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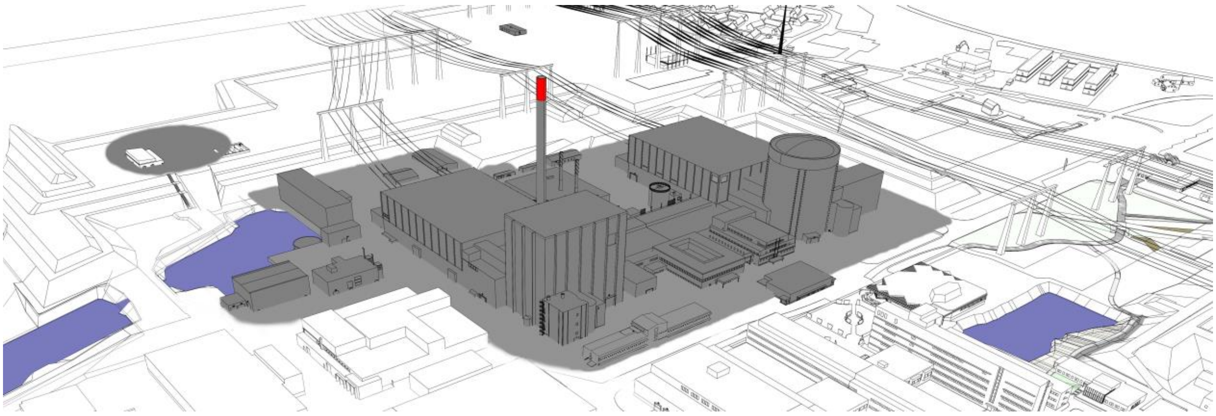

Peaking power plant at Ringhals

A feasibility study

Master's thesis in Sustainable energy systems (MPSES)

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MASTER'S THESIS 2018

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Cover: Part of the industrial area at Ringhals with nuclear reactors R1 and R2 in focus. For more information about the Ringhals site, see section 2.2.

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ABSTRACT

By 2020, two out of four nuclear power plants at Ringhals will be decommissioned. The thesis investigates the possibilities of using existing land and infrastructure at Ringhals for a carbon neutral peaking power plant, after the decommissioning of nuclear reactors R1 and R2. Different alternatives were evaluated and compared from a technical- and economic point of view.

An initial selection of technologies to include in the study was made, based on technical aspects. The selected technologies (biogas-fired turbine, hydrogen fuel cell and three different battery types) were then included in a combined investment- and dispatch model. The model was constructed to invest in power plants to cover for the electricity demand in southern Sweden at minimum total system cost. Cases with different flexibility providers implemented (DSM, hydrogen demand and trade with neighboring countries) were modelled.

By studying the modelling results, the need of peaking power in southern Sweden, and thus the possibilities for such a plant at Ringhals, was identified for three modelled time intervals between 2026-2055. The results indicate a need of peaking power in southern Sweden, but to what extent is strongly correlated to what other flexibility providers that are available in the electricity system. The model suggests an investment in a 300 MW biogas-fired peaking power plant at Ringhals in all studied cases except the case where all studied flexibility providers were combined. The investment is suggested to be made during the time interval 2036-2045 in most studied cases.

Keywords: peaking power plant, energy system model, flexibility provider, Ringhals

Sammanfattning

Fram till år 2020 kommer två av fyra kärnkraftsreaktorer på Ringhals att avvecklas. Syftet med detta projekt är att undersöka hur infrastruktur och mark på Ringhals skulle kunna nyttjas för alternativ elproduktion efter att de två kärnkraftsreaktorerna har avvecklats. Projektet fokuserar på koldioxidneutrala spetslastanläggningar och olika alternativ har utvärderats utifrån tekniska och ekonomiska aspekter.

Det första urvalet av tekniker baserades på tekniska aspekter och resulterade i följande alternativ; biogasturbin, bränsleceller och tre olika batterityper. Dessa tekniker implementerades sedan i en kombinerad investerings- och leveransmodell över södra Sverige. Modellen konstruerades för att uppfylla södra Sveriges energibehov till en minimal systemkostnad och användes för att identifiera det framtida behovet av spetslast i regionen. I modellen implanterades även tre flexibilitetsleverantörer; efterfrågeflexibilitet, ett ökat vätgasbehov och möjligheten att handla elektricitet med andra länder.

Genom att studera modelleringsresultaten kunde ett behov av spetslast i södra Sverige identifieras och därmed också en möjlighet att uppföra en spetslastanläggning på Ringhals. Behovet av spetslast beror dock i stor utsträckning på vilken övrig flexibilitet som finns tillgänglig i systemet. Modellen förespråkar en investering i en 300 MW biogasturbin på Ringhals under tidsperioden 2036-2045 i majoriteten av de studerade fallen.

Nyckelord: spetslastanläggning, energisystemmodellering, flexibilitetsleverantör, Ringhals

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Elin Andersson and Isabella Lindholm,
Gothenburg, June 15, 2018

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TERMINOLOGY

ACER	Agency for the Cooperation of Energy Regulations
Bat_flow	Flow battery
Bat_flow_R	Flow battery at Ringhals
BC	Base case
BG_CCGT	Biogas-fired power plant (closed cycle)
BG_peak	Biogas-fired peaking power plant
BG_peak_R	Biogas-fired peaking power plant at Ringhals
CCGT	Combined cycle gas turbine
DE4	Electricity price area 4 in Germany
DK1, DK2	Electricity price area 1 and 2 in Denmark
DSM	Demand side management
EB	Electric boiler
Efuel	Hydrogen electrolyzer
Efuel_R	Hydrogen electrolyzer at Ringhals
EI	The Swedish energy markets inspectorate (Energimarknadsinspektionen)
ELIN	Electricity investment model
EPOD	European power dispatch model
F1	Forsmark 1 (operating nuclear reactor in Forsmark)
FC	Hydrogen fuel cell
FC_R	Hydrogen fuel cell at Ringhals
FI	Electricity price area Finland
GF	Biomass gasification plant
H2LRC	Hydrogen lined rock cavern storage
H2tank	Hydrogen tank storage
H2tank_R	Hydrogen tank storage at Ringhals
HP	Heat pump
HYBRIT	Hydrogen Breakthrough Ironmaking Technology
Hydro	Hydropower plant
Li_ion	Lithium-ion battery
Li_ion_R	Lithium-ion battery at Ringhals
LRC	Lined rock cavern
LT	Electricity price area Latvia
NaS	Sodium-sulfur battery
NaS_R	Sodium-sulfur battery at Ringhals
NO1	Electricity price area 1 in Norway
Nuclear	Nuclear power plant
O&M	Operation and maintenance
OCGT	Open cycle gas turbine
PEM	Polymer electrolyte membrane
PO	Electricity price area Poland
PV_opt	Optimized tilt solar photovoltaics power plant
PV_two	Two-axis solar photovoltaics power plant
R1, R2, R3, R4	Ringhals 1-4 (nuclear reactors at Ringhals)
R12, R34	Ringhals 1+Ringhals 2, Ringhals 3+Ringhals 4
SE1, SE2, SE3, SE4	Electricity price area 1-4 in Sweden
SvK	The Swedish transmission system operator (Svenska kraftnät)
TotBG_peak	Total amount of biogas-fired peaking power plants (BG_peak+BG_peak_R)
Wa_CHP	Waste-fired combined heat and power plant
WEO	World Energy Outlook
WOFF	Offshore wind power plant
WON	Onshore wind power plant
VRE	Variable renewable energy source
VRFB	Vanadium redox flow battery

1. INTRODUCTION

The access to clean, affordable and reliable electricity has a large impact on the environment, economy and wellbeing of humans. The electricity sector stands for about a fourth of the world's anthropogenic CO_2-emissions (Klimstra, 2014, p. 17) and in order to reduce the greenhouse gases, the share of renewable power plants is increasing rapidly around the world. However, most renewable power plants are strongly weather dependent and maintain an intermittent power output, which impose challenges for the electricity systems.

The intermittent power outputs are often complemented by flexible electricity production and/or energy storage, so the system always can cover for the electricity demand in a cost-efficient way. Many carbon neutral alternatives are available to cover for the peak load, for instance biogas-fired peaking power plants, hydrogen peaking power plants and battery storages. Ancillary services such as frequency control, reactive power and voltage stabilization are also essential to ascertain for a successful integration of the intermittent power plants in the electricity system (Klimstra, 2014, pp. 12, 185).

Vattenfall owns the four nuclear power plants at Ringhals, and by 2020 two out of four reactors will be taken out of service. Ringhals maintains a good connection to the transmission grid and the technical lifetime for a large share of the electrical power components will reach far beyond the decommissioning of the two reactors. The site also offers existing office buildings and personnel. In addition, the Ringhals area is classified as *national interest for energy production* by the Swedish energy agency, which may simplify future permit processes. It is therefore highly important for Vattenfall to efficiently utilize the existing infrastructure and the other benefits that the site offers.

The site is located in the south of Sweden, where the electricity consumption generally is relatively high. A deficit of electricity production is expected to arise once the nuclear plants, which all are positioned in southern Sweden, are taken out of service. Therefore, it is beneficial to produce power in this part of Sweden. The Ringhals site is also located near Sweden's second largest city, which is a large consumer of electricity. Hence, the electricity generated at the Ringhals site doesn't have to be transported a long distance, which consequently reduces the losses in power lines.

1.1. PURPOSE

The aim of this master's thesis is to investigate the possibilities of using existing land and infrastructure at Ringhals for a carbon neutral peaking power plant, after the decommissioning of reactor Ringhals 1 (R1) and Ringhals 2 (R2). Different alternatives will be evaluated and compared from a technical and economic point of view.

1.2. DISPOSITION OF THE REPORT

Chapter 1 brings a short introduction to the project followed by chapter 2 providing further information regarding the Ringhals site and its surroundings. Basic information regarding the electricity system can be retrieved in appendix A.

Chapter 3 describes the process of selecting technologies with potential to be installed at Ringhals. An overview of potential peaking power plants along with a specification of requirements describing what a potential peaking power plant at Ringhals must fulfill in order to be installed are presented. The specification of requirements is divided into technical-, economic-, local-, environmental- and safety aspects. The project focuses on the technical- and economic aspects. Remaining aspects are described in the report but require expertise to be fully verified. The evaluation and first selection of technologies is based upon the technical aspects, see section 3.4. Information regarding the selected technologies is presented in chapter 4.

The economic aspect in the specification of requirements is investigated through modelling of the electricity system in southern Sweden. A description of the model is presented in section 5.1, followed by specific assumptions, limitations and data for the Ringhals site, the selected technologies and the studied cases. Remaining information required for the modelling can be retrieved in appendix B.

Chapter 6 presents the results of five modelled cases. Chapter 7 discusses the results both from a system perspective and a Ringhals perspective. Conclusions are drawn in chapter 8 and recommendations for future work can be obtained in chapter 9.

2. DESCRIPTION OF THE RINGHALS SITE AND ITS SURROUNDINGS

Ringhals is located by the Swedish west coast, approximately 60 km south of Gothenburg. The area is classified as *national interest for energy production* by the Swedish energy agency. Currently there are four nuclear power plants in operation at the site, R1-R4. The nuclear power plants were taken into operation during the 1970s and the 1980s. The two oldest reactors, R1 and R2, will be taken out of service before the end of 2020 due to economic reasons. The remaining reactors are planned to be in operation until the beginning of the 2040s. The site is owned by Ringhals AB, which further is owned by Vattenfall AB (70,4 %) and Sydkraft Nuclear power AB (29,6 %) (Ringhals AB, 2016, pp. 3, 18). The local conditions at Ringhals will be described in the following chapter, to give a better understanding of the preconditions for a peaking power plant and handling of the possibly related fuel at Ringhals.

2.1. THE SURROUNDINGS OF RINGHALS

Ringhals is surrounded by natural areas under protection. A nature reserve called Biskopshagen is located to the south-west of the site and the Natura 2000-area (Båtafjordens strandängar) is located to the south-east of the site. There is also an adjacent area called Gloppe. It mainly consists of summerhouses. Videberg port, used by Ringhals AB for heavy goods- and nuclear fuel transportation, is positioned nearby. Access to railway and highway for goods- and passenger transport is available at 3.5 and 6 km distance, respectively, from the site (Ringhals AB, 2014, pp. 16-21).

Södra cell Värö is a large industry located in the vicinity, approximately 6 km away from Ringhals. Their core business is to produce pulp, but they also produce biofuel, electricity and heat. One byproduct from the production of the pulp is bark. Some of the bark is used in the pulp process and the rest of the bark is sold to customers in southern Sweden (Södra, 2016). Södra cell investigates different ways of refining their bark. A collaboration with Statkraft is initiated to produce a second-generation liquid biofuel from the forest feedstock. There is a pilot plant under construction at an old site for pulp production in Norway, which is planned to be completed in 2019. Södra cell is also investigating the possibility to create methanol from black liquor (Södra, 2018).

The national gas grid, operated by Swedegas, reaches along the west coast. The distance from Ringhals to the pipeline is approximately 8 km. Most of the gas transported through the grid is natural gas from Denmark. The operator aims to increase the share of biogas to 30% by 2030 and 100% by 2050 (Swedegas, 2018). There are certain requirements for producers delivering biogas to the grid to ensure that the quality of the gas in the grid is maintained (Swedegas, 2015). Hanna Paradis (2018), business developer at Swedegas, does not see any hinder to establish a connection point to the gas grid in the Ringhals area. Such a connection point could be bidirectional. Further investigations are needed to determine a possible capacity of a connection point, although the capacity typically is high.

Ringhals is connected to the 130 kV- and the 400 kV grids. There is one common switchyard for all four nuclear reactors. Two parallel overhead lines are connecting the site to the 400 kV transmission grid. The Swedish transmission system operator (SvK) has applied for a prolongation of the permission to operate these power lines to the Swedish energy markets inspectorate (EI) (Svenska kraftnät, 2016).

2.2. THE RINGHALS SITE

The industrial area of Ringhals is about 2.5 km^2. Each nuclear power plant consists of a reactor building, a fuel building, a turbine building, an electrical building and stand-by diesel generators. Two coolant intake channels exist at the site, one for R1 and R2 (R12) and one for R3 and R4 (R34). After the coolant water has been used, it is led from the site back to the sea through tunnels (Ringhals AB, 2014, pp. 17, 25-26).

An extensive, continuous work is done at Ringhals to identify, assess and prevent different events which could impose danger to people, the environment and material assets. A part of this work is to analyze external events and their possible impact on the nuclear operations at Ringhals. All risks are assessed and categorized according to their potential impact and frequency (Ringhals AB, 2014).

Ringhals' environmental impact is limited by environmental permissions that are decided by the court in Vänersborg. The environmental impact can be divided into three categories: resources, emissions and waste. The extent of the environmental impact and Ringhals' actions to reduce their impact are described in the environmental report which annually is submitted to the Swedish Environmental Protection Agency (Naturvårdsverket). An area of special interest while examining the environmental aspects of a new power plant at Ringhals is the industrial noise (Ringhals AB, 2018, pp. 6-7). The noise level in 2017 was slightly below the stipulated level for industrial noise at night (43 dB) during all 24 hours of the measured day. This measurement was done when all four reactors were in operation (Ringhals AB, 2018, p. 35).

Different kinds of fuels, such as diesel and hydrogen, are already handled at Ringhals today. A description of how this is done can be found below. By understanding what are handled at site today, one can have an initial idea of what type of fuels which can be accepted to be used in a new peaking power plant.

THE MANAGEMENT OF DIESEL AT RINGHALS

Today, a maximum amount of 1555 ton diesel is stored at Ringhals. Diesel is mainly used as fuel in the diesel generators, which constitute one of the safety systems in the nuclear power plants. If a nuclear power plant lacks access to electricity from the grid, it can generate electricity in a diesel generator. The back-up system is tested regularly, and the diesel is kept in storages at each nuclear power plant. Each storage is equipped with two fire detectors. The storages are filled from a tank truck. When the truck arrives to the site, it follows a predetermined route to the diesel storages (Ringhals AB, 2016, pp. 57-58).

THE EXISITING HYDROGEN FACTORY AT RINGHALS

Currently, a small hydrogen factory is operated at the Ringhals site. The produced hydrogen is mainly used for two applications. The first application utilizes the high heat capacity of hydrogen to cool generators. The second application reduces the concentration of oxygen in the primary water of the reactor to avoid corrosion. The hydrogen which is produced at site is produced by electrolysis of water. The system is easy to monitor and prevents critical conditions from happening by several safety arrangements such as gas detectors, ventilation system and an emergency setting (Deimer, 2000, pp. 6-9).

3. TECHNOLOGY SELECTION PROCESS

The technology selection process is presented in this chapter. The methodology used is described in section 3.1, followed by an overview of available carbon neutral peaking power plants. The specification of requirements is thereafter presented along with the results of the technology selection process.

3.1. METHODOLOGY OF SELECTION PROCESS

The selection process was performed according to the methodology presented below.

Initially, a literature study was performed to gather information regarding technical aspects for different peaking power plants along with information of the electricity system. In addition to the literature study, information was gathered through workshops and interviews.

A specification of requirements was then formulated in consensus with Vattenfall to determine what a potential peaking power plant at Ringhals must fulfill in order to be installed at the site. A first selection was thereafter made, by evaluating technologies identified in the literature study according to the technical aspects in the specification of requirements.

3.2. OVERVIEW OF PEAKING POWER PLANT ALTERNATIVES

The identified alternatives to supply the system with carbon neutral peaking power can be subdivided into flexible electricity production and energy storage solutions. An overview of the identified alternatives is given in Figure 1. Alternatives involving carbon capture and storage (CCS) were not included in the overview since it's not considered fully carbon neutral, and typically associated with high investment costs and thus not suitable to supply peaking power. A recommended source for further reading regarding energy storages is the handbook released by Sandia National Laboratories (2015).

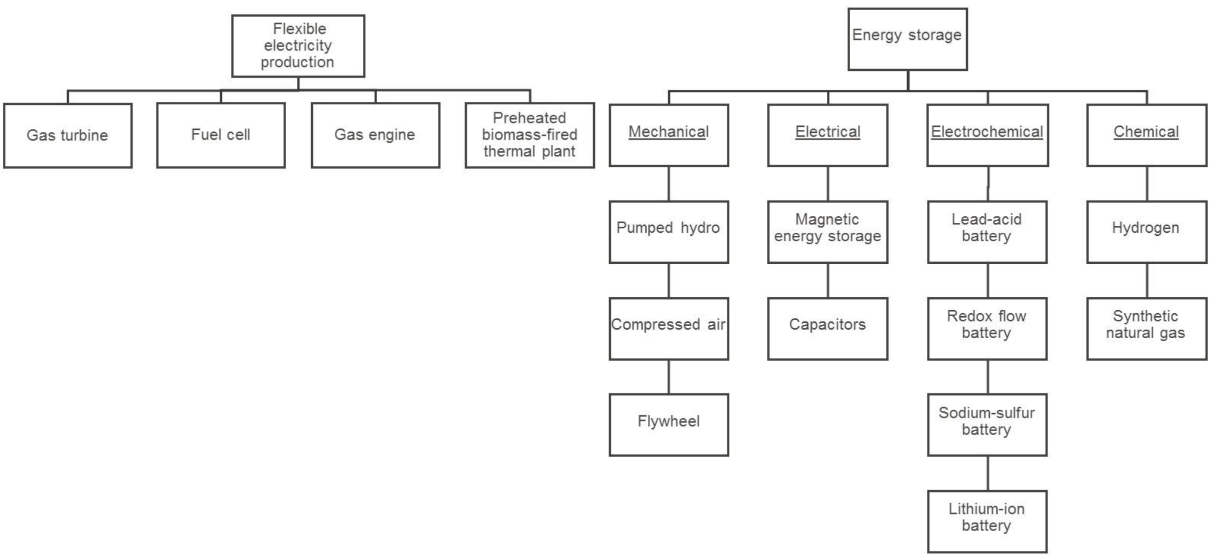

Figure 1. Carbon neutral peaking power plant alternatives divided into flexible electricity production and energy storage solutions.

