using the Julia language [49]. To construct the LP model the JuMP package [50] was used together with an optimizer of choice. In this thesis the Gurobi optimizer was used.

4

Results

Results are presented for each investigated case and weather year. References to additional results relates to results found in Appendix B. Cost results were scaled by an inflation factor 1.23, to convert from Euro2020 to Euro2025, as all cost data is given in Euro2020. Inflation factor was calculated with the Inflation Tool [51].

4.1 Base Case

The system costs for the base case of each weather year are displayed in Table 4.1. The majority of costs comes from Capex, while export of electricity to neighbouring regions brings down the costs, even though Sweden is net importer for both weather years as presented below. Hydrogen production, hydrogen storage and heat storage include their respective Capex and O&M costs, while electrolyser electricity cost is not included in total cost.

Base Case Costs [G€]

Cost	DWY	WWY
Total	4.88	4.36
Capex	4.17	3.79
O&M Fix	1.98	1.85
O&M Var	0.60	0.59
Trade	-3.27	-3.08
Cycling	0.004	0.001
Fuel	0.41	0.34
Hydrogen Production	0.56	0.49
Electrolyser Electricity Cost	*1.4*	*1.28*
Hydrogen Storage	0.30	0.27
Heat Storage	0.12	0.11

Table 4.1: System costs for Base case of each weather year. Hydrogen production, hydrogen storage and heat storage include their respective Capex and O&M costs. Electrolyser electricity cost is not included in total cost.

Figure 4.1 shows the electricity production mix for DWY and WWY. For both weather years, the demand is $\sim$ 263 TWh, with a total production of 251(249) TWh for DWY(WWY). For both weather years, Sweden becomes a net importer of electricity, making use of cheap electricity from neighbouring regions to help meet the electricity demand, while simultaneously exporting electricity when profitable.

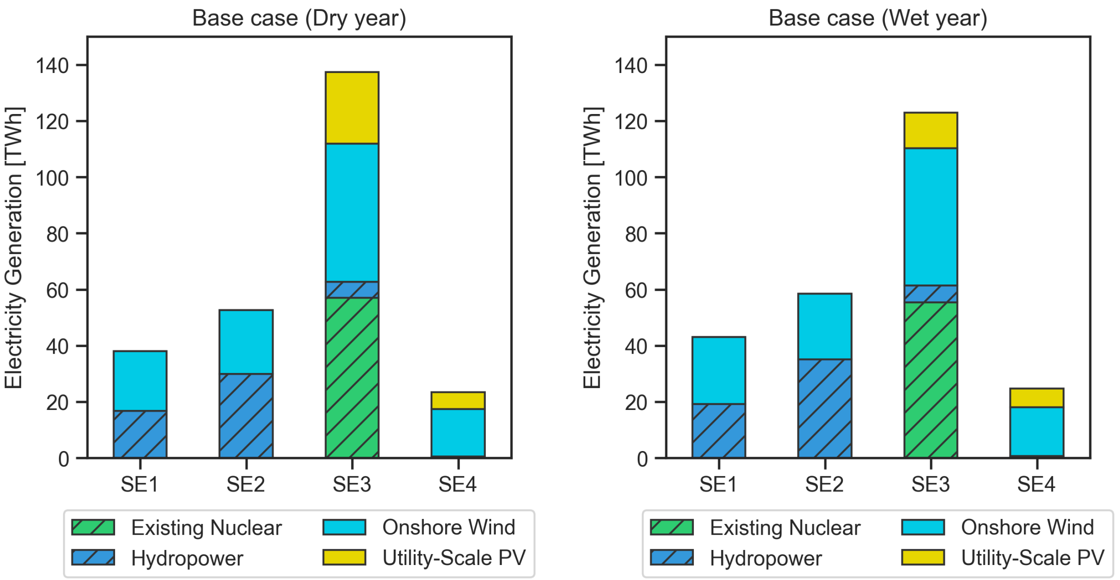


Figure 4.1: Electricity generation per Swedish electricity price region for Base case.

In both weather years, the production mix consists of nuclear, hydropower, onshore wind and utility-scale solar PV. Onshore wind is the largest producer, generating 110-114 TWh of electricity, with nuclear generating 55-57 TWh of base power for SE3. No new investments are made in nuclear power, production only coming from existing nuclear power with prolonged life. The weather year characteristic impacts hydropower generation mostly, with an 8 TWh difference between the weather years. The reduction in available hydropower flexibility results in larger investments in utility-scale solar PV, especially in SE3, where production increases with 13 TWh for DWY compared to WWY. For both weather years an investment in Li-Ion batteries of ~ 2 GWh, coupled with a power component investment of 0.65 GWh, was made in SE4, which act as a shifting strategy to Solar PV.

As mentioned, Sweden becomes a net importer of electricity for both weather years, where main import comes from Norwegian electricity price regions NO2 and NO3. NO2 and NO3, like SE1 and SE2, have lots of available hydropower [52], generating electricity at a low cost. For DWY there is a small reduction in import from these regions and a large increase in export to NO1. As hydropower in NO2 and NO3 cannot deliver as much cheap electricity to NO1, it enables SE3 to sell electricity to NO1 for a high price. Furthermore, SE3 and SE4 imports electricity from the Danish regions, where cheap electricity is produced by wind farms [53]. Total trade with external regions is presented in Figure B.1.

Figure 4.2 shows the marginal cost of electricity curves for base case of both weather years, which is the electricity price duration curve in a perfect energy-only market. The lower available hydropower generation in DWY impacts the average price across all regions, giving higher prices compared to WWY. Especially, WWY has 4500 –

4850 price hours above 40 €/MWh while DWY has 5100 – 5900 price hours above 40 €/MWh, contributing to the higher average prices.

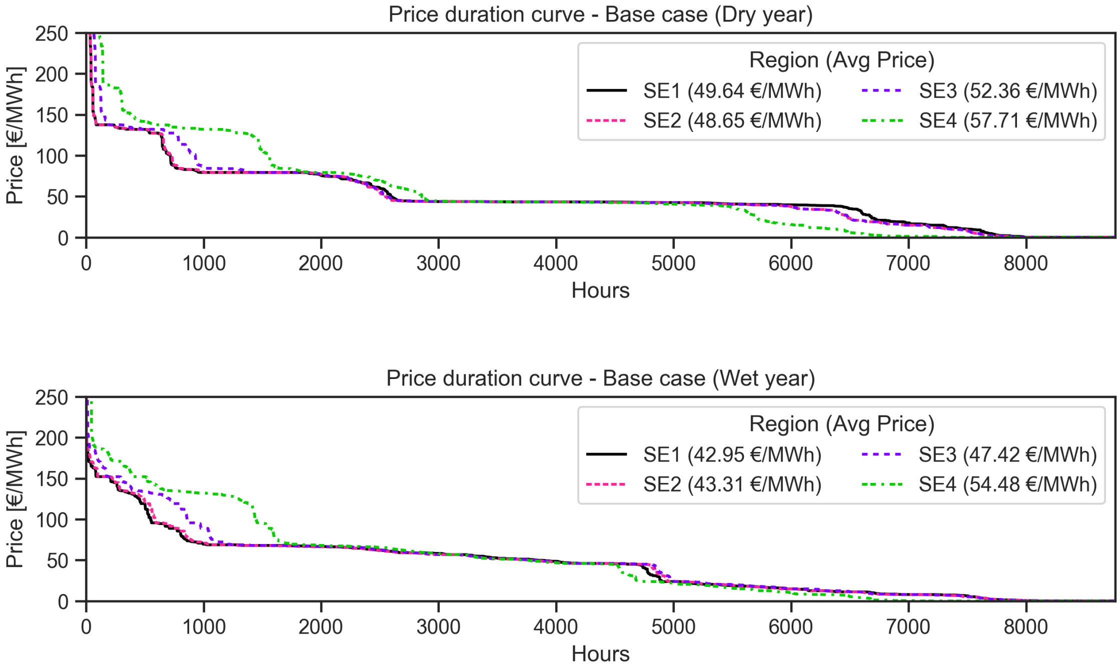


Figure 4.2: Electricity price duration curves for Base case.

There are large fluctuations in electricity price throughout the year, for both weather years. For DWY there is 760-1450 zero price hours, 700-1550 price hours above 100 €/MWh and 30-115 price hours above 250 €/MWh. The difference in price is especially significant for SE4 which has the most low, high and very high price hours of all regions. Reason being that SE4's electricity production mix consists of only variable renewable energy (VRE) technologies, which production curve depends on the weather conditions of the given hour. Thus, it receives low prices when there are a lot of available generation and higher prices with lower available generation. During the higher price hours, it depends on transmission with neighbouring regions, of which many have higher average electricity prices. SE1-SE2 have roughly the same amount of low and high price hours, in the lower end of the interval, and SE3 have price hours roughly in the middle of each interval.

For WWY there is 640-1680 zero price hours, 550-1450 price hours above 100 €/MWh and 1-45 price hours above 250 €/MWh. Reduction in zero price hours happens in SE1-SE3 while it increases in SE4 compared to DWY. Reduction in high and very high price hours is seen throughout all regions, with largest reductions seen in SE1-SE2 due to their increased flexibility of hydropower production.

Figures 4.3-4.4 shows the investments in hydrogen generation and storage. For both weather years it is preferable to invest in hydrogen storage, both tank and LRC storage, together with investments in electrolyser overcapacity. For DWY there is overcapacity investments of 51-79% across the regions, while for WWY the overcapacity investments are 31-58%. In SE1-SE2 the larger investment in DWY is coupled with larger investments in hydrogen storage, as larger overcapacity enables larger charging of the increased storage. In SE1-SE2 the hydrogen storage consists of both

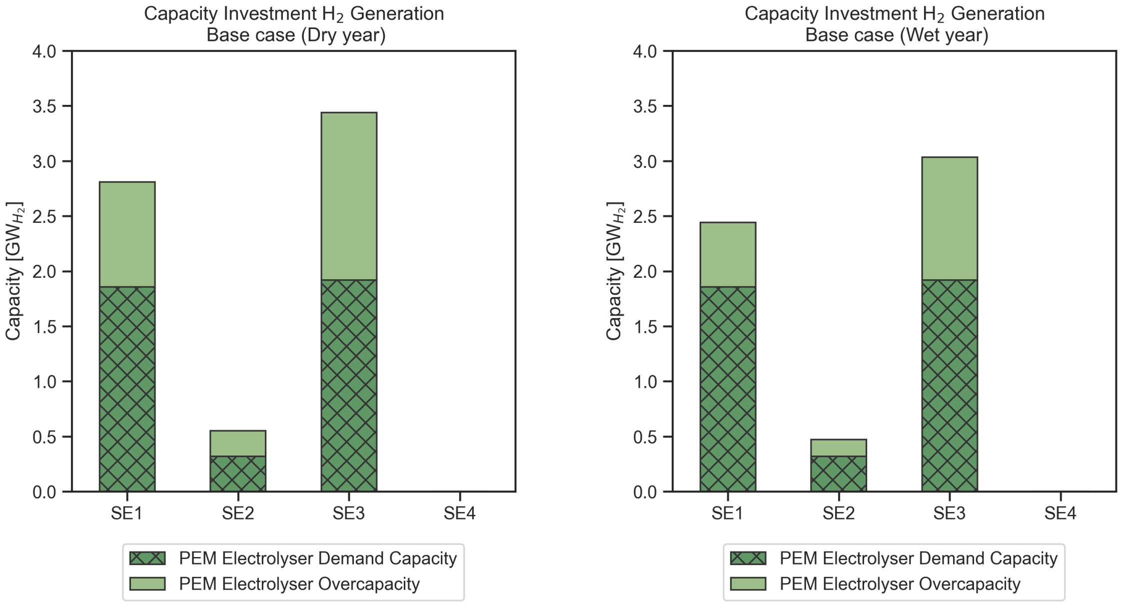


Figure 4.3: Capacity investment in hydrogen generation in Base case.

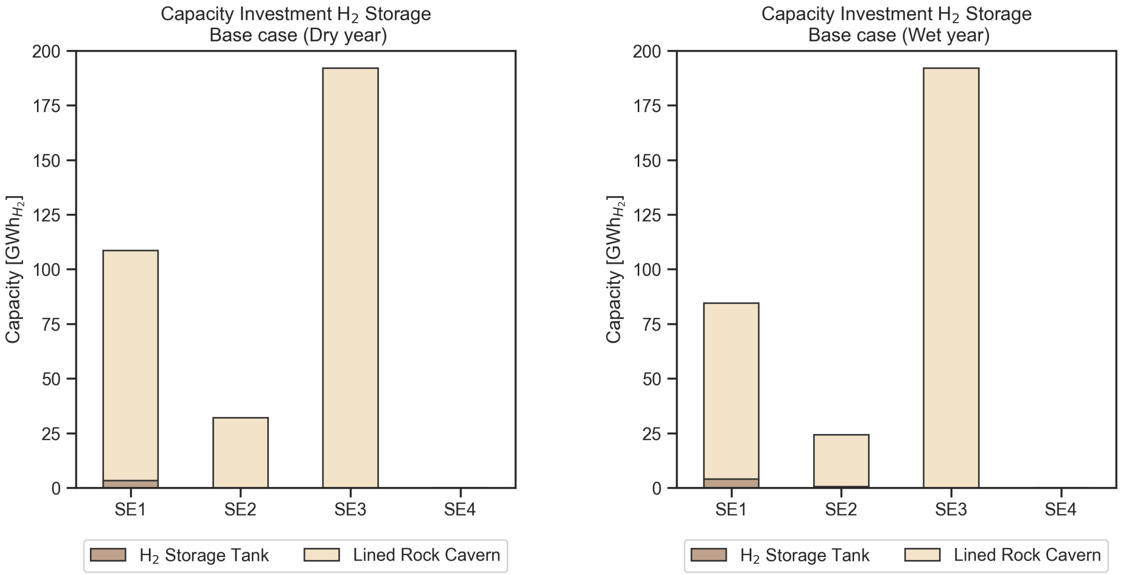


Figure 4.4: Capacity investment in hydrogen storage in Base case.

tanks and LRC for DWY, for WWY there is no tank investment in SE2. LRC is the main storage technology because it has a smaller investment cost than tanks, but with downside of not being able to charge and discharge as fast. Therefore, LRC is used for long time storage while tanks are used for short time storage.

