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Assessing the potential of hydrogen energy storage in a stand-alone electricity grid

Applying mathematical programming to balance electricity production and consumption. A case study on the Faroe Islands

Halvor Heier & Endre Villa Elnan

Supervisor: Julio C. Góez

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NORWEGIAN SCHOOL OF ECONOMICS

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Halvor Heier

Endre Villa Elnan

Abstract

The increasing adaption of renewable energy sources (RES), with intermittent and non-dispatchable production output, requires an increased effort to continuously balance supply to meet demand in electricity grids. Failing to establish this balance can lead to blackouts. Energy storage technologies can be applied to increase the utilization of RES and maintain a balanced grid. This is especially relevant for stand-alone systems that are unable to import or export electricity. A technology showing great potential in resolving this issue is the production and storage of hydrogen gas (Power-to-Hydrogen, PtH_2) utilizing excess electricity.

This thesis seeks to answer what combinations of production and storage technologies in a stand-alone, multi-energy system (MES), make PtH_2 a cost-effective option to balance production and demand. To do this, a mixed integer linear programming model (MILP) is developed and applied to a case study on the Faroe Islands.

The model objective is defined to minimize lifetime costs of acquiring, installing and operating the system components while continuously satisfying demand. The model optimizes the system based on one year of input data with hourly resolution. Through six distinct scenarios, each containing different combinations of technologies, we create hypothetical environments with unique characteristics to uncover when PtH_2 is a cost-effective method of balancing a stand-alone grid. Three sensitivity analyses are conducted to asses how the cost-effectiveness of PtH_2 is affected by shifting production towards RES.

The results show that PtH_2 can be a cost-effective technology, significantly contributing to reduced lifetime costs of a stand-alone energy system. However, some prerequisites are needed for this to be the case. Specifically, PtH_2 is cost-effective when large hydro power capacities are unavailable and there is a focus on shifting production from diesel generators towards renewable production. In cases where large capacities in hydro power or diesel generation is available, PtH_2 does not prove to reduce total costs of the system.

Keywords – Power-to-Hydrogen, Multi-Energy System, Grid-Balancing, Renewable Energy Sources, Energy Storage, Optimization, Mathematical Programming, MILP

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1 Introduction

Balancing electricity grids is a continuous challenge for grid operators, and this job is becoming more challenging with the introduction of large-scale intermittent production from renewable energy sources (RES). Grid operators can either use dispatchable production or active storage technologies to establish the necessary balance in the grid. Hydrogen production and storage has received increasing attention in the last decade, and has the potential to facilitate grid-balancing and reduce total costs of supplying electricity in a power grid.

The inherent nature of a power grid is that the production must match the demand at all times, otherwise there may be blackouts (Lago et al., 2020). To achieve this balance, grid operators must ensure that the total production from all sources supplying the grid matches the demand. Dispatchable production technologies can be controlled by the grid operator, i.e. their production can be adjusted according to demand. Renewable energy sources such as wind turbines and solar panels are non-dispatchable and provide intermittent production. This means that the production cannot be controlled by the grid operator as it is dependent on the weather, and the production thus varies over time. When increasing the RES penetration in a grid, the problem of balancing the grid becomes more challenging. The production from RES might at some points exceed demand, leading to curtailment of excess electricity. In other periods, RES production might be insufficient to meet demand, and other sources of electricity generation must be applied to balance the grid.

In order to combat the unpredictability and intermittency of RES, avoid large curtailments and balance production and consumption, storage technologies can be valuable. These technologies enable the storage of surplus energy production to be saved for consumption whenever production is insufficient to meet demand. The most common type of energy storage today is pumped hydro storage (PHS) accounting for 95% of global energy storage (World Energy Council, 2020). Other viable candidates are batteries, compressed air, flywheels and thermal energy storage (Chen et al., 2009).

However, an alternative that has become a promising solution to the problem, is the production and storage of hydrogen, PtH_2. According to a report by International Energy

Agency (2019), this technology is one of the leading options for low-cost, long-term electricity storage. We are curious to understand what factors that potentially make PtH_2 a cost-effective technology for grid-balancing, especially when increasing the penetration of RES. Through discussions with Daniel Janzen in the Bergen-based company Greensight, who's focus lie on accelerating the shift towards a green, emission-free future through hydrogen technology solutions, we were intrigued by the concept of a remote community becoming self-sufficient in renewable energy production and grid balancing. A remote or isolated community in this sense is thus reliant on completely balancing their own grid as import and export of energy is not possible through the grid. Such a system can be classified as a stand-alone power system (U.S. Department of Energy, ndc).

An example of such a system is found on the Faroe Islands. Traditionally being dependent on the import of oil to satisfy their energy needs, the community-owned Faroese energy company SEV has launched a target to have a 100% self-sufficient supply of renewable energy by 2030 (SEV, 2020c). This goal seeks to eliminate dispatchable production from fossil-fueled generators, which can increase the potential cost-effectiveness of storage solutions such as PtH_2.

In this thesis we use the Faroe Islands as a case study to assess the potential of PtH_2 for energy storage in a stand-alone power system, and evaluate what characteristics of such a system make PtH_2 a cost-effective technology. Specifically, we seek to answer the following research question:

What characteristics of a stand-alone power system makes hydrogen (PtH_2) a cost-effective storage technology, and how is the cost-effectiveness affected by the shift towards renewable energy?

1.1 Scope

We utilize business analytics and mathematical programming to develop an optimization model that provides a minimum cost system for electricity production and grid-balancing. We propose a model including hydro power, wind, solar and diesel generators, as well as storage through PtH_2, pumped hydro and batteries. We include investment costs (CAPEX) and operational cost (OPEX), as well as re-investments made during the model period of 20 years. The optimization is completed with real data for demand and weather for one year to estimate production and consumption, and optimize the installed capacities in each technology, while costs are estimated over a 20-year lifetime.

The model is applied to the specific case of the Faroe Islands in six main scenarios. The scenarios exclude different technologies from the model, which allows us to analyse what characteristics of a stand-alone system make PtH_2 a cost-effective technology. Furthermore, we analyze the trade-off between increased RES penetration (reduced diesel generation) and increased costs through three sensitivity analyses. This enables us to to evaluate how the attractiveness of PtH_2 is affected by increased RES penetration.

1.2 Structure

Following the introduction, Chapter 2 presents a review of related research and projects. Chapter 3 presents background information for the case study on the Faroe Islands, including their current energy system and weather potential. It then provides an explanation of the technologies included in our analysis. In chapter 4 the methodology and model used for optimization of the system is presented, along with its simplifications and limitations. Chapter 5 contains a detailed description of the input data used in the model, both in terms of the Faroe Island-specific data for demand and weather, as well as technologies with costs, efficiencies and other relevant parameters. In chapter 6 we present the results of our analysis. Chapter 7 provides a discussion of the results and chapter 8 concludes.

2 Literature review

Multiple research studies have considered the balancing of electrical grids, combating curtailment and minimizing the costs of producing electricity, both quantitatively through optimization models and simulations, as well as qualitatively through research and discussion. Significant research has also been conducted on stand-alone power grids, and there has also been conducted specific research on the Faroe Islands' energy system.

Khalid et al. (2016) assess the role of hydrogen energy storage in an integrated energy system with several RES for residential application in Oshawa, Canada. The proposed system is optimized through the online optimization tool Homer Energy (nd) based on the levelized cost of electricity (LCOE) and net present cost (NPC) of the system. Buttler and Spliethoff (2018) provide a basis for a techno-economic analysis of water-based electrolysis concepts for large-scale flexible energy storage and grid-balancing, to give an overview of the current status of water electrolysis. Further, Matute et al. (2019) present a techno-economic MILP model for calculation of optimal dispatch of large-scale multi-MW electrolysis plants, with a focus on alternative hydrogen uses.

From the perspective of grid-balancing and electricity demand uncertainty, Wang et al. (2018) create an optimization model for a power generation expansion in China. The primary focus lay on biomass and nuclear power in a grid-connected power system.

Mavromatidis et al. (2018) present a methodological framework for investigating the effect of uncertainty on the optimal design of distributed energy systems (DES). They do this through uncertainty analyses (UA) and global sensitivity analysis (GSA) in a MILP optimization, applied to a case study in a Swiss urban neighborhood.

Gabrielli et al. (2018a) develop a MILP methodology to optimize the design and operation of multi-energy systems involving seasonal energy storage. They do this through a novel approach that allows optimization with a one-year horizon and hourly resolution, while reducing the complexity of the optimization. They apply and evaluate their methodology on a residential area in Switzerland. From an electrochemical conversion standpoint, Gabrielli et al. (2018b) provide a modeling framework and technology assessment tool to create optimal designs of decentralized integrated multi-energy systems. The optimal level of detail for modeling the technologies is developed through linear approximations to the dynamic behavior of electrolyzers and fuel cells in a MILP framework.

Petkov and Gabrielli (2020) look into PtH_2 as a seasonal energy storage method by analyzing uncertainties for the optimal design of low carbon multi energy systems. They apply a MILP optimization that selects, sizes and operates technologies to satisfy electrical and thermal demands, while minimizing annual costs and carbon emissions. They consider wind, solar, gas boilers, heat pumps, thermal storage, PtH_2 and batteries, but do not consider neither hydro power, nor diesel generators.

2.1 Stand-alone power grids

Several studies investigate power production and grid-balancing in isolated, stand-alone power grids. Ulleberg et al. (2010) evaluate the system performance of a wind-hydrogen hybrid demonstration system at the Norwegian island of Utsira by assessing operational data and applying updated hydrogen energy system modelling tools. The project revealed the system could provide 2-3 days of full energy autonomy for 10 households.

Rahimi et al. (2014) perform a techno-economic analysis of a wind-fuel cell hybrid system on a household scale in a stand-alone area in two cities in Iran that uses curtailment from wind turbines to produce and store hydrogen through electrolysis and high-pressure storage tanks. Shaner et al. (2016) perform a comparative techno-economic analysis of renewable hydrogen production using solar energy in an off-grid and grid-supplemented environment to assess the economics of each technology. Kavadias et al. (2018) develop a model for the optimal sizing of a H_2-system supplied by RES curtailments from wind and solar, as well as diesel-fueled thermal plants, in autonomous grids on nine Greek islands. Jamshidi and Askarzadeh (2019) look into an Iranian application and perform a techno-economic analysis and multi-objective size optimization of an off-grid, hybrid H_2-system.

Rodrigues et al. (2017) through their article aim to determine the most cost-effective energy storage system for excess electricity to deploy on the Portuguese island Terceira, while considering demand and supply constraints. No PtH_2 technology was included. Abdin and Mérida (2019) study how to determine cost-effective configurations and optimal sizing of system components for micro-grid systems. Wind and solar is used for electricity production, PtH_2 technology and batteries are used for energy storage. Tsai et al.

(2019) study how a Philippine offshore island reliant on diesel can optimize the capacity configuration of a hybrid energy system. Neither PtH_2 technology nor hydro power is included. Suresh et al. (2020) examine electrification in rural areas in India through the modelling and optimization of an off-grid hybrid renewable energy system comprised of wind, solar, biomass and biogas.

2.2 Faroe Island specific research

Specific research related to the Faroe Islands on these topics has also been conducted, although none of them has considered the inclusion of PtH_2. Norconsult (2018) conduct a project for the Faroese power provider SEV on how wind, solar and PHS can be exploited to reach the goal of 100% renewable power production on the Faroe Islands. Based on production simulations with real constraints and data on water inflow, wind and solar production, they find that full RES electrification can be accomplished through hydro, wind and solar production, although this includes significant investments in the expansion of hydro power facilities. Furthermore, the results show that if the goal of 100% RES is discarded, more than a quarter (2.95 bNOK) of total investment cost can be reduced, which gives a RES percentage of 92.3%. Similarly, Ea Energy Analyses (2018) also tasked by SEV, study how to find the least-cost option to develop the Faroe Island electricity system into a 100% RES-based system. Using the open-source electricity and heat model Balmorel (2020), with given inputs about cost and performance of alternative technologies, they find the optimal dispatch of the system and point at the least cost investment of new power generation that can fulfil the goal of 100% RES. The model focused especially on how to include the Faroes' hydro power plants, and expansions of these plants, with wind and solar in the power system. Hydro power expansion included investments in additional hydro turbines, expansion of reservoirs and investments in PHS facilities.

We seek to add to this body of research by developing an optimization approach on a case study of the Faroe Islands. We especially seek to minimize the costs of electricity production from both wind, solar, hydro and diesel to understand the attractiveness of PtH_2 compared to pumped hydro storage and batteries in a stand-alone power system. Additionally, we use the model to asses how the attractiveness of PtH_2 is affected by a shift towards increased RES penetration.

3 Background

In this chapter we first present the background relating to the case study of the Faroe Islands. We then proceed with an explanation of how the technical components implemented in the model works.

3.1 The Faroe Islands case study

The Faroe Islands, an autonomous territory within the Kingdom of Denmark, is an archipelago located in the West Nordics, 320 km north-west of Scotland and approximately halfway between Iceland and Norway. The archipelago consists of eighteen islands and is inhabited by 49.000 people (World Bank, 2018). The largest industry and contributor to international trade is fishing, with farmed salmon accounting for 93,7% of total exports and 45% of national GDP (Statistics Faroe Islands, 2020).

Due to its isolated location, lack of connectivity to the European power grid and cold sub-polar oceanic climate (Faroe Islands, 2020), the Faroe Islands have historically relied heavily on imported oil for domestic and industrial heating, electricity generation and transportation. In 2018, the expenses of importing oil accounted to more than 15% of total imports (Statistics Faroe Islands, 2020).