3.3. SPECIFICATION OF REQUIREMENTS

The specification of requirements for a potential peaking power plant at the Ringhals site is shown in Table 1.

Table 1 Specification of requirements.

TECHNICAL ASPECTS	Require-ment (R)/ want (W)	Target value	Unit	Verification
Minimum capacity/maximal capacity	R	100 /1000	MW	Choice of technology
Maximal ramp-up time/maximal ramp-down time	R	1/1	h	Choice of technology
Minimum run time	R	1	h	Choice of technology
Minimum technical lifetime	R	20	years	Choice of technology
The plant provides ancillary services	W	-	-	Choice of technology
The technology is scalable	W	-	-	Choice of technology
ECONOMICAL ASPECTS				
The investment must be profitable	R	-	-	Modelling
LOCAL ASPECTS				
The construction and operation of the plant (including fuel storage) do not interfere with the operation of R3, R4 or the switchyard at Ringhals	R	-	-	Expert opinion
Personnel at Vattenfall or in the area close to Ringhals have competence regarding the technology	W	-	-	Investigation

ENVIRONMENTAL ASPECTS	**Require-ment (R)/ want (W)**	**Verification**
No fossil carbon dioxide emissions from the plant	R	Choice of technology and fuel
The operation of the plant should not contribute to increased noise levels compared to the operation of R1 and R2 today	R	Theoretical analysis
The nature reserve "Biskopshagen" and the Natura 2000 area "Båtafjordens strandängar" are not considerably affected by construction, operation and decommissioning of the plant	R	Expert opinion
Hazardous substances released from the power plant should be limited and within set limits	R	Choice of technology and fuel
Transportation of fuel and waste should be minimized or have a minor environmental impact	R	Choice of technology and fuel
The plant has a minor visual impact	W	Choice of technology and dimensions
SECURITY ASPECTS		
Transportation of fuel and other potential dangerous goods should be able to be performed according to the dangerous goods regulation	R	Theoretical analysis
The probability of an accident at the power plant or in the fuel storage should not contribute considerably to the already existing risk of external events which could damage R3, R4 or the switchyard at Ringhals	R	Expert opinion

3.4. EVALUATION OF PEAKING POWER PLANT ALTERNATIVES

The initial evaluation can be obtained in Table 2. The technologies that had potential to fulfill the technical aspects listed in the specification of requirements were further investigated and marked *yes*. The technologies that didn't fulfill the technical aspects were excluded and marked *no* with attached comment.

Table 2. Initial evaluation of technologies with potential to fulfill the technical requirements listed in section 3.3.

Technology	Further investigated	Comment
Gas turbine	Yes	
Gas engine	No	Too low capacity
Fuel cell	Yes	
Preheated biomass-fired power plant	No	Too long ramp-up time
Pumped hydro	No	Local topology is not suitable
Compressed air	No	Local geological conditions are not suitable, too low energy density to fulfill the capacity requirement
Flywheel	No	Too short run-time
Magnetic energy storage	No	Too short run-time
Capacitors	No	Too short run-time
Lead-acid battery	No	Too short technical lifetime
Flow battery	Yes	
Sodium-sulfur battery	Yes	
Lithium-ion battery	Yes	
Hydrogen	Yes	Included in the hydrogen turbine and fuel cell options. The combinations are referred to as hydrogen peaking power plant.
Synthetic natural gas	Yes	Included in the gas turbine option

The following technologies have been selected for further investigation:

- Hydrogen peaking power plant
- Biofuel-fired gas turbine
- Battery parks
    - Lithium-ion battery (Li_ion)
    - Sodium-sulfur battery (NaS)
    - Flow battery (Bat_flow)

4. PEAKING POWER PLANT TECHNOLOGIES WITH POTENTIAL TO BE INSTALLED AT RINGHALS

A theoretical background is in this chapter given to the five selected technologies with a potential to be installed at Ringhals. Focus will be on production, storage and/or transportation of the required fuel, the functionality of each power plant and the expected technical development of these technologies.

4.1. HYDROGEN PEAKING POWER PLANT

A hydrogen peaking power plant consists of three main parts: hydrogen production, hydrogen storage and a re-electrification of hydrogen. Hydrogen can be produced by splitting water into hydrogen and oxygen under the influence of an electric current. The process is referred to as electrolysis and is preferably performed during low electricity price hours. Unlike electricity, hydrogen can be stored as gas, liquid or bound to other substances. During a deficit of electricity in the power system, hydrogen can be used to generate electricity through a fuel cell (FC) or a hydrogen gas turbine. The main advantages of hydrogen as an energy carrier is its storability in addition to the fact that no hazardous emissions arise during combustion and the main product is water. However, the major drawback is to gain profitability in such a power plant and manage the safety aspects related to the explosive hydrogen gas (Nationalencyklopedin, 2018).

4.1.1. FUELS AND COMPONENTS

Hydrogen is very volatile in its gaseous form. The gas is lighter than air which gives it the property of quickly dissolving into the atmosphere rather than forming a heavy layer along the ground as gasoline and diesel fuels (Agata & Detlef, 2015, pp. 1-3). The volatile properties along with an ability to diffuse through materials make the gas difficult to compress and store. The gas is non-toxic to inhale unless the concentrations are extremely high, causing the concentration of oxygen to decrease rapidly. Since the gas is invisible and has no obvious smell, a leakage of hydrogen is hard to detect without instruments measuring the concentrations (Nationalencyklopedin, 2018).

Hydrogen yields high energy per unit weight. The energy density per kg has been measured significantly higher than for conventional fuels such as gasoline, methanol and diesel. On the other hand, the energy per unit volume is relatively low. The gas is very flammable and larger volumes of ignited gas will result in explosions. The ignition temperature is 857 K, which can be compared to the lower ignition temperature of gasoline at 501 K. The flammability range on the other hand is much wider than for most hydrocarbons (Agata & Detlef, 2015, pp. 1-3).

Hydrogen can be produced in several ways and is commonly extracted from fossil fuels, biomass or water. Steam methane-reforming is the most commercialized and cheapest production method of hydrogen today (Agata & Detlef, 2015, pp. 11, 13). However, the usage of fossil gas implies, to some extent, an undesired bi-product of carbon dioxide. Only 4 % of the hydrogen is produced from other sources than coal, gas and oil (Parthasarathy, 2013, p. 1). The fossil free hydrogen production is mainly performed through different forms of electrolysis.

HYDROGEN PRODUCTION THROUGH ELECTROLYSIS

Electrolysis refers to the splitting of water into oxygen and hydrogen using an electrical current. The process can be accomplished in different electrolyzers. An electrolyzer can be designed for both small and big scale hydrogen production and a lot of research is in progress to make the process more efficient. Solid oxide electrolysis (operation temperature 700-800°C) and thermochemical electrolysis (operation temperature >2500°C) are two examples of developing technologies. These methods utilize heat from e.g. modern nuclear power plants or concentrated solar power plants to split water at higher temperatures (EERE, 2018). At higher temperatures less electricity is needed to split the water molecules. Since heat is cheaper than electricity, a potential drop in cost during large scale hydrogen production has been identified. However, these technologies are still very expensive and only in research state (Agata & Detlef, 2015, p. 385).

Alkaline electrolysis is the traditional way of splitting water to extract hydrogen. Two electrodes are immersed in an alkaline liquid consisting of concentrated potassium hydroxide. The electrodes are connected to an external power supply and if a current is induced, an inequality in potential between the electrodes will occur. This causes anodic and cathodic reactions that eventually will form hydrogen and oxygen gas (EERE, 2018). The alkaline electrolysis is a commercialized and well-established way of producing hydrogen. In addition, the electrolyzer can be made with a large share of inexpensive materials and is therefore currently the cheaper alternative while investing in an electrolyzer. The modulus can be made in the range of MW and the technical lifetime is estimated to 55-120 kh. Some of the disadvantages are low current density and reduced gas purity of the final product. In addition, the technology maintains a low capability of dynamic operation (Rashid et al., 2015, p. 89).

The polymer electrolyte membrane (PEM) electrolyzer is based on a similar set up as the alkaline electrolyzer. A main difference is the absense of electrolyte in liquid form. Deionized water is instead circulating, and a membrane manufactured of a special polymer material functions as the electrolyte (Agata & Detlef, 2015, pp. 64-65). The technology is in an earlier stage of development compared to the alkaline electrolyzer and also contains expensive components (Rashid et al., 2015, p. 89). The modulus is still manufactured slightly smaller than for the alkaline electrolyzer and the lifetime is estimated to 60 to 100 kh. The technology has a rapid system response and operates better at dynamic loads, which are important properties for a peak load supplier. At cold conditions, the ramp up time is 1-5 minutes and for warm conditions the ramp up time is below 10 seconds (Buttler & Spliethoff, 2017, p. 2451). The PEM electrolyzer also has higher gas purity and higher current efficiency than the alkaline electrolyzer. The technology is expected to be commercialized in near future (Rashid et al., 2015, p. 89).

HYDROGEN STORAGE

Hydrogen can be stored as gas or liquid at high pressure. Researchers are also examining the potential of binding hydrogen to liquid or solid materials (EERE, 2018). Large storage volumes are often placed below ground. The volatile properties of hydrogen make the gas difficult to compress and store without small particles escaping. This combined with the risk of explosion entail storage challenges (Östling, 2017, p. 18).

However, large storage solutions are possible. The largest hydrogen storage is currently found in Texas, USA, with capacity of storing 6 000 000 m^3 of hydrogen. The storage is placed in an oxygen free salt cavern to avoid accidental ignition (Wallach, 2017). A storage is also planned by Vattenfall in order to replace coal with hydrogen to achieve a fossil free steel production. The project is referred to as the Hydrogen Breakthrough Ironmaking Technology (HYBRIT) project.

The storage is planned to preserve 20 000-100 000 m^3 of gas pressurized at 200 bar and will classify as a hydrogen lined rock cavern storage (H2LRC). The size would make the hydrogen storage the largest in Sweden and also the first of its kind (Nohrstedt, 2018). Lined rock cavern storages (LRC) have previously been constructed for storing natural gas. The cylindrical caverns are primarily excavated from crystalline rock and coated with concrete and steel. They are typically placed 100-200 meters underground and are of large scale. Skallen, located outside Halmstad, is an example of a LRC storage that can preserve 40 000 m^3 pressurized natural gas (Brandshaug et al., 2001, p. 2).

Hydrogen can also be stored above ground in tanks or vessels. The geological requirements are therefore less strict compared to e.g. pumped hydro storages or compressed air storages which require large volumes to supply the same energy as hydrogen. These storage solutions are often more expensive if larger volumes of gas need to be stored (Bünger et al., 2016, p. 138).

HYDROGEN GAS TO ELECTRICITY

The hydrogen gas needs to be reconverted to electricity in order to supply peak power. Three available technologies for conversion are: combustion engines, gas turbines and fuel cells. Combustion engines are good for smaller applications and not preferred for larger power plants. Gas turbines can be used for larger applications and the technology is a known method for converting fuel into electricity. However, hydrogen has properties that deviate from fossil and organic fuels. The combustion temperature is higher, which makes traditional gas turbines less efficient. Gas turbines customized for hydrogen gas are currently being developed. These turbines are expensive and still need to be further investigated before commercialization (Kraftwerk Forschung, 2018).

Fuel cells are currently the more efficient way of producing electricity from hydrogen. The construction of a fuel cell appears similar to an electrolyzer. The reactions that take place in a fuel cell are basically electrolysis in reverse where hydrogen and oxygen is converted through electrochemical reactions to water, heat and electricity (Curtin & Gang, 2016, p. 2). Figure 2 shows a simplified process scheme of a hydrogen peaking power plant.

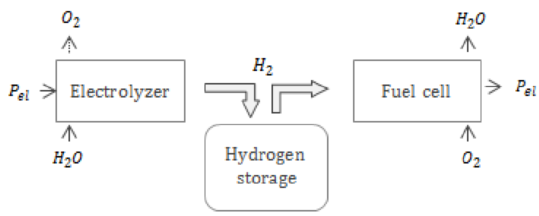

Figure 2. Simplified process scheme over a hydrogen peaking power plant.

4.1.2. STATUS OF TECHNOLOGY DEVELOPMENT

Even though hydrogen has great potential to provide the electricity systems with flexible energy storages, or work as an alternative fuel in the transportation sector, it is not the main area of use today. Hydrogen is more commonly used for industrial applications, refineries, manufacturing processes and food production. In 2012, the estimated usage of hydrogen was 40 million tons per year (Nationalencyklopedin, 2018). The first predicted market area for profitable use of hydrogen within the power system is to support small scale off grid areas with energy storage (Agata & Detlef, 2015, p. 27). The cost for the different parts of the hydrogen cycle is predicted to drop due to technical development and increased number of production units.

The properties of hydrogen are well known, but to really determine the risks involved in a large-scale hydrogen peaking power plant, experience within long term operation need to be withheld. The round-trip efficiency for the hydrogen cycle is currently 30-50 %. Hence, fluctuating electricity prices in the electricity system is crucial to gain profitability in such a peaking power plant (Östling, 2017, p. 14). However, if hydrogen production through electrolysis is present in the energy system due to other reasons such as transport or industrial use, the circumstances don't have to be as extreme for the plant to be profitable. By investing in additional fuel cells in adjacent to already existing electrolyzers and storages, the total cost of a hydrogen peaking power plant is reduced.

4.2. Gas-fired peaking power plant

A gas turbine is a suitable technology for flexible electricity production during peak load hours. It has a low investment cost and a short ramp-up time (Soares, 2015, p. 20).

Natural gas or diesel has historically been used as fuel in gas turbines. Gas turbines have therefore been optimized according to their characteristics, but other fuels can also be used in gas turbines. The most common alternatives are methane-based fuels, syngas, hydrogen and biodiesel (Jansohn, 2013). Suppliers are now developing gas turbines which offer higher fuel flexibility to enable a larger share of carbon neutral fuel-fired gas turbines.

4.2.1. Fuels and components

A gas turbine consists of a compressor, a combustion chamber and a turbine. Fuel is burned together with compressed air in the combustion chamber. The combustion gases are expanded through the turbine and the rotating turbine shaft drives the generator. The capacity of a gas turbine typically varies from 50 kW to over 200 MW. The exhaust gases from the turbine can be used to raise steam in a heat recovery steam generator. The steam is then led through a steam cycle to increase the electrical efficiency of the plant. A plant which combines a gas turbine and a steam cycle is called a combined cycle gas turbine (CCGT). A CCGT has higher investment cost and longer ramp-up time compared to a simple gas turbine with no steam cycle, usually called open cycle gas turbine (OCGT). Due to the longer ramp-up time, a CCGT is not considered as a peaking power plant (Soares, 2015, pp. 1-3, 17-20).

Heating value (expressed as energy per mass unit), viscosity and caused emissions differ between various fuels. Hydrogen and methane have high heating value, while syngas and biodiesel have a much lower heating value. NO_X-emissions are created during the combustion due to a high combustion temperature for all mentioned fuels.

Biogas can be produced by anaerobic digestion of different types of organic material or gasification of forest residuals. The intermediate gas in the gasification process is called syngas. To achieve approximately the same heating value as natural gas, both the gaseous output from the digestion and the syngas need to be methanized ("upgraded"), upgraded biogas is called biomethane. It consists of the same molecules as natural gas. Biomethane can also be produced from hydrogen, using a catalyst and carbon dioxide. The energy efficiency from electricity to biomethane via hydrogen produced in an electrolyzer is approximately 60-65 % (Ragnar, 2013, p. 18).

Biomethane gas can be stored at nearly ambient pressure in a gasometer or in a pressurized vessel and can be transported through a gas grid or in gas bottles by truck. It is economical efficient to transport gas by truck for distances up to 200 km. The gas liquefies at -163 ^{0}C and can then be transported further distances in chilled tanks by truck, train or boat. Production and distribution of biomethane causes relatively small leakages of methane gas which contribute to the greenhouse effect (Ragnar, 2013, pp. 8-13).

Biodiesel (fatty acid methyl esters) is produced from vegetable and animal oils which have been chemically modified to have similar combustion properties as conventional diesel. Most biodiesel produced in Sweden originates from rapeseed oil (Nationalencyklopedin, 2018).

4.2.2. STATUS OF TECHNOLOGY DEVELOPMENT

Generating electricity through gas turbines is a mature technology. The efficiency can to some extent be enhanced, even though a lot of work already has been done in the field. The turbines are currently being adapted to run on biofuels instead of natural gas in a more efficient way. However, a possibly larger potential for technological development is seen in the manufacturing process of the biofuels, which in turn has potential to lower the running cost of the gas. The mentioned gasification process is expected to become cheaper than the traditional anaerobic digestion process within near future. The anaerobic digestion process is also predicted to drop in both running cost and capital cost (van Melle, 2018, p. 14).

4.3. BATTERY PEAKING POWER PLANT

Batteries have many different areas of appliances. Currently they are mainly used as grid support and energy storage in vehicles. Larger units of battery modules ("battery parks"), with potential to be used as peaking power plants, are currently under development. The technological development is expected to make great progress during the following decade (IVA, 2015, pp. 14-16).

A battery consists of two electrodes, one positively and one negatively charged, separated by an electrolyte. The electrolyte only allows for ions to pass, not electrons. The electrons are therefore forced to pass through the external circuit, and thus the load, between the negative electrode and the positive electrode during discharge. When the battery is charged, the electrons move in the opposite direction. The characteristics of a battery are dependent on its chemical composition (Sanda national laboratories, 2015, pp. 97-98).

The three battery technologies which were assessed to have a potential to be used as peaking power plants at Ringhals will be presented in this section. The last part of the section describes the status of development for the different technologies.

4.3.1. LITHIUM-ION BATTERIES

There are many different variants of lithium-ion batteries. Some common characteristics are high energy density, discharge rate and round-trip efficiency. The battery cell usually consists of a negative electrode of graphite, a positive electrode of a lithiated metal oxide and a solid electrolyte of a lithium compound (IVA, 2015, pp. 16-17).

The high energy density in combination with inflammable lithium and available oxygen in the chemical composition of the battery entail a risk of fire in the battery (IVA, 2015, pp. 16-17).