In SE3 there is a 0.4 GW larger overcapacity investment in DWY compared to WWY, but the same storage capacity investment. The storage investment amounts to 192 GWh_{H_2}, of which 1% equals the hourly hydrogen demand in SE3. This is also the maximum withdrawal that can be made in one hour from the LRC. The larger overcapacity investment for DWY can be linked to the amount of high price hours. In DWY we have more high price hours compared to WWY, for which there is an incentive to lower electricity demand. One way is to limit hydrogen production to either make use of storage or operate electrolyser at demand capacity. Therefore there is less hours where its preferable to charge the storage, which leads to larger investment in overcapacity to produce more hydrogen during low price hours.

In both weather years, charging and discharge of hydrogen storage align with wind and solar production, as previously presented by Walter et al. [36], and with trade. Figure 4.5 shows this behaviour for 3 summer days in SE3 for WWY. Here, the charging of the storage follows the solar and wind production along with net import of electricity. The import comes mainly from SE2 and SE4, where SE2 makes use of its flexible hydropower and SE4 provides electricity from daily peaks in solar PV production. These hours also correspond to low price hours where there are large amounts of available electricity to match the demand. During nights, when solar PV production goes down, discharge of hydrogen storage instead takes over and covers the hydrogen demand.

In SE1-SE2, the hydrogen production is dependent on wind generation, hydropower generation and trade. For both regions hydrogen demand is met by hydrogen storage discharge when hydropower production is ramped up, seen in Figures 4.6-4.7. This because the hydropower ramping is made to transmit electricity to neighbouring regions, both internally and externally. The hydrogen storage is then charged when wind and hydropower generation goes down. The large amount of hydropower production in SE2 provides additional electricity to SE1 to charge the hydrogen storage. The behaviour is the same for DWY as WWY.

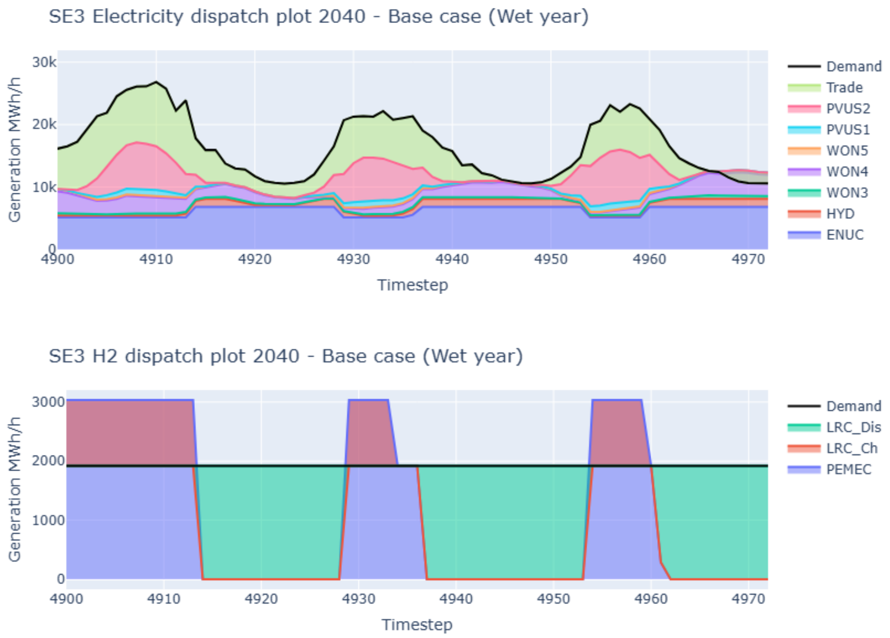


Figure 4.5: Electricity- and hydrogen dispatch plots for 3 summer days in SE3, for Base case and WWY. Electricity demand includes hydrogen and heat electricity demand, as per Eq. 3.31. Everything above electricity demand line is exported. For hydrogen dispatch, everything above demand line is charged to hydrogen storage.

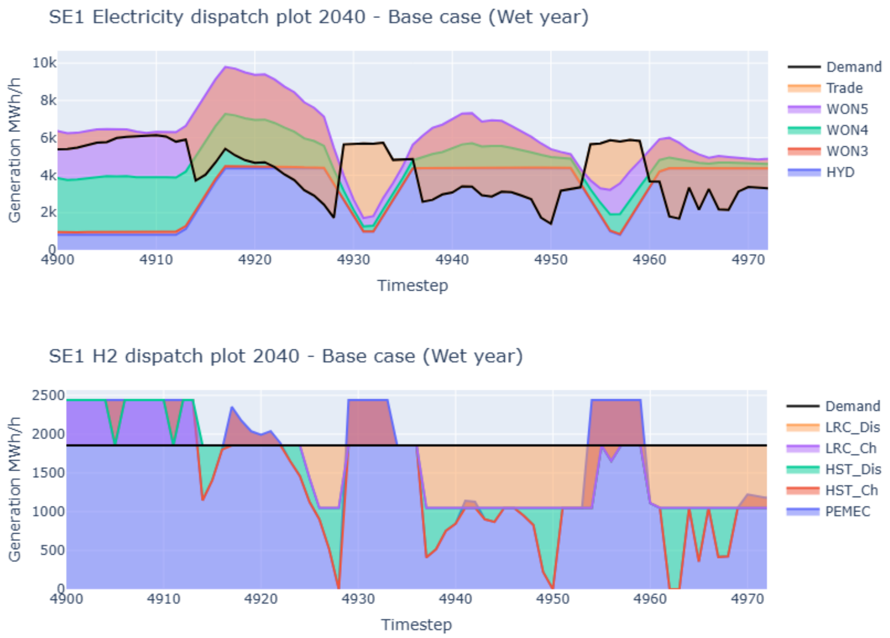


Figure 4.6: Electricity- and hydrogen dispatch plots for 3 summer day in SE1, for Base case and WWY. Electricity demand includes hydrogen and heat electricity demand, as per Eq. 3.31. Everything above electricity demand line is exported. For hydrogen dispatch, everything above demand line is charged to hydrogen storage.

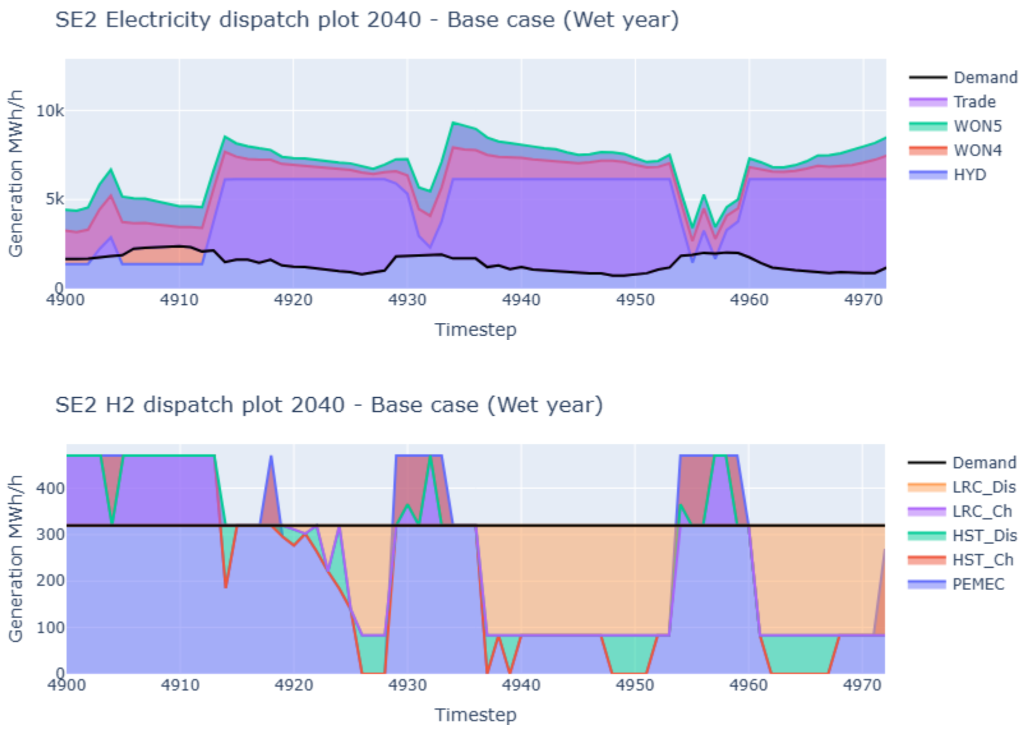


Figure 4.7: Electricity- and hydrogen dispatch plots for 3 summer day in SE2, for Base case and WWY. Electricity demand includes hydrogen and heat electricity demand, as per Eq. 3.31. Everything above electricity demand line is exported. For hydrogen dispatch, everything above demand line is charged to hydrogen storage.

Lastly, heat demand is met by investments in electric fuelled technologies, electric boilers and air heat pumps, in combination with large hot-water tanks (LHWT) and biogas HOB, as seen in Figures 4.8-4.9. Heat pumps are acting as base heating with coverage by discharge of LHWT. Electric boilers are mostly activated to charge the heat storage. Heat dispatch plots for 4 winter weeks in SE1 and SE3, for both weather years, are displayed in Figures B.2-B.3.

For DWY there is larger investments in Biogas HOB which is activated during peak winter. The HOB is activated at the same time for all regions, indicating a high heat demand where it is not financially optimal to increase production from electricity fuelled heating technologies. In addition to activation of HOB, the heating demand, in this period, is covered by discharge from LHWT. For DWY, this period is also the period where we find the highest electricity prices in all regions, indicating high demand with low available resources to produce or import electricity.

For WWY there is one small investment in Biogas HOB of 1 MW in SE1, which is activated for ∼ 250 hours in the later part of the year. Remaining hours heating demand is met by electric fuelled technologies and storage discharge. As in DWY, heat pumps act as base heating, with electric boilers mostly activated to charge the heat storage.

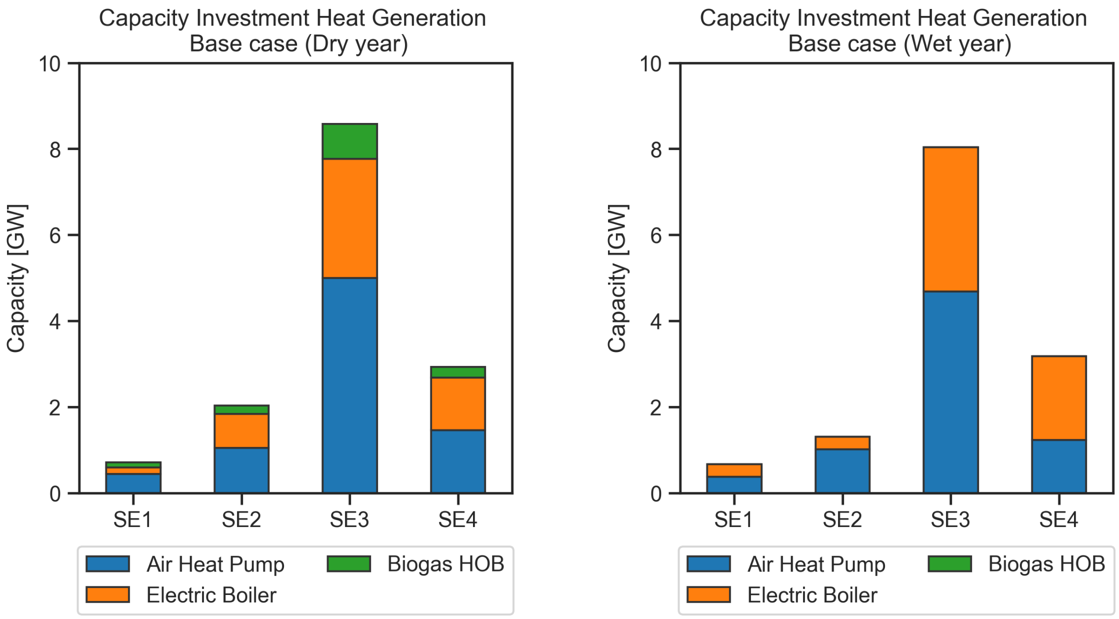


Figure 4.8: Capacity investment in heat generation in Base case.

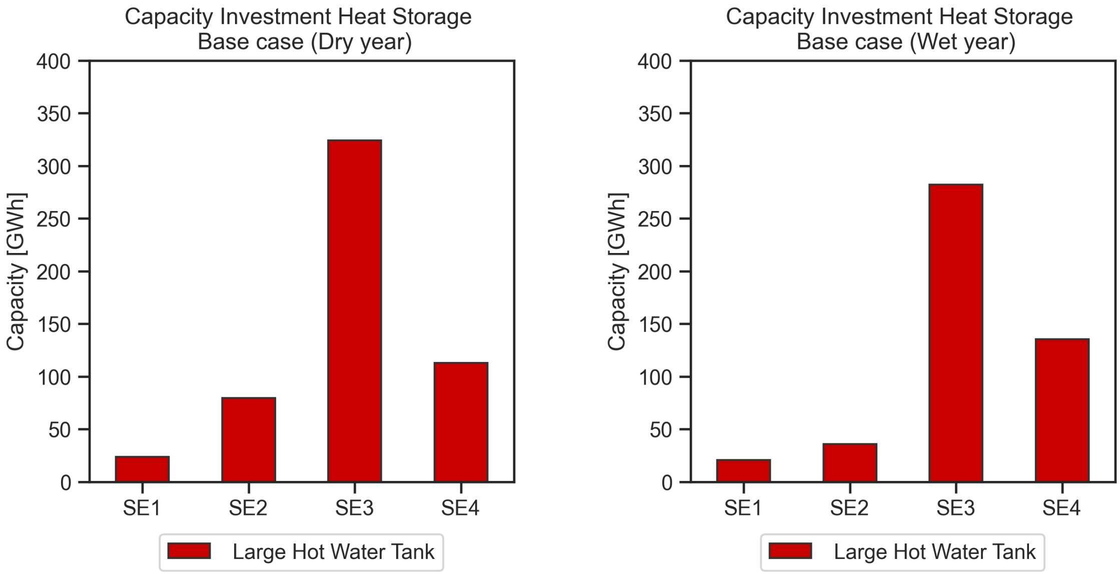


Figure 4.9: Capacity investment in heat storage in Base case.