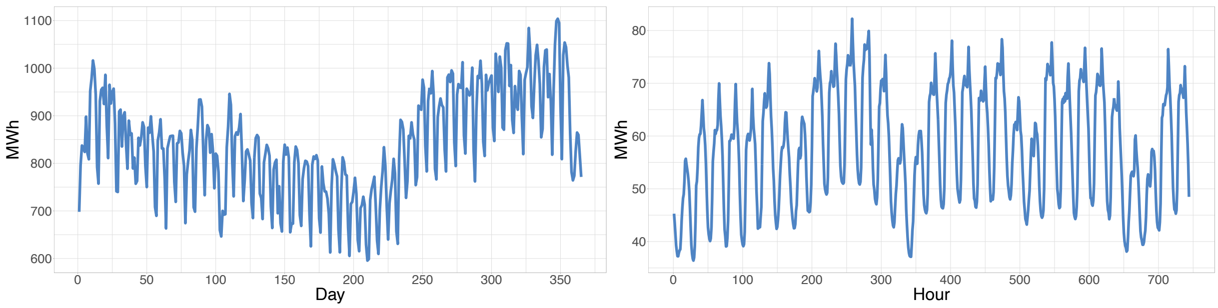
Several studies have been initiated through the 2000's on how to decrease the Faroes' dependency on imported oil resources. The Faroese electricity company SEV in 2014 launched an initiative for 100% RES by 2030, meaning that all electricity generated must come from renewable energy sources (SEV, 2020c).

3.1.1 Electricity demand and grid infrastructure

Demand

Up until the early 1960s, electricity on the Faroe Islands was primarily produced by hydro power. However, hydro alone could not meet the rising demand for electricity, so the remaining demand needed to be covered by imported oil (Katsaprakakis et al., 2018).

Due to the harsh climate, domestic and industrial heating is required throughout the year. The average daily temperature varies between 2-11 degrees Celsius (Meteomatics, 2020d) and almost all heating relies on imported oil. More than 20,000 oil burners are in operation in households, offices and industry buildings all throughout the Faroes. In 2016, 24% of all imported oil was used solely for heating purposes, corresponding to 520 GWh. Meeting this additional demand with heat pumps would require 175 GWh of electricity (Katsaprakakis et al., 2018).



(a) Daily load, 2017 in MWh. **(b)** Hourly load, January 2017 in MWh

Figure 3.1: Load curve data (energy demand)

Figures 3.1a and *3.1b* show the load curves for the main islands of the Faroe Islands for the whole year of 2017, and January 2017, respectively. *3.1a* shows some seasonality throughout the year, with higher demand during autumn and winter compared to summer. It also shows significant weekly seasonality with ~52 peaks and troughs throughout the year. *3.1b* shows a weekly pattern, as well as an intraday seasonality.

Grid infrastructure

The Faroese energy system can be divided into the production facilities and the grid, in which the electricity is transmitted and supplied from the producer to the end user. Since the Faroes are not connected to the European power grid, they have a stand-alone power system. Eleven of the Faroese islands are connected to the main grid, while the southernmost island Suðuroy has its own. This case study focuses on the main grid, and Suðuroy is not included.

The community-owned company SEV is today the only electricity provider on the Faroes. SEV holds the monopoly right to all grid-related activities and is responsible for around 97% of the total electricity produced. The remaining 3% is produced by wind turbines owned by Røkt, but bought by SEV (Ministry of Trade and Industry, 2011).

3.1.2 Electricity production & storage

The subpolar oceanic climate is rich with renewable energy sources, providing the Faroe Islands with a high potential for producing clean electricity.

Production

Wind

Figure 3.2 shows the daily average wind speed on the Faroe Islands, based on data from Meteomatics (2020e). Although wind speeds vary between days, they are relatively stable throughout the year, forming a slight seasonal trend of higher winds in the winter months and lower winds during summer months.

With average wind speeds above 10 m/s per year, the archipelago has world record wind potential (Katsaprakakis et al., 2018). Installing a wind turbine in the Faroes costs relatively little more than installing it elsewhere, while experience and wind measurements show that the electricity generated by Faroese turbines is almost twice that produced on the European continent (Ministry of Trade and Industry, 2011).

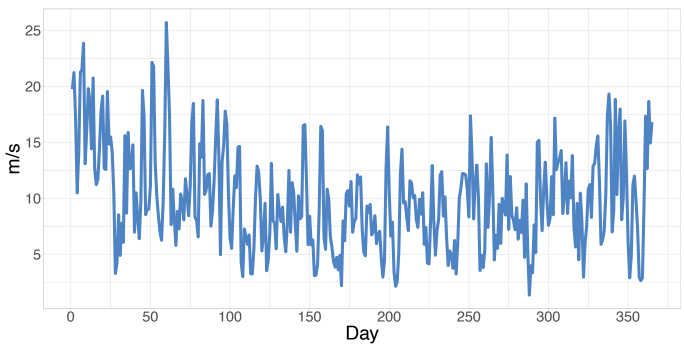


Figure 3.2: Average daily wind speeds on the Faroe Islands

There is however a drawback to the large wind potential. The wind is a result of strong ocean winds that regularly reach extreme speeds, often exceeding the operational limit of wind turbines and can thus not be exploited, leading to unpredictable and intermittent production (Katsaprakakis et al., 2018).

Today, the Faroe Islands have installed a total of 21 wind turbines, of which thirteen 910 kW Enercon 44 turbines are located in the Húsahagi wind farm. This SEV operated farm generates 41 GWh annually (SEV, 2020a), accounting for ~13% of the total electricity demand in 2017. Of the remaining wind turbines, SEV operates five 910 kW Enercon 44 turbines in Neshagi and three Vestas 47 660 kW turbines are operated by Røkt.

Hydro

Another climatic benefit of the archipelago is its high potential in hydro power. With annual rainfalls higher than 3000 mm measured in certain locations, hydro power production has historically been the dominating source of electricity (Katsaprakakis et al., 2018). Utilizing the kinetic energy of flowing water, SEV today has a total of six operational hydro plants with a combined generator capacity of 39 MW that together account for 40% of the company's annual electricity production (SEV, nda).

Solar

As in other northern countries, the solar irradiation in the Faroes is low during the winter months, with a total annual irradiation of 780 kWh/m^2 (Katsaprakakis et al., 2018). Although low during the winter, a solar panel facility can potentially contribute significantly during the summer months. Research has shown that solar panels in the summer have a potential of generating as much as 900 W/kWp[1] (Katsaprakakis et al., 2018). SEV has a small solar project currently under testing to uncover the potential of solar power on the Faroes. The 250 kWp plant will operate during the summer months and is expected to generate approximately 160 MWh per year (SEV, 2019).

Figure 3.3 shows the daily production from 1 MW of installed solar capacity, according to data from Meteomatics (2020c). This shows that 1 MW of solar capacity would generate ~677 MWh annually, corresponding to ~169 MWh per ~250 kW plant, very close to the expectations for the SEV solar project. This indicates that solar energy might be an attractive technology for supporting the power generation at the Faroe Islands.

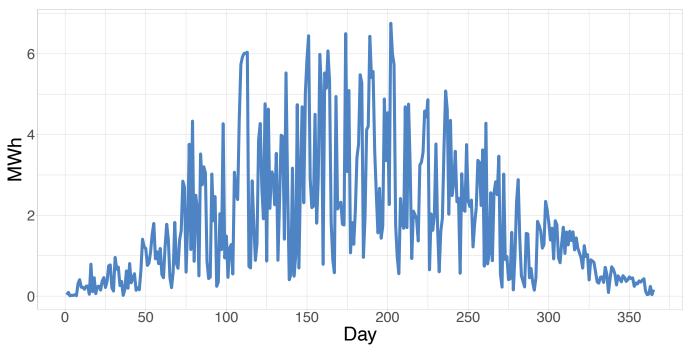


Figure 3.3: Average daily production, 1 MW solar on the Faroe Islands

[1]kWp = kiloWatt peak, peak power of the installation

Diesel generators

Much of the Faroese demand for electricity relies on the import of oil and gas. Today, a total of 13 thermal diesel powered engines are in operation throughout the Faroes. Though varying in size and output, together they provide an estimated 65 MW of generator capacity (SEV, ndb).

Storage

Pumped Hydro Storage

A storage method utilizing hydro power is pumped hydro storage. There is not currently any installed capacity PHS capacity on the Faroe Islands, but hydro reservoirs throughout the archipelago are suitable for accommodating PHS. Research conducted in 2018 investigating these reservoirs did however uncover that neither of the existing reservoir capacities are adequate to cover the requirements for energy storage on the Faroe Islands (Katsaprakakis et al., 2018). Substantial investments for expanding the reservoir capacity are thus needed for this to be a storage option. Although a costly investment, the Faroes have a topography well suited for the construction of new PHS systems or to implement pump capacity in existing reservoirs. This could help meet the storage capacity needed in order to maintain a steady supply of electricity.

Lithium-ion batteries

As a European pioneer, SEV in late 2015 commissioned the first fully commercial li-ion Energy Storage System (ESS) operating in combination with a wind farm. The system is located in the biggest wind farm, the Húsahagi farm on the island of Streymoy. The container-based 2.3 MW battery system helps overcome short-term variations in production due to variable wind speeds. The use of energy storage thus helps to minimize curtailment from wind power in periods of both high wind and low demand (European Association for Storage of Energy, 2018).

3.1.3 Relevance of case study

The Faroe Islands have a climate highly suitable for producing clean electricity through RES. Although SEV has a goal of 100% RES penetration within 2030, solving the problems that arise with increased penetration of intermittent RES production is important to reach the goal.

This presents an interesting opportunity of using the Faroe Islands as a case study to evaluate the attractiveness of PtH_2 technology in terms of cost-efficiency. We utilize demand and weather data from the Faroe Islands in our analysis. We also implement the specific hydro power capacity and proposed PHS expansions on the island. Furthermore, we make adjustments to other available technologies to evaluate the attractiveness of PtH_2 in a broader sense than for the specific case of the Faroe Islands.

3.2 Technical aspects of system components

With the topography and weather potential on the Faroe Islands, we propose a multi-energy system (MES) composed of several sources for producing and storing energy, see system overview in *figure 4.1* in chapter 4.

3.2.1 Production technologies

There are numerous potential sources of energy production available. We focus on the Faroe Islands and assume that the main technologies utilized there are the most relevant for energy production on the Faroe Islands. This includes wind, solar, hydro and diesel generated electricity. SEV is also experimenting with offshore wind, tidal and biomass production. These are currently being tested and introduced in the Faroese energy system, and are excluded from our model.

Wind turbine technology

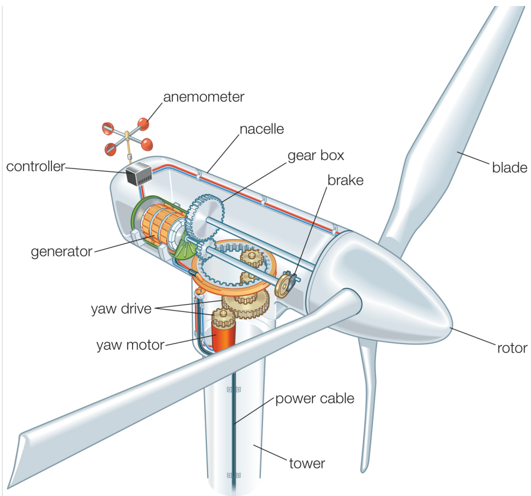


Figure 3.4: Wind turbine, technical illustration

Wind turbines are available in a wide range of sizes and can be installed both on- and off-shore. Common for all wind turbines is that they operate by taking advantage of the kinetic energy in wind to create electricity. According to the U.S. Department of Energy (nda), depicted in *figure 3.4* by Badurek (2020), when the wind blows in front of the turbine, it makes the blades turn around a rotor. The rotor is connected to the body of the turbine by a shaft, which in turn is connected to a gear box that ensures the correct rotational speeds needed to produce electricity. Electricity is produced when the shaft spins a generator.

On the back of the nacelle sits an anemometer that measures the wind speed and transmits the data to the controller. The controller starts up the machine at about 3.5 to 7 m/s, and shuts the machine off at about 24 m/s. These wind speeds are known as a turbine's cut-in and cut-out speeds, respectively. Operation in wind speeds above the cut-out speed can potentially damage the turbine, while speeds below the cut-in speed will not be sufficient to create the rotational speeds necessary to generate electricity. A brake will stop the rotor in emergencies or high wind speeds.

Behind the anemometer sits a wind vane that measures wind direction and can communicate with the yaw drive, which orients the turbine so it faces the wind. The electricity created in the system is sent through cables inside the tower of the turbine and dispatched into the grid (U.S. Department of Energy, nda).

Seeing that the wind electricity production on the Faroe Islands today almost solely originates from onshore Enercon E44 900kW turbines (SEV, 2020b), these are the turbines implemented in our model.

Solar panel technology

A solar panel, depicted in *figure 3.5* by American Chemistry Society (nd), is comprised of several smaller cells, called photovoltaic (PV) cells. Several PV cells linked together create a solar panel (Dhar, 2017). Within each PV cell is a thin semiconductor made from two layers of silicon. Each silicon atom is connected to its neighboring atom by four bonds that keep the electrons in place (Ted-Ed, 2016). This way, no current can flow. One of the two layers contains extra electrons (n-layer), while the other has extra spaces, or "holes", for electrons (p-layer). In the junction of the two layers, the depletion zone, the free electrons in the n-layer can wander freely to the holes in the p-layer. When this happens, the n-layer becomes

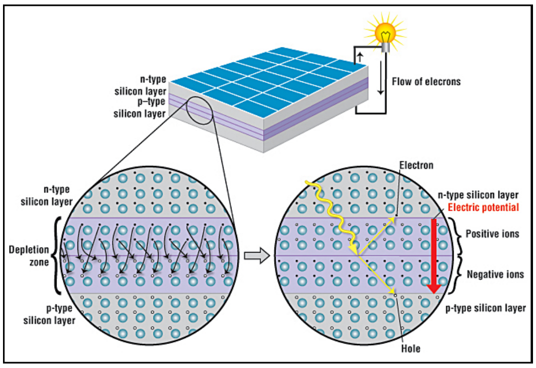


Figure 3.5: Solar panel, technical illustration

negatively charged and the p-layer positively charged (Ted-Ed, 2016).