4.3.2. SODIUM-SULFUR BATTERIES

The battery cell consists of a negative electrode of molten sodium, a positive electrode of molten sulfur and a solid electrolyte of beta alumina. The sodium-sulfur battery has a relatively high energy density and discharge duration. The sodium-sulfur battery is dependent on a heat source, since it needs to be operated at a temperature of approximately 300 °C. (Sanda national laboratories, 2015, pp. 43-45)

If sodium gets in contact with water, it can spontaneously start to burn. Each sodium-sulfur battery cell is therefore sealed and organized in a matrix system of many cylindrical cells in a box of doubly walled stainless steel. A battery management system needs to be installed to monitor the operation of the battery (Sanda national laboratories, 2015, pp. 43-45).

4.3.3. FLOW BATTERIES

A flow battery is designed differently compared to a conventional battery. The battery consists of a battery cell, in which the chemical reactions occur, and two tanks with electrolyte. The battery cell contains the positive and negative electrodes separated by a membrane. The membrane lets only ions pass and forces the electrons to go through the external circuit. The liquid electrolytes are pumped from the tanks to the two electrodes in the battery cell. The tanks enable large volumes to be stored and simplify maintenance (Sanda national laboratories, 2015, pp. 54-56).

Flow batteries have low energy density which make them more suitable for stationary rather than mobile applications. An advantage of flow batteries is the possibility to design the tanks and the battery cell according to existing energy and power needs. The tanks and the battery cell can also be located at different locations. Relatively long technical lifetime, rapid charging and low risk of fire are other advantages related to this technology (Sanda national laboratories, 2015, pp. 54-56).

4.3.4. STATUS OF TECHNICAL DEVELOPMENT

The sodium-sulfur battery is a known technology which has been commercialized for many years. A state-of the art facility, with a capacity of 34 MW and 245 MWh of energy storage, is located in Japan (Energy storage association, 2018). The battery type dominates the market of battery energy storage even though lithium-ion battery market share grows fast (IVA, 2015, p. 14). The most powerful lithium-ion battery system in the world was built in 2017 by Tesla in Australia. It has a capacity of 100 MW and an energy storage of 129 MWh (Lambert, 2017).

Several types of flow batteries are only in the demonstrating phase but have great potential to revolutionize the battery market. The most mature type of flow battery is the vanadium redox flow battery (VRFB). A state-of-the art system of vanadium redox flow batteries is installed in Japan with a capacity of 1 MW and 5 MWh of energy storage (Sanda national laboratories, 2015, pp. 56-57). Technical problems related to the low rate of active components in the electrolytes and the cost of the electrolytes have been identified as major hinders which need to be resolved for further development of the technology (Soloveichik, 2015).

A summary of the current characteristics of the different batteries can be found in Table 3.

Table 3. Characteristics of lithium-ion batteries, sodium-sulfur batteries and vanadium redox flow batteries.

Type	**Energy density [Wh/kg]**	**Number of discharge cycles during its lifetime**	**Round trip efficiency [%]**
Lithium-ion	$120-180^{a}$	10000^{b}	$80-95^{b}$
Sodium-sulfur	$60\ ^{a}$	$4500\ ^{a}$	80^{a}
Vandium redox flow	$10-30^{b}$	$10\,000^{b}$	85^{b}

a. Source: IVA (2015)
b. Source: Akinyele et al (2017)

5. MODELLING METHODOLOGY

The economic aspect, listed in the specification of requirements (see section 3.3), was evaluated through modelling. To assess if a power plant would be profitable, several different analyses was performed. The initial analysis was focused on the potential need of peaking power plants in southern Sweden from a system's perspective. If an investment in any of the five selected peaking power plant technologies will be considered to be installed at Ringhals, Vattenfall need to further calculate revenues and costs for the individual plant with market-based energy system tools.

The modelling methodology used in this project will be described in the following chapter. The model is described in section 5.1. Assumptions, limitations and data regarding the Ringhals site, the peaking power plant technologies and the flexibility providers included in the model are presented in section 5.2. The remaining assumptions, limitations and data which were implemented in the model can be retrieved in appendix B. Finally, an introduction to the studied cases is given in section 5.3. A discussion regarding the chosen modelling methodology can be found in appendix E.

5.1. MODELLING DESCRIPTION

The linear model which was used in this project is an adapted version of the One node model developed at Chalmers University of Technology. A detailed description of the One node model can be found in the article by Göransson et al (2017). The software GAMS was used for the modelling work in this project.

The model is a combination of a dispatch model and an investment model which can be run for one year, representing a selected time interval, and one region at a time. In this project, the model was run for the time intervals 2026-2035, 2036-2045 and 2046-2055 in a region represented by the southern part of Sweden (electricity price areas SE3 and SE4). The model could be run with an hourly resolution, but there is also an option to run the model for every third hour of a year. Due to long running times, a three-hour time resolution was used. All technologies included in the model are listed in in Table B.1. The objective function of the model is to minimize the total system cost, which is the sum of the total investment cost, operation and maintenance (O&M) cost, cycling cost and fuel cost.

There are many different constraints implemented in the model which together define the solution space for the optimization problem. Firstly, there are constraints to make sure that the electricity and heat production cover the demand during all hours of the year. Secondly, there are constraints to make sure that the electricity production from each technology is within its limitations. The electricity production in thermal power plants is limited by installed capacity, fuel availability, the possibility to perform thermal cycling and the set emission limits for thermal plants. The electricity production from renewable technologies is limited by installed capacity and available resource (water, wind or solar radiation). Thirdly, there are constraints which are describing the possibilities for variation management. These constraints are explained in detail in the article by Johansson & Göransson (2018). The variation management technologies included in this model are the energy storage solutions of hydrogen production/re-electrification and batteries. The final set of constraints is related to transmission of electricity and trade with neighboring regions. The trade with a certain region is limited by the transmission capacity between the southern part of Sweden and the neighboring region in question. A constraint describing the limited transmission capacity between the Ringhals site and the rest of the transmission grid was added in the model.

The model is mainly focused on the electricity system. A simplified description of the heat sector was also included to get a reasonable operation pattern for combined heat and power plants. Since the demand of heat is seasonally dependent, it was implemented with a monthly time resolution. The heat sector in the model is represented by combined heat and power plants, heat pumps (HP) and electric boilers (EB). Heating plants were not included in the model since they only are operated during peak load hours. With a monthly time resolution for the heat demand, no need of heating plants can be identified.

The model has perfect foresight, meaning that it knows how data such as electricity demand and weather dependent resources will vary during a modelled year. In addition, all installed plants are implemented with 100% availability. The model can therefore perfectly optimize the usage of e.g. hydropower. This is not possible in a real electricity system, since system operators and electricity generating companies only have access to forecasts and statistics from previous years.

Existing power plants in SE3 and SE4 were aggregated and implemented as a starting point for the optimization (see Table B.2). The model was first run for time interval 2026-2035. The suggested capacities of different technologies to be installed for this time interval was then implemented as existing capacities for the next time interval 2036-2045. The same procedure was performed for the final investigated time interval, 2046-2055.

5.2. ASSUMPTIONS, LIMITATIONS AND DATA

Assumptions, limitations and data regarding the Ringhals site, the peaking power plant technologies and the flexibility providers included in the model are presented in this section. The remaining assumptions, limitations and data which were implemented in the model can be retrieved in appendix B.

5.2.1. THE RINGHALS SITE

In the following section, the assumptions, limitations and data for the Ringhals site will be presented.

The decommissioning of nuclear reactors R1 and R2 is estimated to take 10 years due to the handling of radioactive components. It was therefore assumed that the site will be available for a peaking power plant in 2030. The static transmission capacity between the Ringhals site and the transmission grid was assumed to remain at today's level during the modelled time intervals. Considering the fact that R3 and R4 still will be in operation during two of the three modelled time intervals, the available static transmission capacity between Ringhals and the transmission grid was set to 2000 MW, which corresponds to the capacity of R1 and R2 today (Ringhals AB, 2016). Limitations in transmission capacity due to power flow were not considered in the project.

The value of the connection point to the transmission grid was assumed to be equal to the investment cost of an average switchyard in Europe. The value of the connection point is derived in appendix B. Based on these calculations, the cost of an investment in a peaking power plant at

Ringhals was reduced with 8.5 EUR/kW compared to investments done elsewhere in the modelled region.

It was assumed that the biogas which is consumed at Ringhals could be transported to the site through the gas grid (a description of the grid is given in section 2.1). The capacity of the gas grid was assumed to be high enough to provide a 300 MW gas turbine with fuel during all hours it is operated. This is in line with the gas turbine plant Öresundsverket, which is connected to the gas grid today (E.ON, 2010). No biogas storage was considered for a biogas-fired peaking power plant at Ringhals (BG_peak_R). The maximum capacity of a biogas-fired peaking power plant at Ringhals was therefore set to 300 MW.

The possibility to import or export hydrogen from Ringhals was not implemented in the model. Thus, hydrogen was forced to be produced locally to be used as fuel at Ringhals. In addition, it was assumed that a hydrogen lined rock cavern storage won't be established at Ringhals. This assumption was based on uncertainties related to the site's geological conditions and limitations due to the coexistence of nuclear power plants at the site.

5.2.2. MODELLED PEAKING POWER PLANT TECHNOLOGIES

The implementation of the peaking power plant technologies in the model will be described further in this section.

BIOGAS-FIRED PEAKING POWER PLANT

A biogas-fired turbine was chosen to be implemented as the biogas-fired peaking power plant in the model. The biogas was assumed to be methanized and produced by gasifiers in the modelled region. Assumptions and data related to gasification are presented in appendix B. The data for the biogas-fired peaking power plant are taken from World Energy Outlook (WEO) 2016 (International energy agency, 2018) and presented in Table 4. The data for the natural gas-fired turbine were used for the biogas-fired peaking power plant.

Table 4. Data used for the biogas-fired peaking power plant.

Parameter	Value
Investment cost 2026-2055 [EUR/kW]	450 (441.5 for BG_peak_R)
Variable O&M cost [EUR/MWh]	0.8
Fixed O&M cost [EUR/kW]	15
Start-up cost [EUR/MW]	20.2
Part load cost [EUR/MW deviating from rated power]	0.5
Efficiency	0.37
Minimum load	0.6
Start-up time [h]	0

ENERGY STORAGE TECHNOLOGIES

An overview of the included energy storage technologies can be seen in Table 5. The vanadium redox flow battery was the type of flow battery which was implemented in the model. This type was chosen since it is the most mature of the flow battery technologies. For the hydrogen cycle, a PEM electrolyzer and a PEM fuel cell were modelled. The PEM technologies were chosen mainly due to their ability to operate during dynamic loads, see section 4.1. The cost data for the energy storage technologies (except the lithium-ion battery) were taken from the technology data catalogues published by the Danish energy agency (2018). For the time interval 2026-2035, the estimated cost data for 2030 were used etc. If data for the time intervals 2036-2045 or 2046-2055 were missing in the data catalogues, data for a time interval as close as possible to the time interval in question were used. The data for the modelled energy technologies are summarized in Table 6.

Table 5. Overview of the implemented energy storage technologies in the model.

Technology	Type used in model	Source
Flow battery	Vanadium redox	Technology data catalogue for energy plants (2017), p. 106
Electrolyzer	Proton exchange membrane electrolyzer cell	Data sheet for energy carrier generation and conversion (2018), sheet 87
Fuel cell	Protone exchange membrane fuel cell	Technology data for energy plants (2012), p. 110-111
Sodium-sulfur battery		Technology data catalogue for energy plants (2017), p. 105
Lithium-ion battery		Investment cost 2026-2045: Nykvist & Nilsson (2015) 2046-2055: Assumption Fixed O&M cost: Assumption

Table 6. Data for the implemented energy storage technologies in the model.

Technology	Inv cost 2026-2055 [EUR/kW]	Var O&M cost [EUR/MWh]	Fixed O&M cost [EUR/kW]
Bat_flow	1100 [EUR/kW capacity], 51 [EUR/kWh storage]	2.8	54
Bat_flow_R	1091.5 [EUR/kW capacity], 51 [EUR/kWh storage]	2.8	54
Efuel	600 (400 in 2046-2055)		30 (20 in 2046-2055)
Efuel_R	600 (400 in 2046-2055)		30 (20 in 2046-2055)
FC	400	10	
FC_R	391.5	10	
H2LRC	11		
H2tank	45		
H2tank_R	45		
Li_ion	144 (135 in 2046-2055)		25
Li_ion_R	135.5 (126.5 in 2046-2055)		25
NaS	136	5.3	51
NaS_R	127.5	5.3	51

The assumed characteristics of the energy storage technologies can be found in Table 7 and Table 8.

Table 7. Assumed characteristics for the battery storage technologies.

Type of data	Flow battery	Li-Ion battery	NaS battery
Charging efficiency	0,84	0,95	0,80
Discharging efficiency	0,84	0,95	0,80
Injection rate [share of battery capacity per timestep]	1	0,5	0,5
Withdrawal rate [share of battery capacity per timestep]	1	0,5	0,5

Table 8. Assumed characteristics for the technologies related to hydrogen.

Type of data	Electrolyzer	Fuel cell	H2tank	H2LRC
Charging efficiency			0.999 (H_2)	0.999 (H_2)
Discharging efficiency			1	1
Process efficiency	0,8	0,6	0,978 (electrical efficiency)	0,978 (electrical efficiency)
Injection rate [share of storage capacity per timestep]			1	0,025
Withdrawal rate [share of storage capacity per timestep]			1	0,05

5.2.3. MODELLED FLEXIBILITY PROVIDERS

In addition to hydropower, other flexibility providers were added to the modelled system in most of the studied cases. The assumptions, limitations and data related to these flexibility providers will be presented in this section. The studied cases will be presented in the next section.

DEMAND SIDE MANAGEMENT

It was assumed that maximum 20% of the total electricity demand can be shifted in time through Demand Side Management (DSM). The shifted demand needs to be served a later hour. The maximum time interval for a shifted electricity demand was set to 6 hours. The additional served demand during a certain hour was limited to 30 % of the total electricity demand. These assumptions were taken from the study by Göransson et al (2014).

TRADE WITH REGIONS IN NEIGHBORING COUNTRIES

Import of electricity from northern Sweden was implemented in all studied cases, see appendix B. In addition, trade with regions in neighboring countries was implemented in some of the studied cases. The sum of the annual import of electricity was then constraint to equal the sum of the annual export of electricity. This constraint did not include the import of electricity from northern Sweden.

The implemented maximum transmission capacities to regions in neighboring countries were model results from the long-term Electricity Investment model (ELIN), developed at Chalmers university of technology. The model is an investment model, covering the European electricity system. The implemented objective function is to minimize total system cost. Investments in both transmission capacity and power plants are allowed in this model. Existing transmission capacities were implemented as the minimum level of investment. The transmission capacities given by the ELIN model are shown in Table 9. The model suggested constant transmission capacities for all modelled time intervals.

Table 9. Overview of transmission capacities to neighboring countries, retrieved from the ELIN model.

Region	Norway (NO1)	Denmark (DK1)	Denmark (DK2)	Germany (DE4)	Poland (PO3)	Lithuania (LT)	Finland (FI)
Capacity [GW]	3.3	1.7	0.74	0.6	0.6	0.7	1.3

The implemented electricity prices for the different regions are model results from the European Dispatch model (EPOD), which is used in combination with ELIN. The results from ELIN are inputs to EPOD. The models are described more in detail in the article by Odenberger et al (2009) and the dissertation by Göransson (2014). A time resolution of three hours was used when the ELIN/EPOD package was run.

HYDROGEN DEMAND

A possible development towards an electrified industry was in this project represented by the HYBRIT project. The aim of the HYBRIT project is to produce steel without any usage of coal. The new production process utilizes hydrogen as a substitute for fossil fuels. A hydrogen demand corresponding to a transformation of the entire Swedish steel production was implemented in the model for two of the studied cases. It was assumed that the hydrogen production will increase the electricity demand with 20 TWh/year (Nohrstedt, 2018).

5.3. STUDIED CASES

The studied cases were chosen so that different flexibility providers' impact on the need of peaking power in southern Sweden could be investigated. A base case (BC) was constructed as a reference. The base case represents a probable development of the studied system but with only hydropower imported from northern Sweden as implemented flexibility provider. A summary of the base case is shown in Table 10, all assumptions and data can be found in appendix B.

Table 10. Summary of assumptions made for the Base case.

Parameter	**Value**
Annual electricity demand for Sweden	2026-2035: 143 TWh 2036-2045: 160 TWh 2046-2055: 160 TWh
Annual heat demand for Sweden	47 TWh
Fossil CO2-cap	0 g/kWh (emissions from waste-fired power plants were neglected)
Annual water availability in the Swedish dams	65 TWh
Number of years in operation for power plants	Estimated technical lifetime
Biomass price	30 EUR/MWh
Transmission capacity between SE2 and SE3	7.8 GW

The flexibility providers DSM, trade and hydrogen demand were studied in this project. The assumptions, limitations and data related to the implementation of the different flexibility providers in the model were described in section 5.2. An overview of the implemented flexibility providers in the different cases is given in Table 11.

Table 11. Overview of the implemented flexibility providers for the five studied cases.

	Base case (BC)	DSM (BC+DSM)	Trade (BC+trade)	Hydrogen demand (BC+H2)	Combination (BC+comb)
Swedish hydropower	Yes	Yes	Yes	Yes	Yes
DSM		Yes			Yes
Trade with regions in other countries			Yes		Yes
Hydrogen demand				Yes	Yes

Sensitivity analyses were made on the Base case and the Combination case to investigate different parameters' impact on the results. The parameters included in the sensitivity analyses are listed below.

Base case:

- Dry and wet hydrological years
  The annual water availability in the Swedish dams was changed from 65 TWh (normal year) to 56 TWh (dry year) and 91 TWh (wet year).
- Operation of nuclear (minimum load, decommissioning year)
  - Minimum load was changed from 60% to 100% to illustrate an inflexible operation of nuclear power plants.
  - The decommissioning year of the remaining reactor with lowest capacity, Forsmark 1 (F1), was changed from 2040 to 2025.
  - The decommissioning year of the reactors R3 and R4 was changed from 2041 respectively 2043 to 2056.
- Biomass price
  The biomass price was stepwise increased.
- Investment cost for batteries and hydrogen peaking power plant
  The investment cost for one technology at a time was stepwise reduced.

Combination case:

- DSM level
  The DSM level was changed from 20% of the total electricity demand to 10% of the total electricity demand.
- Transmission capacity between SE2 and SE3
  The possibility to import electricity from northern Sweden was reduced by setting the transmission capacity between SE2 and SE3 to 7.0 GW instead of 7.8 GW. 7 GW represents the present transmission capacity between SE2 and SE3 (Svenska kraftnät, 2017).

6. MODELLING RESULTS

Chapter 6 presents the modelling results of the electricity sector. The chapter begins by explaining how the need of peaking power in the studied region is affected by the implemented flexibility providers. The results for the Ringhals site are thereafter presented.

A more detailed description of how the electricity system is developed in the studied cases can be found in appendix C. Appendix D describes how the results are affected by dry and wet hydrological years, varied operation patterns for nuclear power plants, changes in biomass price and reduced investment costs for batteries and hydrogen peaking power plants.