4.2 No Hydrogen Storage Case

In the case of no hydrogen storage, the main impact is seen on hydrogen production. The capacity investment in hydrogen production matches the hourly demand with no overcapacity, as presented in Table 3.3 and shown in patterned part of bars in Figure 4.3. As the hydrogen production can not store excess produced hydrogen, it is not economically viable to invest in a larger PEM electrolyser, as it will not operate above the hourly demand.

System costs for NoH2S case are presented in Table 4.2. As in base case, hydrogen production, hydrogen storage and heat storage include their respective Capex and O&M costs, while electrolyser electricity cost is not included in total cost. Not allowing hydrogen storage increases the total system cost to 5.24 G€ for DWY and 4.63 G€ for WWY, increases of 7.4% and 6.2% respectively compared to base case. For both weather years the hydrogen storage cost is removed and the cost of hydrogen production lands at 0.33 G€, a decrease of 32-40% compared to base case. But, the electrolyser electricity cost increases by 33-40%, indicating a large increase in running costs of electrolyser, independent of weather year. The largest increase in electrolyser electricity cost is seen in SE3. The decrease in hydrogen production and storage costs is countered by increases in system Capex and Trade costs.

No Hydrogen Storage Case Costs [G€]

Cost	DWY	WWY
Total	5.24	4.63
Capex	4.42	4.05
O&M Fix	2.04	1.92
O&M Var	0.59	0.58
Trade	-2.69	-2.74
Cycling	0.005	0.002
Fuel	0.38	0.34
Hydrogen Production	0.33	0.33
Electrolyser Electricity Cost	*1.96*	*1.7*
Hydrogen Storage	0	0
Heat Storage	0.14	0.14

Table 4.2: System costs for NoH2S case of each weather year. Hydrogen production, hydrogen storage and heat storage include their respective Capex and O&M costs. Electrolyser electricity cost is not included in total cost.

For both weather years, the increase in Capex is mainly driven by increased capacity investments in Onshore wind in SE3 and utility-scale PV investments in SE3 and SE4. Consequentially, total wind production increased with 2.2 TWh for DWY and 3.9 TWh for WWY, while solar production increased with ~ 2 TWh for both weather years, compared to base case. The increased production comes as a consequence of the reduced flexibility to shift hydrogen production with the use of hydrogen storage. The majority of increased capacity is placed in SE3, as it has the largest electricity and hydrogen demand.

To help with the intermittency of the increased share of VRE technologies, capacity investments are made in Li-Ion batteries in SE3 and SE4. As hydrogen production, and its share of electricity demand, can not be shifted with the use of hydrogen storage, it makes use of the batteries to shift the electricity production instead. Figure 4.10 shows the capacity investments in Li-Ion batteries for the respective weather years. In SE4 there is a capacity increase in energy component of 115(122)% and 82.5(113)% in power component compared to base case for DWY(WWY). Batteries supports the regions by discharging during mornings and nights, where solar production is limited, and is charged during daytime. To charge the batteries and meet the demand during high solar production, import into SE3 and SE4 increases, mainly due to low electricity prices in neighbouring regions. Figure 4.11 displays this behaviour in SE4 for one day.

Larger capacity investments in electricity storage is made in DWY compared to WWY, as a consequence of the reduced flexibility in hydropower production, which decreases the transmission capabilities from northern to southern regions, mainly SE2 to SE3. Therefore, larger investments in storage technologies are made, in order to shift more production in DWY compared to WWY.

In both weather years, Sweden remains a net importer of electricity. Net import amounts to 11.5 TWh for both weather years, which is an increase of 1 TWh for DWY and a decrease of 3 TWh for WWY, respectively compared to base case. Total transmission with neighbouring regions for NoH2S case is presented in Figure B.4. The increase in net import for DWY is mainly connected with transmission with FI from SE1 and SE3. For both Swedish regions the net export is reduced due to the removal of flexible hydrogen production. Because of the removal there is a constant need to meet demand in the respective region and less available electricity to

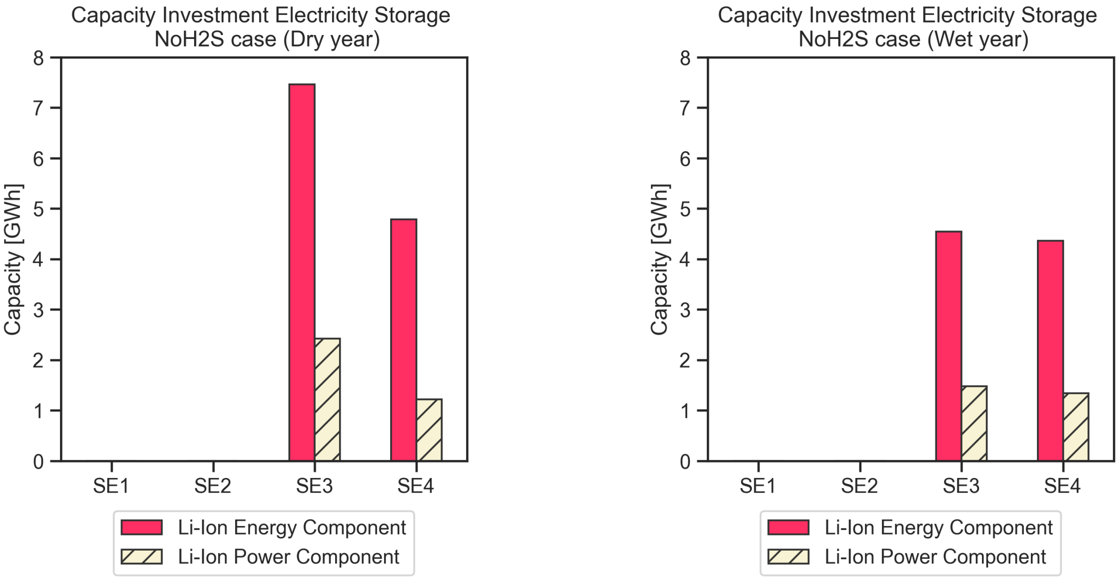


Figure 4.10: Capacity investment in electricity storage in NoH2S case.

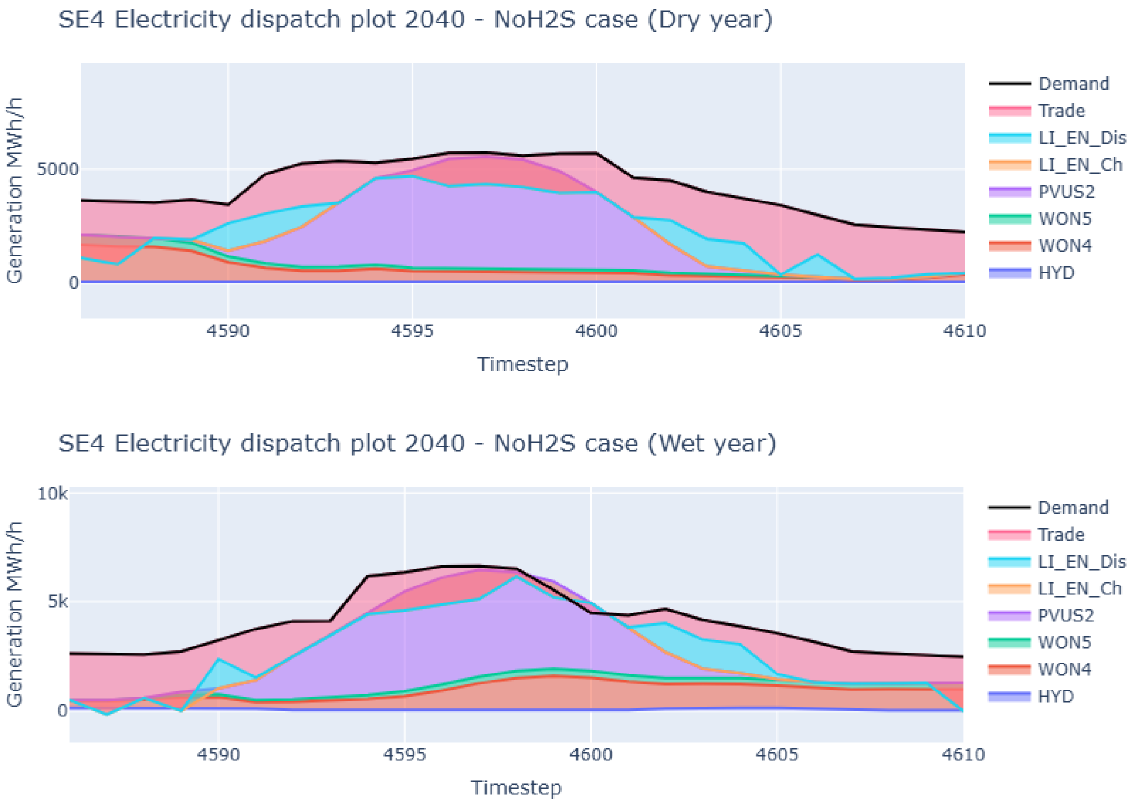


Figure 4.11: Electricity dispatch plot for 1 summer day in SE4 in NoH2S case.

export. The decrease in net import for WWY comes from decreased net import in SE3 and SE4. Both regions are supported by SE1 and SE2 as both regions have lots of available hydropower. This decreases the need for import from external regions and in the total net import.

Figure 4.12 displays the price duration curves for NoH2S case, of both weather years, in a perfect energy-only market. Table 4.3 shows the difference in average electricity price for each region between NoH2S and Base case. The smallest difference occurs in SE4, where the electricity price is marginally increased for both weather years. As SE4 do not have any hydrogen demand to account for, it is not impacted as much by the removal of the hydrogen storage flexibility compared to other SE regions.

Region	DWY	WWY
SE1	+4.9%	+3.0%
SE2	+6.3%	+3.7%
SE3	+10.4%	+6.8%
SE4	+2.0%	+0.8%

Table 4.3: Average electricity price difference between NoH2S case and base case for both weather years.

Remaining regions see increases of 3-10%, with higher increases for DWY. Reason being that DWY is less resilient to removed flexibility compared to WWY, as it has less flexibility in its hydropower production, which makes it hard to shift and support its electricity production with existing hydropower. This contributes to an increase of 100-260 price hours above 100 €/MWh for SE1-SE3, with SE4 kept the same, for DWY. Especially significant is the increase of 45-77 price hours above 250 €/MWh for NoH2S case compared to base case, indicating more hours with really high electricity prices throughout all regions. SE3 has the highest percentage-wise increase, which connects to its high electricity and hydrogen demand. SE3 therefore made use of a large LRC storage to flex its hydrogen production in both weather years, which in this case is not possible. Thus, resulting in more expensive technologies being activated, or expensive trade with neighbouring regions, during peak demand, driving up the average electricity price in the region.

For WWY, hydropower production is more flexible, which drives down electricity prices in both the Base and NoH2S case. But, the lack of flexibility in hydrogen production creates more high priced hours compared to base case in SE1-SE3. Price hours above 100€/MWh increases by 300-350 hours for SE1-SE3 and 90 hours for SE4, compared to base case. Price hours above 250 €/MWh is not affected as the flexibility in hydropower is used to minimize the peak high price hours.

Lastly, like in base case, heat demand in NoH2S case is covered by investments in air heat pumps, electric boilers, biogas HOB and LHWT. There is however differences in the size of the capacity investments. For both weather years, capacity investments

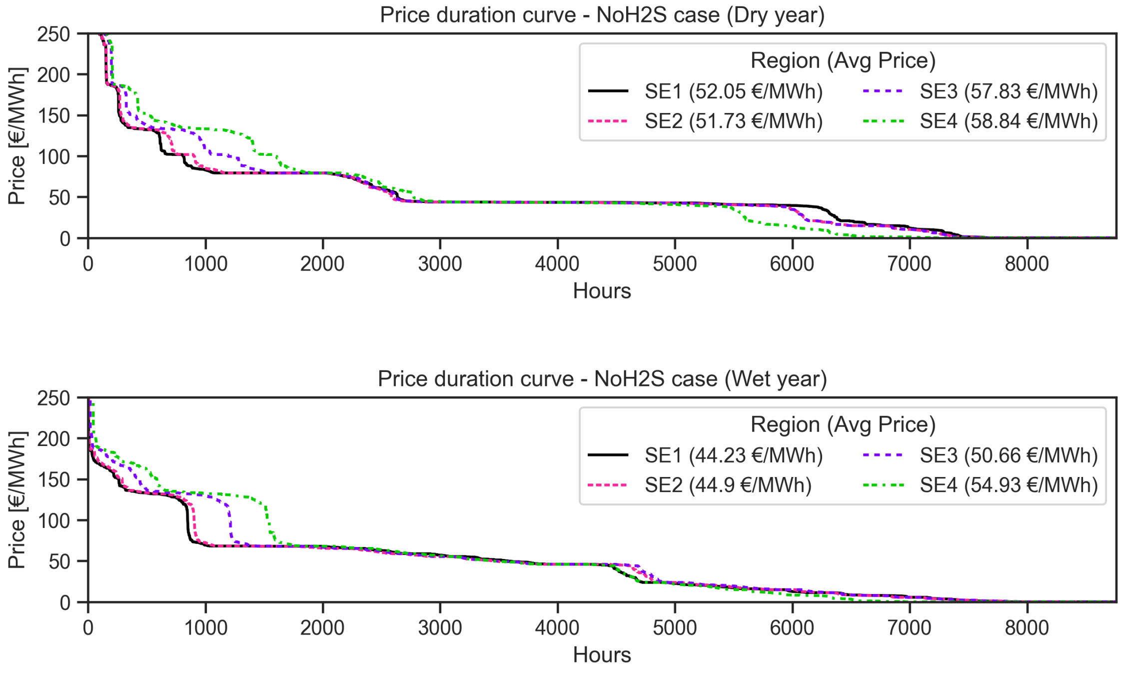


Figure 4.12: Electricity price duration curves for NoH2S case.

in biogas HOBs is reduced, for WWY there is no HOB investments in either region, investments in electric boilers are increased and investments in LHWT are increased compared to base case, seen in Figures B.5-B.6. Investments in air heat pumps are kept at the same levels as in base case.