Solar panels work by allowing photons, which are light particles emitted from the sun, to dislocate electrons from the bond between silicon atoms in the panel (Dhar, 2017). The dislocated electrons leave vacant holes in the n-layer. The electrons and holes are now free to move around inside the cell, but because of the electric field between the layers, the electrons cannot move through the junction. Instead, all mobile electrons on the n-side move trough an external wire to fill the holes on the p-side. Electrons in the wire is electricity which can be utilized. The electrons are the only moving parts in a solar cell, and they all eventually go back to where they came from. Nothing is used up, so solar cells can last for decades (Ted-Ed, 2016).

The electricity generated by solar panels is direct current (DC) electricity. The electricity in power grids is alternating current (AC). The DC electricity thus needs to be transformed into AC using an inverter before being dispatched to the grid (CertainTeed Saint-Gobain, nd).

Diesel generator technology

According to Hananina et al. (2015), a diesel generator is a machine that uses a combination of an electric generator and a diesel engine to produce electricity by burning diesel fuel. The chemical energy in diesel is converted to mechanical energy through combustion. The mechanical energy rotates a crankshaft, which is connected to a rotor covered with copper wires. When the rotor rotates between two polarized magnets, magnetic induction occurs, creating voltage in the wire. The voltage can be used to satisfy electrical demand in the grid.

Hydro power technology

A hydro power plant uses water in motion to generate electricity. There are several types of hydro power plants, but common for all facilities is that they make use of the kinetic power of flowing water to spin a turbine that in turn rotates a generator to produce electricity, which can be dispatched to the grid (U.S. Department of Energy, ndd).

The most common type of hydro plant, and the type currently installed on the Faroes, is the impoundment facility. This facility uses a dam to store water from rivers or inflows in a reservoir. The facility releases water through the generator to produce electricity.

3.2.2 Storage technologies

Energy storage can be accomplished through numerous technologies. According to the World Energy Council (2020), the most common storage method today is pumped hydro storage (PHS) accounting for approximately 95% of global energy storage. Batteries are the second most common type. Energy can be stored in electrical, mechanical, electromechanical, chemical or thermal technologies. There are many important aspects and trade-offs between storage technologies. One aspect is cost, which varies greatly between technologies. Some have high investment costs, others have high operational costs. Furthermore, some technologies require individual conversion and storage capacities, such as PtH_2, while other technologies allow for direct storage, such as in batteries. This impacts the total costs of the storage technology. Another important aspect is efficiency, which defines the share of energy put into storage that can be successfully retrieved and dispatched back into the grid. Furthermore, the storage capacity is important and depends on the intended usage of the storage. Some technologies are intended for short-term balancing of the grid, such as supercapacitors, flywheels and thermal storage. This is generally within-the-hour balancing. Other technologies such as PHS, PtH_2 and compressed air energy storage (CAES) are more relevant for energy storage of larger amounts of energy over longer periods of time.

We are interested in evaluating the attractiveness of PtH_2, and short-term grid-balancing technologies are thus excluded from our analysis. We compare PtH_2 with the most common storage technologies, PHS and li-ion batteries, all of which are further described below.

PtH_2 technology

PtH_2 consists of three main components; an electrolyzer for H_2 production, a H_2 storage method and a fuel cell to convert H_2 to electricity.

<u>Electrolysis technology</u>

There are at least thirteen different methods to which H_2 can be produced, both from fossil fuels and from renewable sources (Kumar and Himabindu, 2019). In the case of green[2] H_2 production, water electrolysis is the most fitting method of production. There are three main technologies using different types of materials: Alkaline, Solid-Oxide and

[2]Green hydrogen is hydrogen produced from RES (World Energy Council, 2019)

Proton Exchange Membrane (PEM) water electrolysis (U.S. Department of Energy, ndb). The advantage of all types of water electrolysis is that it is an established technology with oxygen as the only by-product (Kumar and Himabindu, 2019).

Alkaline electrolysis has been commercially available for many years and is a mature technology (Buttler and Spliethoff, 2018). Solid-Oxide Electrolysis is a technology under development and not yet available on a commercial scale (Schmidt et al., 2017). PEM electrolysis, although expensive because platinum is an important material used, is commercially available and regarded as the most sustainable and environmentally friendly technique (Kumar and Himabindu, 2019). PEM provides the additional advantages of producing a higher rate of H_2, has a more dynamic response, a more compact design and a greater energy efficiency (Maric and Yu, 2018). Furthermore, PEM is preferable over the other types of electrolyzers due to its superior ability to handle variable power inputs (Ulleberg and Hancke, 2020). This aspect is especially important, considering the research question and the intermittent nature of RES. Thus, the PEM electrolyzer technology is considered the most fitting for our proposed system.

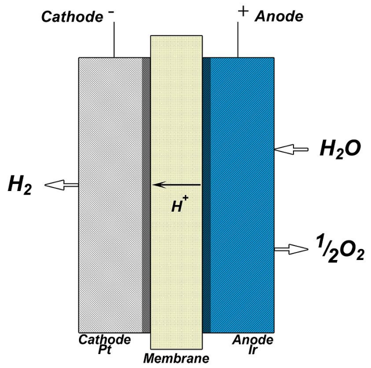


Figure 3.6: PEM electrolyzer, technical illustration

A PEM electrolyzer consists of an anode and a cathode separated by an electrolyte. The electrolyte is a material called polymer electrolyte membrane. *Figure 3.6* by Fritz (nd), shows that when electricity is applied, the anode oxidizes and reacts with the water to produce oxygen, electrons and hydrogen ions (Maric and Yu, 2018). The ions are small enough to pass through the membrane to the cathode, while the electrons exit from the anode to the cathode through an external power circuit, providing the driving force for the reaction. At the cathode, electrons, and protons re-combine to produce H_2 (Kumar and Himabindu, 2019).

Hydrogen storage technology

After H_2 is produced it must be stored before it can be sold or used in a fuel cell. There are three primary ways of storing the gas: as a supercooled liquid, in metal hydride canisters (MH) or as a compressed gas in high-pressure containers.

Although H_2 is denser when liquefied, keeping the gas super-cooled at -253 degrees Celsius is energy inefficient, technically challenging, unsafe and uneconomical (Shanzbaatar, 2007). This means that liquid storage continuously requires a lot of electricity to store the H_2, making it less attractive for long-term storage. Metal hydride canisters prove superior in most ways (Shanzbaatar, 2007). They require less compression, have low risks and deliver high purity, stable pressure hydrogen. However, through e-mail correspondence with professors at NTNU, we learnt that MH canisters are not yet commercially available and can thus not be realistically implemented in our system (Sunde, 2020).

H_2 storage in high-pressure containers is the main storage method today, and is a proven and commercially available technology. The containers have some disadvantages when it comes to security, technological and economical aspects. It requires a compressor to compress the gas, as H_2 produced by electrolyzers is of low pressure (Shanzbaatar, 2007). Through e-mail correspondence with the leader of the Institute for Energy Technology, Øystein Ulleberg, we learnt that for medium to large scale operations as in our scope, H_2 stored in pressurized containers is most suitable (Ulleberg, 2020). We thus implement compressed H_2 in high-pressure containers in our system. Furthermore, H_2 has a lower heating value (LHV) of 0.033 MWh per kg H_2 (Horne and Hole, 2019). This is used to calculate the storage levels from MWh to kg.

Fuel cell technology

A fuel cell is in essence the opposite of an electrolyzer. While an electrolyzer converts electricity to chemical energy, a fuel cell converts the chemical energy in H_2 to electricity through a set of chemical reactions. There are five primary types of fuel cells, classified by the materials used: Proton Exchange Membrane (PEMFC), Phosphoric Acid (PAFC), Alkaline (AFC), Molten Carbonate (MCFC) and Solid Oxide (SOFC) (Williams, 2011).

According to a technical report of large capacity stationary fuel cells by Weidner et al. (2019), each type has benefits and challenges. They all operate in a temperature range of 120-1000 degrees Celsius and have an electrical efficiency rate that varies between 40-60%. PEMFC's are low maintenance, operate in low temperatures, have quick start-up times and are thus suitable as a source of backup power and grid support. However, as platinum is a material used in the cell membrane, PEM fuel cells are quite expensive. AFC's operate in low temperatures, are low-cost relative to other types, but are sensitive to CO_2 in the air or fuel. They also have a low lifetime and require higher maintenance. PAFC's have a higher tolerance for fuel impurities but are expensive and have long start-up times. MCFC's and SOFC's have high efficiency rates and fuel flexibility, but as they operate in high temperatures, they have a higher rate of component breakdown and long start-up times (Weidner et al., 2019). In conclusion, stationary PEM fuel cell technology is chosen as most suitable for our system.

Like its electrolyzer equivalent, a PEM fuel cell consists of an anode, a cathode and a polymer electrolyte membrane. The process of converting H_2 to electricity in a PEM fuel cell starts when H_2 is channeled into the anode side of the cell and oxygen at the cathode side. Here, H_2 undergoes an oxidation reaction that splits the gas into hydrogen ions and electrons. The ions move through the electrolyte and the electrons move through an external circuit, producing a flow of electricity that can be dispatched to the grid. On the cathode side, the electrons and ions combine with the channeled oxygen to produce water as a by-product (Williams, 2011).

Pumped Hydro Storage

A type of hydro plant facility that works as a method of energy storage is pumped hydro storage. Using two reservoirs, the energy is stored by using excess electricity to pump water uphill to a reservoir at a higher elevation. When electricity is needed, water is released to turn a turbine and generate electricity (U.S. Department of Energy, ndd). PHS facilities are able to start up quickly and make rapid adjustments in output and can operate efficiently when used for one hour or several hours (U.S. Geological Survey, nd). In our combined system, PHS technology will be considered, as the Faroese topography is well suited for PHS expansion investments.

Battery technology

Depending on their usage area, batteries are available in a wide range of sizes and capacities. The general classification divides batteries into consumer batteries and industrial batteries (Electronics 360, 2017). While consumer batteries are mass-produced and used for powering rechargeable consumer devices such as cell phones and laptops, industrial-grade batteries are designed to last much longer, store more energy, and are often deployed in extreme environments. Lithium-ion (li-ion) is today considered the leading technology because of its small footprint, low maintenance and long life. Although costly and known for reduced performance at low temperatures, it has the benefit of being light-weight and thus partially portable for installations in remote locations (Battery University, 2019). Additionally, the Faroe Islands have already installed a li-ion battery in one of the existing wind farms to help minimize curtailment in periods of both high wind and low demand (European Association for Storage of Energy, 2018). Li-ion batteries are therefore implemented in our system.

According to BASF (2018), each li-ion battery is comprised of several smaller batteries, called cells. Like in an electrolyzer and a fuel cell, each li-ion cell contains one positive and one negative electrode, called the cathode and anode, respectively. The cathode is made from lithium and the anode from graphite, separated by an electrolyte. When the battery is charged, the cathode oxidizes into lithium ions and electrons. The ions pass through the electrolyte to the anode, where they are stored, while the electrons move through an external circuit. When electricity is needed, the battery is discharged by reversing the process. The ions move from the anode back to the cathode, and the electrons move through the circuit. The electrons in motion here is electrical energy that can be dispatched to the grid.

Nevertheless, rechargeable batteries do not have an infinite lifetime (Ted-Ed, 2015). Over time, repetition of charging and discharging causes imperfections and irregularities in the surface of the electrodes, which prevents them from oxidizing further. The depletion of the electrodes in a battery will over time reduce the battery's capacity, and the battery must be replaced (Ted-Ed, 2015). Additionally, batteries suffer from self-discharge, which is the depletion of the stored energy over time (Panasonic Batteries, nd).

4 Methodology and model

This chapter presents the methodology used to answer our research question. It then explains the characteristics of our decision model, including its sets, variables, parameters, objective and constraints. Finally, we discuss key simplifications made to the model in order to make it relevant in addressing the research question while running efficiently.

4.1 Methodology

The methodology is primarily based on developing a Mixed Integer Linear Programming (MILP) model in AMPL (A Mathematical Programming Language) corresponding to the system shown in *figure 4.1*. The generic model is applied to six distinct scenarios containing different combinations of technologies to analyze how the they affect the optimal system and its associated cost. All scenarios are run both with and without the possibility to invest in PtH_2, enabling an evaluation of PtH_2 and its impact on total costs in each scenario. The second part of the analysis applies various limits on the production from diesel generators as a way of inducing increased RES penetration. This is done by looping the MILP model over a set of diesel generation limits, enabling an analysis of the trade-off between total system costs and increased RES penetration. This is done, firstly, with all technologies available, secondly by excluding PHS and thirdly by excluding hydro power completely. This analysis provides a better opportunity to see how and when PtH_2 is cost-efficient in the shift towards higher RES penetration.