6.1. NEED OF PEAKING POWER IN SOUTHERN SWEDEN

The total need of peaking power for the modelled region in the time intervals 2036-2045 and 2046-2055 is shown in Figure 3. In the time interval 2026-2035, a need of peaking power only occurs in the Base case (1.1 GW TotBG_peak). The annual electricity demand in the next time interval (2036-2045) has been raised by 17 TWh, which increases the need of peaking power in all cases. When the nuclear power plants are decommissioned in the last time interval (2046-2055), an additional need of peaking power can be observed.

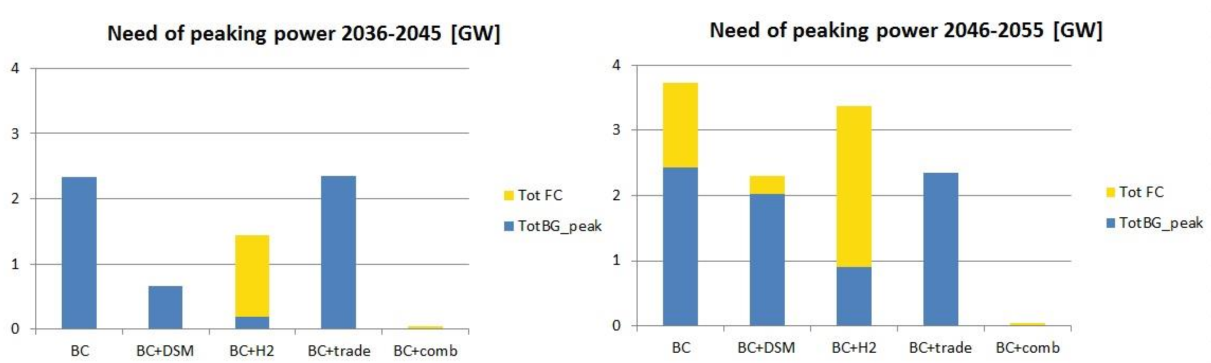

Figure 3. Estimated need of peaking power in region SE3 and SE4 during time interval 2036-2045 and 2046-2055.

DSM, hydrogen production and trade act as flexibility providers in the electricity system, and they are to some extent competitors to peaking power plants. Since DSM and trade are implemented with no related cost, the model uses DSM and trade optimally before it invests in a peaking power plant. The need of peaking power is therefore largest in the Base case, in which neither DSM, hydrogen production or trade is implemented. The model accounts for the possibility to export electricity during peak load hours in other countries while optimizing the installed capacity of peaking power plants in the cases with implemented trade.

The model chooses to invest in biogas-fired peaking power plants in all studied cases except the Combination case. According to the sensitivity analyses for the Base case (see appendix D), the choice of peaking power plant technology seems quite robust. An increased biomass price or a reduced investment cost of the hydrogen peaking power plant would lead to a reduced, but still considerable, amount of installed capacity biogas-fired peaking power plants. If a nuclear power plant is decommissioned before its technical life time is reached, the suggested investment in biogas-fired peaking power plants is suggested to be increased.

The model also invests in hydrogen peaking power plants in the time interval 2046-2055. The reason to why the model chooses to invest in two types of peaking power plants can be explained by studying their operation pattern in combination with the electricity price. A reduced electricity demand and more electricity generated from solar PVs generally result in many low electricity price hours during summertime. The difference in running cost between a hydrogen peaking power plant and a biogas-fired peaking power plant during summer is large enough to compensate for the higher investment cost of the hydrogen peaking power plant compared to the biogas-fired peaking power plant. In order to minimize total system cost, the model invests in a small hydrogen peaking power plant. The plant is mainly utilized during summertime as a complement to the biogas-fired peaking power plants which operate the remaining peak hours of the year.

For cases with implemented hydrogen demand, the investments in peaking power plants are made already in time interval 2036-2045. The system takes advantage of already existing hydrogen infrastructure in these cases, by placing fuel cells in adjacent to the storages and electrolyzers at the HYBRIT site. An extra amount of hydrogen is stored to satisfy both the demand of HYBRIT and the demand of the fuel cells simultaneously. The timing of charging and discharging of the hydrogen storages is crucial.

By combining all studied flexibility providers, the need of peaking power plants is almost eliminated for all modelled years. The model only suggests an installation of 40 MW of fuel cells during the last two time intervals, 2036-2055. However, sensitivity analyses show that small changes in DSM level or available transmission capacity between SE2 and SE3 have large effects on the results. Two examples are given below.

- If the DSM level is reduced from 20% to 10% of the total electricity demand (remaining parameters unchanged), the model suggests an investment of 0.7 GW fuel cells for the last two time intervals (2036-2055). No other significant changes in installed capacity of different technologies occur.
- If the possibility to import electricity from northern Sweden is reduced by setting the transmission capacity between SE2 and SE3 to 7 GW instead of 7.8 GW (remaining parameters unchanged), the model suggests an investment of 0.5 GW fuel cells for the last two time intervals (2036-2055). No other significant changes in installed capacity of different technologies occur.

6.2. PEAKING POWER PLANT AT RINGHALS

Among all investigated technologies with a potential to be installed at Ringhals, the model only suggests an investment in a biogas-fired peaking power plant. But it could also be interesting to investigate an investment in flow batteries, if the investment cost would drop significantly compared to the projected cost (see appendix D for more details). The lower cost of the flow battery technology compared to other battery technologies can be explained by the inherent possibility to choose an optimal capacity and size of energy storage separately, and its higher injection- and withdrawal rates. According to the results, it will be economically infeasible to invest in a hydrogen peaking power plant at Ringhals during the studied circumstances, unless a larger storage (e.g. H2LRC) is installed at site or in adjacent to the site. Alternatively, if the plant can advantage from exporting hydrogen gas to other consumers or utilize existing infrastructure in collaboration with other projects such as HYBRIT.

The model chooses to utilize the maximum allowed capacity of 300 MW biogas-fired peaking power plant for all cases except the Combination case (no investment at Ringhals in this case, but investments in fuel cells in other parts of the region, see section 6.1) and the Hydrogen demand case (190 MW at Ringhals 2036-2045). The maximum allowed capacity is a consequence of the excluded biogas storages at Ringhals. The size is thereby limited to the capacity of the gas grid. The capacity of the peaking power plant can therefore be increased if a biogas storage facility is allowed at site. The suggested capacity of the biogas-fired peaking power plant at Ringhals is visualized in Table 12.

Table 12. Capacity of a biogas-fired peaking power plant at Ringhals.

[MW]	BC	BC+DSM	BC+H2	BC + trade	BC+comb
2026-2035	300	-	-	-	-
2036-2045	300	300	190	300	-
2046-2055	300	300	300	300	-

The operation pattern for the peaking power plant also differs depending on the surrounding circumstances of the various cases. The total amount of hours that the model suggests for BG_peak_R to operate is visualized in Table 13.

Table 13. Aggregated number of operation hours for a biogas-fired peaking power plant at Ringhals.

[hours per time interval]	BC	BC+DSM	BC+H2	BC + trade	BC+comb
2026-2035	690	-	-	-	-
2036-2045	1410	870	780	270	-
2046-2055	2520	1980	1860	1620	-

The number of operation hours for a biogas-fired peaking power plant increases for later time intervals. The main reasons are an increased electricity demand compared to the first time interval and the decommissioning of nuclear plants during the last time interval. Both these reasons lead to more intermittent power production and thus a larger number of operation hours for peaking power plants. The Base case represents a quite inflexible system and consequently holds the greatest amount of operation hours among all studied cases. When flexibility providers are added to the system, the number of operation hours for the biogas-fired peaking power plant is considerably reduced.

A sensitivity analysis was performed on the Base case to investigate which impact the inflow of water has on the number of operation hours for peaking power plants, see appendix D. The results show that the number of operation hours for the biogas-fired peaking power plant at Ringhals was increased both during wet and dry years.

The marginal costs of electricity production for the studied cases are shown in Figure 4 and Figure 5. The cost data were sorted from the highest to the lowest value of the year.

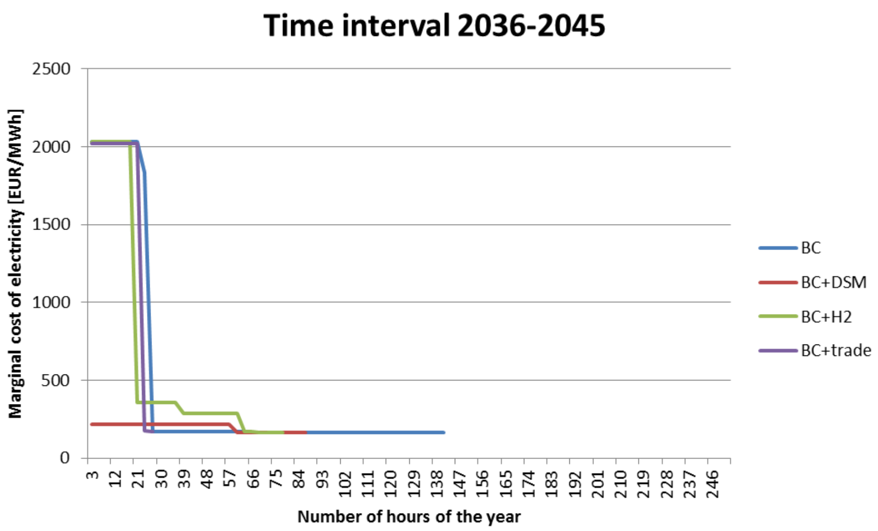

Figure 4. The marginal cost of electricity production during peak hours in time interval 2036-2045.

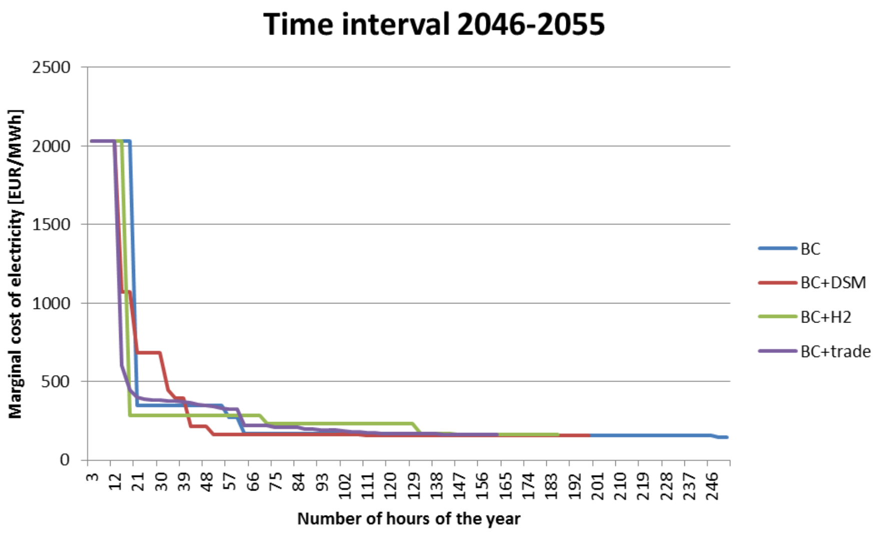

Figure 5. The marginal cost of electricity production during peak hours in time interval 2046-2055.

A number of hours with extreme marginal cost of electricity can be seen in Figure 4 and Figure 5. These hours are important for the biogas-fired peaking power plant to also cover for its fixed costs. The number of hours with extreme marginal cost of electricity is reduced in systems with flexibility providers implemented.

7. Discussion

In this section, the results presented in chapter 6 will be discussed. The chapter starts with a discussion from a system perspective. A discussion related to the Ringhals site can be found in the following section. The modelling methodology is discussed in appendix E.

7.1. Need of peaking power in southern Sweden

A transformation of the Swedish energy system is required in order to fulfill the energy agreement described in appendix A. The declining amount of nuclear power capacity brings additional challenges to the transition and the model results describe how this may affect the electricity system in southern Sweden. Similar developments are also anticipated in other countries. Sweden is in a favorable position compared to many other countries due to the large amount of installed hydropower plants that can contribute with flexible electricity production. Despite the access to hydropower, the model results indicate a need of peaking power for all studied cases. For most cases, the need of peaking power doesn't occur until the second time interval 2036-2045. These results are in line with SvK's analysis, anticipating a risk of 400 insufficient power supply hours in SE3 and SE4 by 2040 (Svenska kraftnät, 2017, p. 25). The need of peaking power is radically reduced when all studied flexibility providers are fully developed, and their contribution combined.

While observing the results, it is important to consider that the model is designed to preferably underestimate rather than overestimate the need of peaking power. In appendix E, the factors available transmission capacity, perfect foresight and DSM level are mentioned. The impact of a reduced transmission capacity or a reduced DSM level was illustrated in the sensitivity analysis on the Combination case, see section 6.1. The sensitivity analysis on the Base case showed that an early retirement of one or several nuclear reactors also could lead to a larger need of peaking power than expected. Depending on how the electricity system will develop, there is also a risk that the need of peaking power is overestimated by the model. This was also mentioned in appendix E, where future potential flexibility providers were discussed.

A conflict between what's favorable for the system and what’s favorable for a potential investor can be identified. Peaking power plants are a part of the model's suggested investments to minimize total system cost. However, an investment in a peaking power plant is related to high economic risk for the investor. The power plant owner is dependent on enough number of peak hours with sufficient electricity price to cover for the power plant's investments costs. If the peaking power plant for some reason is unable to operate during the peaks due to e.g. technical errors or absence of fuel/personnel, the lack of income might cause severe financial consequences. Small changes in the energy system compared to what was expected when the investment decision was made may have a big impact on the plant's profitability.

As described in appendix A, some of the peaking power plant owners in Sweden currently have contracts with the grid operator to ensure power generation during really extreme peak hours. This possibility is limited by law and expires in 2025, thereafter a market-based solution is envisioned. It can be questioned if the electricity system is ready for a market-based solution. The back-up reserves are sensitive investments since they only operate a few hours per year or sporadically not at all. The electricity system will receive problems if nobody is willing to take the investments necessary, without the contracts to justify it financially. A discussion is held whether the back-up reserve contracts should be prolonged. If the contracts for back-up reserves are prolonged, new peaking power plants have a possibility to join and thus strengthen their financial situation.

If the back-up reserves aren't prolonged, it is likely that there will be a discussion regarding the limitation in maximum electricity price on the Nord Pool market. If the limit is increased, the number of operation hours needed for a peaking power plant owner to cover for its investment cost might be reduced. A possibility to profit from the contribution of more ancillary services is another alternative for strengthen the arguments for an investment in a peaking power plant. Today, no monetary compensation is given for providing e.g. inertia or reactive power to the electricity system (see appendix A for a further explanation). Depending on how such a compensation might be implemented, it might have an impact on the results in this study.

7.2. THE RINGHALS SITE

Since the project focuses on the Ringhals site, it is essential to reflect upon the local context. The following section discusses the technical- and economic aspects stated in the specification of requirements determined in section 3.3. The environmental-, safety- and local aspects require additional expertise to be fully evaluated. The evaluation of these aspects is recommended as future work in chapter 9.

During the review of technical- and economic aspects, the biogas-fired peaking power plant emerged as a potential choice of peaking power plant at Ringhals. Hence, the discussion will focus on the biogas-fired peaking power plant.

In addition to the technical requirements for a peaking power plant at Ringhals, listed in section 3.3, a contribution of ancillary services and a possibility to scale the power plant was desired. The biogas-fired peaking power plant itself contributes with inertia to the system and reactive power once it is in operation. The plant can also be complemented with technologies maintaining faster response to dynamic load, such as flywheels, capacitors or magnetic energy storages. These combinations have not been modelled and the economical outcome is not established. Such combinations would most likely depend on additional compensation for providing ancillary services compared to the situation today. The biogas-fired peaking power plant also has potential to fulfill the requirement of scalability. The Ringhals site offers both enough space and an oversized transmission capacity in case of expansion.

A drawback related to the biogas-fired peaking power plant compared to the battery technologies is its dependency on fuel. The biogas needs to be transported to reach the site, which can be done by rail, road, sea or pipeline. The simplest option is probably to import biogas through pipelines from the nearby gas grid. By importing biogas from the grid, Vattenfall will always be dependent on the availability of gas in the network. The imported volume needs to be sufficient to operate the gas turbine during peaks. The uncertainty cause problems since the income from a peaking plant is dependent on only a few operating hours per year. Therefore, it is of high importance for the plant to be available when opportunities for operation are given. The usage of biogas at Ringhals during peak hours will probably coincide with high consumption by other customers connected to the grid, which could lead to higher gas prices. A good agreement with the biogas supplier is therefore necessary.

Another strategic option is to produce own biogas at Ringhals or close to the site. This option is not related to any dependency on delivery from the gas grid. On the other hand, it follows with a higher economic risk related to the additional investments. There are uncertainties related to the policy for biogas and the future demand from other customers. A need of gas storage will also arise, which might be problematic to locate at Ringhals due to safety reasons related to the nuclear reactors in operation at the site. A partnership with the local actor Södra cell could be considered for the delivery of biogas. Södra cell can contribute with competence and a local source of forest residues which can be used in a gasification process. They also have experience from other innovative partnerships within the processing of biomass, see section 2.1.

8. Conclusions

The possibilities of using the existing land and infrastructure at Ringhals for a peaking power plant, after the decommissioning of the reactors R1 and R2, have been investigated in this project. A selection of suitable peaking power technologies to study further has been made based on a formulated specification of requirements. The technical aspects were used as initial selection criteria. The selected technologies (biogas-fired turbine, hydrogen fuel cell and three different battery types) have then been included in a combined investment- and dispatch model, which has been constructed to invest in power plants to cover for the electricity demand in southern Sweden at lowest possible total system cost. Cases with different flexibility providers implemented (DSM, trade with neighboring countries and a hydrogen demand) have been modelled. By studying the modelling results, the need of peaking power in southern Sweden, and thus the possibilities for such a plant at Ringhals, has been investigated for the modelled time intervals 2026-2035, 2036-2045 and 2046-2055. The project's main conclusions are listed below.

- A need of peaking power in southern Sweden can be identified from year 2036 in all studied cases. The required amount of peaking power is strongly related to what flexibility providers that are available in the electricity system. A large reduction of installed peaking power capacity compared to the Base case can for instance be seen in the Combination case, where DSM, trade and a hydrogen demand simultaneously are activated. The need of peaking power occurs already 2026 in the studied Base case, in which no flexibility providers except hydropower are implemented.
- If the DSM level is reduced to 10% of the total electricity demand or the transmission capacity between electricity price areas SE2 and SE3 remains at the same level as today, a larger need of peaking power is obtained in time intervals 2036-2045 and 2046-2055 also for the Combination case, where DSM, trade and a hydrogen demand simultaneously are activated.
- The biogas-fired peaking power plant would, from a system's perspective, be the economic preferable choice of peaking power plant in all studied cases except the ones with an implemented hydrogen demand. For the Hydrogen case and the Combination case, the cases with an implemented hydrogen demand, investments in mainly fuel cells would lead to the lowest total system cost. These fuel cells would not be located at Ringhals.
- It is economical beneficial from a system's perspective to invest in a biogas-fired peaking power plant at Ringhals in all studied cases except the Combination case, where DSM, trade and a hydrogen demand simultaneously are activated. The optimal year of investment depends on which other flexibility providers that are active in the electricity system of southern Sweden. But it is not likely that a biogas-fired peaking power plant at Ringhals would cover its costs if an installation occurs in the initial time interval (2026-2035) and the only source of income is the electricity spot market.
- An investment at Ringhals is favored by the model, since the investment cost is lower there due to the already existing infrastructure. Local conditions are therefore limiting the installed capacity of biogas-fired peaking power plant turbines at Ringhals in most cases.
- The studied battery technologies (VRFB, Li-Ion and NaS) are found to be more expensive than the biogas-fired peaking power plant and the hydrogen peaking power plant when they are considered as peaking power plants. The model has therefore not suggested an investment in batteries in any of the studied cases. But if the price of vanadium redox flow

batteries would drop significantly, model results show that this technology could be interesting to investigate further.