The increased investments in electric boilers and LHWT is made to increase the flexibility from heating. With reduced flexibility in hydrogen production, increased flexibility in heating act as a measure to decrease electricity demand during peak hours. Therefore, larger investments are made in heat storage, which can discharge more heat during peak hours, which decreases the need for production by electric boilers and HOBs. Larger investments in electric boilers are made in order to charge the larger heat storage, while investments in HOBs decreases with the reduced need of peak plants due to the larger heat storage.

4.3 Electrolyser Cost Case

In the Electrolyser cost case (ECC), SEmLa is run for 5, including base case, different investment costs of PEM Electrolyser, as specified in Table 3.5. Figure 4.13 displays the normalized total system costs for each investment level compared to the base case, which had an investment cost 450 k€/MW. As can be seen for both weather years, the total system cost steadily increases with the increasing investment cost of the electrolyser. Total system cost for each investment level and respective weather year is presented in Table B.1.

For all investment levels, and both weather years, the change in total system cost is linked to the electrolyser cost, capacity investment in hydrogen storage and income from transmission. The change in total system cost, for each ECC investment level, can be described by the following:

> Higher Electrolyser cost ⟶ Less H_2 storage ⟶ Less flexible H_2 production ⟶ Less available electricity for trade ⟶ Decreased income from trade ⟶ Higher total system costs.

In short, a higher electrolyser cost leads to an increase in hydrogen production cost, in order to meet the demand capacity each hour. A high electrolyser cost minimizes the benefits of electrolyser overcapacity investments, which in return leads to less capacity investments in hydrogen storage which reduces the flexibility of hydrogen production. Thus, more electricity is needed to cover the regional Swedish demand and less electricity is available to export to neighbouring regions, during high-price hours especially. Therefore, income from electricity export decreases, which increases the total system cost. Investment levels above base case follows this path,

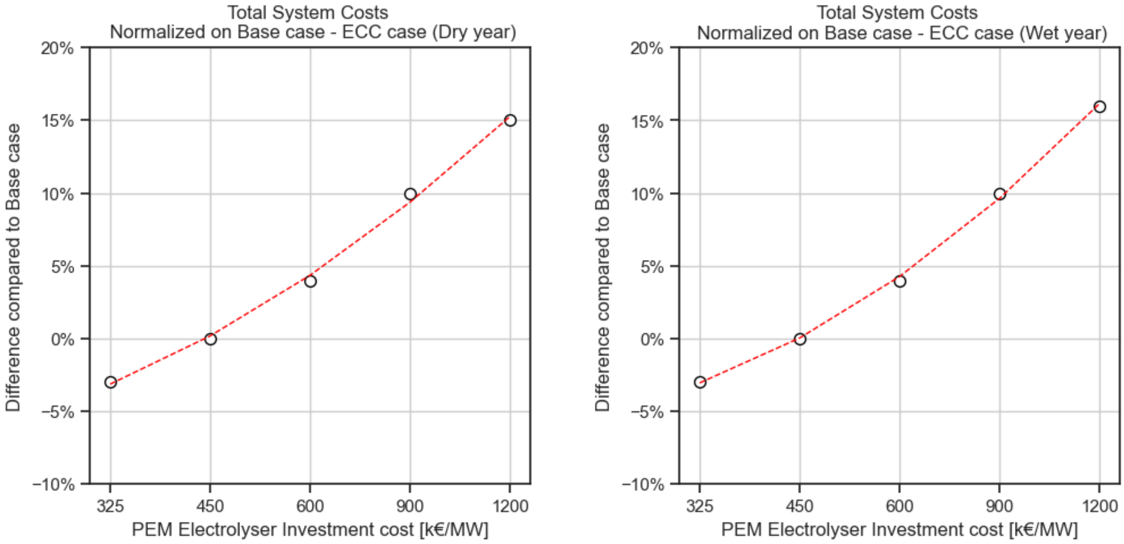


Figure 4.13: Total system costs trend plot for ECC case of both weather years. Values normalized on Base case total system cost, see Table 4.1, and shown as percentage values of increase/decrease compared to base case.

while the low investment level has the opposite trait, as the electrolyser cost is lower compared to base case.

Figure 4.14 displays the normalized overcapacity investment in electrolysers, for each electrolyser investment level and weather year. As mentioned above, higher electrolyser cost reduces the incentive to invest in overcapacity, which is clearly shown here for each region and weather year. For the highest electrolyser investment cost level, the overcapacity investments in SE1 and SE2 are reduced by around 90% for both weather years. Instead of flexing its hydrogen production, the regions make use of their flexible hydropower to shift their electricity production. In SE3, the reduction in overcapacity investments is larger for DWY compared to WWY. Thus, because there is less available low-cost electricity to power the electrolyser overcapacity to charge the hydrogen storage.

Figures 4.15-4.16 shows the capacity investment in hydrogen storage for ECC case of both weather years. In SE1, LRC capacity investment decreases with increased electrolyser cost. LRC follows the same trend as investments in electrolyser overcapacity, seen in Figure 4.14. For DWY, the reduction in LRC capacity is met with increased capacity investments in hydrogen tanks. Because hydrogen tanks can be charged and discharged with its full capacity, it makes it preferable to use for short peak durations. For SE1, tanks are used to lower peak demand during high price hours, and is increased in size for higher electrolyser costs where overcapacity investments are lower. For WWY, the tank storage investments decreases with higher electrolyser cost. This, because the increased flexibility of hydropower in the region can help with short- and long time shifting.

In SE2, like SE1, the capacity investment in LRC follows the trend of electrolyser

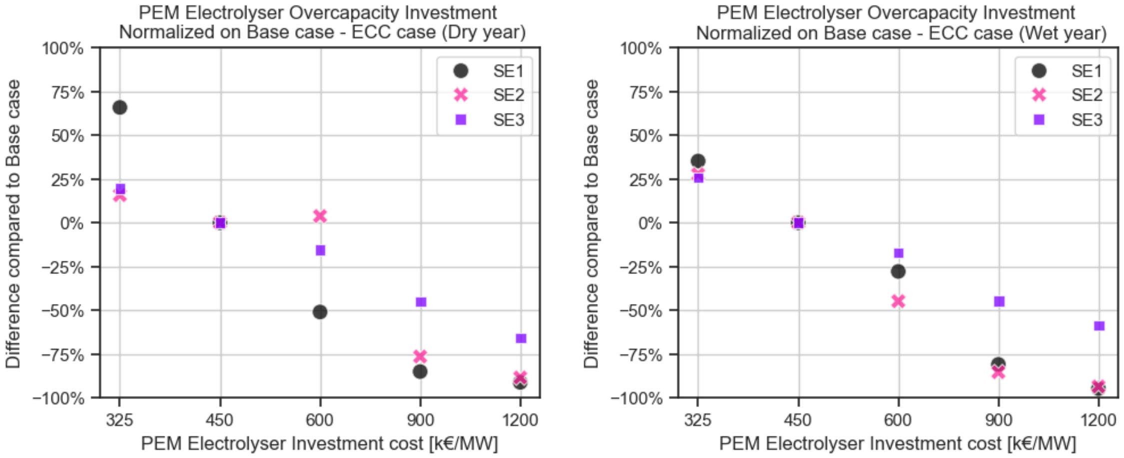


Figure 4.14: Overcapacity investment in PEM Electrolyser for ECC case of both weather years. Values normalized on Base case overcapacity investment, see Figure 4.3, and shown as percentage values of increase/decrease compared to base case (450 k€/MW).

overcapacity investments for the respective weather year. The main difference happening for the lowest investment level, where there is a small difference compared to base case, that is complemented by hydrogen tanks instead. For DWY, investments in tank storage increases when LRC investments decrease. Making use of the tank storage in peak hours. For WWY, the investments in tank storage is kept static throughout all electrolyser investment levels. Thus, because the region makes use of tank storage during peak hours, while the large hydropower flexibility handles long-term shifting.

SE3 has the same behaviour as SE2, with increase in tank storage when LRC investments decrease. But, investments in LRC capacity don not follow the electrolyser

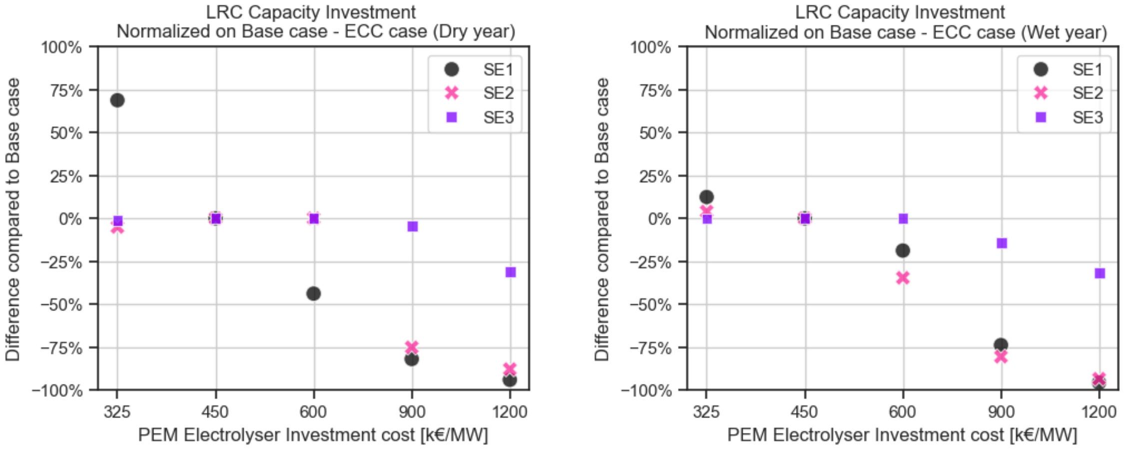


Figure 4.15: Capacity investment in LRC for ECC case of both weather years. Values normalized on Base case capacity investment, see Figure 4.4, and shown as percentage values of increase/decrease compared to base case.

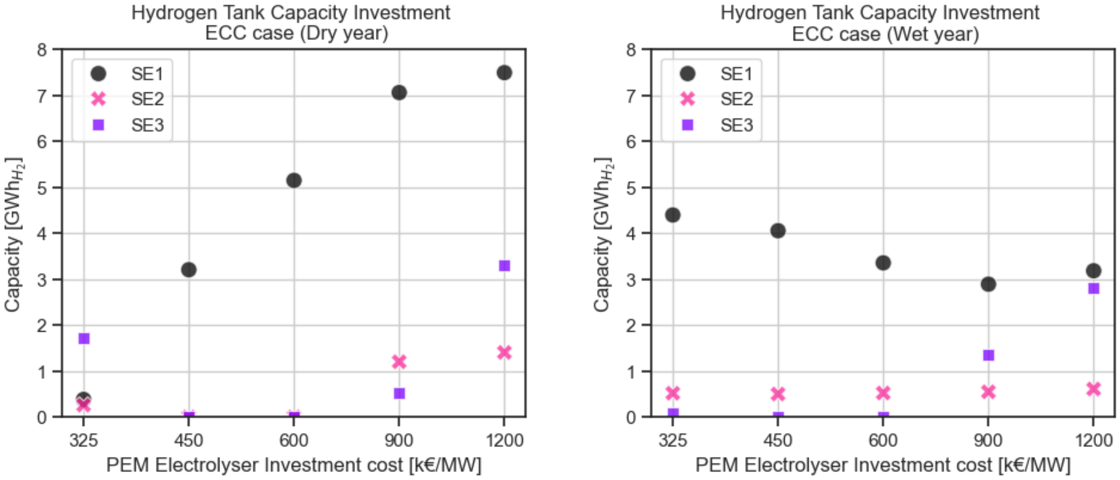


Figure 4.16: Capacity investment in hydrogen tanks for ECC case of both weather years.

overcapacity trend in the respective weather year. For both weather years, the investment in LRC is kept static for the 3 lowest investment levels, with small decreases for the second to highest investment levels. This because SE3 lacks technologies to shift production for a long period. SE1-SE2 makes use of their existing hydropower, while SE3 makes use of a large LRC storage. For highest electrolyser cost, LRC capacity investment is reduced by 30% in both weather years, while capacity investment of 3 GWh$_{H_2}$ in hydrogen tanks are made to cover peak hours.

Figure 4.17 shows the average electricity price for ECC case of both weather years. For DWY, the average electricity price in all regions increases with increased electrolyser cost. Reason being that less investments are made in flexible hydrogen production which shifts less production to low price hours. Smallest increase is seen in SE4, due to the region not having any hydrogen demand, but is impacted as it receives less support from SE3 during peak hours.