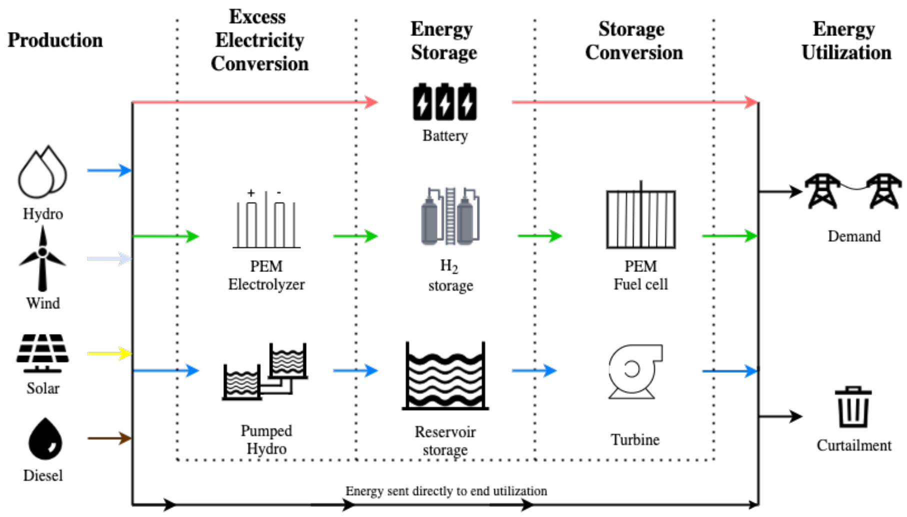


Figure 4.1: Complete system overview

The general outline of the system is depicted through five sections in *figure 4.1*. The first section represents the total electricity production. Wind, solar, diesel and hydro power are electricity generating sources. The second section is a middle step of excess electricity conversion before storage. The third section represents the storage options for excess energy, including hydrogen storage, pumped hydro storage and batteries. Finally, after the fourth section of storage conversion, the fifth section depicts the two options for final energy utilization, either through satisfying demand or curtailing excess electricity that can not be exploited. The arrows in the figure represent the transferring of energy from either production, conversion, storage conversion or end utilization.

4.2 Model formulation

To assess the relevance of PtH_2, we develop a generic MILP model that optimizes a system as shown in *figure 4.1*. The model has an hourly resolution and inputs such as demand, rain, solar and wind production is required for each hour of one year (8760 hours). The model has perfect foresight, meaning that it knows the demand and production from RES for the entire year when solving the model. This implies that the model can operate all dispatchable energy sources optimally, given the weather and demand data for the year. We use data for one year to model the needed capacities for that year and assume that installed capacity is sufficient for the following years. The time-horizon of the model, is set to estimate the present value of operational costs and re-investments, but does not affect the installed capacities or the operations of the technologies throughout the year.

There are some differences between how the included technologies operate, and thus also how they are modeled. This will be shown through the variables, parameters and constraints of the model.

Generally, the model decides the capacities to install in each technology (except hydro) as well as how they are operated throughout the year to satisfy demand and minimize the total costs of the system. Hydro capacity is not decided by the model, as it is given by the currently installed capacity on the Faroe Islands. However, operation of the hydro power plants are decided by the model. Additional parameters, decision variables and constraints are required to model the technologies corresponding to their nature of operation. We present the model in its entirety including explanations wherever we see fit.

4.2.1 Sets

We define three main sets; a set of all components of the system, a set of hours of the year and a set of hydro power plants.

T = *Set of all parts of the system that produce, store or use energy*

= *[wind, solar, electrolyzer, PtH_2, fuel cell, battery, diesel, HPP, grid, curtailment]*

H = *Hours*, H = *[1..8760]*

HPP = *Hydro power plants*

Subsets

To define variables and parameters that are not valid for all parts of the sets defined above, we define additional subsets. This allows us to efficiently define variables and parameters. The PHS subset consist of the hydro power plants with available PHS investments. K defines all parts of the system that are restricted by capacity limitations, while P and C define technologies used for production and consumption respectively. S is the set of storage technologies.

$PHS \subset HPP$, *Includes all HPPs with available PHS investments*

$K \subset T$, K = *[wind, solar, electrolyzer, PtH_2, fuel cell, battery, diesel, HPP]*

$P \subset T$, P = *[wind, solar, fuel cell, battery, diesel, HPP]*

$C \subset T$, C = *[electrolyzer, battery, HPP, grid, curtailment]*

$S \subset T$, S = *[PtH_2, battery, HPP]*

4.2.2 Decision variables

The model includes multiple decision variables. All decision variables start with x (continous) or y (binary). The model decides the capacities to install in each technology (x^k). This is not defined for hydro power as this is set as an input parameter for the currenlty installed capacity on the Faroes. Decision variables are also implemented for hourly production (xp_h^p) and energy use (xc_h^c) for all sources that can produce ($\forall p \in P$) and use ($\forall c \in C$) energy. A variable for the stored energy (xs_h^s) for each hour is also implemented for all storage technologies ($\forall s \in S$).

$x^k \geq 0$, *Installed capacity in each technology*, $\forall\ k \in K,\ k \neq HPP$

$xp_h^p \geq 0$, *Hourly production from each production technology (MWh)*, $\forall\ h \in H,\ p \in P$

$xc_h^c \geq 0$, *Hourly consumption by each consumption technology,* $\forall\ h \in H,\ c \in C$

$xs_h^s \geq 0$, *Hourly stored energy in each storage technology,* $\forall\ h \in H,\ s \in S$

Furthermore, we implement decision variables for the initial water level in each hydro reservoir (x_{hpp}^{iw}). This enables the model to decide how much water is available at the start of the year, which will also be the required level at the end of the year (see (4.26)). This ensures that the reservoirs can have storage levels corresponding to the optimal usage given the demand and inflow throughout the year. A binary variable for PHS investments at each HPP (y_{hpp}) is included, as well as a discharge variable from hydro power plants ($xd_{hpp,h}$). The discharge variable ensures that storage levels in each reservoir (HPP) do not exceed their capacity when there are inflows to the reservoir and they are already full. Finally, a linearization variable is introduced to enable correct storage levels in the hydro reservoirs. See constraints (4.17) to (4.22).

$x_{hpp}^{iw} \geq 0, \leq 1$, *Initial storage level in hydro reservoirs,* $\forall\ hpp \in HPP$

y_{hpp}, *binary variable for PHS investments, 1 if invested,* $\forall\ hpp \in HPP$

$xd_{hpp,h} \geq 0$ *Discharge from hydro reservoirs,* $\forall\ hpp \in HPP,\ h \in H$

z_{hpp}, *Variable used for linearization of initial hydro storage level,* $\forall hpp \in HPP$

4.2.3 Parameters

The parameters of the model are provided below, and further explanations of their use accompany the relevant constraints and will also be further elaborated in chapter 5.

Y = *Years*

r = *Required rate of return*

$capex^k$ = *CAPEX for technologies given as NOK per unit capacity* (x^k), $\forall\ k \in K$

$opex^k$ = *OPEX for technologies given as NOK per unit capacity* (x^k) *per year,* $\forall\ k \in K$

$vopex^k$ = *Variable OPEX, NOK per MWh produced,* $\forall\ k \in K$

L^k = *Lifetime for each technology in years,* $\forall\ k \in K$

e^s = *Efficiency in storing energy for all storage technologies,* $\forall\ s \in S$

ed^s = *Efficiency in dispatch from storage in all storage technologies,* $\forall\ s \in S$

sd^s = *Self-discharge in storage for all storage technologies,* $\forall\ s \in S$

max^k = *Maximum invested capacity* (x^k) *in each technology,* $\forall\ k \in K$

BCD = *% of battery capacity* ($x^{Battery}$) *that can be charged and discharged in an hour*

IS^s = *Initial level of storage in storage technologies,* $\forall\ s \in S,\ S \neq Hydro$

$wind_h$ = *Hourly wind turbine production (MWh per turbine),* $\forall\ h \in H$

sun_h = *Hourly solar panel production (MWh per MW),* $\forall\ h \in H$

$rain_h$ = *Hourly rain in mm,* $\forall\ h \in H$

$demand_h$ = *Hourly demand in MWh,* $\forall\ h \in H$

NRI^k = *Number of re-investments made during model period (Y) based on lifetime* (L^k) *of each technology,* $\forall\ k \in K$

WC_{hpp} = *Reservoir capacity in hydro power plants (MWh),* $\forall\ hpp \in HPP$

rs_{hpp} = *A scalar for each HPP scaling rain (mm) to total hourly inflow,* $\forall\ hpp \in HPP$

GC_{hpp} = *Existing generator capacity at HPP (MW),* $\forall\ hpp \in HPP$

$exCost_{hpp}$ = *Cost of PHS investment (NOK),* $\forall\ hpp \in HPP$

$exGen_{hpp}$ = *Added generator capacity from PHS investment (MW),* $\forall\ hpp \in HPP$

$exPump_{hpp}$ = *Added pump capacity from PHS investment (MW),* $\forall\ hpp \in HPP$

$exWC_{hpp}$ = *Added reservoir capacity from PHS investment (MWh),* $\forall\ hpp \in HPP$

4.2.4 Objective

The objective as shown in (4.1) sums the total system costs, including investments, re-investments and operational expenditures.

$$
\begin{aligned}
&Min: \\
&\sum_{k \in K, k \neq Hydro} \left(x^k \cdot capex^k\right) + \sum_{k \in K, k \neq Hydro} \sum_{i=1}^{NRI^k} \left(\frac{x^k \cdot capex^k}{(1+r)^{i \cdot L^k}}\right) + \\
&\sum_{k \in K, k \neq Hydro} \left(x^k \cdot opex^k \cdot \frac{1-(1+r)^{-Y}}{r}\right) + \\
&\sum_{p \in P} \sum_{h \in H} \left(vopex^p \cdot xp_h^p \cdot \frac{1-(1+r)^{-Y}}{r}\right) + \sum_{phs \in PHS} \left(y_{phs} \cdot exCost^{phs}\right) + \\
&\sum_{phs \in PHS} \left(\left(y_{phs} \cdot (ExGen_{hpp} + ExPump_{hpp}) + GC_{hpp}\right) \cdot opex^{Hydro} \cdot \frac{1-(1+r)^{-Y}}{r}\right)
\end{aligned}
\tag{4.1}
$$

The first term summarizes $capex^k$ of all technologies based on the implemented capacity (x^k). Hydro is not included as we utilize existing hydro capacity without an associated CAPEX. The second term summarizes costs from re-investments that must be made in technologies with lifetimes shorter than the time horizon of the model, Y. The NRI-parameter is calculated with a floor-function of the time horizon divided by the lifetime, ($floor(\frac{Y}{L^k})$), which is the number of re-investments necessary in each technology within the time horizon. The re-investments are discounted to present value with the required return, r.

The third term summarizes OPEX for all technologies dependent on the installed capacity in each technology ($opex^k \cdot x^k$). OPEX is an annual cost, and it is thus included as an annuity with Y periods, discounted at the required return, r. Hydro is excluded here as it is added separately in the last term.

The fourth term considers the variable OPEX. The model summarizes the production (xp_h^k) over a year for each technology, and multiplies this with the variable OPEX ($vopex^k$). This is also converted to present value as an annuity with Y periods, discounted at the required return, r. In our implementation of the model, only diesel generators are given a variable OPEX component.

The fifth term adds the costs of PHS investments that are made, and the final term adds the operational expenditure of existing (GC_{hpp}) and new ($y_{hpp}(exGen_{hpp} + exPump_{hpp})$) hydro power capacity. The OPEX is added for both pump and generator capacity.

4.2.5 Constraints

The constraints ensure that variables take on values that are in line with the intentions of the model and the nature of the different technologies.

Satisfy demand

The energy sent to the grid (xc_h^{grid}) must at all hours of the year equal the demand (D_h).

$$xc_h^{grid} = D_h, \qquad \forall h \in H \tag{4.2}$$

Production equals consumption

The total energy produced by all production technologies ($\sum_p xp_h^p$) must match the total consumption ($\sum_c xc_h^c$) for every hour of the year. All technologies for consumption ($c \in C$) have inherent limitations based on capacities or demand, except curtailment ($xc_h^{curtailment}$). The curtailment variable is thus constrained to be a residual, equal to production minus energy consumed by other sources.

$$\sum_{p \in P} xp_h^p \; = \; \sum_{c \in C} xc_h^c, \qquad \forall h \in H \tag{4.3}$$

Production limited by installed capacities

Hourly production from diesel and fuel cell is limited by installed capacity (x^k)

$$xp_h^i \; \leq \; x^i, \qquad \forall i \in [diesel, fuelcell], h \in H \tag{4.4}$$

Hydro production at each hydro power plant is limited by existing (GC_{hpp}) plus acquired ($y_{hpp} \cdot exGen_{hpp}$) generator capacity acquired thorugh PHS investments.

$$xp_h^{hpp} \; \leq \; GC_{hpp} + y_{hpp} \cdot exGen_{hpp}, \qquad \forall hpp \in HPP, h \in H \tag{4.5}$$

Energy dispatched from battery is limited by the battery capacity ($x^{Battery}$) multiplied by the available discharge per hour (BCD), which is given as a percentage of installed storage capacity.

$$xp_h^{battery} \; \leq \; x^{battery} \cdot BCD, \qquad \forall h \in H \tag{4.6}$$

The variable for wind production (xp_h^{wind}) is set equal to the number of installed turbines (x^{wind}) multiplied by the hourly production per per turbine ($wind_h$). The hourly production from wind is therefore determined by the number of turbines rather than being determined by the model directly. This reflects the non-dispatchable nature of wind turbines.

$$xp_h^{wind} \; = \; x^{wind} \cdot wind_h, \qquad \forall h \in H \tag{4.7}$$

The variable for solar production (xp_h^{solar}) is set equal to the amount of installed solar capacity (x^{solar}, MW) multiplied by the hourly production per MW (sun_h). The hourly production from solar is therefore determined by the installed capacity rather than being determined by the model directly. This reflects the non-dispatchable nature of solar power.