- An investment in a hydrogen peaking power plant at Ringhals (electrolyzer, hydrogen tank storage and fuel cell) to be used only for electricity production, has not been shown economic feasible in any of the studied cases unless larger underground storages and a possibility to export hydrogen from the site are applied.

9. FUTURE WORK

The project has resulted in a first suggestion of what can be done at the Ringhals site after the decommissioning of nuclear reactors R1 and R2. A lot of work remains before an investment decision can be made.

The suggested power plant for peaking power purposes at the site is a biogas-fired turbine. Most of the alternative technologies are still in early stages of their technical developments. Their related properties and costs are expected to change during the timespan between now and an actual installation after 2030. It is therefore recommended to track the development of these technologies. Additional modelling is also recommended, with focus shifted from a system perspective to an individual plant perspective. This can be done by investigating the profitability of the different peaking power plants through market-based modelling.

The project has been focused on the technical- and economic aspects in the formulated specification of requirements. If any of the peaking power technologies are shown to be profitable in the market-based modelling, the next step would be to investigate if the remaining aspects in the specification of requirements can be fulfilled. Suggested actions are listed below.

- Expertise need to analyze the risks related to a new power plant in coexistence with the remaining nuclear reactors. If it is assessed feasible to install a peaking power plant at Ringhals, measures to reduce the risks to an acceptable level needs to be identified and their related costs needs to be estimated. There are risks related to different areas, such as:
    - Risk of an accident
      The risk of an accident at the peaking power plant or in the fuel storage should not contribute considerably to the already existing risk of external events which could damage R3, R4 or the switchyard at Ringhals. An important aspect regarding this requirement is the handling of fuels. As described in section 2.2, Ringhals AB has previous experience from handling flammable and explosive fuels such as diesel and hydrogen close to nuclear power plants. However, the volumes are not nearly as large as the required volumes for running the peaking power plant.
    - Risks related to electrical safety
      A new plant connected to the switchyard at Ringhals would complicate the work concerning electrical safety at the site. An unplanned stop in the peaking power plant's electricity production could impact the electric safety systems which are installed at the remaining nuclear power plants at Ringhals. Since Ringhals AB is forced to have several parallel- and diversified safety systems online to be allowed to run the nuclear power plants, such an event could force Ringhals AB to shut down R3 or/and R4. Controversially, an unplanned event in any of the nuclear power plants or in the transmission grid may have an impact on the operation of the peaking power plant.
    - Risk of interfering the operation of R3, R4 or the switchyard
      The operation of R3 and R4 has a higher priority than the operation of a potential peaking power plant due their high capacity. If the production in any of these reactors is stopped, that would cause a big loss of income for the owners. Except electrical safety, which was mentioned in the previous bullet point, other areas

need to be investigated related to the construction and operation of the peaking power plant.

- Expertise is required to ensure that environmental regulations for a potential peaking power plant at Ringhals are fulfilled.

Further research regarding the geological conditions at the Ringhals area for examining the potential of building underground storages is also recommended. This is of interest while investigating the biogas-fired peaking power plant- and the hydrogen peaking power plant alternatives. A possibility to store biogas underground would reduce the delivery dependency on the gas grid. An alternative is to further investigate the capacity of the gas grid during peak hours to ensure a sufficient supply. It is also important to investigate the cost of importing biogas. Based on the results in this study, a lined rock cavern would probably be one of the prerequisites to find profitability in a hydrogen peaking power plant at Ringhals.

Vattenfall has competence within hydrogen lined rock cavern storages, thanks to the collaboration with HYBRIT. Hence, it can be of interest for the company to investigate if fuel cells can be placed in adjacent to already invested infrastructure at the HYBRIT site.

The aim of the project is to examine the potential of peaking power plants at Ringhals. However, other types of power production may utilize the connection point in a more efficient way. Hence, other alternatives could be investigated further. Based on the results in this project, large investments in offshore wind power are expected in Sweden. An offshore wind power park outside Ringhals is therefore an option. Combinations of technologies could also be considered in order to utilize the entire available capacity of the connection point and the concept of trading electricity locally at the Ringhals site.

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Appendix A: The electricity system and the Nordic context

The electricity system

Energy balance

The electricity demand in our society is constantly fluctuating. The load curve is varying both daily and seasonal due to e.g. variations in human activity, different levels of industry procedures and temperature shifting. In addition, the supply side is altering depending on for instance what power plants that currently are in operation, installed capacity, weather conditions, trade- and market situations and the transfer capacity in between regions.

A balance between demand and supply is crucial for the electricity system to operate properly. This balance need to be fulfilled for every time instant. The traditional approach for achieving balance in the system is by regulating the power output from the electricity generating units and thus compensate for variation in demand and changed power output from supplementary power plants. Trade with other regions is another alternative which can be used to balance generation and consumption in a cost-effective way. Energy storage is a concept that also can contribute to maintain the energy balance. Times where excess electricity is generated in the electricity system will arise more often in a system based on intermittent energy resources. Electricity in itself can't be stored, but through mechanical, electrical, electrochemical or chemical solutions the energy can be saved for times where a deficit of electricity in the system is striking. The load can also, to some extent, be shifted to smoothen out peaks in the energy demand, this is referred to as Demand Side Management (DSM) (Klimstra, 2014).

Baseload-, intermittent-, intermediate- and peaking power plants

The electricity generating units in the system are often categorized into four categories: baseload-, intermittent-, intermediate- and peaking power plants.

The purpose of baseload power plants is to deliver cheap electricity in large amounts. Baseload power plants typically maintain a high investment cost followed by a lower running cost. They traditionally supply a high proportion of the total energy demand most hours of the year. Coal-fired power plants and nuclear power plants belong to this category (Kaplan, 2008, p. 3). The Swedish baseload power plants mainly consist of nuclear power plants. The nuclear power plants are less flexible compared to several electricity production technologies, and consequently more suitable to be operated at nominal load for most hours of the year.

Intermittent power plants have very low running cost and therefore contribute to significant lower electricity prices while in operation. Countries with large shares of intermittent power plants occasionally receive negative electricity prices if many intermittent power plants are running and supplementary plants have reasons not to reduce their power output (high cycling costs, subsidies etc.). Thus, the customer gets paid for consuming electricity in order to benefit the energy balance in the power system (Amelang & Appunn, 2018).

Intermediate power plants can to some extent be regulated to follow the load curve, for instance thermal power plants with a steam cycle (Kaplan, 2008, p. 3). The Swedish intermediate power plants consist mainly of hydropower plants, which are even more flexible and can pave for fluctuations in demand and output from other power plants.

Sometimes, the accumulated capacity from the baseload-, intermittent-, and intermediate power plants aren't enough to cover for the demand. In the Nordic system these circumstances typically appear during cold winter days when the demand is high and only a small share of the wind- and solar power plants are in operation.

At these occasions the highly responsive peaking power plants are activated. The peaking power plants are typically expensive to operate, nevertheless very flexible and a great access for the electricity system. The investment cost is relatively low if compared to many other power plants. Common peaking power plants are combustion turbines or various energy storages (Kaplan, 2008, p. 3). The Swedish electricity system uses oil- and natural gas fired power plants to back up the system in extreme cases.

TRANSMISSION OF ELECTRICITY

The Swedish electricity grid is very strong compared to numerous of national grids in other parts of the world. A law has been implemented which basically prohibits power shortages longer than 24 h (Wallnerström, 2017, p. 3). The Swedish authority SvK is responsible for the transmission capacity and stability of the grid. A future energy system based on intermittent energy sources implies challenges for the grid operators. Two central parameters for maintaining a stable grid are an increased transmission capacity and a continued delivery of ancillary services by power producers in the system.

TRANSMISSION CAPACITY WITHIN SWEDEN

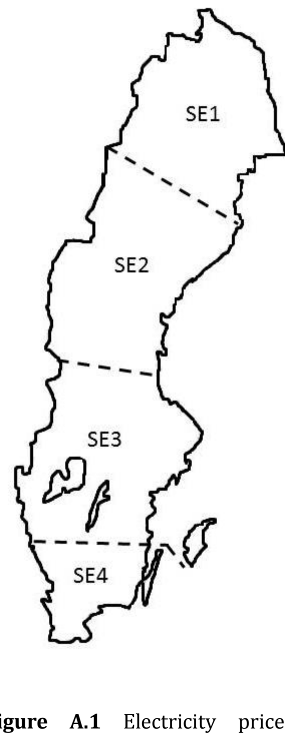

Figure A.1 Electricity price areas of Sweden. Picture based on information from SvK (Svenska kraftnät, 2015, p. 18).

Sweden is divided into four electricity price areas called SE1, SE2, SE3 and SE4. In general, more electricity is produced than consumed in the north and more electricity is consumed than produced in the south. Therefore, it is very important to preserve sufficient transmission capacity throughout the country. The different price areas are visualized in Figure A.1. As observed in Figure A.1, the electricity price area for SE3 and SE4 stretches through the southern part of Sweden. The upper cut towards SE2 is located slightly north of Gävle. Hence, the region contains some of the biggest cities of Sweden which generates a relatively high demand for electricity. According to historical data from Nord Pool, the electricity demand of SE3 and SE4 constitutes nearly 82 % of the total electricity demand of Sweden.

All Swedish nuclear power plants are located in SE3. Therefore, the deficit in power generation can be anticipated to increase as the technical lifetime is reached for the nuclear reactors. The risk of insufficient power supply in SE3 and SE4 is estimated to be 400 hours per year by 2040, and the gap needs to be compensated for by flexible electricity generation or consumption (Svenska kraftnät, 2017, p. 25). In addition most wind power plants are planned to be installed in the north of Sweden (Svenska kraftnät, 2017, p. 12). SvK therefore plans to increase the transmission capacity between SE2 and SE3 to at least 7800 MW in 2025, compared to the 7000 MW available today. The construction work also includes restoration of existing lines. The transmission capacities from SE3 and SE4 to neighboring countries are also planned to expanded (Svenska kraftnät, 2015, p. 64).

Ancillary services

Ancillary services is a term used for functions that supports the functionality and stability of the grid, such as frequency control, voltage control and reactive power supply (Klimstra, 2014, p. 185). It is hard to rely on a supply of ancillary services from intermittent power production, since ancillary services only can be supplied when a plant is in operation. Since the installations of intermittent power plants are expected to increase, SvK needs to make sure that the ancillary services can be supplied also in the future. This can be done by modifications in the grid code, monetary compensation to certain actors or market-based solutions (Svenska kraftnät, 2017, pp. 15, 34).

A vital feature among the ancillary services is to maintain sufficient inertia in the system to counteract changes in frequency. If the electricity generated in the system can't match the demand, the generating units will respond by lowering the rotational speed causing the frequency to drop. The frequency need to be constant around 50 Hz for the Swedish grid to operate ordinarily. Electricity can't be stored by itself, and therefore it's good for the system to have energy stored in some sort of rotating mass. The inertia from the rotating mass creates a buffer, which provides enough time for turbines and engines to switch output when needed (Klimstra, 2014, p. 30). Short term deviations in frequency can also be normalized by systems with a fast response. One example is control systems which are installed in wind power plants or battery parks (and by doing so, the plants provide what sometimes is called synthetic inertia). If the frequency isn't quickly stabilized, the system will collapse and result in a black out (Svenska kraftnät, 2017, p. 34).

The inertia in the Swedish electricity system is mainly provided by heavy turbines from nuclear- and hydro power plants. Hence, a major reduction of nuclear plants means less inertia in the system. This makes the grid more vulnerable, unstable and sensitive for disruptions. There is currently no compensation for contributing with inertia to the system in the Swedish electricity system. A discussion whether producers should be able to profit from this type of ancillary service is ongoing. Countries such as USA and Ireland have already involved an element of this in their market model to promote the stability of the grid (Löfstedt, 2016).

Other ancillary services are voltage stability and reactive power supply. Loads and power lines consume reactive power. A grid which supplies the need of reactive power in all parts of the grid is in a state of voltage stability. To avoid voltage instability, it is preferable to produce reactive power close to where it is consumed. Synchronous generators and power electronic equipment can supply reactive power to the grid. Loads usually consume reactive power. Nuclear power plants constitute a large share of the synchronous generators in southern Sweden. Due to the decommissioning of the nuclear power plants, investments in power electronic equipment need to be made. A market-based solution is not preferable for these ancillary services, since the locations of the installations are of importance (Svenska kraftnät, 2017, pp. 33-34).

ELECTRICITY MARKETS

Sweden is part of the Nordic electricity market Nord Pool. The Baltic States are also a part of this market. The main actors on Nord Pool are power producers, power consumers and daily traders. Nord Pool is basically divided into a day-ahead market and an intraday market. Most of the trading occurs on the day ahead market. At the day-ahead market the aggregated bids are summarized for both the demand side and supply side for every hour. The minimum bid that a power producer typically submits is to cover for its marginal cost of electricity production (unless high cycling costs need to be avoided etc.). Based upon the bids, a reference electricity price is set without any congestion restrictions for the whole system along with specific area prices. Insufficient transmission capacity in-between regions will result in different electricity prices in different regions (Nord Pool, 2018).

As a supplement, the intraday market balances the actual demand and supply to ensure a maintained energy balance. Providers with additional capacity or flexible production/load bid on the balancing market. The time slots for contributing with flexibility on the intraday market are 15 minutes, 30 minutes, 60 minutes or block products (Nord Pool, 2018).

As obtained in the section above, a market for additional ancillary services such as frequency stabilization could also be considered.

SWEDISH ENERGY POLICIES

Sweden wants to have a robust, environmental friendly and economic viable energy system. Five big political parties of the Swedish government have decided upon an energy agreement. The goal of the agreement is for Sweden to achieve a 100 % renewable power production by 2040 and a fossil free nation by 2045. A framework has been set up and will be updated to ensure a smooth transition (Regeringskansliet, 2016).

Sweden is also, in association with Norway, part of the Electricity certificate system. The scheme aims to increase the share of renewable energy production in the two countries. In 2012 a common certificate market was introduced. The certificates are given for renewable power production in either country, the certificates can also be traded on the market. The target is to increase the level of aggregated electricity generated from renewable energy sources by 28.4 TWh between 2012 to 2020. Moreover, Sweden has a prolonged target of increasing the amount with additional 18 TWh till 2030 (Energimyndigheten, 2017).

Some regulations in the energy system are less comprehensively considered. Swedish regulations currently disadvantage energy storage solutions, even though energy storages have great potential of contributing with stability to the grid. A fee (electricity consumption tax) is withdrawn when a storage facility feeds electricity from the grid and another fee (electricity production tax) is withdrawn when the storage facility feeds electricity back to the grid, even though the electricity is neither produced nor consumed. In addition, the plant owner must pay full grid charges. Discussions are currently held to whether the dual tax principal should be removed (Karlsson, 2017).

Another topic frequently discussed among energy policies is the development of the contracts for back-up reserves. Contracts are currently made between SvK and a number of power producers and consumers. The power producers commit to always be available for power production or to reduce their power output if necessary, in return they receive financial compensation. Thus, the total electricity system receives higher energy security. The agreement expires in 2025 and a market-based solution is envisioned thereafter. Nevertheless, the electricity system is going through big transitions and it can be questioned if the power system is ready for a market-based solution. The back-up reserves that currently ensure power generation during the extreme peak hours are very sensitive investments since they only operate a few hours per year or sporadically not at all. The electricity system will receive problems if nobody is willing to take the investments necessary or reduce their power output when needed, without the contracts to justify it financially (Svenska kraftnät, 2015, p. 27).

Appendix B: Modelling assumptions and data

For the time interval 2026-2035, the estimated cost data for 2030 were used etc. If data for the time interval 2036-2045 or 2046-2055 were missing in the data catalogues, data for the previous time interval as close as possible to the time interval in question were used.

Demand

The electricity demand profile, which describes the variation in electricity demand throughout a year, and the heat demand profile were taken from ENTSO-E's statistics for Sweden from year 2012.

The annual Swedish electricity demand was set to 143 TWh for time interval 2026-2035 and 160 TWh for the time intervals 2036-2045 and 2046-2055. These assumptions are similar to the reference scenarios presented by SvK and the Swedish Energy agency (Svenska kraftnät, 2015, pp. 22-23).

The annual Swedish heat demand and the market share for district heating were assumed to remain the same as today for all modelled time intervals. The total Swedish demand of district heating which was implemented in the model is 48 TWh/year (SCB statistics from year 2014). These assumptions were based on a prognosis by Värmemarknad Sverige (2014, pp. 7-8).

Southern Sweden's share of the total electricity consumption in Sweden was set to 0.82. The same share was used for the heat consumption.

INCLUDED TECHNOLOGIES

The technologies which were included in the model are shown in Table B.1.

Table B.1 Included technologies in the model.

Technology	Abbreviation	Category
Biogas-fired power plant	BG_CCGT	Thermal power plant
Biogas-fired peaking power plant	BG_peak	Peaking power plant
Biogas-fired peaking power plant at Ringhals	BG_peak_R	Peaking power plant
Biomass-fired combined heat and power plant	Bio_CHP	Thermal power plant, CHP
Biomass-fired power plant	Bio_cond	Thermal power plant
Biomass gasification plant	GF	Thermal power plant
Electric boiler	EB	Heating plant
Flow battery	Bat_flow	Peaking power plant
Flow battery at Ringhals	Bat_flow_R	Peaking power plant
Hard coal-fired combined heat and power plant	H_CHP	Thermal power plant, CHP
Hard coal-fired power plant	H_cond	Thermal power plant
Heat pump	HP	Heating plant
Hydrogen electrolyzer	Efuel	
Hydrogen electrolyzer at Ringhals	Efuel_R	
Hydrogen fuel cell	FC	Peaking power plant
Hydrogen fuel cell at Ringhals	FC_R	Peaking power plant
Hydrogen lined rock cavern	H2LRC	
Hydrogen tank storage	H2tank	
Hydrogen tank storage at Ringhals	H2tank_R	
Hydropower plant	Hydro	
Lignite-fired power plant	B_cond	Thermal power plant
Lithium-ion battery	Li_ion	Peaking power plant
Lithium-ion battery at Ringhals	Li_ion_R	Peaking power plant
Natural gas-fired combined heat and power plant	NG_CHP	Thermal power plant, CHP
Natural gas-fired power plant	NG_CCGT	Thermal power plant
Natural gas-fired turbine	NG_peak	Peaking power plant
Nuclear power plant	Nuclear	Thermal power plant
Offshore wind power plant	WOFF	Variable renewable energy source (VRE)
Onshore wind power plant	WON	VRE
Optimized tilt solar photovoltaics power plant	PV_opt	VRE
Sodium-sulfur battery	NaS	Peaking power plant
Sodium-sulfur battery at Ringhals	NaS_R	Peaking power plant
Two-axis solar photovoltaics power plant	PV_two	VRE
Waste-fired combined heat and power plant	Wa_CHP	Thermal power plant, CHP

EXISTING POWER PLANTS IN SE3 AND SE4

Data regarding existing power plants in southern Sweden were taken from Chalmers' database of European power plants. The database contains information such as installed capacity, commissioning year and type of fuel used. A summary of the data which were implemented in the model can be found in Table B.2. The nuclear reactors which will be taken out of service before 2026 are not included in the summary.