For WWY, the electricity price difference for each investment level differs between regions. In SE1 and SE2, there is a steady increase in average electricity price between lowest and second to highest investment level. This is connected to lowered investments in hydrogen storage which in return shifts less production. For highest electrolyser investment level there is an increase in tank storage for both regions, compared to second to highest investment level, while LRC investment decreases. Therefore, both regions make use of larger tank storages during peak hours, while their flexible hydropower shifts production long term, which decreases prices in the respective region. In SE3, there is a steady increase throughout all investment levels, as expected with the reduced flexibility in hydrogen production. In SE4, there is less impact on the average electricity price, due to it not having any hydrogen

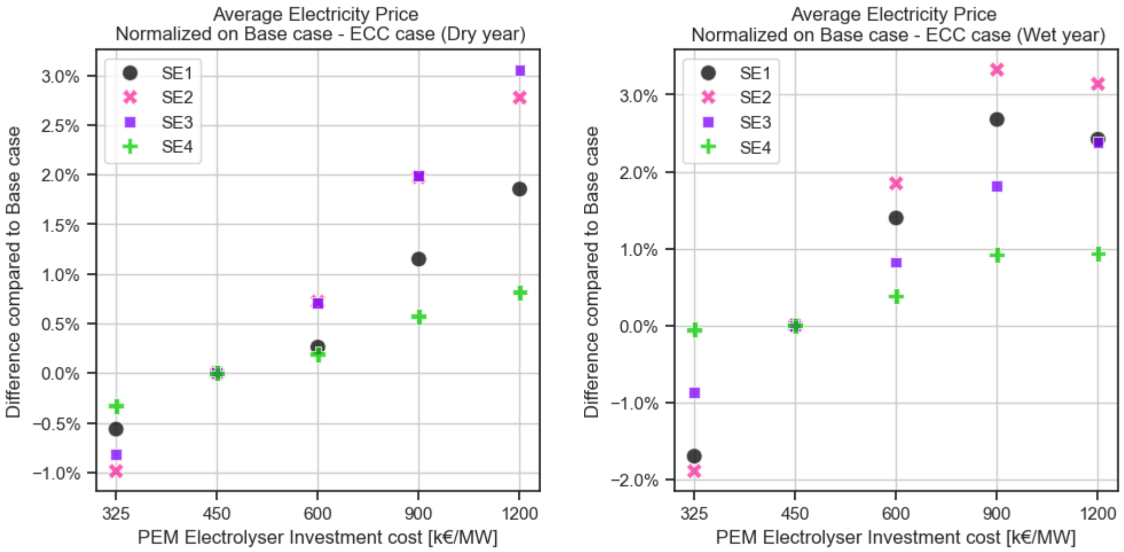


Figure 4.17: Average electricity price in each region for ECC case of both weather years. Values normalized on Base case electricity prices, see Figure 4.2, and shown as percentage values of increase/decrease compared to base case.

demand and the availability of cheap hydropower in the northern regions, which is transmitted down to the southern regions.

For each electrolyser investment level in ECC case, the electricity production mix remains the same as in base case. Generation from each production technology is roughly kept the same depending on the investment level, for both weather years, compared to base case. Investments in electricity storage, for both weather years, is kept the same as in base case. For each investment level, heat production is made by the same technologies as in base case, for both weather years. Increasing electrolyser investment cost results in larger investments in electric boilers and heat storage, in all regions and for both weather years. This as a result of the reduced flexible hydrogen production, which gives incentives to invest in more flexible heat production, as also seen in NoH2S case.

5

Discussion

It is important to note that the results presented in this thesis assumes a perfect energy-only market, and that results are optimized with the objective to minimize the total system cost, in other words the lowest cost for society. The results aim to show how a future energy system *could* look like, particularly how different technologies and demands impact the energy system, rather than what the future system will look like.

The model was run for one year, in which there is an assumption that every technology could be placed in each region, except nuclear and hydropower. This assumption creates a scenario where it is easy to meet the demand, without considering build time, permit time and social acceptance. Onshore wind becomes the main electricity producer throughout all investigated cases, which show that onshore wind will be a key technology to meet future demand. The risk, however, is that the realization of the needed expansion of onshore wind does not materialize, as there are already indications today that its expansion will decrease in the coming years.

There is also a factor of social acceptance when it comes to granting permits for weather-based technologies, especially wind farms, that could prevent needed expansion in areas with future large industry demand, such as SE1 and SE3. These factors are not captured fully through the works of this model, as it makes use of price region scope. Although, the wind profiles and potentials produced from the GlobalEnergyGIS tool makes use of a mask to limit available area, it does not capture social acceptance. The inclusion of social acceptance could impact assumed max capacities for wind and solar. With a reduced amount of available area to install weather-based technologies, the result could lead to a reduction in weather-based production, which in turn could lead to higher total costs. For this work, social acceptance is simplified, using a percentual number of total areas after application of mask as specified in Section 3.2.5, to limit model complexity. It is however important to keep in mind when discussing the feasibility of the future energy system constructed by the model.

As mentioned, the model was run for one year, where parameters, for example demand and weather profiles, where taken from a representative weather year. The weather years mainly differed in their hydropower inflow, to capture the effects of available flexibility in hydropower. It is important to note that these weather years are not absolutes, and that another year with the same hydropower inflow could generate other results. Thus, because another year could, for example, have been hotter or colder which impacts multiple parameters. Therefore, the results should be interpreted as possible cases of a future energy system with different hydropower flexibility. To run the two weather years after one another could have generated different results, but due to time constraints this was not possible.

Another aspect is that the electricity prices, produced by the ELLI model, are produced using the cost and technical parameters for base case of the respective weather years. These electricity prices are subsequently applied in the NoH2S and ECC cases, where the available technologies and cost assumptions differ from those used when producing the electricity prices in ELLI. Therefore, there is a margin of error when it comes to the transmission behaviour for these cases. As prices produced by ELLI, with correct parameters for each case, could yield differently to those in base case. For both weather years this could mean an increase in high price hours in NoH2S and ECC cases across neighbouring regions, as the Swedish hydrogen production is less flexible and less electricity is available for export during peak hours.

Another assumption is the prolonged life of existing nuclear reactors in SE3. It is unclear whether the life-extension will happen, as no final decision has been made [54]. Therefore, the electricity production mix, especially in SE3, could look significantly different compared to presented results. The probable result would be a capacity increase in wind technology, primarily onshore wind, to cover the lost generation from nuclear, as it has the capabilities to act like a base power when combined with complementing strategies.

Although the results are impacted by the assumptions above, the study shows that hydrogen, that could only be produced through electrolysis, has a large impact on a future energy system. Sweden's ambitions for net-zero by 2045 will include a transition from grey- to green hydrogen production and will require increased capacity investments in new electricity production. Together with the transition to green hydrogen, the study shows that usage of hydrogen storage reduces total system costs and makes it possible to limit high electricity price hours, in a perfect energy-only market. With usage of hydrogen storage, the hydrogen production can be used flexibly and decrease electricity demand during peak hours. The impact of no hydrogen storage is higher total system costs, higher average electricity prices (especially for a year with low hydropower inflow) and less flexibility across the system. Although there are additional investments in heat and electricity storage, they do not offer the same flexibility to shift production as the hydrogen storage.

Hydrogen storage consists primarily of LRC across all investigated cases, but hydrogen tanks are also included in the northern regions and in the cases of a high investment cost for electrolysers. The tanks offer more short-term flexibility, peak hours, due to its high investment cost and high ability to charge and discharge. LRC instead offers long-term flexibility with lower investment cost, paired with low ability to charge and discharge. There is however a margin of error when it comes to LRC, as no project have been commercially built. Cost and operating parameters for the storage are based on small scale pilot studies, like HYBRIT, or on commercially built LRC storing natural gas. Therefore, it is hard to say exactly how beneficial LRC will be for storing hydrogen. In this thesis, conservative assumptions for both cost and technical parameters of LRC have been used, and despite this, its use remains part of the optimal solution. This shows that LRC long-term flexibility is essential for reducing system costs, especially in SE3, where the absences of large flexible hydropower resources, as in the northern regions, limits the ability to shift production during peak hours.

The thesis results show a shift in Sweden's role in the Nordic energy system. Today, Sweden is a large net exporter of electricity, supporting its neighbours with its large production from VRE technologies. The results instead indicate that Sweden could become a net importer of electricity in a future system, becoming dependent on its neighbours to bring down costs of the total system. As seen in every case, Sweden becomes a net importer, but costs of trade are negative. This indicates that Sweden is making use of its neighbouring regions to import cheap electricity to support its demand, while simultaneously exporting electricity during high price-hours to bring down total system costs. It is however worth noting that other studies have shown that Sweden stays a net exporter for future scenarios, so results are uncertain in that aspect [14].

Additionally, future demand, and fundamentally the extent of electrification in Sweden, remains uncertain. This thesis assumes that Sweden will achieve its net-zero target and that the energy system will consist solely of carbon-neutral technologies. However, this represents an ambitious scenario that requires substantial progress in the coming years. Future demand is also particularly uncertain, especially concerning industries demand for hydrogen. Reports have a shown a large span concerning future hydrogen demand, across Swedish industries. In northern Sweden, demand could be significantly higher if all planned expansions in iron and steel production are realized, but considerably lower if these plans do not materialize. A similar uncertainty exists on the west coast. Given these uncertainties, this thesis adopts a slightly conservative approach to demand projections, while still assuming that Sweden will meet its net-zero ambitions.

5.1 Future work

This thesis work has set a stable ground for future work to be done, where the SEmLa model can be used to investigate different areas of the Swedish energy system. There is however some work needed in the model, primarily regarding cycling constraints. The following is a list of subjects that could be of interest for future work and studies:

- Improved code formulations for cycling constraints. The start-up time of cycling technologies is to progressive in its code implementation and would need some work in order to achieve accurate results in accordance with previous studies.
- Expansion of model to include more countries and demands. This could enable a more detailed analysis of Swedish interactions with neighbouring regions.

- Study on the impact of LRC cost and technical parameters. As mentioned above, the cost and technical parameters for LRC are based on assumptions due to no project being commercially built. A study, similar to ECC case in this thesis, on impact of LRC parameters are therefore of interest.
- Further analysis of ECC case with more investment levels for the ECC. An investigation into what cost of electrolyser that hydrogen storage is not utilized, in other words when is it not profitable to make use of hydrogen storage because of electrolyser cost?
- What happens to the energy production mix when electricity demand exceeds 300 TWh? In this thesis the electricity demand amounted to about 260 TWh, but there is projections that Swedish electricity demand could amount to over 300 TWh by 2050.
- What is the implications if Sweden was to become totally self-sufficient and not be able to trade with its neighbouring regions? There is increasing interest in strengthening Swedish interests in order to be self-sufficient in the case of war. An investigate study on what is needed to have a fully self-sufficient energy system is possible with the use of the SEmLa model.
- What happens if cost and technical parameters for technologies are more conservative or progressive? In this thesis, data has been taken as a projection for 2040, but cost are continuously updated each year depending on multiple factors. An investigative study of more conservative and/or progressive estimates is therefore preferable to do as a sensitivity analysis to these thesis results.

6

Conclusion

This study has investigated how the future energy system could look like in Sweden, if industry and society were electrified. For a future electrified Sweden, the study shows that a cost-optimal system could mainly consist of VRE technologies to cover the electricity demand. Onshore wind becomes the largest electricity production technology, with capacity investments being made in each region. Existing flexible hydropower enables electricity to be transmitted from the northern regions to the southern regions, especially helping SE3 to cover its large demand. The flexibility of hydropower production is dependent on the hydropower inflow, where a dry weather year, with low hydro inflow, limits the flexibility of hydropower generation and leads to increased total system costs, with increased investments in onshore wind and utility-scale solar PV.

Average electricity prices, for a perfect energy-only market, range between 40-60 €/MWh depending on Swedish electricity price regions. The highest price is found in SE4, with largest changes, depending on investigated case, being in SE3. Higher prices across all regions are found for a dry weather year compared to wet weather year, due to the limitations in hydropower.

Removal of hydrogen storage have large impacts on the total energy system. With removal of flexible hydrogen production, as hydrogen storage is not allowed, brings with it increased total system costs and higher average electricity prices across all regions. Largest increase in regional total cost and average electricity price is seen in SE3, where average electricity price increases with 6-10% depending on weather year. Additional capacity investments in electricity storage and heat storage are made in the system, to shift electricity production.

Electrolyser investment cost impacts hydrogen production, capacity investments in hydrogen storage and average electricity price. Higher electrolyser investment cost leads to reduced investments in hydrogen storage and electrolyser overcapacity, resulting in less flexible hydrogen production, which leads to increased average electricity prices across all regions, for both weather years.

In conclusion, the thesis shows that hydrogen will play a large part in a future energy system where industry and society is electrified. It will be essential to include hydrogen storage together with overcapacity investments in hydrogen production to minimize total system costs, regardless of electrolyser investment cost.

Usage of AI

Throughout this thesis AI has been used for generating illustrative images, example code for data handling in result production, spell checks and reference inspiration for background section. Optimization model has been developed without AI help, relying instead on inspiration from other developed models provided by supervisors. AI has helped with example data-handling code and example plot code during the production of results, but no result data has been included in prompts with the AI and final plots have been produced through code scripts. Microsoft Copilot and ChatGPT are the AI tools that have been used.

Bibliography

[1] IEA, “World energy outlook 2025,” Paris, Nov. 12, 2025. [Online]. Available: `https://www.iea.org/reports/world-energy-outlook-2025`.

[2] European Union. “European climate law - climate action - european commission,” Accessed: Feb. 20, 2026. [Online]. Available: `https://climate.ec.europa.eu/eu-action/european-climate-law_en`.

[3] IEA. “Europe – countries & regions,” IEA, Accessed: Feb. 20, 2026. [Online]. Available: `https://www.iea.org/regions/europe`.

[4] K. Guerra, P. Haro, R. Gutiérrez, and A. Gómez-Barea, “Facing the high share of variable renewable energy in the power system: Flexibility and stability requirements,” *Applied Energy*, vol. 310, p. 118 561, Mar. 2022, ISSN: 03062619. DOI: `10.1016/j.apenergy.2022.118561`.

[5] Svenska Kraftnät. “Program NordSyd,” Accessed: Feb. 20, 2026. [Online]. Available: `https://www.svk.se/nordsyd`.

[6] IEA. “Sweden - countries & regions,” IEA, Accessed: Mar. 8, 2026. [Online]. Available: `https://www.iea.org/countries/sweden`.

[7] R. o. Regeringskansliet. “Sweden’s carbon tax,” Regeringskansliet, Accessed: Mar. 8, 2026. [Online]. Available: `https://www.government.se/government-policy/taxes-and-tariffs/swedens-carbon-tax/`.

[8] European Commission. “EU emissions trading system (EU ETS),” Climate Action, Accessed: May 21, 2026. [Online]. Available: `https://climate.ec.europa.eu/eu-action/carbon-markets/eu-emissions-trading-system-eu-ets_en`.