$$xp_h^{solar} = x^{solar} \cdot sun_h, \qquad \forall h \in H \tag{4.8}$$

Limits on energy usage

Energy used for pumping (xc_h^{hpp}) is restricted by pump capacity from PHS investments ($y_{hpp} \cdot exPump_{hpp}$) at each plant. For plants without investment opportunities this will always be 0, i.e pumping can not occur.

$$xc_h^{hpp} \leq y_{hpp} \cdot exPump_{hpp}, \qquad \forall hpp \in HPP, h \in H \tag{4.9}$$

Energy consumed in the electrolyzer ($xc_h^{electrolyzer}$) is limited by the installed capacity ($x^{electrolyzer}$).

$$xc_h^{electrolyzer} \leq x^{electrolyzer}, \qquad \forall h \in H \tag{4.10}$$

Energy sent to battery storage is limited by total battery capacity ($x^{Battery}$) and available charge per hour (BCD), given as a percentage of storage capacity.

$$xc_h^{battery} \leq x^{battery} \cdot BCD, \qquad \forall h \in H \tag{4.11}$$

Limits on capacities

All capacities are restricted by a parameter for maximum installed capacity (max^k).

$$x^k \leq max^k, \qquad \forall k \in K \tag{4.12}$$

The number of installed wind turbines must be integer. Capacities in all other technologies are included as continuous variables.

$$x^{wind} = integer \tag{4.13}$$

Battery and hydrogen storage

Energy stored after the first hour (xs_1^s) equals the initial storage level (IS^s, in % of total capacity) multiplied by the capacity (x^s) adjusted for self-discharge (1-sd^s). Energy sent to storage during the first hour, adjusted for efficiency losses ($xc_h^s \cdot e^s$) is added. Energy dispatched, scaled to include efficiency losses ($\frac{xp_h^s}{ed^s}$), is subtracted. Hydro storage is excluded from (4.14) as it is modeled separately, see (4.24) to (4.29).

$$xs_1^s \ = \ IS^s \cdot x^s \cdot (1 - sd^s) \ + \ xc_1^s \cdot e^s \ - \ \frac{xp_1^s}{ed^s}, \qquad \forall s \in S, s \neq Hydro \tag{4.14}$$

For all hours except the first ($h \geq 2$) the storage level depends on the opening balance (xs_{h-1}^s), rather than the initial state ($IS^s \cdot x^s$). Constraint (4.15) is similar to (4.14) in all other aspects.

$$xs_h^s \ = \ xs_{h-1}^s \cdot (1 - sd^s) \ + \ xc_h^s \cdot e^s \ - \ \frac{xp_h^s}{ed^s}, \qquad \forall h \in H, h \geq 2, s \in S, s \neq Hydro \tag{4.15}$$

Energy storage in hydro reservoirs

For all hydro plants in which PHS investments are unavailable, we set the binary investment variable to 0 to make the model more efficient.

$$y_{hpp} \ = \ 0, \qquad \forall hpp \notin PHS \tag{4.16}$$

<u>Linearization of initial hydro storage</u>

The total initial storage level in each hydro reservoir is given by (4.17) and (4.18) which includes a multiplication of a binary (y_{hpp}) and a continuous variable (x_{hpp}^{iw}). This is not linear, and cannot be included directly in a constraint in the model.

$$(WC_{hpp} \ + \ y_{hpp} \cdot exWC_{hpp}) \cdot x_{hpp}^{iw} \tag{4.17}$$

$$x_{hpp}^{iw} \cdot WC_{hpp} \ + \ y_{hpp} \cdot x_{hpp}^{iw} \cdot exWC_{hpp} \tag{4.18}$$

To avoid this non-linearity, we introduce a variable, z_{hpp}, which is constrained to equal the product of $y_{phs}(binary)$ and x^{iw}_{hpp} $(0 \leq x^{iw}_{hpp} \leq 1)$ by implementing constraints (4.19) to (4.22)

$$z_{hpp} \ \leq \ y_{hpp}, \qquad \forall hpp \in HPP \tag{4.19}$$

$$z_{hpp} \ \leq \ x^{iw}_{hpp}, \qquad \forall hpp \in HPP \tag{4.20}$$

$$z_{hpp} \ \geq \ 0, \qquad \forall hpp \in HPP \tag{4.21}$$

$$z_{hpp} \ \geq \ x^{iw}_{hpp} - (1 - y_{hpp}), \qquad \forall hpp \in HPP \tag{4.22}$$

(4.19) ensures the z_{hpp} variable is less than the binary variable y_{hpp}, and (4.20) ensures it is less than the continuous variable x^{iw}_{hpp}. As neither the binary or the continuous variable can be larger than one, the product of the two (z_{hpp}) can never be larger than the value of the largest of the two. Furthermore, (4.21) limits the product to be larger than 0, as neither the binary or the continuous variable can be negative. Finally, (4.22) ensures that z_{hpp} is equal to x^{iw}_{hpp} when y_{hpp} is 1. The z_{hpp} variable can now be used in the constraints for the storage level in hydro reservoirs.

(4.18) can now be rewritten in a linear constraint as shown in (4.23). This represents the initial hydro storage levels and is used in constraints (4.24), (4.26) and (4.28).

$$x^{iw}_{hpp} \cdot WC_{hpp} \ + \ z_{hpp} \cdot exWC_{hpp} \tag{4.23}$$

Initial hydro storage level

Storage level at the end of hour 1, xs^{hpp}_1, equals reservoir capacity multiplied by initial level $(WC_{hpp} \cdot x^{iw}_{hpp})$ plus capacity from investments multiplied by initial level $(exWC_{hpp} \cdot z_{hpp})$. Inflow $(rain_1 \cdot rs_{hpp})$ as well as energy from pumped, less efficiency losses, $(xc^{hpp}_h \cdot e^{Hydro})$ is added. Discharge $(xd_{hpp,h})$ and energy used for generation, including efficiency loss, is subtracted $(\frac{xp^{hpp}_h}{ed^{Hydro}})$. Heyga is excluded as this reservoir is modeled as cascading with Myru, and can receive pumped energy from Hvalvik. Heyga is thus modeled separately in (4.28) and (4.29).

$$\begin{aligned} xs^{hpp}_1 \ &= \ WC_{hpp} \cdot x^{iw}_{hpp} \ + \ exWC_{hpp} \cdot z_{hpp} \ + \ rain_1 \cdot rs_{hpp} \ + \\ xc^{hpp}_1 \cdot e^{Hydro} \ &- \ xd_{hpp,h} \ - \ \frac{xp^{hpp}_1}{ed^{Hydro}}, \qquad \forall hpp \in HPP, hpp \neq Heyga \end{aligned} \tag{4.24}$$

Hourly hydro storage level level

This constraint, (4.25), is similar to (4.24) and is applied for every hour larger than or equal to 2. However, the initial level is set as the level from the previous hour (xs_{h-1}^{hpp}) rather than based on the initial level as in (4.24). Heyga is still excluded and modeled separately in (4.28) and (4.29).

$$xs_h^{hpp} = xs_{h-1}^{hpp} + rain_h \cdot rs_{hpp} + xc_h^{hpp} \cdot e^{Hydro} - xd_{hpp,h} - \frac{xp_h^{hpp}}{ed^{Hydro}}, \quad \forall h \in H, h \geq 2, hpp \in HPP, hpp \neq Heyga \tag{4.25}$$

End-of-year hydro storage level

The energy stored at the end of the year must be at least as large as the initial level to ensure that reservoir levels are not reduced throughout the year, as the same initial level will be needed in the following year. This way the model allows the system to start with the optimal stored level (by deciding x_{hpp}^{iw}), without emptying the storage before the next year.

$$xs_{8760}^{hpp} \geq WC_{hpp} \cdot x_{hpp}^{iw} + z_{hpp} \cdot exWC_{hpp}, \qquad \forall hpp \in HPP \tag{4.26}$$

Energy storage restricted by reservoir capacity

The energy stored can never exceed the total storage capacity, original (WC_{hpp}) plus storage acquired through PHS investments ($y_{hpp} \cdot exWC_{hpp}$). Whenever the reservoir is full, and there are inflows, the model can discharge energy from the reservoir ($xd_{hpp,h}$) to ensure the constraint is satisfied.

$$xs_h^{hpp} \leq WC_{hpp} + y_{hpp} \cdot exWC_{hpp}, \qquad \forall hpp \in HPP, h \in H \tag{4.27}$$

Initial hydro storage level at Heyga

For the Heyga reservoir, the constraint (4.24) is expanded to (4.28). Water used for pumping at Hvalvik ($xc_1^{Hvalvik}$) is added to the Heyga reservoir. Additionally, water used in generators at Myru (xp_1^{Myru}) flows into the Heyga reservoir, while water pumped at Myru is taken from the Heyga reservoir ($-\frac{xc_1^{Myru}}{e^{hpp}}$), adjusted to account for efficiency losses.

$$xs_1^{Heyga} = WC_{Heyga} \cdot x_{Heyga}^{in} + z_{Heyga} \cdot exWC_{Heyga} + rain_1 \cdot rs_{hpp} + xc_1^{Heyga} \cdot e^{Hydro} - xd_{Heyga,1} - \frac{xp_1^{Heyga}}{ed^{Hydro}} + xc_1^{Hvalvik} \cdot e^{Hydro} + xp_1^{Myru} - \frac{xc_1^{Myru}}{e^{hpp}} \tag{4.28}$$

Hourly hydro storage level for Heyga

For every hour larger than or equal to 2, the storage level at Heyga is given by (4.29). This is similar to (4.28), except that the initial level is substituted by the inbound balance (xs_{h-1}^{Heyga}). This difference is the same as the difference between (4.24) and (4.25) for the other hydro power plants.

$$xs_h^{Heyga} = xs_{h-1}^{Heyga} + rain_h \cdot rs_{hpp} + xc_h^{Heyga} \cdot e^{Heyga} - xd_{Heyga,h} - \frac{xp_h^{Heyga}}{ed^{Hydro}} + xc_h^{Hvalvik} \cdot e^{Hydro} + xp_h^{Myru} - \frac{xc_h^{Myru}}{e^{Myru}}, \qquad \forall h \geq 2 \tag{4.29}$$

Diesel production limits for sensitivity analyses

For each sensitivity analysis as applied in chapter 6, the model is looped over a set of diesel generation limits (j) between 0% and 32.5% with 2.5% increments. The model is re-solved for each constraint. The constraint is set so that the sum of production from diesel ($\sum_h xp_h^{diesel}$) is less than or equal to the total annual demand ($\sum_h demand_h$) multiplied by the allowed share, j.

$$\sum_{h \in H} xp_h^{diesel} \leq j \cdot \sum_{h \in H} demand_h \tag{4.30}$$

4.3 Model simplifications

4.3.1 Perfect foresight and deterministic model

The model operates with perfect foresight, meaning that it can operate all technologies optimally given the input data for the entire year, i.e it knows the irradiation, wind, rain and demand of the entire year when optimizing the system. In reality, some suboptimal operations are unavoidable, as the weather and demand is unpredictable. This might affect the installed capacities and the total cost of the system. However, we do not believe it significantly affects the general trade-off between the technologies. Thus, we believe the model is still relevant for answering our research question.

The model we develop is deterministic, and does not include stochastic variables. This means that the model will provide the same results every time it is solved with the same input data. The model optimizes the system based on input data for one year, while the system costs are calculated for a period of Y years, assuming the same capacities are needed in all years of the model. During a period of Y years, it is likely that some years would require larger and some would require smaller capacities. Thus, the capacities needed to satisfy demand over the entire period is likely to be larger than the ones implemented in this model. However, as explained above, even though the exact capacities and costs might be affected, we believe the model is highly relevant in answering the proposed research question of the relevance of PtH_2 in grid-balancing. Perfect foresight and the deterministic model is further discussed in chapter 7.

4.3.2 Resolution and system balancing

We operate the model with an hourly resolution. We thus exclude grid balancing and storage technologies relevant in balancing on shorter time-frames than an hour. Within-the-hour balancing can be done with flywheels, supercapacitors, and other short-term energy storage solutions (International Energy Agency, 2014). This is considered to be a justified simplification, as these capacities would be required regardless of long-term balancing technologies, and thus do not significantly impact the relevance of evaluated technologies in this model.

4.3.3 Network capacity

We do not include network or transferring capacities in the system. We assume that generation from any source can immediately be consumed by any other part of the system, without lag or capacity restrictions other than individual components capacities. The network must handle similar transfer capacities regardless of which energy source is used for production. Thus, the distribution network lies outside the scope of this project as including it does not improve the models ability to answer our research question.

4.3.4 Scalability

We assume that all technologies included in the model can be applied in any multiple, including non-integer multiples (except wind turbines which must be integer). Some technologies might have economies of scale, but these are disregarded as they are difficult to determine precisely and complicates maintaining a linear model. We believe this is sufficient to obtain interesting results for the suggested research question. There are also some technologies that have minimum-load capacities, this means that they cannot run on a capacity below a certain percentage of rated capacity. As most our results implement capacities that are large multiples of smaller units, this is disregarded as the system can operate single units at that minimum load, thus providing much larger flexibility in operation. Modelling each unit separately would add complexity without significantly improving the precision of the model.

4.3.5 Limitations of implemented hydro power

The hydro power capacity on the Faroe Islands is modelled approximately. For pumped hydro at Hvalvik, we assume unlimited available water for pumping. The pumps available at Hvalvik through PHS investments are small, and this is thus not considered to be a problem. The model does not consider evaporation from hydro reservoirs, but this is assumed to be of insignificant importance in the Faroese climate. Additionally, the water inflow can be adjusted to account for this effect.