Table B.2 Existing capacities of SE3 and SE4 implemented in the model.

Technology	**Commissioning year**	**Installed capacity [GW]**
Bio_CHP	2010	0,51
Bio_CHP	2000	0,29
Bio_CHP	1990	0,10
Bio_CHP	1980	0,54
Bio_CHP	1970	0,46
Bio_CHP	1960	0,18
Bio_cond	2010	0,07
Bio_cond	1990	0,93
Bio_cond	1980	0,14
Bio_cond	1970	0,13
Bio_cond	1960	0,08
H_CHP	1990	0,14
H_CHP	1980	0,03
H_CHP	1960	0,08
H_cond	1970	0,19
H_cond	1960	0,02
Hydro	1960	2,9
NG_CCGT	2010	0,02
NG_CCGT	1990	0,07
NG_CCGT	1970	0,09
NG_CHP	2010	0,70
NG_CHP	2000	0,07
NG_CHP	1990	0,04
NG_CHP	1970	0,04
NG_CHP	1960	0,04
NG_peak	2010	0,02
NG_peak	1990	0,07
NG_peak	1970	0,09
Nuclear	1980	6,7
PV_opt	2010	0,01
Wa_CHP	2010	0,17
Wa_CHP	2000	0,13
Wa_CHP	1990	0,05
Wa_CHP	1970	0,04
WOFF	2010	0,08
WOFF	2000	0,02
WON	2010	2,5
WON	2000	0,36

THERMAL PLANTS

No production stops for maintenance of thermal plants were implemented in the model. However, a possibility to perform maintenance of individual plants occurs during summer when many thermal plants are shut down due to a decreased electricity demand.

It was assumed that the installed capacity of waste-fired CHPs in southern Sweden will remain at the same level as today during all modelled time intervals. The expected increase of waste related to an increasing population is assumed to be equal to the amount of waste that is avoided by society's effort to reduce waste.

A possibility to change power level within one hour was implemented for nuclear power plants. Swedish nuclear power plants are today mainly operated at maximum power level. This model implementation aims to represent a more flexible operation pattern, which is expected for nuclear power plants in the future electricity system. However, a more realistic implementation of this flexible operation pattern would be to restrict each nuclear power plant to only change power level a few times per day, but this was not possible to implement since it would be a non-linear constraint. The consequences of the chosen model implementation will therefore be analyzed in appendix D. No investment in nuclear power was allowed in the modelled region during the modelled time intervals.

The gasifier uses 1.39 units of biomass to produce 1 unit biogas. For each produced unit of biogas, 0.017 units of electricity are exported from the plant (Alamina et al, 2016).

The cost data for thermal plants were taken from World Energy Outlook 2016 (International energy agency, 2018). The costs related to cycling of thermal plants were taken from National Renewable Energy Laboratory (NREL) (2012). All data for nuclear power plants were given by Alexander Lindqvist, technical nuclear advisor at Vattenfall, except the investment-, fixed O&M- and start-up costs which were taken from the same sources as for other thermal plants. The data set given by Lindqvist was assumed to be valid for all Swedish nuclear reactors. A summary of costs and properties for the implemented thermal power plants can be obtained in Table B.3 and Table B.4.

Table B.3 A summary of costs for the implemented thermal power plants in the model.

Technology	Investment cost [EUR/kW] alt [EUR/kWh storage]	Variable O&M cost [EUR/MWh]	Fixed O&M cost [EUR/kW] alt [EUR/kWh storage]	Start-up cost [EUR/MW]	Part load cost [EUR/MW deviating from rated power]
B_cond	1980	2.1	50	56.9	1.9
BG_CCGT	900	0.8	18	42.9	0.5
Bio_cond[a]	2070	2.1	56	56.9	1.9
Bio_CHP[b]	3240	2.1	105	56.9	1.9
GF[c]	1780	1.9	29.1	-	-
H_cond	1980	2.1	50	56.9	1.9
H_CHP	1980	2.1	50	56.9	1.9
Nuclear	5400	8.0	85	400	5
NG_CCGT	900	0.8	18	42.9	0.5
NG_CHP	1170	0.7	30	50.6	1.5
NG_peak	450	0.8	15	20.2	0.5
Wa_CHP[d]	6480	2.1	230	56.9	1.9

a. Investment cost for Bio_cond during the time interval 2036-2045: 1980 EUR/kW
Investment cost for Bio_cond during the time interval 2046-2055: 1935 EUR/kW
b. Investment cost for Bio_CHP during the time interval 2036-2045: 3150 EUR/kW
Investment cost for Bio_CHP during the time interval 2046-2055: 3105 EUR/kW
c. Investment cost for GF during the time interval 2046-2055: 1670 EUR/kW
Var O&M cost in 2046-2050: 1.8 EUR/MWh. Fixed O&M cost in 2046-2055: 26.8 EUR/kW
d. Investment cost for Wa_CHP during the time interval 2036-2045: 6300 EUR/kW
Investment cost for Wa_CHP during the time interval 2046-2055: 6210 EUR/k

Table B.4 A summary of the properties for the implemented thermal power plants in the model.

Technology	Efficiency	Minimum load level	Start-up time
B_cond	0.47	0.35	12
BG_CCGT	0.62	0.2	6
Bio_cond	0.41	0.35	12
Bio_CHP	0.30	0.35	12
GF	12	0.35	12
H_cond	0.48	0.35	12
H_CHP	0.36	0.35	12
Nuclear	0.39	0.6	24
NG_CCGT	0.62	0.2	6
NG_CHP	0.49	0.32	12
NG_peak	0.37	0.5	0
Wa_CHP	0.16	0.35	12

WIND POWER

A wind power plant's performance is dependent on its location. The number of wind power plants which can be built in high performance areas is limited. The model can therefore invest in 12 different onshore wind power categories, categorized by the annual average number of full load hours. A potential for each onshore wind power category was implemented as a limitation in the model. The specific power was assumed to be constant for all wind turbine categories.

Each wind turbine was assumed to occupy an area of 7*7 rotor diameters. Data regarding available land area in SE3 and SE4 was taken from a Geographical Information System analysis made by Nilsson and Unger (2014). It was assumed that 5 % of all available land in SE3 and SE4 can be used for wind power plants.

The majority of all planned offshore wind power plants in Sweden is planned to be located in SE3 and SE4. It was therefore assumed that the maximum level of installed offshore wind power plants in the modelled region is equal to the planned offshore windpower capacity in Sweden (slightly above 7 GW) (Sweco Energuide AB, 2017, pp. 21-22).

SOLAR POWER

There are two different categories of crystalline silicon PVs implemented in the model. One category has a fixed tilt (PV_opt). The other category is called two-axis solar photovoltaics power plant (PV_two) and is mounted on an arm which enables it to rotate as well as changing tilt during the day. The PV type which is mounted on an arm is more expensive but has a higher number of full load hours during a year. The efficiency of a solar cell is assumed to be constant throughout its entire lifetime.

COMMON DATA SOURCES FOR WIND- AND SOLAR POWER

The cost data for wind- and solar power plants were taken from WEO 2016 (International energy agency, 2018).

The regional wind- and solar profiles (number of full load hours produced each modelled hour) for different categories of wind and solar power plants were constructed by re-analysis of data from year 2012, collected by Nasa in the Modern Era Retrospective-analysis for Research and Applications (MERRA) project. The regional wind resource (wind velocity each modelled hour) for year 2012 was taken from the European Reanalysis-interim database. The wind profile for the best onshore wind power category the model chooses to invest in was used to represent the wind profile for the offshore wind power plants in the region.

The investment cost of wind- and solar power plants from WEO 2016 (International energy agency, 2018) were needed to be adjusted to be able to include the technologies in the model. The investment cost data for these technologies need to be implemented as in equation 1.

$$Total\ investment\ cost = investment\ cost * e^{learn * mod\ year} \quad \text{(Equation 1)}$$

Constant learn rates were set for these technologies. The investment cost from WEO 2016 was inserted as total investment cost in equation 1. The investment cost was then calculated for all modelled time intervals. The value of the investment cost which was implemented in the model is the average value of the calculated investment cost for all modelled years. The implemented investment cost can then be used to recalculate the total investment cost for all modelled years. The set learn rates and the resulting investment costs are shown in Table B.5.

Table B.5 Learn rates and investment costs for wind- and solar power plants.

Technology	Learn rate	Inv cost 2026-2035 [EUR/kW]	Inv cost 2036-2045 [EUR/kW]	Inv cost 2046-2055 [EUR/kW]
Wind onshore	0,4	1560	1500	1442
Wind offshore	2,0	2868	2350	1926
PV_two	2,1	Not relevant	974	786
PV_opt	2,5	Not relevant	690	538

HYDRO POWER

The annual import of electricity from northern Sweden (electricity price areas SE1 and SE2) was assumed to, in energy terms, be limited by the access of water which can pass the hydropower turbines in that region during a hydrologic year minus the total electricity consumption in northern Sweden during the same year.

The total water availability in all Swedish dams was set to 65 TWh, which represents a normal hydrological year. The regional shares were based on statistics from Svensk energi (2014, p. 29), and set to 0.78 for northern Sweden (SE1, SE2) and 0.22 for southern Sweden (SE3, SE4). The hydropower turbines were assumed to be operated at a level between 10-90 % of their rated capacity. The efficiency of the hydropower turbines was assumed to be 90 %.

The import of electricity every modelled timestep was limited by available capacity in the transmission lines from SE2 to SE3. The static transmission capacity between SE2 and SE3 was assumed to be 7800 MW for all modelled time intervals. This assumption is in line with the system operator SvK's plan to increase the transmission capacity between the two electricity price areas until 2025 (Svenska kraftnät, 2017).

The cost data for hydropower plants were taken from WEO 2016 (International energy agency, 2018) and can be found in Table B.6. No investment in hydropower was allowed in the modelled region during the modelled time intervals.

Table B.6 Costs data for the hydropower plants.

Technology	Investment cost [EUR/kW]	Variable O&M cost [EUR/MWh]	Fixed O&M cost [EUR/kW]	Start-up cost [EUR/MW]
Hydro	2385	1.0	60	0

HEAT PUMP & ELECTRIC BOILER

The efficiency of the electric boiler was assumed to be 95 % and the coefficient of performance (COP) for the heat pump was assumed to be 4. An industrial scale of the heat pump was assumed. The cost data for the heat pump and the electric boiler were taken from WEO 2016 (International energy agency, 2018) and can be found in Table B.7.

Table B.7 Cost data for electric boilers and heat pumps.

Technology	Investment cost [EUR/kW]	Variable O&M cost [EUR/MWh]	Fixed O&M cost [EUR/kW]	Start-up cost [EUR/MW]
EB	55	0.8	1.1	0
HP[a]	491	2.1	4.0	0

a. Investment cost for HP during the time interval 2036-2045: 438 EUR/kW
Investment cost for HP during the time interval 2036-2045: 386 EUR/kW

FUELS

It was assumed that thermal plants don't change fuel type during their lifetime. No fossil CO_2 emissions from power plants in the region were allowed during the modelled time intervals. An exception was implemented for waste-fired plants. Carbon capture and storage technologies were not included in the model.

The biomass price was set to 30 EUR/MWh during all modelled time intervals. This assumption was based on the business as usual case in the study for Swedish forest federation by Pöyry (2016, p. 50). The price was implemented as fixed during a modelled time interval, independently on the demand of biomass.

The biogas that was suggested to be consumed in the region was assumed to be produced regionally in gasifiers. By not allowing trade of biogas with other regions and limiting the biogas production to gasification, there is a possibility that the cost of biogas is overestimated in the model. But since the available amount of substrate for anaerobic production of biogas is more limited than forest residues and more difficult to predict, one can argue that the assumption which is implemented in the model is to be preferred.

THE VALUE OF THE CONNECTION POINT AT RINGHALS

The estimated value of the connection point at Ringhals was based on a cost estimation of a new one, using cost data from Agency for the Cooperation of Energy Regulators (ACER) (2015) and the Swedish energy markets inspectorate (2015). The average cost of a European switchyard was in the investigation by ACER assessed to be 42.6 kEUR/kV. The switchyard at Ringhals is connected to the 400 kV grid. The cost of an overhead line (24 kV) from the peaking power plant to the switchyard was also included in the cost estimation of the connection point at Ringhals. The cost of the overhead line is 0.391 MSEK/km according to EI's reference price list. The estimated distance between the peaking power plant and the switchyard was 500 m. The total cost of a new connection point would be the sum of the cost of the switchyard and the overhead line, 17.1 MEUR. By using the assumption that the available static transmission capacity is about 2000 MW, the value of the connection point was expressed as 8.5 EUR/kW installed peaking capacity. The cost of an investment in a peaking power plant at Ringhals was therefore reduced with 8.5 EUR/kW compared to if the same investment was done somewhere else in the modelled region.

Miscellaneous data

The maximum cost of electricity production was set to 2000 EUR/MWh. If the marginal cost of electricity production would exceed this value, the model is allowed to cut load at a cost of 2000 EUR/MWh. The maximum amount of allowed load shedding for every timestep (3h) was set to 6 GW. In a real world setting, the load shedding could be avoided by initiating e.g. a power reserve.

The interest rate was set to 5 % and the economic lifetime was assumed to be equal to the technical lifetime. Inflation was not considered in the calculations.

Appendix C: THE DEVELOPMENT OF THE ENERGY SYSTEM IN SOUTHERN SWEDEN

The model results for the whole region (SE3+SE4) will be presented in this appendix. An overview is presented initially. The results from all studied cases are then presented in detail.

OVERVIEW OF THE RESULTS

Large investments are made to ensure that the electricity production can cover for the demand during every timestep in the modelled time intervals. The model chooses to invest in the combination of power plants which gives the lowest total system cost. An overview of the first year of investment in different technologies for the studied cases is given in Table C.1.

Table C.1 First year of investment for various technologies in the studied cases.

	BC	BC+DSM	BC+H2	BC+trade	BC+comb
Onshore wind power plant (WON)	2026	2026	2026	2026	2026
Offshore wind power plant (WOFF)	2036	2036	2036	2046	2046
Optimized tilt solar photovoltaics power plant (PV_opt)	2046	2046	2046	2036	2036
Biogas-fired power plant, closed cycle (BG_CCGT)	2036	2036	2026	-	-
Total amount of biogas-fired peaking power plants in region (TotBG_peak)	2026	2036	2036	2036	-
Hydrogen fuel cell (FC)	2046	2046	2036	-	2036

Table C.1 can be used to describe the development of the electrical system in the different cases. The model starts to invest in onshore wind power plants in all studied cases. The investments in onshore wind power plants are followed by investments in offshore wind power plants. When the land areas with best wind resources get occupied, it is economical beneficial to pay higher investment and O&M costs to utilize the good wind resources offshore, and by doing so getting more full load hours per installed wind turbine. Solar PVs with an optimal tilt are installed in the time interval 2036-2045 for the cases with trade implemented and in time interval 2046-2055 for the remaining cases. The earlier investment in solar PVs seen in cases with implemented trade is motivated by the possibility to export electricity produced during summer days to neighboring countries. The large investments in wind power and solar power seen in time interval 2046-2055 are initiated due to the decommissioning of all nuclear plants in the modelled region.

Biogas-fired CCGTs act as intermediate plants in the studied cases without implemented trade and follow the load curve as a complement to the available hydropower. The biogas-fired CCGT has a much higher efficiency than the biomass-fired peaking power plant, which explains why the model chooses the CCGTs for this type of operation even though the CCGT has higher investment- and O&M costs than the peaking power plant. Since the biogas-fired CCGT has 6 hours of starting time, there is a need of peaking power plants which can handle quicker variations in load when the hydro power capacity is insufficient. The model starts to invest in biogas-fired peaking power plants in all studied cases except the ones with an implemented hydrogen demand, where fuel cells instead are installed initially.

BASE CASE

The installed capacities for the Base case are visualized in Figure C.1 for the three modelled time intervals.

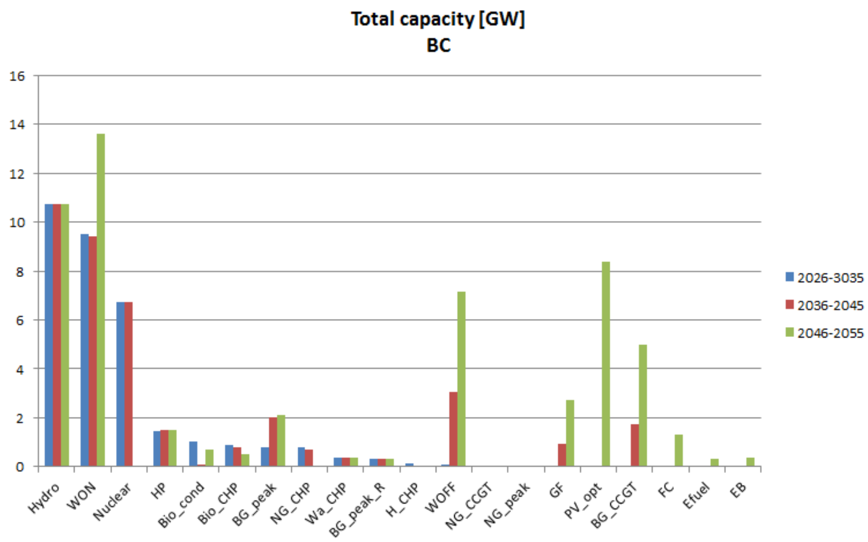

Figure C.1 Installed capacities in region SE3 and SE4 in the Base case.

The total capacity of hydropower is constant at 10.7 GW throughout all modelled time intervals (2026-2055) and includes both capacity for electricity production in the region and imported electricity from price area SE1 and SE2.

The Base case is modelled without trade and DSM. Hence, the system is relatively inflexible and the need of peaking power plants is obvious. The total installed capacity of biogas-fired peaking power plants is 1.1 GW in 2026-2035, 2.3 GW in 2036-2045 and 2.4 GW in 2046-2055 of which 0.3 GW is installed at Ringhals for all modelled time intervals. Hence, the upper limit of 300 MW installed capacity of the biogas-fired peaking power plant at Ringhals is maximized at all times. The model prioritizes to place the biogas-fired peaking power plant at the Ringhals site due to the reduced investment cost derived from the already existing infrastructure at this site. Thereafter, the model fills up with the remaining peaking power plants in the rest of SE3 and SE4. In time interval 2046-2055, an additional need of peaking power is required, and a hydrogen peaking power plant is suggested in the region. The suggested capacity of electrolyzers (0.3 GW) is smaller than the capacity of fuel cells (1.3 GW) since hydrogen can be produced in electrolyzers during a longer time period and then be stored in the hydrogen storage until the fuel cells are operated. The majority of the produced hydrogen is stored in a lined rock cavern with a capacity of 38 GWh. A smaller hydrogen storage in form of tanks with higher withdrawal rate is also installed to manage quicker variations in load.