[9] Naturvårdsverket. “Sveriges utsläpp och upptag av växthusgaser,” Accessed: May 21, 2026. [Online]. Available: `https://www.naturvardsverket.se/data-och-statistik/klimat/sveriges-utslapp-och-upptag-av-vaxthusgaser/`.

[10] Energimyndigheten. “CCS,” Accessed: May 21, 2026. [Online]. Available: `https://www.energimyndigheten.se/klimat/ccs/`.

[11] Energimyndigheten. “Tillförsel av energi,” Accessed: Mar. 8, 2026. [Online]. Available: `https://www.energimyndigheten.se/energisystem-och-analys/sveriges-energisystem/hur-fungerar-energisystemet/tillforsel/`.

[12] Statens energimyndighet, “Scenarier över sveriges energisystem,” ER 2025:13, Mar. 2025.

[13] Svenska Kraftnät, “Långsiktig marknadsanalys,” 2023/4164, Jan. 26, 2024. [Online]. Available: `https://www.svk.se/om-oss/rapporter-och-remissvar/langsiktig-marknadsanalys/`.

[14] L. Göransson et al., "Tre elsystem som kan möta omställningen av industri- och transportsektorerna," Mistra Electrification, May 19, 2025.

[15] IEA, "Global hydrogen review 2025," Paris, 2025. [Online]. Available: `https://www.iea.org/reports/global-hydrogen-review-2025`.

[16] IEA, "The future of hydrogen," Paris, 2019. [Online]. Available: `https://www.iea.org/reports/the-future-of-hydrogen`.

[17] European Comission. "EU hydrogen strategy under the EU green deal | european hydrogen observatory," Accessed: May 12, 2026. [Online]. Available: `https://observatory.clean-hydrogen.europa.eu/eu-policy/eu-hydrogen-strategy-under-eu-green-deal`.

[18] Z. Mohammadi, S. Allahyari, S. Rahimi, M. Fathi, S. Mohammadi, and A. H. Mosaffa, "Comprehensive review of hydrogen production technologies, pathways, and applications for advancing global sustainable energy goals," *Energy Conversion and Management: X*, vol. 28, p. 101 319, Oct. 2025, ISSN: 25901745. DOI: `10.1016/j.ecmx.2025.101319`.

[19] M. Nasser, T. F. Megahed, S. Ookawara, and H. Hassan, "A review of water electrolysis–based systems for hydrogen production using hybrid/solar/wind energy systems," *Environmental Science and Pollution Research*, vol. 29, no. 58, pp. 86 994–87 018, Dec. 2022, ISSN: 0944-1344, 1614-7499. DOI: `10.1007/s11356-022-23323-y`.

[20] L. Mulky et al., "An overview of hydrogen storage technologies – key challenges and opportunities," *Materials Chemistry and Physics*, vol. 325, p. 129 710, Oct. 2024, ISSN: 02540584. DOI: `10.1016/j.matchemphys.2024.129710`.

[21] J. Miocic, N. Heinemann, K. Edlmann, J. Scafidi, F. Molaei, and J. Alcalde, "Underground hydrogen storage: A review," *Geological Society, London, Special Publications*, vol. 528, no. 1, pp. 73–86, Aug. 30, 2023, ISSN: 0305-8719, 2041-4927. DOI: `10.1144/SP528-2022-88`.

[22] M. Frost et al., "Hydrogen storage – knowledge overview and technical analysis," Energiforsk, 2025:1092, Feb. 2025.

[23] M. Masoudi, A. Hassanpouryouzband, H. Hellevang, and R. S. Haszeldine, "Lined rock caverns: A hydrogen storage solution," *Journal of Energy Storage*, vol. 84, p. 110 927, Apr. 2024, ISSN: 2352152X. DOI: `10.1016/j.est.2024.110927`.

[24] J. Andersson and S. Grönkvist, "A comparison of two hydrogen storages in a fossil-free direct reduced iron process," *International Journal of Hydrogen Energy*, vol. 46, no. 56, pp. 28 657–28 674, Aug. 2021, ISSN: 03603199. DOI: `10.1016/j.ijhydene.2021.06.092`.

[25] "HYBRIT: Large-scale storage of fossil-free hydrogen gas successfully proven," Accessed: May 17, 2026. [Online]. Available: `https://www.hybritdevelopment.se/en/hybrit-large-scale-storage-of-fossil-free-hydrogen-gas-successfully-proven/`.

[26] J. Andersson, "Non-geological hydrogen storage for fossil-free steelmaking," Ph.D. dissertation, Kungliga Tekniska högskolan, 2022, 104 pp., ISBN: 9789180401623.

[27] A. Fagerström et al., "The potential of hydrogen in a swedish context," Energiforsk, 2024:1011, Apr. 2024.

[28] M. Edvall, L. Eriksson, S. Harvey, J. Kjärstad, and J. Larfeldt, “Vätgas på Västkusten,” RISE, Göteborg, 2022:31, Feb. 8, 2022.

[29] “Sveriges nationella klimatmål – uppdaterat etappmål till 2030,” SOU, Stockholm, 2025:107, Oct. 2025.

[30] Statistikmyndigheten SCB. “Electricity supply and use 2001–2024 (GWh),” Accessed: May 17, 2026. [Online]. Available: `https://www.scb.se/en/finding-statistics/statistics-by-subject-area/energy/energy-supply-and-use/annual-energy-statistics-electricity-gas-and-district-heating/pong/tables-and-graphs/electricity-supply-and-use-20012024-gwh/`.

[31] T. Unger et al., “Coordinated use of energy system models in energy and climate policy analysis: Lessons learned from the nordic energy perspectives project,” Profu, Mölndal, NEI-SE-874, 2010.

[32] H.-K. Ringkjøb, P. M. Haugan, and I. M. Solbrekke, “A review of modelling tools for energy and electricity systems with large shares of variable renewables,” *Renewable and Sustainable Energy Reviews*, vol. 96, pp. 440–459, Nov. 2018, ISSN: 13640321. DOI: `10.1016/j.rser.2018.08.002`.

[33] J. Lundgren, P. Värbrand, and M. Rönnqvist, *Optimization*, 1. ed. Lund: Studentlitteratur, 2010, 537 pp., ISBN: 9789144053080.

[34] Svenska Kraftnät. “Elområden,” Accessed: Feb. 10, 2026. [Online]. Available: `https://www.svk.se/om-kraftsystemet/om-elmarknaden/elomraden/`.

[35] L. Göransson, J. Goop, M. Odenberger, and F. Johnsson, “Impact of thermal plant cycling on the cost-optimal composition of a regional electricity generation system,” *Applied Energy*, vol. 197, pp. 230–240, Jul. 1, 2017, ISSN: 0306-2619. DOI: `10.1016/j.apenergy.2017.04.018`.

[36] V. Walter, L. Göransson, M. Taljegard, S. Öberg, and M. Odenberger, “Low-cost hydrogen in the future european electricity system – enabled by flexibility in time and space,” *Applied Energy*, vol. 330, p. 120 315, Jan. 2023, ISSN: 03062619. DOI: `10.1016/j.apenergy.2022.120315`.

[37] V. Walter and L. Göransson, “Trade as a variation management strategy for wind and solar power integration,” *Energy*, vol. 238, p. 121 465, Jan. 2022, ISSN: 03605442. DOI: `10.1016/j.energy.2021.121465`.

[38] V. Johansson and L. Göransson, “Impacts of variation management on cost-optimal investments in wind power and solar photovoltaics,” *Renewable Energy Focus*, vol. 32, pp. 10–22, Mar. 2020, ISSN: 17550084. DOI: `10.1016/j.ref.2019.10.003`.

[39] Chalmers University of Technology. “Division of energy technology,” Accessed: Apr. 16, 2026. [Online]. Available: `https://www.chalmers.se/en/departments/env/research/energy-technology/`.

[40] N. Mattsson, V. Verendel, F. Hedenus, and L. Reichenberg, “An autopilot for energy models – automatic generation of renewable supply curves, hourly capacity factors and hourly synthetic electricity demand for arbitrary world regions,” *Energy Strategy Reviews*, vol. 33, p. 100 606, Jan. 1, 2021, ISSN: 2211-467X. DOI: `10.1016/j.esr.2020.100606`.

[41] L. Göransson, “The impact of wind power variability on the least-cost dispatch of units in the electricity generation system,” 2014, ISSN: 0346-718X.

[42] P. Nugroho Prianto, "Equivalent models for hydropower operation in sweden," Master Thesis, KTH Royal Institute of Technology, Jun. 2021. [Online]. Available: `https://kth.diva-portal.org/smash/get/diva2:1599616/FULLTEXT01.pdf`.

[43] S. Öberg, L. Göransson, H. E. Fälth, U. Rahmlow, and F. Johnsson, "Evaluation of hydropower equivalents in electricity capacity expansion models," *Renewable Energy*, vol. 270, May 8, 2026, ISSN: 09601481. DOI: `10.1016/j.renene.2026.125924`.

[44] S. Rosén, L. Göransson, M. Taljegård, and M. Lehtveer, "Modeling of a "hydrogen valley" to investigate the impact of a regional pipeline for hydrogen supply," *Frontiers in Energy Research*, vol. 12, p. 1 420 224, Jul. 17, 2024, ISSN: 2296-598X. DOI: `10.3389/fenrg.2024.1420224`.

[45] Statistikmyndigheten SCB. "Fjärrvärme (GWh)," Accessed: Mar. 20, 2026. [Online]. Available: `https://www.scb.se/hitta-statistik/statistik-efter-amne/energi/tillforsel-och-anvandning-av-energi/arlig-energistatistik-el-gas-och-fjarrvarme/pong/tabell-och-diagram/fjarrvarme-gwh/`.

[46] M. Taljegard, L. Göransson, M. Odenberger, and F. Johnsson, "To represent electric vehicles in electricity systems modelling—aggregated vehicle representation vs. individual driving profiles," *Energies*, vol. 14, no. 3, p. 539, Jan. 21, 2021, ISSN: 1996-1073. DOI: `10.3390/en14030539`.

[47] ENTSO-E, "TYNDP 2022 system needs study - opportunities for a more efficient european power system in 2030 and 2040," May 2023.

[48] Danish Energy Agency (DEA), *Technology data catalogue*. Accessed: Feb. 1, 2026. [Online]. Available: `https://ens.dk/en/analyses-and-statistics/technology-catalogues`.

[49] J. Bezanson, A. Edelman, S. Karpinski, and V. B. Shah, "Julia: A fresh approach to numerical computing," *SIAM Review*, vol. 59, no. 1, pp. 65–98, Jan. 2017, ISSN: 0036-1445, 1095-7200. DOI: `10.1137/141000671`.

[50] M. Lubin, O. Dowson, J. D. Garcia, J. Huchette, B. Legat, and J. P. Vielma, *JuMP 1.0: Recent improvements to a modeling language for mathematical optimization*, 2022. DOI: `10.48550/ARXIV.2206.03866`.

[51] Inflation Tool. "Inflation calculator - euro," Accessed: Apr. 21, 2026. [Online]. Available: `https://www.inflationtool.com/euro`.

[52] Norwegian Ministry of Energy. "Electricity production norway," Norwegian Energy, Accessed: May 2, 2026. [Online]. Available: `https://energifaktanorge.no/norsk-energiforsyning/kraftforsyningen/`.

[53] IEA. "Energy system of denmark," IEA, Accessed: May 4, 2026. [Online]. Available: `https://www.iea.org/countries/denmark/electricity`.

[54] Vattenfall. "Forsmark och Ringhals siktar på 80 års drifttid av befintliga kärnkraftreaktorer," Accessed: May 21, 2026. [Online]. Available: `https://group.vattenfall.com/se/nyheter-och-press/pressmeddelanden/2024/forsmark-och-ringhals-siktar-pa-80-ars-drifttid-av-befintliga-karnkraftreaktorer`.

[55] M. Dillén, "Promemoria Finansiering och riskdelning vid investeringar i ny kärnkraft," Finansdepartementet, Stockholm, Aug. 12, 2024.

A

Model data

A.1 Model overview

An overview of the SEmLa model is presented in Figure A.1

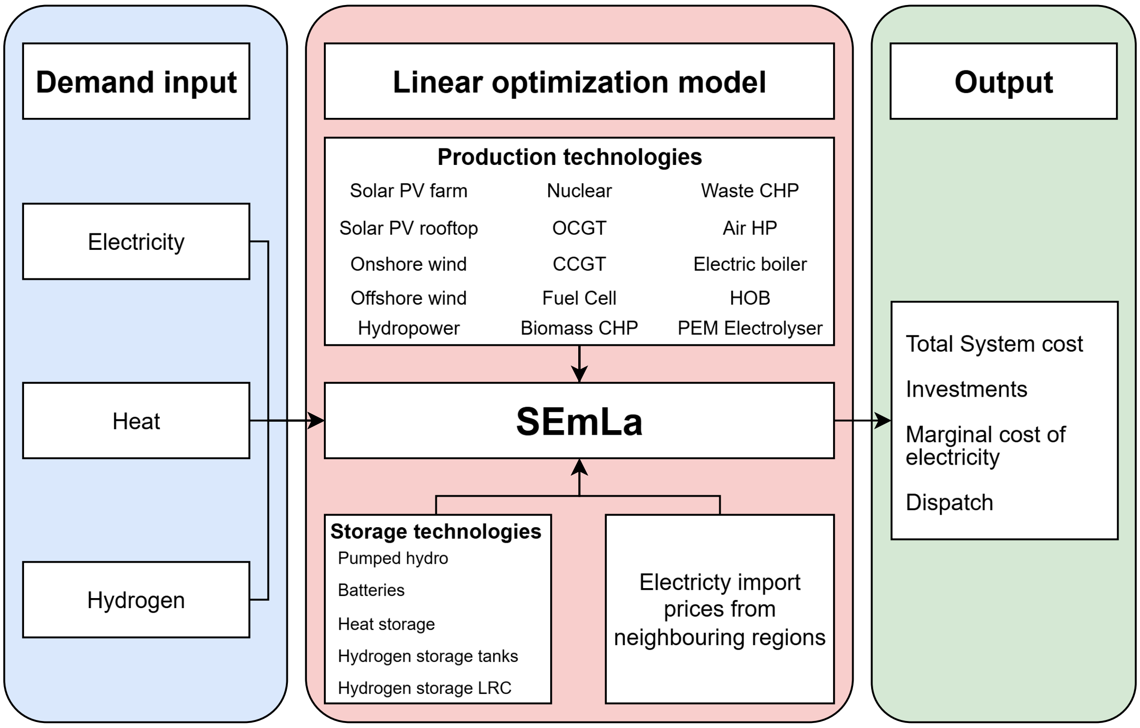


Figure A.1: Overview of core components in SEmLa model.