4.3.6 Increasing demand and continuous investments

We do not consider gradual investments in each technology or increases in demand over time. This is because the purpose of the thesis is to identify aspects of the power-supply system that make PtH_2 an attractive option, rather than identifying and developing a concrete plan for the development of the power system at the Faroe Islands.

5 Model Inputs

The generic model developed and presented in chapter 4 is utilized by implementing specific data for weather, demand and technology specifications. This chapter presents the specific parameters we use in our analysis.

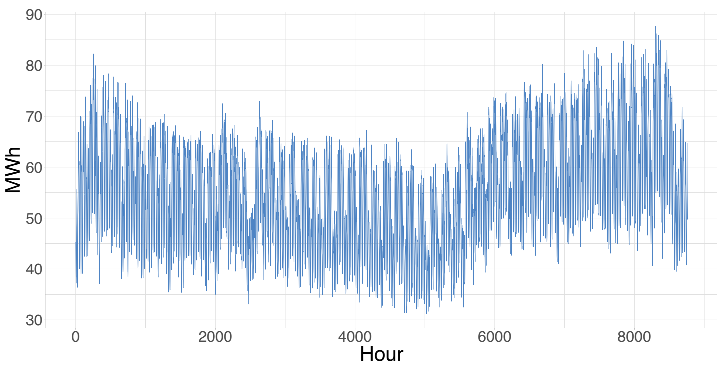
5.1 Time series data

5.1.1 Demand (D_h)

The load data (demand) is provided directly to us by SEV with an hourly resolution for the year of 2017. We adjusted one observation (hour 2,271) which was eight times as large as the second largest observation, and thus assumed to be a registration error. This was adjusted from 410.53 to 41.53 MWh by simply removing a 0 to make it similar to the demand of the hour before and after said observation. The demand data is then scaled to account for an additional need of 175 GWh of energy to replace current oil heaters in household by heat pumps (Katsaprakakis et al., 2018). Each hour is therefore scaled by the same multiple (1.57) . The final data is summarized in *table 5.1a* and plotted in *figure 5.1b*.

	Demand
Min.	31.191
1st Qu.	46.285
Median	54.443
Mean	54.968
3rd Qu.	62.930
Max.	87.670

(a) Load data summary, (D_h)



(b) Load curve (D_h)

Figure 5.1: Summary of demand (load) data as used in model

5.1.2 Weather data

The weather data as well as production data for wind and solar has been collected from a weather data provider called Meteomatics (2020f). They have provided access to their API allowing collection of numerous weather parameters as well as wind turbine and solar panel production data based on historical weather. The service provides access to data for the previous 366 days.

Wind turbine production ($wind_h$)

The Meteomatics service allows us to choose among 600 predefined wind turbines, including the Enercon E44 used by SEV and extract the production from this turbine given the weather data of the location (Meteomatics, 2020a). We extract data for the last 366 days from the location of the Húsahagi wind farm, grid reference (62.021764, -6.829848). The production data from one such turbine ($wind_h$) is provided in *figure 5.2*, aggregated to daily production in MWh.

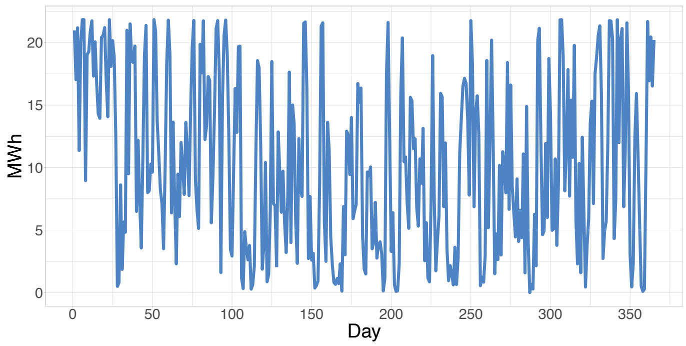


Figure 5.2: Daily Enercon E44 production (MWh)

Solar panel production (sun_h)

We extract production data for solar through the Meteomatics API (Meteomatics, 2020c). For simplicity we use the location of the Húsahagi wind farm. The service allows us to define orientation and tilt. Tilt is the angle of the panels where 0° means they are facing straight up, and 90° means that the panels are facing the horizon. We tested 10 tilts ranging from 35° to 80°, of which a tilt of 50° provided the highest annual production. We repeated the process for orientation, deciding on a 180° orientation. This means that the solar panels are facing directly south. The extracted data then provides the hourly energy produced per MW of installed solar panel capacity. The Meteomatics API estimates production based on the combination of irradiation and temperature. *Figure 3.3* in chapter 3 shows the data aggregated to daily production.

Rain data ($rain_h$)

To estimate the inflow of water (energy) into each hydro plants' reservoir, we use rain data for the location of Eidsivatnet, the largest of the plants on the Faroe Islands (grid reference 62.285360, -7.051596) (Meteomatics, 2020b). This is combined with data of the historic production of the hydro power plants taken from the article by Katsaprakakis et al. (2018). The annual (historic) production from each hydro power plant is shown in *table 5.3a* and the rain profile as collected from Meteomatics, aggregated to weekly numbers, is shown in *figure 5.3b*. The rain data provides a profile of inflow, while the historically generated power provides the total annual inflow. Thus, the rain scalar (rs_{hpp}) is calculated by solving (5.1) for each HPP.

$$\sum_{h \in H} rain_h \cdot rs_{hpp} = Generation, \qquad \forall hpp \in HPP \tag{5.1}$$

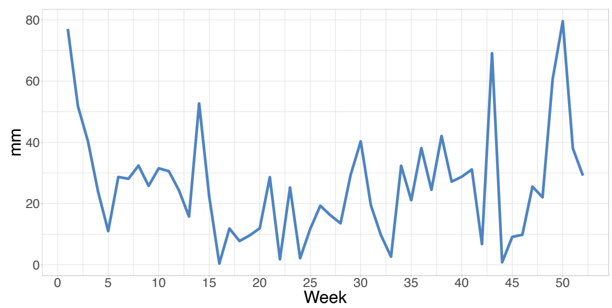
This scalar (rs_{hpp}) is used to scale the hourly rain inflow into each hydro power plant in constraints (4.24) and (4.25). Furthermore, the well capacity in m^3 is recalculated to MWh by equation (5.2) converting mass at height to potential energy.

$$WC_{hpp} = WellCap(m^3) \cdot 1000 \cdot Height \cdot G \cdot MWh/Joules \tag{5.2}$$

The well capacity in MWh is based on the mass (in kg) that the reservoir can store (WellCap(m^3) $\cdot$ 1000), the height (in meters) and the gravitational force ($G = 9.81 m/s^2$). Additionally, the energy is converted from Joules to MWh by multiplying by 2.778$\cdot$e^{-10}.

HPP	Generated (MWh)	rs_{hpp}	Height m	WellCap (m m^3)	WC_{hpp} (MWh)
Fossa	21,757	16.07	222	4.95	2,994
Heyga	11,920	8.80	107	2.10	612
Myru	12,412	9.17	239	4.10	2,670
Eidi	63,289	46.74	149	33.00	13,399
Strond	2,678	1.98	223	0.04	24
Botnur	4,629	3.42	210	1.75	1,001
Hvalvik	-	-	-	-	-

(a) Hydro power plant characteristics



(b) Weekly rain data, in mm ($rain_{hpp}$)

Figure 5.3: Rain inflow and reservoir capacities

5.1.3 Matching of data

The data provided by SEV is given for 2017, while the data from Meteomatics is given for the previous 366 days, collected on October 23rd, 2020, for the last 366 days. As 2020 is a leap-year, we remove the observations on February 29th from weather and production data. We then proceed with matching weather and production data with demand, so that demand data of January 1st, 2017, is matched with weather and production data for January 1st, 2020. For the period of October 23rd to the end of December we match 2019 data for weather and production with the 2017 data for demand. Even though the demand and production data is taken from different years, we believe it sufficiently captures the seasonal trends and covariances of demand and weather on the Faroe Islands.

5.2 Technical input parameters

This section presents technical input parameters used in our model, including the costs, lifetimes, efficiencies and other relevant parameters for each system component. All costs are listed in Norwegian Crowns (NOK). In cases where sources are older than 2020, the costs are price adjusted to 2020 numbers using a local[3] currency inflation calculator. In cases where prices are listed in other currencies, they are converted into NOK using the current spot exchange rate with a currency converter from Norges Bank. The 2020[4] conversion rate for Euro and US Dollars is 10.7769 NOK/€ and 9.1406 NOK/$, respectively (Norges Bank, 2014).

All costs in the model are separated into costs for investment ($capex^k$), and operation and maintenance. The $capex^k$ includes the cost of acquiring and installing the component and all sub-components necessary to make the system work. The OPEX includes the yearly costs, herein both fixed ($opex^k$) and variable ($vopex^k$), for operating and maintaining the system component. In cases where a component is in need of replacement during the model horizon (Y), a replacement expenditure equal to the $capex^k$ is added, discounted at the rate r for the appropriate time, L^k.

Several of our chosen $capex^k$ and $opex^k$ model inputs originate from a meta study by

[3]Relevant for USD for wind turbines only. A US inflation calculator was used (U.S. Inflation Calculator, 2020)
[4]Monthly rate for September 2020, at the time of writing.

Petkov and Gabrielli (2020) where the authors list a range of cost values for the different components from a wide selection papers. They list a mode-value to specify the most commonly found cost among the data observed in the papers. For the majority of our $capex^k$ and $opex^k$ parameters the mode-value is chosen, unless another source is considered more relevant. In the following section, capitalized CAPEX and OPEX are used when referring to general numbers, while $capex^k$ and $opex^k$ are used when referring to the specific numbers used in our analysis.

Table 5.1, 5.2 and *5.3* provides an overview of the parameters used, and the following sections describes how they are selected.

Table 5.1: Miscellaneous parameters

Parameter	Value
Y	20
r	0.05

Table 5.2: Hydro power plant parameters

HPP	WC_{hpp} (MWh)	GC_{hpp} (MW)	rs_{hpp} (mNOK)	$exCost_{phs}$	$exGen_{phs}$ (MW)	$exPump_{phs}$ (MW)	$exWC_{phs}$ (MWh)
Fossa	3,255	6	16.068	-	-	-	-
Heyga	666	2	8.803	196.5	0	0	2,537
Myru	2,906	5	9.166	1,452.3	75	140	28,202
Eidi	14,565	22	46.740	-	-	-	-
Strond	26	1	1.978	-	-	-	-
Botnur	1,089	3	3.418	-	-	-	-
Hvalvik	0	0	0	158,800	0	5	∞

Table 5.3: Technical input parameters

	Wind	Solar	Elecrolyzer	PtH_2	Fuel cell	Battery	Diesel	Hydro
$capex^k$ mNOK/	21.974 turbine	13.902 MW	13.956 MW	0.108 MWh	18.148 MW	3.071 MWh	4.113 MW	-
$opex^k$ mNOK/	0.558 turbine	0.236 MW	0.488 MW	0.002478 MWh	0.690 MW	0.077 MWh	0.530 MW	0.535 MW
$vopex^k$ mNOK/	-	-	-	-	-	-	0.002612 MWh	-
L^k (Years)	25	27	15	23	14	12	60	∞
NRI^k	0	0	1	0	1	1	0	-
max^k	368	700	∞	∞	∞	∞	100	-
e^s	-	-	-	0.71	-	0.9539	-	0.9
es^s	-	-	-	0.5	-	0.9539	-	0.92
sd^s	-	-	-	-	-	0.000834	-	-
IS^s	-	-	-	0.5	-	0	-	x^{iw}_{hpp}
BCD^k	-	-	-	-	-	0.4	-	-

5.2.1 Production technology parameters

Wind turbines

The traditional wind turbine model used on the Faroes is the Enercon E44 900 kW wind turbine. The Enercon E44 has a rotor diameter of 44 m and a hub height of 55 m (Ragnarsson et al., 2015). As the location of each turbine relative to other turbines is important in order to minimize wake losses, each turbine will be placed with a distance between turbines of 5 times the diameter of the turbine, as suggested by Katsaprakakis et al. (2018). This translates into spatial requirements of a diameter of 220 m for each turbine. Each turbine will thus require 38,013 m^2. Assuming that the Faroese government limits the land-use of RES expansion to 1% of the total available land on the Faroes (1,399 million m^2), this gives 13.99 million m^2 of available space. This space can accommodate 368 Enercon E44 turbines, which is selected as the max^{wind}.

An analysis of a wind power generation system at Búrfell in Iceland done by Ragnarsson et al. (2015) concluded that the Enercon E44's lifetime (L^{wind}) is 25 years, CAPEX is 2229 $/kW and the OPEX is 0.015 $/kWh. After conversion and price adjustment this translates into $capex^{wind}$ of 21,974,000 NOK/MW and an OPEX of 150 NOK/MWh. This is scaled by the annual production of 3.774 MWh of a Enercon E44 turbine based on the Meteomatics data, yielding an annual $opex^{wind}$ of 558.360 NOK/MW.

Solar panels

According to Petkov and Gabrielli (2020), the mode-value for solar PV systems CAPEX is 1,290 €/kW and OPEX is 1.7% of CAPEX. After conversion and price adjustment this gives a $capex^{solar}$ of 13,902,000 NOK/MW and an $opex^{solar}$ of 236,334 NOK/MW. The lifetime (L^{solar}) of a solar PV system is 27 years.

Additionally, if we assume the same spatial constraints of 1% as for wind turbines and an estimated average spatial requirement of 20,000 m^2 per MW of solar panels, we get a maximum limit (max^{solar}) of 699.5 MW (based on Greencoast (2019)).