Figure C.2 shows the generated electricity for the different technologies in the Base case. Load shedding and the electricity generation from gasifiers are neglected in the Figure C.2 due to the small contributions.

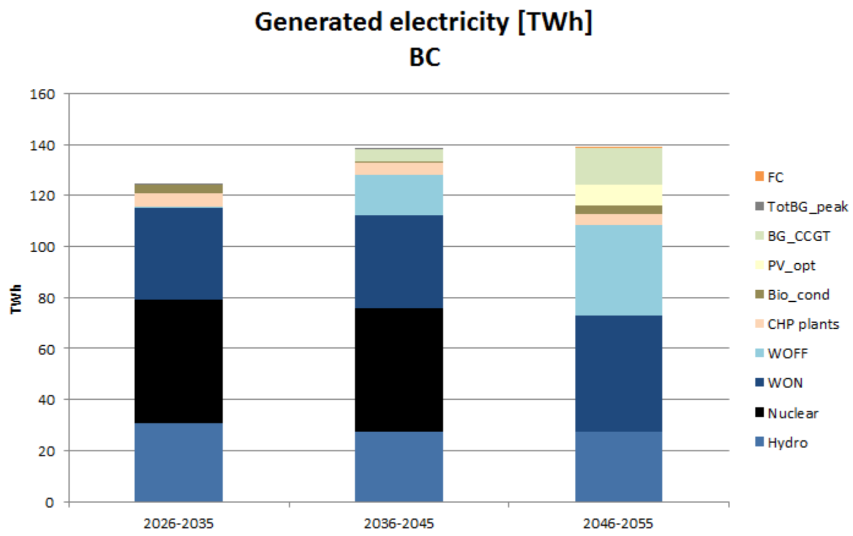

Figure C.2 The aggregated annual electricity generated by respective technology in the Base case for the three modelled time intervals.

Figure C.3 visualizes how much electricity various power plants are generating in order to satisfy the demand. The figure is plotted for the Base case in time interval 2026-2035.

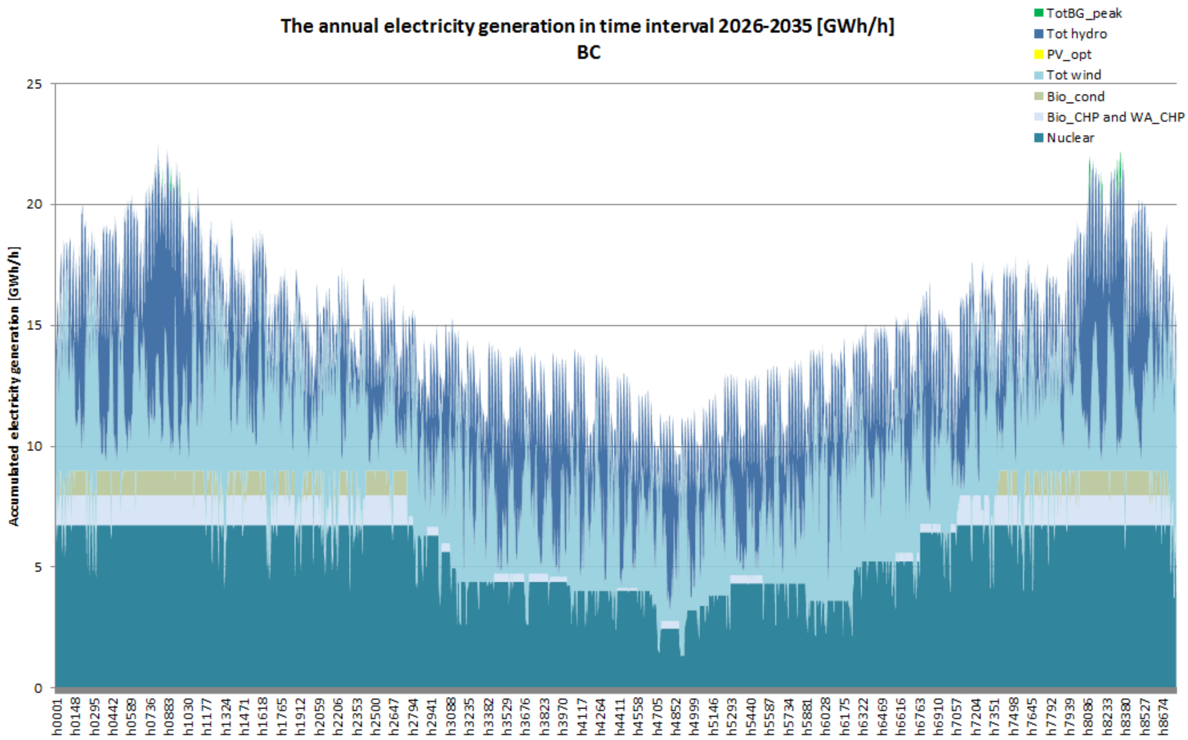

Figure C.3 The annual electricity generation in the BC during time interval 2026-2035.

CASE: DSM

The installed capacities for the Base case with implemented demand side management are visualized in Figure C.4 for the three modelled time intervals.

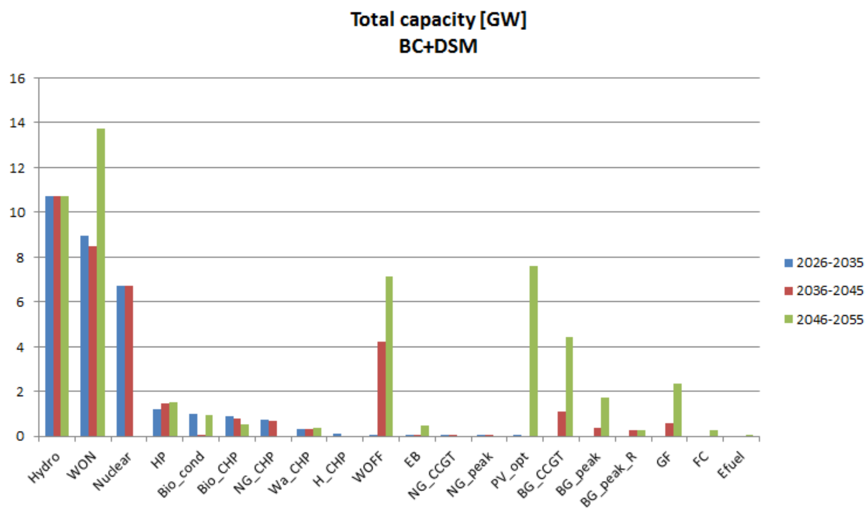

Figure C.4 Installed capacities in region SE3 and SE4 in the DSM case.

The model chooses to invest in the same technologies as in the Base case. The implementation of DSM enables for the model to reduce peaks in the demand load curve, which leads to smaller investments in solar power plants, biogas-fired CCGTs and peaking power plants compared to the Base case. Both the biogas-fired peaking power plants and hydrogen peaking power plants are still suggested to be installed by the model, but the total capacities are lowered. The capacity of the bio-fired peaking power plants is reduced by 1.7 GW in time interval 2036-2045 and by 0.4 GW in time interval 2046-2055 compared to the Base case. The capacity of the fuel cells is reduced from 1.3 to 0.3 GW in time interval 2046-2055. The hydro power plants of Sweden along with DSM provide enough flexibility in the system during the first time interval. Therefore, the installation of biogas-fired peaking power plants is not suggested until the second time interval (2036-2045). An investment in a 300 MW biogas-fired peaking power plant is suggested to be installed at Ringhals during the second time interval.

CASE: HYDROGEN DEMAND

The installed capacities in the Base case with an implemented hydrogen demand are visualized in Figure C.5 for the three modelled time intervals.

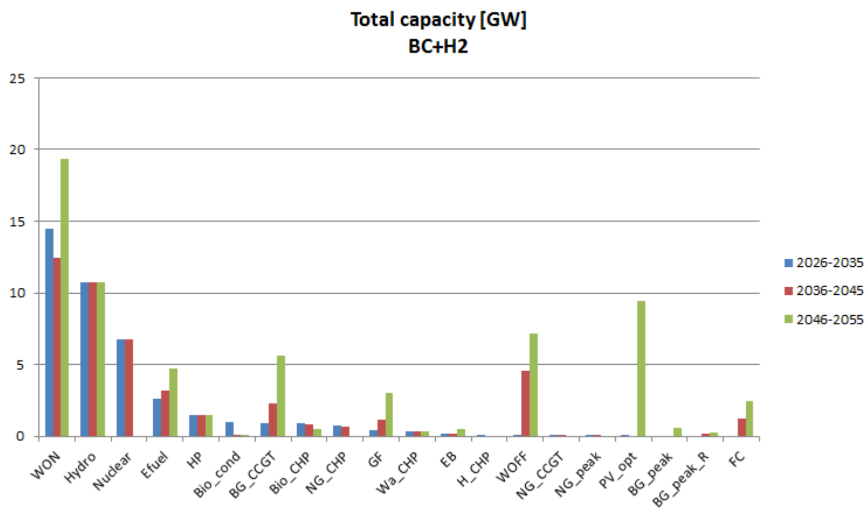

Figure C.5 Installed capacities in region SE3 and SE4 in the Hydrogen demand case.

In comparison to the Base case, an overall increase of total installed capacity is necessary in order to satisfy the additional electricity demand caused by the required hydrogen production. Large investments are made in wind- and solar power plants. The system favors producing hydrogen during low electricity price hours to satisfy the electrolyzers' consumption of electricity to a minimum cost.

A large share of the generated electricity from wind- and solar power plants is used to produce hydrogen. The remaining system relies on a larger share of Biogas-fired power plant (BG_CCGT), and a lower share of peaking power plants compared to the Base case. The Base case with introduced hydrogen demand can therefore be seen as a more robust system with less dependencies on peaking power plants. Peaking power plants are not required by the system at all for the first-time interval 2026-2035. In 2036-2045, the operation of fuel cells is introduced. The fuel cell technology is chosen instead of the biogas-fired peaking power plant to lower the total system cost by taking advantage of the electrolyzers and the storages that the system already is forced to invest in due to the demand of hydrogen. Consequently, the fuel cells are not placed at the Ringhals site.

The need of biogas-fired peaking power plants is completely removed for time interval 2026-2035. Nevertheless, a need of Tot_BG_peak can still be identified during a few hours in the winters of the next time interval (2036-2045) and the model invests in a 186 MW biogas-fired peaking power plant at Ringhals. The installed capacity at Ringhals is increased to 300 MW for the last time interval (2046-2055). An additional investment of 0.6 GW Tot_BG_peak in southern Sweden is suggested by the model for the last time interval.

CASE: TRADE

The installed capacities for Base case with implemented trade are visualized in Figure C.6 for all modelled time intervals.

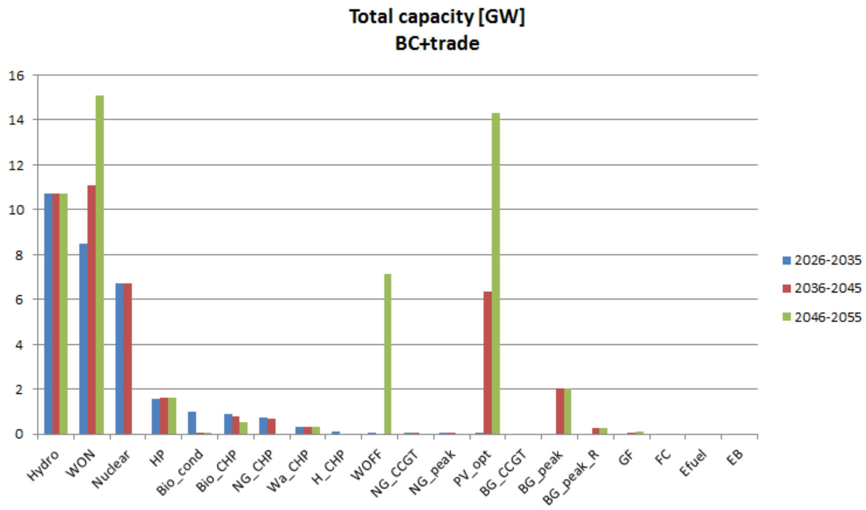

Figure C.6 Installed capacities in region SE3 and SE4 in the Trade case.

In comparison to the Base case, the investments in intermediate and peaking power plants are decreased. At the same time, big investments are made in solar PVs and wind power plants.

The model again indicates an eliminated need of peaking power plants during the first time interval 2026-2035. The peaks can instead be covered by importing electricity from other regions. Norway, with an electricity system based on flexible hydropower, is the prime exporter to SE3 and SE4. A need of peaking power plants can still be identified for time intervals 2036-2045 and 2046-2055. Similar to the Base case, investments in biogas-fired peaking power plants are suggested by the model. The investments in hydrogen peaking power plants visible in the Base case for time interval 2046-2055 are not needed in this case.

The implementation of trade in the model can be discussed. There is a risk that the large investment in PV_opt is a consequence of the implemented constraint saying that the annual net import of electricity should be zero. If the model exports a lot of electricity during summertime, it can import a lot of electricity during wintertime. Since the neighboring countries' need of electricity only is indicated by a price, it is hard to tell if the export during summertime is exaggerated. An exaggerated export during summertime could lead to an overestimation of the possibility to import electricity during wintertime. If the import during wintertime would be reduced, a need of CCGTs could arise also in this case. The need of peaking power could also be increased. The implementation of trade is also discussed in appendix E.

Figure C.7 shows the actual electricity generation for different technologies in the Base case with implemented possibility to trade with neighboring countries. The share of imported/exported electricity stands for roughly 20% of the total electricity supply in SE3 and SE4.

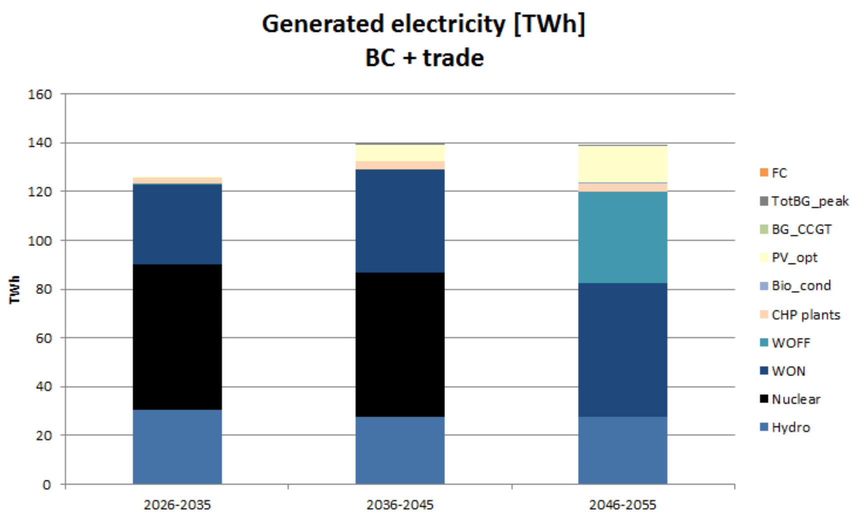

Figure C.7 The aggregated annual electricity generated by respective technology in the Trade case for the three modelled time intervals.

Despite the ability to import electricity, the model still suggests a 300 MW biogas-fired peaking power plant at Ringhals (2036-2045) in order to minimize the total system cost. The peaking power plants also function as an exporter during electricity deficit in other countries.

CASE: COMBINATION

The combined impact of DSM, trade and a hydrogen demand is studied in this case. The installed capacities for the Combination case are visualized in Figure C.8 for all modelled time intervals.

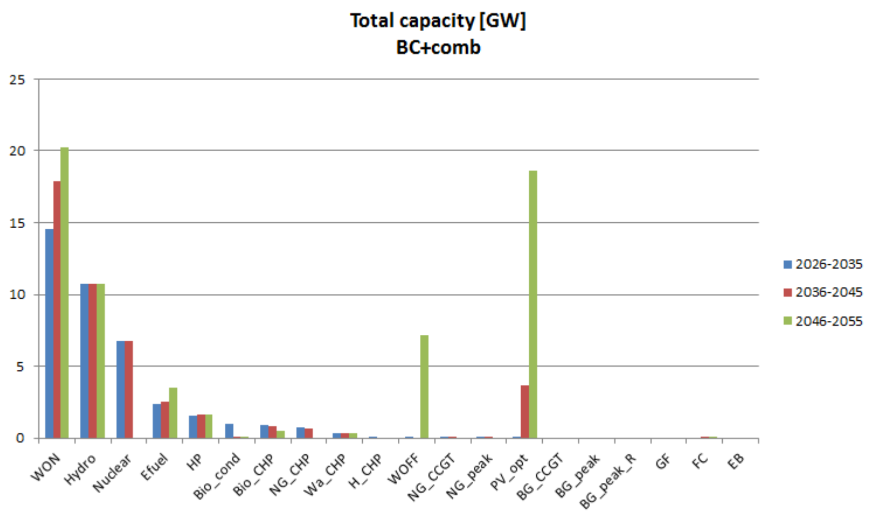

Figure C.8 Installed capacities in region SE3 and SE4 in the Combination case.

Large investments in wind- and solar power plants are suggested for the Combination case compared to the Base case. These investments are motivated by the continuous need of hydrogen and thus access to electricity at low cost. Similar tendencies are seen in the Hydrogen case, but the level of investments is more extreme for the Combination case. The installed capacities of electrolyzers and hydrogen storages are reduced compared to the Hydrogen case since more low electricity price hours are available in the Combination case.

By combining all studied flexibility providers, the need of peaking power plants and biogas-fired CCGTs is almost eliminated for all modelled years. The model only suggests an installation of 38 MW of fuel cells during the last two intervals, 2036-2055. However, sensitivity analyses show that small changes in DSM level or available transmission capacity between SE2 and SE3 have large effects on the results. As in the Hydrogen case, fuel cells are not suggested to be installed at Ringhals. From a system's perspective, it is economical beneficial to locate the fuel cells close to the electrolyzers and the hydrogen storages which are already in operation somewhere in the modelled region.

The electricity generation from different power plants in the original Combination case can be obtained in Figure C.9.

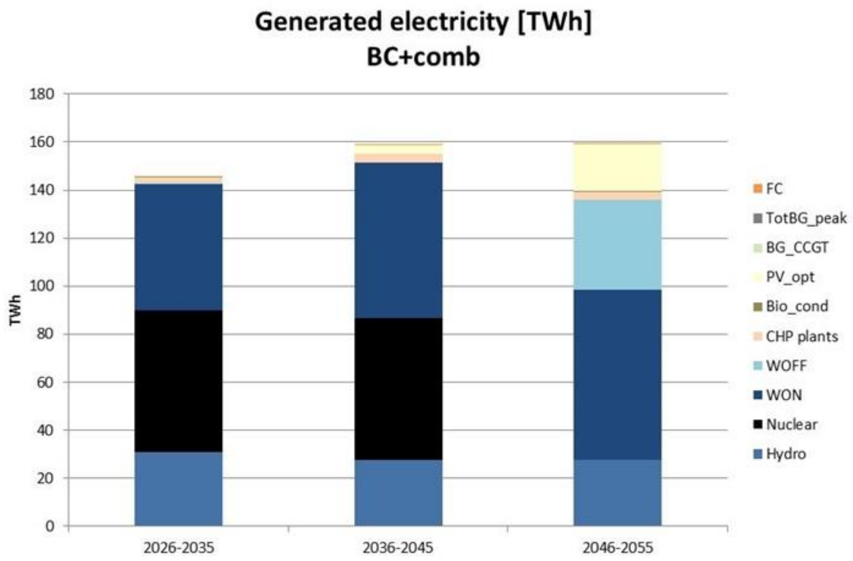

Figure C.9 The aggregated annual electricity generated by respective technology in the Combination case for the three modelled time intervals.