A.2 Cost and Technical data

Biogas and biomass cost data is produced by Chalmers Division of Energy Technology [39]. Uranium is taken from Dillén [55], recalculated to €/MWh by Göransson et al. [14]. Waste cost is calculated by assuming an EU-ETS price for CO_2 of 250 €/ton [14], that 50% of incinerated waste releases CO_2 and an input capacity of 0.3 ton/MWh_{steam}.

Fuel Type	Cost [€/MWh]
Biogas	77.14
Biomass	40
Uranium	1.65
Waste	8.25

Table A.1: Cost data for fuels in 2040.

Cost- and technical data for generation- and storage technologies are taken from the Danish Energy Agency (DEA) [48] for target year 2040, with the exception of Nuclear which is taken from Dillén [55], recalculated to Euro2020 by Göransson et al. [14]. Existing Nuclear power takes the same costs as new nuclear, except for the investment cost. CRF of each technology is calculated using a 5% discount rate and given lifetime of each technology.

Technology	Investment [k€/MW$_e$]	Fix O&M [k€/MW$_e$]	Variable O&M [€/MWh$_e$]	Lifetime [yr]	η [%]
Electricity Generation					
Wind					
Onshore	1109.69	15.97	1.89	30	100
Offshore - Fixed	2140.57	30.00	2.99	30	100
Solar PV					
Rooftop	460.00	8.00	0	40	100
Utility-scale	320.00	8.10	0	40	100
Thermal					
OCGT	574.22	19.46	4.36	25	42
CCGT	866.65	28.60	4.36	25	59
Nuclear	6181.00	123.00	7.10	80	33
Hydropower	-	-	0	50	100
Fuel Cell	1010.2	50.51	0	10	50
Combined Heat-and-Power (Heat production given by power-to-heat ratio α)					
Biomass CHP	3461.28	98.89	4.92	25	27
Waste CHP	8071.00	187.69	27.68	25	21
Heat Generation [MW(h)$_h$]					
Air Heat Pump	808.16	2.13	1.80	25	390
Electric boiler	63.80	1.03	1.06	25	99
Heat-Only-Boiler					
Biomass HOB	435.98	34.40	3.81	25	115
Biogas HOB	53.17	1.91	1.06	25	104
Hydrogen Generation					
PEM Electrolyser	450.00	9.00	0	25	62

Table A.2: Cost and technical data for generation technologies in target year 2040.

Technology	Investment [k€/MW]	Fix O&M [k€/MW]	Variable O&M [€/MWh]	Lifetime [yr]	η (ch./dis.) [%]
Pumped hydro storage	4253.60	8.51	0	50	100/75
Batteries					
Li-Ion (energy)	174.60	-	0	30	98.5/97.5
Li-Ion (power)	72.80	8.68	-	30	100
Redox Flow (energy)	198.00	-	0	35	100/83
Redox Flow (power)	250.00	2.93	-	35	100
Na-S (energy)	164.83	-	1.91	24	100/85
Na-S (power)	350.92	5.26	-	24	100
Na-NiCl$_2$ (energy)	154.19	-	0.64	23	100/87
Na-NiCl$_2$ (power)	350.92	5.26	-	23	100
Heat storage					
PTES	0.98	2.50	0	30	100
Large hot-water tank	3.04	0.01	0	40	100
Hydrogen storage					
Tank	28.77	0.53	0	30	89.6/100
Lined rock cavern	11	0	0	100	99/100

Table A.3: Cost and technical data for storage technologies in target year 2040.

Technology	Injection rate (CF_p^{ch}) [1/h]	Withdrawal rate (CF_p^{ch}) [1/h]
Pumped hydro storage	1	1
Batteries		
Li-Ion	1/0.6	1/0.6
Redox Flow	1/1.3	1/1.3
Na-S	1/6	1/6
Na-NiCl$_2$	1/9.2	1/3.5
Heat storage		
PTES	1/22.5	1/22.5
Large hot-water tank	1/60	1/60
Hydrogen storage		
Tank	1	1
Lined rock cavern	1/40	1/100

Table A.4: Power-to-storage factor for storage technologies in target year 2040.

A.2.1 Wind and Solar Parameters

Wind- and solar profiles together with max capacities are produced using the GlobalEnergyGIS tool developed by Mattsson et al. [40]. The possible full-load hours of each wind and solar technology are presented in Table A.5-A.8, and the max capacities of each technology are shown in Table A.9-A.10.

	Full-Load Hours [h]							
	SE1		SE2		SE3		SE4	
Onshore Wind Class	1991	1992	1991	1992	1991	1992	1991	1992
1	1265	1492	1294	1424	1221	1291	0	0
2	1855	2159	1906	2084	1916	2020	2100	2134
3	2485	2838	2515	2714	2653	2805	2640	2714
4	3169	3518	3230	3385	3241	3419	3222	3305
5	3968	4269	4052	4116	3938	4117	3840	3957

Table A.5: Full-load hours for Onshore Wind classes 1-5 produced by GlobalEnergyGIS tool [40].

	Full-Load Hours [h]							
	SE1		SE2		SE3		SE4	
Offshore Wind Class	1991	1992	1991	1992	1991	1992	1991	1992
1	0	0	0	0	2222	2348	0	0
2	2984	3483	2602	2690	2297	2425	0	0
3	3603	4137	3596	3833	3467	3638	0	0
4	3921	4426	4035	4467	4202	4449	4259	4402
5	0	0	4351	4692	4538	4721	4639	4752

Table A.6: Full-load hours for Offshore Wind classes 1-5 produced by GlobalEnergyGIS tool [40].

	Full-Load Hours [h]							
	SE1		SE2		SE3		SE4	
Utility-scale PV Class	1991	1992	1991	1992	1991	1992	1991	1992
1	975	984	1051	1056	1158	1182	1181	1196
2	0	0	0	0	1290	1288	1273	1318
3	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0

Table A.7: Full-load hours for Utility-scale PV classes 1-5 produced by GlobalEnergyGIS tool [40].

Full-Load Hours [h]								
	SE1		SE2		SE3		SE4	
Rooftop PV Class	1991	1992	1991	1992	1991	1992	1991	1992
1	0	0	0	0	1165	1200	1196	1175
2	0	0	0	0	1266	1284	1241	1290
3	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0

Table A.8: Full-load hours for Rooftop PV classes 1-5 produced by GlobalEnergyGIS tool [40].

Max capacity [GW]								
	Onshore Wind				Offshore Wind			
Class	SE1	SE2	SE3	SE4	SE1	SE2	SE3	SE4
1	2.54	1.54	1.15	0.00	0	0	0.006	0
2	16.34	16.85	6.74	0.002	0.001	0.01	0.03	0
3	13.75	23.11	29.32	8.61	2.40	0.21	0.27	0
4	3.27	4.60	11.44	4.04	10.67	9.31	19.74	3.77
5	2.74	1.93	0.91	1.01	0	1.45	22.24	26.67

Table A.9: Max capacities for Onshore and Offshore Wind classes 1-5 produced by GlobalEnergyGIS tool [40].

Max capacity [GW]								
	Utility-scale PV				Rooftop PV			
Class	SE1	SE2	SE3	SE4	SE1	SE2	SE3	SE4
1	64.31	32.05	21.31	6.32	0	0	6.03	2.93
2	0	0	6.18	6.71	0	0	4.74	0.74
3	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0

Table A.10: Max capacities for Utility-scale and Rooftop PV classes 1-5 produced by GlobalEnergyGIS tool [40].

A.3 Hydropower data

Hydropower data is taken from Öberg et al. [43] with supplementary data provided by Division of Energy Technology at Chalmers University of Technology [39]. Data is only valid for the specified weather year and additional weather years are not specified.

Region	Weather Year	Inflow periods		
		Low	Medium	High
SE1	1991	1 - 2351 7464 - 8760	4608 - 7463	2352 - 4607
	1992	1 - 2831 6984 - 8760	5328 - 6983	2832 - 5327
SE2	1991	-	1 - 2303 7872 - 8760	2304 - 7871
	1992	7368 - 8760	1 - 2903	2904 - 7367
SE3	1991	1 - 1895 7944 - 8760	4656 - 7943	1896 - 4655
	1992	1 - 1559	3334 - 8760	1560 - 3333
SE4	1991	5544 - 8760	-	1 - 5543
	1992	1 - 359 4608 - 7007	-	360 - 4607 7008 - 8760

Table A.11: Data detailing timesteps for each region and different inflow periods of a historical weather year.

Region	Inflow period	$HydP_{min}$ [GW]	$HydP_{max}$ [GW]	$HydL_{min}$ [GWh]	$HydL_{max}$ [GWh]	$HydRamp$ [GW]
SE1	Low	1	4.89	6117	12324	2.13
	Medium	0.7	4.21	4094	14420	0.96
	High	0.81	4.36	1745	14610	0.84
SE2	Low	0.77	6.23	7700	11610	0.97
	Medium	1.81	6.38	2348	8567	1.53
	High	1.38	6.14	1507	12475	2.37
SE3	Low	0.47	1.43	536	1567	0.52
	Medium	0.29	1.26	671	1789	0.32
	High	0.48	1.25	541	1875	0.24
SE4	Low	0.01	0.11	0	109	0.22
	Medium	-	-	-	-	-
	High	0.02	0.12	0	21	0.07

Table A.12: Hydropower parameters given for each region and inflow period.

B

Additional Results

B.1 Base Case

Following section shows additional results from Base case runs.

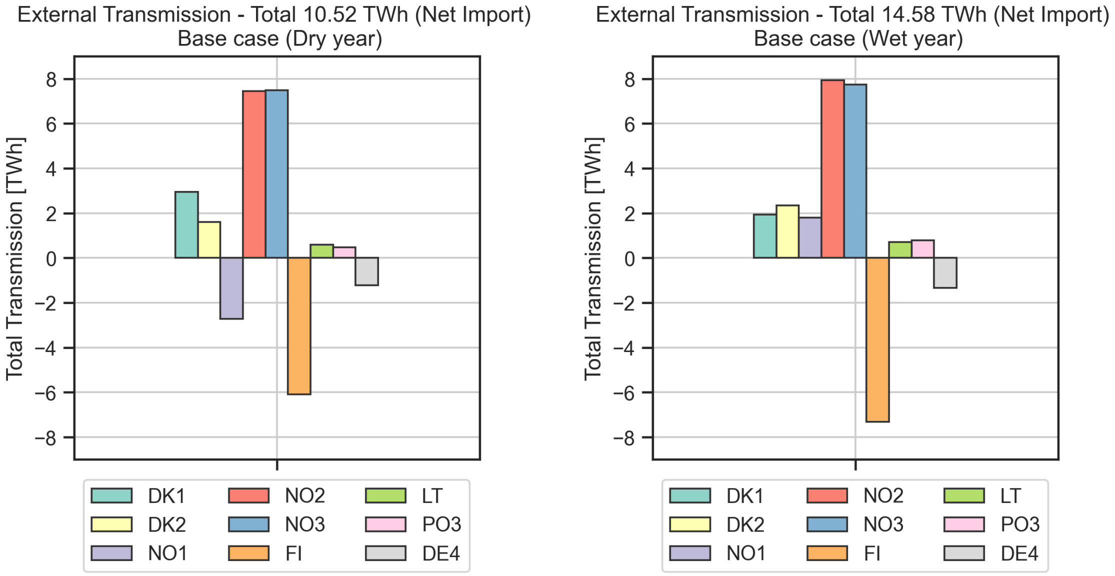


Figure B.1: Total transmission with neighbouring regions in Base case.

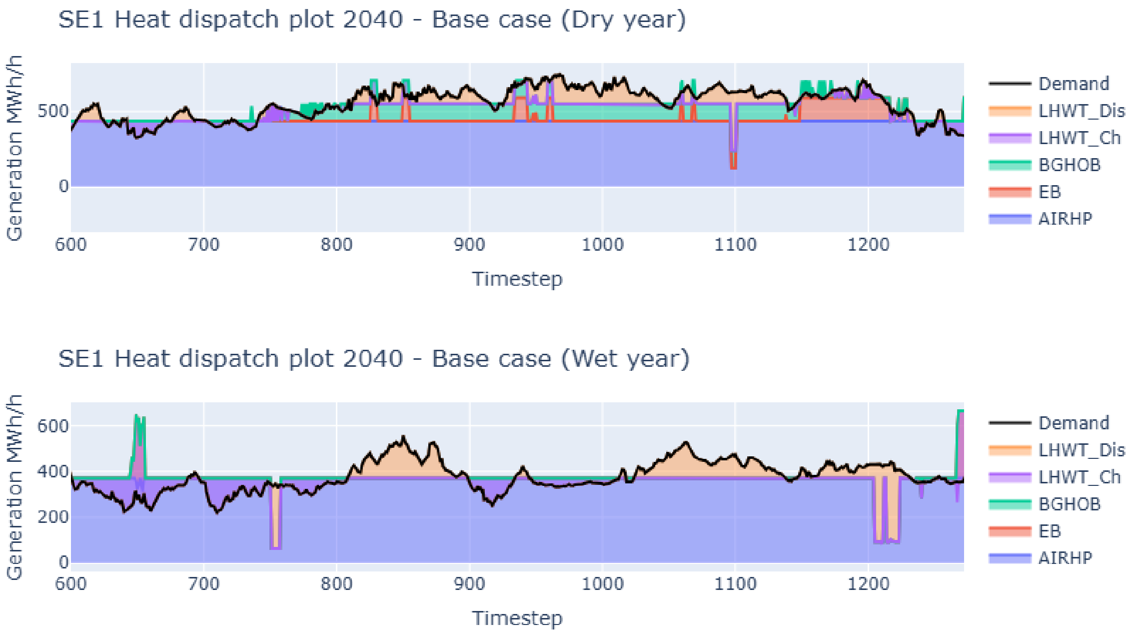


Figure B.2: Heat dispatch plot for 4 winter weeks in SE1, for Base case and both weather years.