Diesel generators

The Faroe Islands already have 13 diesel generators in operation (SEV, ndb). However, in order to create a realistic and generic model we define a CAPEX for diesel generators in the model and a variable to decide the invested capacity (x^{diesel}). The CAPEX for diesel generators, according to Tsai et al. (2019) is \$ 400/kW and to Baricaua et al. (2019) is \$ 500/kW. We settle on \$ 450/kW. When correcting for price adjustment and conversion, this gives a $capex^{diesel}$ of 4,113,000 NOK/MW.

The OPEX of the diesel generators was not found explicitly through research but can be calculated. SEV (ndb) lists the diesel usage of the generators to be ~185 g per kWh. With a density of diesel of 0.85kg per liter (Speight, 2011), this gives 0.21765 liters/kWh, or 217.65 liters/MWh. With a diesel price of 12 NOK per liter (Expatistan, 2020), this gives a variable $vopex^{diesel}$ of 2,612 NOK/MWh, which is implemented in our model. For fixed OPEX$^{\mathrm{NOK}}$, Ea Energy Analyses (2018) lists a price of 371 DKK/kW, which after price adjustment and conversion gives an $opex^{diesel}$ of 529,708 NOK/MW.

Hydro power

The hydro power plants on the Faroe Islands are included without CAPEX, but we implement an $opex^{hydro}$ of 535,420 NOK per MW generator capacity (Ea Energy Analyses, 2018). The generator and pump efficiency (e^{hydro} & es^{hydro}) are set to 0.92 and 0.9 respectively based on Norconsult (2018). The initial state of storage (IS^{hydro}) is set as a variable (x^{iw}_{hpp}) for hydro power, as this level can have significant impact on the results.

5.2.2 Storage technology parameters

$\mathbf{PtH_2}$ - PEM Electrolyzer

Petkov & Gabrielli lists the PEM electrolyzer mode-value for CAPEX and OPEX to be 1,295 €/kW and 3.5% of CAPEX per year. Converting this into NOK yields a $capex^{electrolyzer}$ of 13,956,000 NOK/MW and an $opex^{electrolyzer}$ of 488,460 NOK/MW. Additionally, a PEM electrolyzer has a lifetime ($L^{electrolyzer}$) of 15 years and an efficiency (e^{PtH_2}) of 71%, meaning that 71% of the electricity introduced is converted into H_2. Based on a review of the sources of Petkov & Gabrielli, we assume that costs and efficiency losses related to compression of H_2 are included in the numbers for the electrolyzer. As the subset of storage technologies (S) includes PtH_2, but not the electrolyzer, the efficiency of the electrolyzer is assigned to the general storage technology of PtH_2.

$\mathbf{PtH_2}$ - Storage

Petkov & Gabrielli lists a H_2 storage mode-value for CAPEX of 10 €/kWh and OPEX of 2.3% of CAPEX. Converting this yields a $capex^{PtH_2}$ of 107,740 NOK/MWh and an

$opex^{PtH_2}$ of 2,478 NOK/MWh. There is no efficiency loss when the gas is stored, and the storage tanks have a lifetime (L^{PtH_2}) of 23 years. The model starts with H_2 storage tanks at 50% (IS^{PtH_2}). This is tested to be the optimal starting point to ensure that H_2 levels can be high or low at the right times of the year. The initial H_2 level however, has low overall significance for the total cost of the system.

PtH$_2$ - PEM fuel cell

Petkov & Gabrielli list a PEM fuel cell CAPEX mode-value of 1,684 €/kW and OPEX of 3.8% of CAPEX per year, respectively. After conversion and price adjustment this translates into a $capex^{fuelcell}$ of 18,148,000/MW and an $opex^{fuelcell}$ of 690,000 NOK/MW. Furthermore, it has a lifetime ($L^{fuelcell}$) of 14 years and an electrical efficiency of 50% (e^{PtH_2}), meaning that 50% of the H_2 channeled into the fuel cell is converted into electricity. As with the electrolyzer, this efficiency is assigned to the PtH_2 storage technology.

Pumped Hydro Storage

To include PHS in the model, we use the report from Norconsult (2018). Following this report, we include three possible investments with their respective price estimates. At Myru, a combined upgrade with additional generators, pumps and well capacity is available. At Heyga, an increase in the well capacity is available and at Hvalvik, a 5 MW pump ($exPump^{Hvalvik}$) to fill the reservoir at Heyga is available. These parameters are all summarized in *table 5.2*.

Lithium-ion batteries

According to Petkov & Gabrielli, li-ion batteries have a mode-value for CAPEX of 285 €/kWh and annual OPEX of 2.5% of CAPEX. Converted into NOK, this gives a $capex^{battery}$ of 3,071,000 NOK/MWh and $opex^{battery}$ of 77,000 NOK/MWh. The lifetime ($L^{battery}$) of li-ion batteries is 12 years, and the roundtrip efficiency is 91%. We assume the losses are equal when charging and discharging, implying charging and discharging efficiencies of 95.39% ($e^{battery}$ & $es^{battery}$). The self-discharge of the batteries is set to 0.000834 ($sd^{battery}$), corresponding to 0.2% per day (Dentinho et al. (2017); Chen et al. (2009)). We also implement a maximum charge/discharge rate ($BCD^{battery}$) of 40% (Mavromatidis et al., 2018). This is the share of the batteries' total capacity that can be charged or discharged per hour.

6 Analysis and results

In this chapter we begin by outlining the scenarios to which we apply our model before presenting the results, including costs, production, technology utilization and storage of H_2. We then present the sensitivity analyses conducted on the effect of increasing the RES penetration, followed by the results of the analyses.

6.0.1 Scenarios

An overview of the scenarios is presented in *table 6.1.* Each scenario includes different combinations of technologies in the model. Additionally, each main scenario contains two sub-scenarios; A allows PtH_2, while B does not. The technologies are divided into non-dispatchable production, dispatchable production, and storage technologies (PtH_2, batteries and PHS). Wind, solar and batteries are allowed in all scenarios, while hydro, PHS and diesel are restricted from some scenarios. The scenarios which restrict diesel generators, are classified as "green" scenarios as diesel generators are the only source of emissions from energy production. Furthermore, each scenario is supplemented with a hypothesis of the characteristics of the optimal system.

Table 6.1: Scenario overview

		1A	1B	2A	2B	3A	3B	4A	4B	5A	5B	6A	6B
Non-dispatchable	Wind	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
	Solar	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Dispatchable	Hydro	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	No	No	No
	Diesel	Yes	Yes	Yes	Yes	No	No	No	No	No	No	Yes	Yes
Storage	PHS	Yes	Yes	No	No	Yes	Yes	No	No	No	No	No	No
	PtH_2	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No	Yes	No
	Battery	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Scenario 1 allows all technologies and is the least restrictive scenario. This should be the scenario in which PtH_2 has least impact on the optimal system, and it should yield the lowest total cost, as all alternatives are available to the model.

Scenario 2 allows all technologies except new PHS investments. The hypothesis of this scenario is that the capacity in hydro and diesel is sufficient to supply the grid. As hydro and diesel are flexible and dispatchable sources of energy, it is likely that no significant capacity in batteries or PtH_2 is needed to supply or balance the grid. The capacity in wind and solar is also likely to be smaller compared to other scenarios.

Scenario 3 allows all technologies except diesel. This is the least restrictive green scenario, excluding power generation and emissions from diesel generators. In the absence of diesel generators, PtH_2 is likely to be more attractive compared to scenario 1, although both Hydro, PHS and Batteries are still alternatives to PtH_2.

Scenario 4 is also a green scenario. All technologies except diesel and PHS investments are available. The hypothesis in this scenario is that the lacking generation capacity in diesel must be replaced by a larger capacity in other production methods or will need some form of storage to enable a stable flow of energy to the grid according to demand. Thus, batteries or PtH_2 are likely to be included to a greater extent as both the dispatchable sources, PHS and diesel, are unavailable.

Scenario 5 and 6 restrict hydro power entirely. These scenarios are interesting, as some remote islands or isolated communities do not have the topography or precipitation needed to accommodate hydro power in a meaningful sense. We want to understand how the lack of available hydro power affects the need for storage and RES technologies in the optimal model, especially PtH_2. Furthermore, diesel is excluded in scenario 5 to create a green scenario given the unavailability of hydro power. This zimulates an island without the potential for hydro power seeking 100% RES production in their grid. The hypothesis is that the lacking generation capacity in hydro must be replaced by a combination of RES and storage, and the scenario without diesel is thought to be highly expensive as it does not contain any naturally dispatchable production technologies. All generation capacity in stored resources must be bought and maintained.

6.1 Results

Table 6.2 provides key properties for the optimal system in each scenario as given by the model. A significant number of wind turbines are included in all scenarios. Solar production is included in all scenarios except 3A and 3B, although only marginally in scenarios 1, 2 and 6. Diesel generation capacity is significantly included whenever it is available, seen in scenarios 1, 2 and 6. The existing hydro power capacity of 39 MW is included in all systems that allow hydro power, and the capacity is not decided by the model. PHS investments are available to the model in scenarios 1 and 3, but are only made in scenario 3. PtH_2 is only included in scenarios 4A and 5A, even though it is available to the model in all A-scenarios. Battery capacity is included in all solutions except scenario 3.

Table 6.2: Variable overview

		1A	1B	2A	2B	3A	3B	4A	4B	5A	5B	6A	6B
	Total cost (mNOK)	6,388	6,388	6,388	6,388	6,504	6,504	7,695	12,856	14,993	37,981	9,960	9,960
x^{wind}	Number of turbines	102	102	102	102	109	109	122	144	222	351	108	107
x^{solar}	Solar panel (MW)	2	2	2	2	0	0	94	130	54	158	1	2
x^{diesel}	Diesel (MW)	34	34	34	34	–	–	–	–	–	–	73	73
GC	Hydro Gen (MW)	39	39	39	39	114	114	39	39	–	–	–	–
$exPump$	Hydro Pump (MW)	0	0	–	–	140	140	–	–	–	–	–	–
$x^{electrolysis}$	Electrolysis (MW)	0	–	0	–	0	–	20	–	78	–	0	–
x^{PtH_2}	H2 storage (MWh)	0	–	0	–	0	–	2,587	–	19,808	–	0	–
$x^{fuelcell}$	Fuel cell (MW)	0	–	0	–	0	–	18	–	55	–	0	–
$x^{battery}$	Battery (MWh)	27	27	27	27	0	0	135	1,087	146	4,384	29	28

The dashes (-) indicate that the technology is restricted in the particular scenario.

The lowest cost is achieved in scenario 1A, as expected. Nevertheless, scenarios 1B, 2A and 2B provide the same optimal solution. This is due to the fact that 1A does not invest in PHS or PtH_2 in the optimal solution even though they are available to the model. The additional constraints are not binding, and will thus not affect the optimal system obtained in 1B, 2A or 2B.

When diesel generators are excluded in scenario 3, investment in PHS becomes more attractive in order to replace the missing dispatchable diesel capacity, compared to scenario 1 and 2. Total system costs increase with 1.82% compared to scenario 1. PHS investments in Myru and Heyga are made, but not the one at Hvalvik, (see *table 5.2*).

Scenario 4 allows neither diesel nor PHS. Storage technologies are thus included in the optimal solution to balance the RES production. In 4A, both PtH_2 and batteries are included, and the inclusion of PtH_2 saves ~5.000 mNOK compared to 4B. The restriction on diesel generation, compared to scenario 2A, increases costs in 4A with ~20.5%.

Scenario 5 is the most restrictive only allowing wind, solar and batteries as well as PtH_2 in A. This system thus achieves the highest total cost as large capacities are installed in both wind and solar, and there are no naturally dispatchable production sources. Storage in batteries and PtH_2 is however available in 5A, and both these technologies are included in the optimal system. Compared to 5B, when PtH_2 is allowed, total costs are reduced from ~38.000 mNOK to ~15.000 mNOK.

Scenario 6 reintroduces diesel, while hydro is still not available to the model. PtH_2 is not included in the optimal solution and only a small capacity of batteries is installed. This is because dispatchable diesel production is available and is used extensively. Costs are significantly increased compared to scenarios 1 and 2 as scenario 6 has larger investments in wind, solar and diesel. Additionally, more of the production is shifted towards diesel generators which implies significant costs related to generation, unlike the less expensive hydro alternative.

6.1.1 Production

Figure 6.1 shows the original electricity production in each scenario. Original production is production from sources that do not require energy to be stored to enable dispatch of energy, i.e. wind, solar, hydro and diesel. Energy generated at hydro power plants is adjusted for energy used for pumping in scenario 3, to exclude non-original production. The red line shows the total annual demand, indicating the minimal original production requirement to meet demand. Production beyond this line is either curtailed or lost to inefficiencies in storage and dispatch from storage technologies, and indicates the extent to which the system includes overcapacities and inefficiencies.

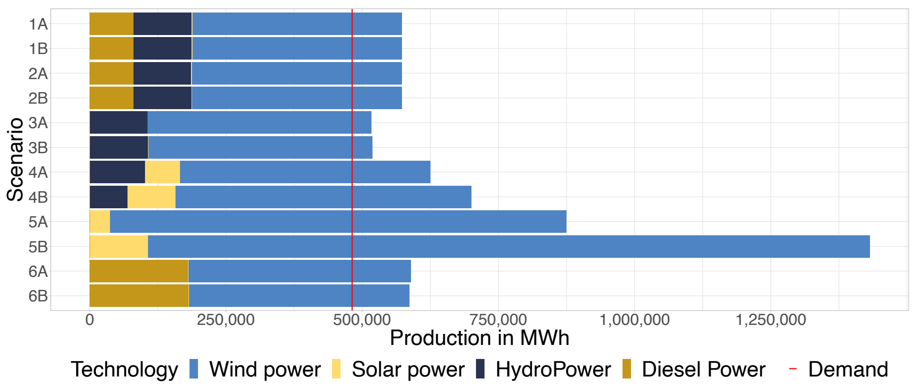


Figure 6.1: Production by each technology, compared to demand, scenarios 1-6

Table 6.3 provides the total energy dispatched from storage technologies. This is the energy dispatched to the grid after efficiency losses. Storage capacities provide significant energy to the grid in scenarios 3, 4 and 5. In 1, 2 and 6, batteries contribute with a small amount of power, but no other storage technologies contribute to the grid.