APPENDIX D: SENSITIVITY ANALYSIS PERFORMED ON THE BASE CASE

The results of the sensitivity analysis performed on the Base case are presented in the following sections.

WET & DRY YEARS

The inflow of water to the hydropower dams vary. Some years are considered as dry while other years are considered as wet. The energy stored in the Swedish dams during a normal hydrological year is 65 TWh. A normal hydrological year is implemented in the Base case. Investment decisions are typically based on a normal hydrological year. But since the energy balance in every timestep needs to be kept even for dry and wet years, this sensitivity analysis was performed. To investigate the need of peaking power during dry and wet years, all capacities installed in the Base case were kept fixed except the peaking power technologies. The results are shown in Figure D.1.

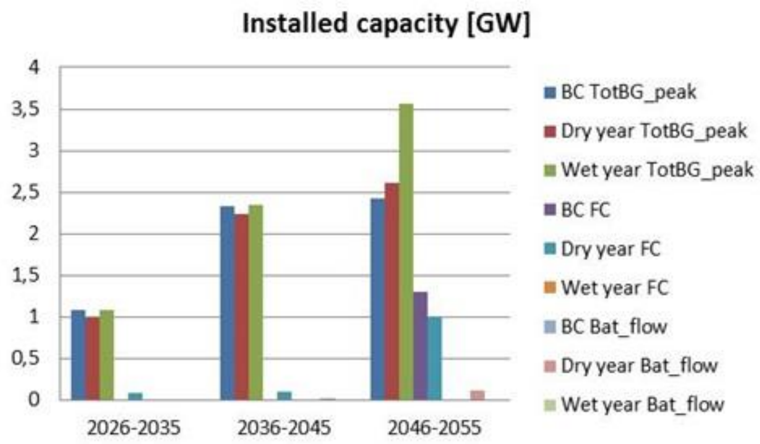

Figure D.1 Installed capacity for peaking power plants under the influence of wet and dry hydrological years.

The dry years investigated in this study had 56 TWh of water stored in the Swedish dams. The results show that a decreased potential for hydropower only has a minor impact on the suggested capacity of TotBG_peak to be installed. A small investment in FC is suggested in the time intervals 2026-2035 and 2036-2045, leading to a small reduction in installed capacity of TotBG_peak. In time interval 2046-2055, a small part of the installed capacity FC is suggested to be redistributed to TotBG_peak and Bat_flow. These results show that the model would like to compensate the decreased water availability with small investments in other kinds of energy storage. But since a dry year is a rare event, it would not be possible to cover for the additional costs for these investments.

The wet years investigated in this study had 91 TWh of water stored in the Swedish dams. The model suggests an increase in installed capacity of TotBG_peak as a complement to the increased potential for hydropower. No investments in fuel cells are suggested for these years. The biogas-fired peaking power plants are operated during wintertime. The fuel cells are mainly operated during summertime in the Base case (but also together with TotBG_peak during peak hours wintertime). An increased electricity production from hydropower during summertime in the wet case replaces the electricity production from the fuel cells in the Base case. Since the total amount of peaking power is approximately the same, the investment of TotBG_peak is suggested to be increased in time interval 2046-2055 corresponding to the installed capacity of FC in the Base case.

The suggested changes in investments indicate that TotBG_peak, from a system perspective, also during dry and wet year is the most economical beneficial peaking power technology.

When comparing the TotBG_peak's share of the total electricity production, it is clear that most electricity is generated by TotBG_peak in the dry case. TotBG_peak's share of the total electricity production in the wet case is similar to the share in the Base case, except during the time interval 2046-2055 when it is slightly higher in the wet case than in the Base case. These results indicate increased revenues for BG_peak during both dry and wet years compared to the Base case.

OPERATION OF NUCLEAR

Changing the minimum load of nuclear power plants from 60 % to 100 % has a very small impact on the results. The installed capacity of biogas-fired peaking power plants is increased with 100 MW in time interval 2036-2045, but no change is seen in the technology's share of the total electricity generation.

If the decommissioning year of nuclear reactor F1 is changed to 2025 (the installed capacity nuclear power is reduced to 5.8 GW during 2026-2035 and 2036-2045), the loss of power output is covered by investments in WON, BG_CCGT and TotBG_peak. BG_CCGT takes a role similar to the one F1 had during wintertime. The difference is that BG_CCGT is more flexible than a nuclear power plant, so if there is a lot of power generated from variable energy resources during one hour the BG_CCGT is shut down.

If the decommissioning of R3 and R4 is postponed until after 2055, the investments in WON and BG_CCGT are reduced during this time interval compared to the Base case. The need of TotBG_peak remains the same, but the model suggests that a lower capacity of FC should be installed.

The changes in need of peaking power which occur when the decommissioning year of the reactors mentioned above is changed are presented in Figure D.2 and Figure D.3.

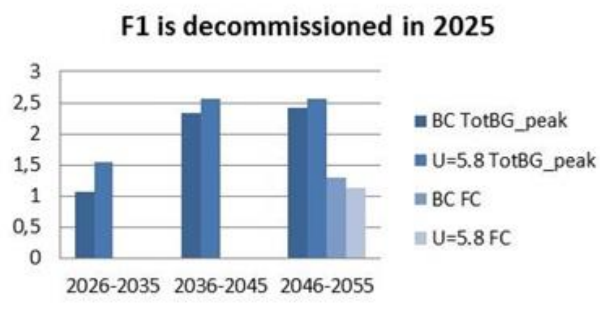

Figure D.2 The installed capacity of peaking power plants if F1 is decommissioned in 2025 (earlier than planned).

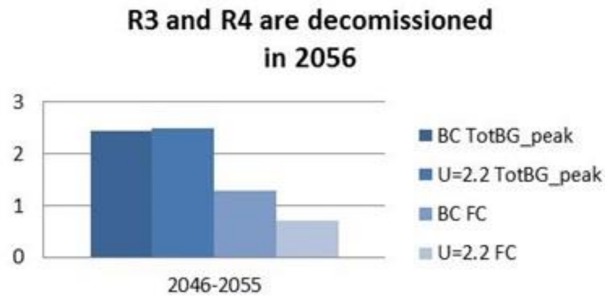

Figure D.3 The installed capacity of peaking power plants if R3 and R4 are decommissioned in 2056 (later than planned).

This sensitivity analysis shows that the model's suggestion to invest in a biogas-fired peaking power plant at Ringhals is quite robost with respect to changes in installed capacity of nuclear power.

BIOMASS PRICE

If the biomass price is increased, the investments in biomass-fired and biogas-fired plants are reduced. In time interval 2026-2035, a reduction of installed capacity of BG_peak and an increase in installed capacity of wind power can be seen. In time interval 2046-2055, a change in investment from biogas-fired CCGT to biogas-fired peaking powers plant can be seen initially. The model starts to reduce the installed capacity of biogas-fired CCGT since it is the biofuel-fired plant with most full load hours during a year, and thus high fuel consumption. When the biomass price is further increased, the model mainly suggests investments in onshore wind power plants and fuel cells. A summary of the biggest changes in installed capacity of the different technologies is shown in Figure D.4 (2026-2035) and Figure D.5 (2046-2055). One can notice that the installed capacity of biogas-fired peaking power plants remains at a quite high level even when the biomass price is doubled (0.6 GW in time interval 2026-2035 and 1.6 GW in time interval 2046-2055).

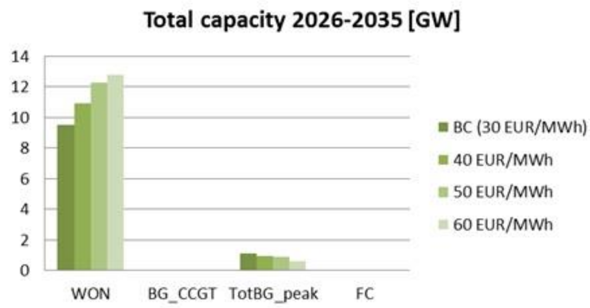

Figure D.4 Total installed capacity of WON, BG_CCGT, BG_peak and FC for time interval 2026-2035 for varied biomass price.

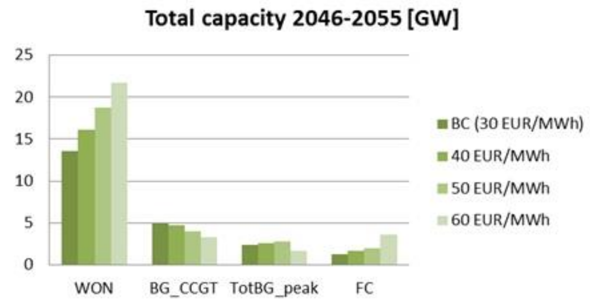

Figure D.5 Total installed capacity of WON, BG_CCGT, BG_peak and FC for time interval 2046-2055 for varied biomass price.

INVESTMENT COST FOR HYDROGEN PEAKING POWER PLANT AND BATTERIES

The goal with this sensitivity analysis was to investigate if the modelling results would differ much if the investment cost of any of the technologies that still are in the demonstrating phase is significantly reduced compared to the data implemented in the model for the Base case (see section 5.2 for detailed information regarding the investment cost for different technologies).

If the investment cost of the hydrogen peaking power plant (electolyzer, hydrogen storage and fuel cell) is reduced by 10%, there is no big impact on the modelling results of the Base case. But if the investment cost is reduced by 30%, it has an impact on the installed capacity TotBG_peak and FC for time intervals 2036-2045 and 2046-2055. Large investments in fuel cells can be seen (total installed capacity 2036-2045 is suggested to be 1.5 GW and total installed capacity in time interval 2046-2055 is suggested to be 3.8 GW), but the model still suggests 0.9 GW TotBG_peak to be installed in the second time interval (2036-2045). The installed capacity of TotBG_peak remains at the same level for the next time interval 2046-2055.

The investment costs of sodium-sulfur and lithium-ion batteries can be reduced by 50% without an impact on the modelling results for the Base case. Considering that the Base case is a quite inflexible system with a big need of peaking power, this sensitivity analysis show that these technologies probably won't be profitable as peaking power plants in southern Sweden during the modelled years.

If the investment cost of the vanadium redox flow battery technology is reduced by 25 %, it has an impact on the modelling results for the Base case in time interval 2046-2055. 0.35 GW/7.7 GWh of flow batteries are suggested to be installed in the modelled region. Since the technology is discounted at Ringhals, it would be economical beneficial from a system's perspective to install as much as possible at Ringhals. The introduction of flow batteries leads to a redistribution of 100 MW peaking power capacity from TotBG_peak to FC compared to the Base case.

Appendix E: Modelling methodology discussion

The methodology described in sections 5.1-5.3 will be discussed in this appendix. This discussion acts as a complement to the discussion in chapter 7.

Estimation of the need of peaking power and the revenues of peaking power plants

In all modelling work, it is important to be aware of the limitations of models. Models used for energy systems modelling usually lack the possibility to include power flow. These analyses are typically performed in other types of models. In this project, the power flow has an impact on the available transmission capacities between Ringhals and the rest of the modelled region, and between the modelled region and its neighboring regions. The available transmission capacities can also be affected by the possible increase in import of reactive power, as a consequence of the decommissioning of nuclear power plants in the modelled region. If SvK doesn't get permission to build new power lines between SE2 and SE3 the available transmission capacity will be affected even further. Due to the mentioned reasons, there is a risk that the available transmission capacity is overestimated in the model. The need of peaking power in the modelled region could therefore be underestimated.

This model has an implemented perfect foresight. In addition, all plants are implemented with 100 % availability. These implementations make it possible for the model to operate all installed plants in an optimal way throughout the modelled year. Since this cannot be done in reality, these implementations can contribute to an underestimation of the need of peaking power. For instance if one nuclear reactor is tripped during a winter day with high electricity demand. Even though the operation of hydropower is maximized, the need of peaking power would probably be greater than the estimated need by the model which assumes that all reactors are available.

It is important to be aware of that the chosen time resolution of 3 hours has an impact on the estimated need of peaking power. Since the model only consider every third hour, hours with a need of peaking power could be missed. On the other hand, there is a risk that the duration of the need of peaking power is exaggerated for some hours. If the model identifies one hour with a need of peaking power, the following two which not are included in the model automatically get the same need of peaking power even though the need of peaking power only lasts for one hour in a model with higher time resolution. However, this time resolution was considered satisfactory for this project.

While studying peaking power plants, the maximum cost of electricity production also has an impact on the plants' revenues. The maximum cost of electricity production was set to 2000 EUR/MWh, but Nord Pool allows electricity prices up to 3000 EUR/MWh on the day-ahead market (Nord Pool, 2018). This could lead to higher revenues for a peaking power plant than what could be expected based on the modelling results. But a well-functioning market would make sure that the maximum limit of the electricity price is avoided.

Selected model resolution and modelling approach

Since the aim was to investigate the need of peaking power, a model with high time resolution was chosen instead of model with a high spatial resolution. A model with a bigger geographical scope (like the ELIN/EPOD package which is described in appendix B) has limitations in time resolution. In addition, the One node model has a reasonable size and level of complexity to be used in the framework of a master's thesis.

The used modelling approach, starting with a base case and gradually adding flexibility providers, was selected to ease the analysis of the results and to make the results more useful as a basis for future work. Compared to just study different fixed scenarios, this approach made it easier to identify factors with a big impact on the need of peaking power. Especially in combination with the sensitivity analyses made. When only studying different fixed scenarios, it can be hard to generalize the results. Since it is hard to predict the future, there is a risk that the development of the energy system in the region heads another direction than the chosen scenarios. It is hopefully easier to build on the conclusions made from this study in future work.

IMPLEMENTED FLEXIBILITY PROVIDERS

The need of peaking power is affected by the number of future flexibility providers and their impact on the electricity system. Only a few of them could be implemented in the model. The implemented flexibility providers in the studied cases entail simplifications that affect the results.

Cases with DSM implemented allow for 20% of the demand, corresponding to the main part of the households' electricity consumption, to be moved up to six hours. This may be a generous number, but with today's digitalization development it is not an unrealistic scenario. It can also be argued that the industry likewise has a possibility of shifting their electricity demand in time, which strengthens the possibility of achieving a DSM level of 20%. On the other hand, the DSM is implemented at no cost in the model, which can be questioned. Someone needs to pay for the technical development and the installations that are needed to realize DSM at such a big scale. But, it is possible that the majority of the cost will be covered by customers who have an incentive to reduce their electricity costs. An implementation of DSM at such a large scale is therefore dependent on households' willingness to sacrifice a part of their privacy. The willingness to change behavior can also vary in time.

While observing the cases with implemented trade it's important to be aware of the inability of the studied region SE3 and SE4 to set the electricity price on the market. Such an implementation would make the model very heavy and complex. Sufficient results can still be obtained in order to analyze the trends of having trade as an option. It was assumed that electricity can be imported to the modelled region whenever the electricity price is lower in a neighboring country. The assumption doesn't always match the circumstances of a real world setting. The lack of power output from intermittent energy sources often correlate with neighboring countries' intermittent power production. Hence, multiple countries sometimes need to import electricity simultaneously, which can be difficult for the exporting countries to deliver. Present implementation of trade in the model can therefore lead to an underestimation of peaking power. Similarly, the implemented export in the model can promote larger investments in peaking power plants.

For cases with an implemented hydrogen demand, hydrogen storage is of big importance. There are two different storage alternatives implemented in the model. The LRC alternative is normally used to store big volumes of hydrogen, but no minimum storage volume constraint was implemented in the model. Since the other storage alternative (H2tank) is more costly, one need to be aware of that there is a risk that the cost of a small hydrogen storage is underestimated by the model. Another consequence of the selected way to implement hydrogen storage in the model is that the cost of a large hydrogen LRC storage might be overestimated. The cost of hydrogen storage is expressed per energy unit stored hydrogen. In reality, it is more likely that there is a high cost related to the initial establishment of the storage independently of its size. A lower cost, dependent on the storage volume, is then added to the initial cost. However, the implementation of hydrogen storage in the model is assessed to be satisfactory for an initial investigation like this feasibility study.

POTENTIAL FUTURE FLEXIBILITY PROVIDERS

It is likely that new flexibility providers will be developed which not are considered today. Other flexibility providers are under development and it is unsure how big their impact will have on the electricity system. Two examples are electric vehicles and prosumers. The impact of electric vehicles is dependent on the number of vehicles and how the charging is arranged. An increased electricity demand is considered in this project, but it would also be of interest to investigate the impact of the "vehicle to grid" concept. Prosumers have a possibility to store self-produced electricity and thus decrease their need of electricity from the transmission grid. The size of the energy storages which are installed by the prosumers will have an impact on how the need of peaking power is developed.

THE SELECTION OF DATA

Technology development is hard to assess. The data used for e.g. peaking power technologies should therefore be considered as unsecure. Several of these technologies are still in the demonstrating phase, and there are no installed plants with such large capacities as modelled in this project. But there are still years for development left before the modelled years arrive. Policies are often of great importance to reach a certain stage of development where the economics of scale mechanism is activated. If the policy makers or the market favors one technology, there is a risk that the other peaking power technologies won't be developed to their full potential. Such a development could also cause problems related to limitations in available material resources that are needed for the technology in question.

In addition to the mentioned difficulties related to assessing technology development, there is an inherent inertia in the academic system. When the technology development goes rapidly (relevant for e.g. battery technologies), there is a delay before reliable public data are available in published scientific papers. To make the best out of a difficult situation, most of the data in this project were taken from a few recognized organizations (the Danish energy agency and international energy agency), who update their data regularly. A sensitivity analysis was also made to better understand how cost reductions impact the results (see appendix D).

THE MODELLING OF THE CONNECTION POINT AT RINGHALS

The size of the discount on the investment costs for peaking power plants at Ringhals, motivated by the already exciting connection point to the transmission grid, can also be discussed. The discount is based on the average cost of a new connection point, but it was hard to assess the capacity of an average switchyard to be able to express the discount per installed kW peaking power plant. Since no data was found on the average capacity of a European switchyard, the data for the switchyard at Ringhals was used. The connection point at Ringhals has probably a higher capacity than the average switchyard that is installed in Europe, which would result in an underestimation of the discount in question. If other aspects related to the value of the site are considered, such as a simplified process to get permission to connect electricity production, favorable net tariffs and advantages of scale related to the already existing electricity production at Ringhals, it is possible that the discount should have been bigger. But it is hard to put an economic value on these advantages and they can also change over time. So, a conservative assumption about the discount, only including the avoided costs related to the already existing connection point, was implemented in the model.