Figure B.3: Heat dispatch plot for 4 winter weeks in SE3, for Base case and both weather years.

B.2 No Hydrogen Storage Case

Following section shows additional results from No Hydrogen Storage case runs.

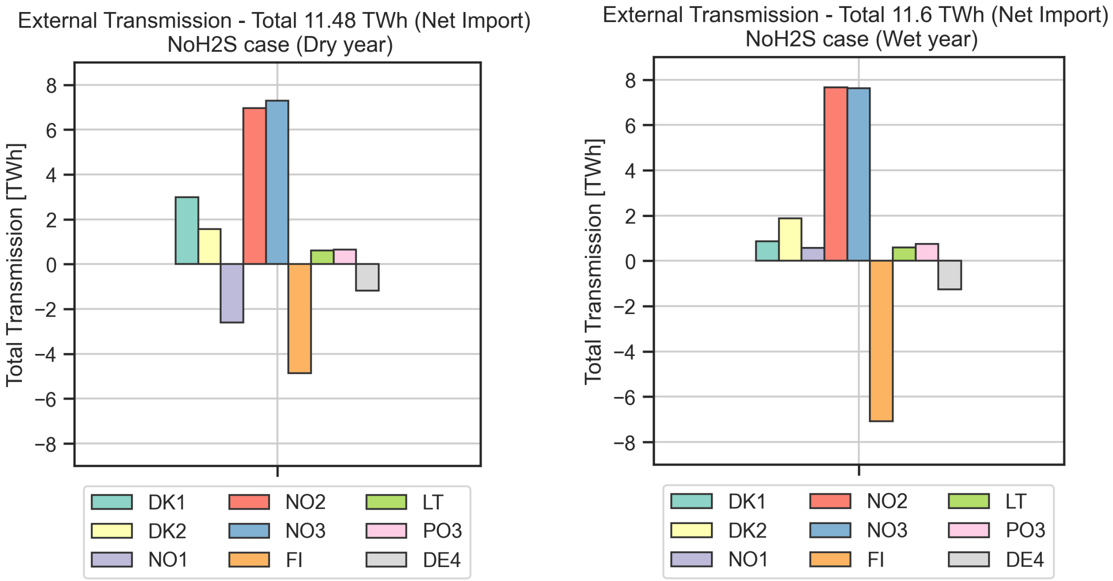


Figure B.4: Total transmission with neighbouring regions in NoH2S case.

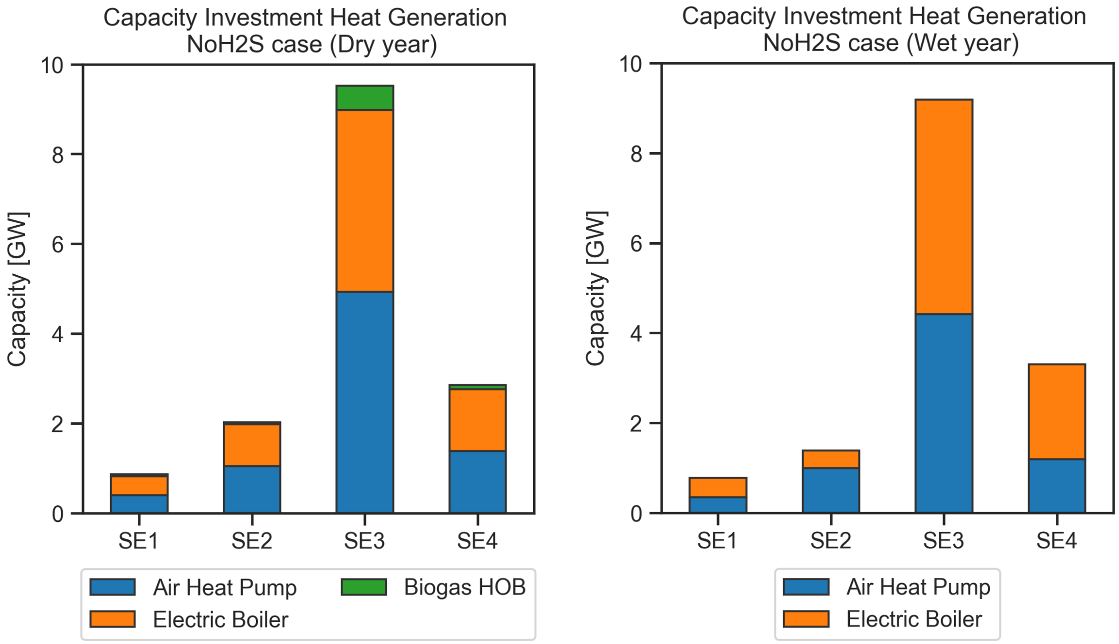


Figure B.5: Capacity investment in heat generation in NoH2S case.

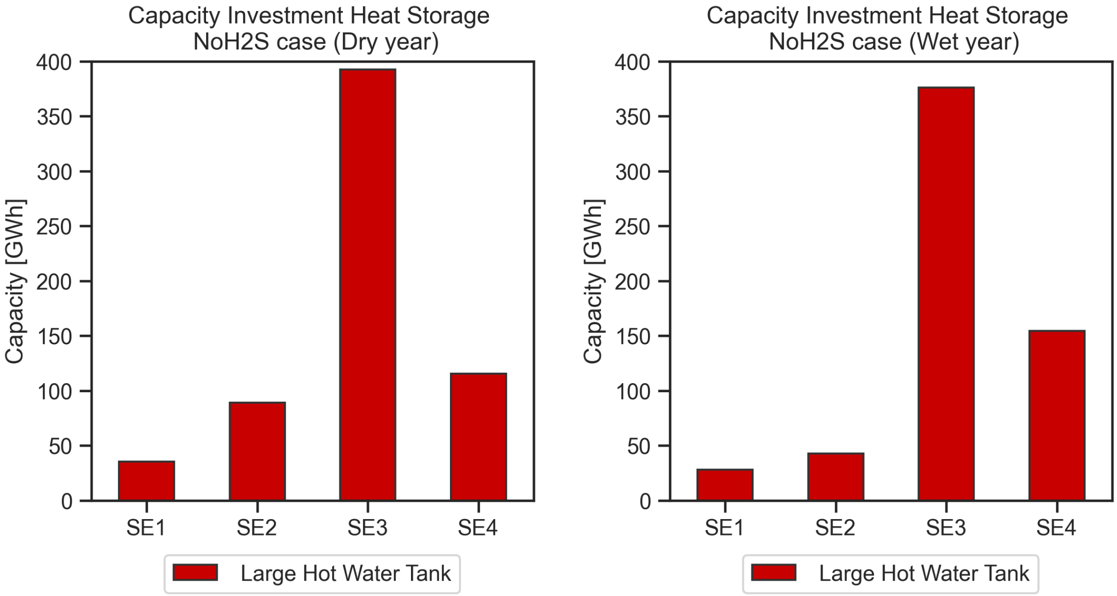


Figure B.6: Capacity investment in heat storage in NoH2S case.

B.3 Electrolyser Cost Case

Following section presents additional results for Electrolyser Cost case.

ECC Case Costs [G€]								
	350		600		900		1200	
	DWY	WWY	DWY	WWY	DWY	WWY	DWY	WWY
Total Cost	4.71	4.22	5.05	4.52	5.35	4.80	5.62	5.06
Capex	4.19	3.78	4.15	3.79	4.12	3.75	4.15	3.80
O&M Fix	1.99	1.84	1.98	1.86	1.97	1.85	1.98	1.86
O&M Var	0.61	0.59	0.60	0.59	0.60	0.59	0.60	0.59
Trade	-3.42	-3.10	-3.14	-3.02	-2.92	-2.82	-2.83	-2.80
Cycling	0.004	0.001	0.004	0.001	0.004	0.001	0.004	0.001
Fuel	0.41	0.34	0.40	0.34	0.40	0.34	0.39	0.34
Hydrogen Production	0.46	0.38	0.66	0.60	0.84	0.79	1.03	1.00
Electrolyser Electricity Cost	*1.33*	*1.24*	*1.45*	*1.32*	*1.55*	*1.42*	*1.63*	*1.47*
Hydrogen Storage	0.36	0.28	0.26	0.25	0.21	0.18	0.16	0.14
Heat Storage	0.12	0.10	0.13	0.11	0.14	0.12	0.14	0.12

Table B.1: System costs for ECC case, given for each investigated electrolyser investment cost. Hydrogen production, hydrogen storage and heat storage include their respective Capex and O&M costs. Electrolyser electricity cost is not included in total cost.

The following figures shows the electricity price duration curves for each electrolyser investment level in ECC case for dry weather year.

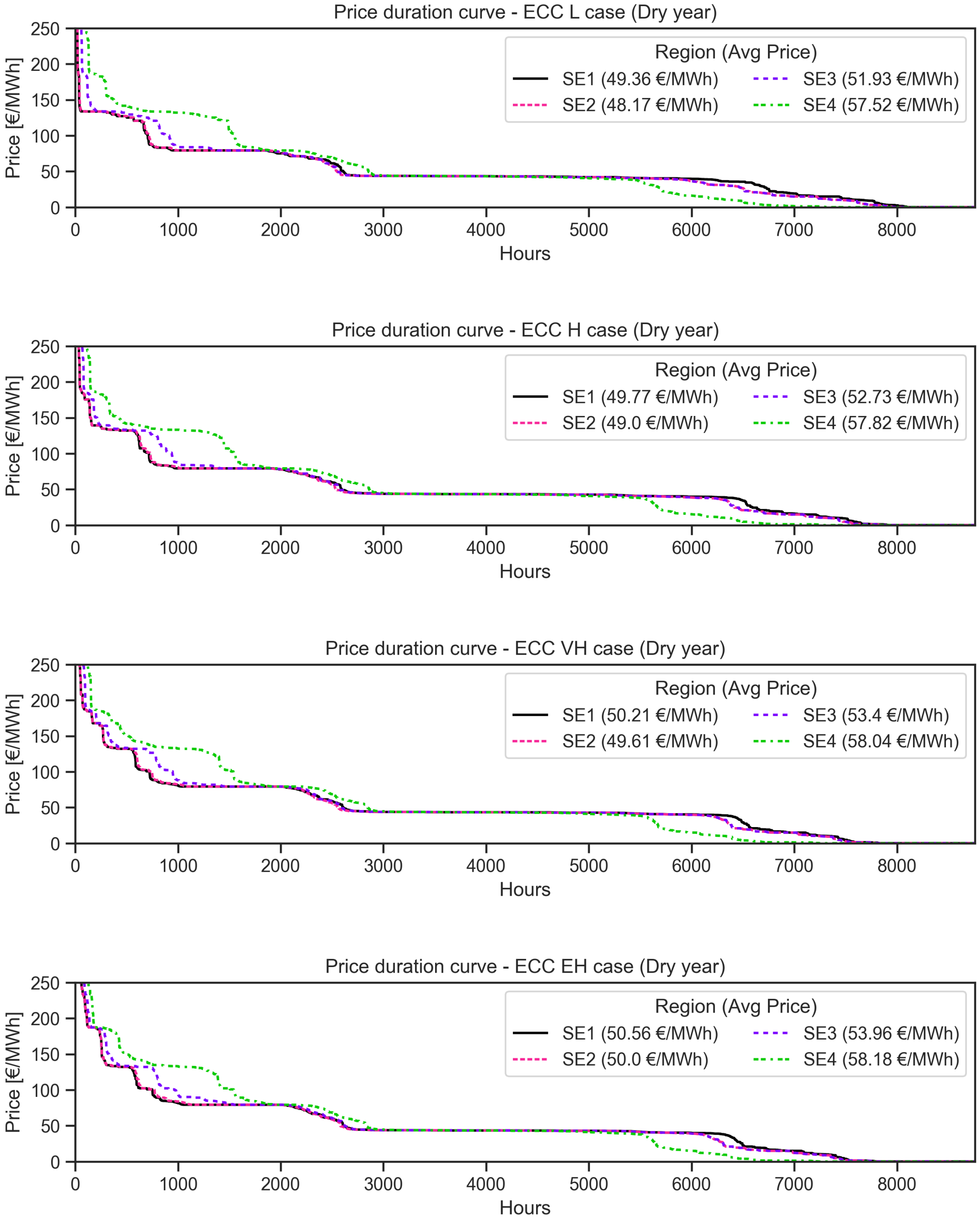


Figure B.7: Electricity price duration curves for ECC case. Electrolyser investment cost: L=325 k€/MW, H=600 k€/MW, VH=900 k€/MW, EH=1200 k€/MW.

C

Contributor acknowledgements

The following is a list of people that have contributed to the thesis with expertise, data and information to make the thesis possible. The people are listed in alphabetical order and I give a big thank you to all involved.

- David Frost - Vattenfall
- Erik Rosengren - Vattenfall
- Fredrik Starfelt - Vattenfall
- Johan Westin - Vattenfall
- Lisa Göransson - Chalmers University of Technology
- Maria Taljegård - Chalmers University of Technology
- Mit Vora - Vattenfall
- Niclas Mattson - Chalmers University of Technology
- Nicklas Simonsson - Vattenfall
- Pandu Nugroho Prianto - Chalmers University of Technology
- Simon Öberg - Chalmers University of Technology
- Sofia Rosén - Chalmers University of Technology

DEPARTMENT OF ENVIRONMENTAL AND ENERGY SCIENCES
CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden
www.chalmers.se