The overproduction in scenario 5 is large because the sources for renewable energy are dimensioned for periods of high demand, low wind and low solar irradiation. This makes

Table 6.3: Energy dispatched to grid from storage technologies (MWh)

	1A	1B	2A	2B	3A	3B	4A	4B	5A	5B	6A	6B
Battery	15, 870	15, 870	18, 085	18, 113	0	0	75, 970	388, 273	96, 104	1, 487, 697	19, 790	19, 212
Fuel cell	0	0	0	0	0	0	27, 098	0	107, 862	0	0	0
PHS	0	0	0	0	99,838	96,297	0	0	0	0	0	0

the system produce significant amounts of unused energy, but this is cheaper than investing in large capacities in batteries or PtH_2. However, compared to 5B, the overproduction is significantly reduced in scenario 5A, as PtH_2 is allowed. This technology allows cheaper storage of large amounts of energy compared to batteries, hereby substantially decreasing total costs, curtailment and efficiency losses.

Production from diesel generators is significant in all the scenarios in which it is included, contributing to increased CO_2 emissions.

6.1.2 Technology contribution to total cost

Figure 6.2 shows the contribution of each technology to total lifetime costs of the system, including both CAPEX and OPEX. Wind is the most apparent contributor to cost in all solutions, while other technologies have substantial costs in specific scenarios. Diesel generation is also a substantial contributor to cost in all scenarios in which it is available, largely because of its high variable production cost.

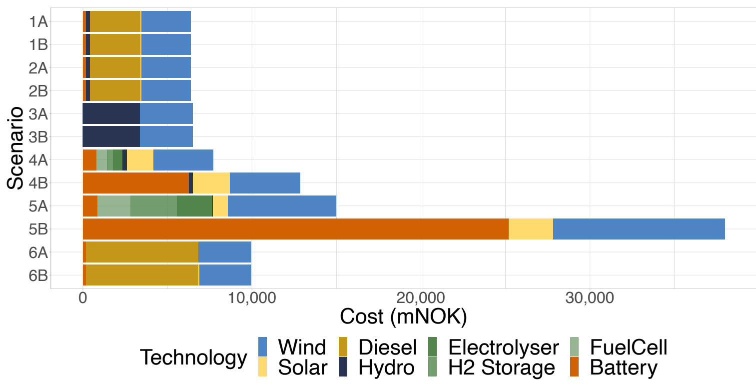


Figure 6.2: Total cost by technology, scenarios 1-6

In light of our research question, the most interesting scenarios are 4A and 5A, in which PtH_2 is included in the optimal solution. PtH_2 replaces considerable costs invested in batteries, and reduces the necessary investments in wind and solar. Because of this, PtH_2 provides significant reductions to the overall system cost in both these scenarios.

Furthermore, PtH_2 costs are also quite evenly distributed between the electrolyzer, storage and fuel cell.

6.1.3 Technology utilization

Figure 6.3 shows the utilization of all technologies in the different scenarios. The most notable finding is the difference in utilization between the electrolyzer and the fuel cell. Interestingly, the electrolyzer utilization is 43-45% in both 4A and 5A, while the fuel cell utilization is much lower at 16-23%. This can be explained by the fact that the electrolyzer benefits from working steadily on increasing the amount of stored H_2, thus having a high utilization. The fuel cell, on the other hand, requires sufficient installed capacity in order to dispatch energy in peak demand periods in which other technologies are not able to satisfy demand. This makes it reasonable to install larger capacities in fuel cells even though they will have a lower overall utilization. The fuel cell also requires sufficient amounts of stored H_2.

The hydro power utilization is restricted by the inflow into the reservoirs. In scenario 3 the utilization is however lower as the installed capacity is higher due to PHS investments that adds additional generator capacity. The added inflow from pumping increases the total generation, but not so much as to increase the hydro utilization with the higher installed capacity. In scenario 4, hydro power has a lower utilization than in scenarios 1 and 2 but has the same generator capacity. This means that inflow into reservoirs is not utilized fully. As the generator capacity in hydro power is only 39 MW, all the production above this level must stem from other sources. This induces a need for large capacities in

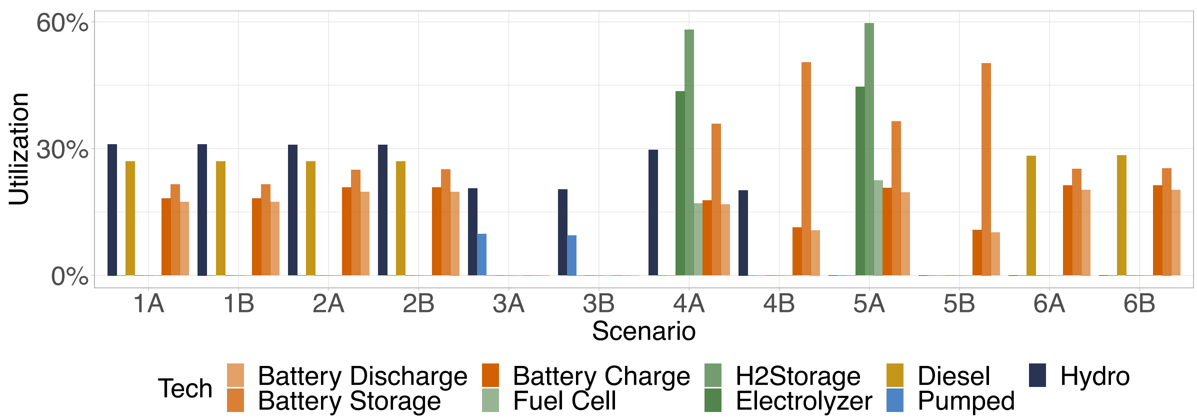


Figure 6.3: Utilization of technologies per scenario

wind, solar and batteries. These produce sufficient energy as to reduce the overall annual need for hydro power. This can indicate that excess generator capacity in hydro would be attractive.

Diesel generators have stable utilization at around 28% in all scenarios in which it is included.

6.1.4 H_2 storage and energy consumption

Figure 6.4 plots the stored energy in H_2 for scenarios 4A and 5A over the course of one year, showing that there are multiple cycles of production and consumption of H_2 throughout the year. Despite the Faroese seasonal variations in wind speed, precipitation and solar irradiation, PtH_2 is not solely used for storing energy from summer to winter or vice versa. For scenario 5A, we do observe that the storage is completely filled around hour 6100, and then completely emptied in the following 900 hours, or 37 days. During this period, the demand is increasing and the production from solar is decreasing, see *figure 3.1a and 3.3*. Additionally, the production from wind turbines is not particularly high (*figure 5.2*). In scenario 4A, the storage is completely filled and emptied several times during the year.

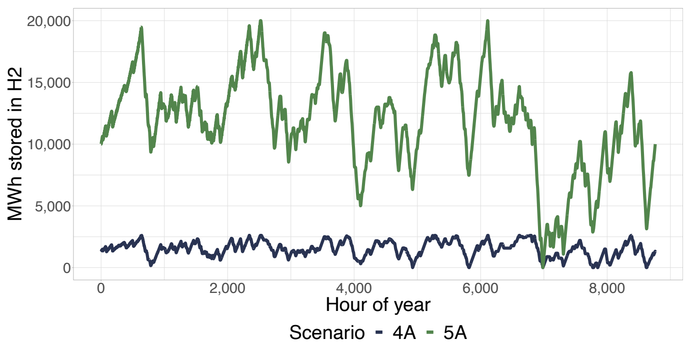


Figure 6.4: H_2 storage in MWh, scenarios 4A and 5A

Figure 6.5 provides an overview of consumption of the generated energy. This includes the energy generated from RES, diesel, as well as energy dispatched from PtH_2 and battery storage. In most cases, the demand accounts for the largest share of energy usage. Note here that energy consumed by storage technologies are counted twice, first when stored and secondly when re-dispatched into the grid for consumption.

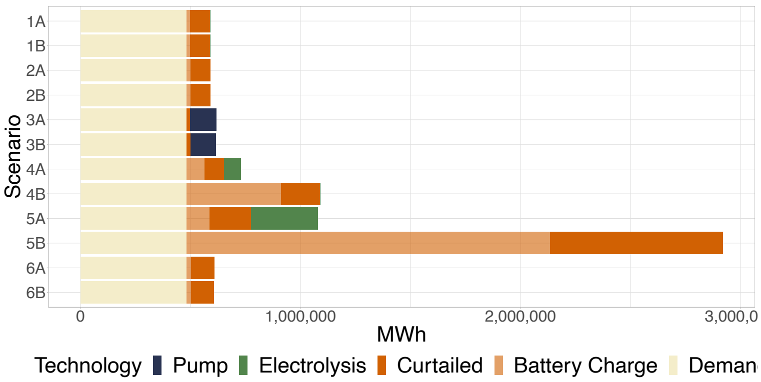


Figure 6.5: Consumption of energy by source, scenarios 1-6

Some energy is curtailed in all scenarios, although much more in 5B than in any other scenario. Additionally, energy consumed by storage technologies also suffers efficiency losses when stored or re-dispatched, depending on the technology used.

In 5B, ~57% of dispatched energy is directed to battery storage, and ~27% of total dispatched energy is curtailed. This corresponds to ~163% of annual demand. In all other scenarios, curtailment accounts for less than 20% of total energy dispatched, and the total energy dispatched is significantly lower due to less energy being sent through storage technologies and being counted twice. In both scenario 4 and 5, the curtailment increases in B because PtH_2 is not allowed. This is due to the reduced ability of the system to postpone consumption of generated energy, increasing the need for larger investments in excess capacity in wind and solar.

6.2 Sensitivity analyses of increasing RES penetration

These analyses seek to investigate how higher RES penetration and lowering the negative environmental emissions affects the total cost of the system. This trade-off is studied through three sensitivity analyses where the model is solved for various limits on diesel generation, incrementally allowing larger shares of diesel production. We do not make specific calculations on CO_2-emissions and we assume diesel generators are the only production source generating negative environmental impacts in operation. Emissions and environmental impacts from production of the installed capacity in each technology are important environmental factors, but quantifying and including these in the model falls outside the scope of this thesis.

For each sensitivity analysis, the model is looped over a set of diesel generation limits ranging from 0% to 32.5% with 2.5% increments. This is shown in constraint (4.30) in which the j-parameter represents the limit as share of total annual demand. The model is re-solved for each constraint. The range of limitations on diesel generation is chosen so that PtH_2 is not included in the least restrictive model in each scenario.

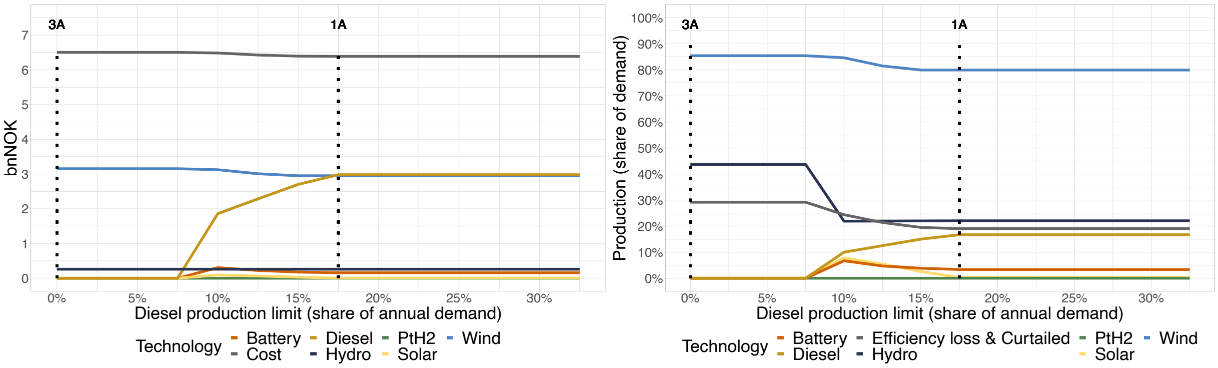
The sensitivity analyses correspond to the main scenarios according to which technologies are included. The first analysis includes all technologies, and corresponds to the solution obtained in scenario 3A at the 0% limit, and 1A from the 17.5% limit and up. The second analysis excludes investments in PHS, and the solutions obtained by the increasing diesel limit corresponds to scenario 4A at the 0% limit and 2A from the 17.5% limit and up. The third analysis excludes hydro power and PHS investments altogether. At the 0% limit, the solution corresponds to scenario 5A. Scenario 6A falls outside the analysis as we do not increase it to the point that it becomes non-binding.

The limits are set on the total annual production from diesel generators, rather than the generator capacity, as the generation is the cause of operational emissions. The installed capacity of diesel generators in itself does not create emissions when it is not in operation (ignoring emissions from production of the generators). Furthermore, we set the limit as a share of total demand, limiting how much of the demand can be satisfied with diesel generators. This allows the system to utilize the full capacity of diesel generators in peak demand periods with low RES production. However, it restricts the model from using the generators to provide base power in the system throughout the year instead of installing RES.

6.2.1 Analysis 1: All technologies included

Displayed in *figure 6.6a* is the total cost and costs associated with each technology for increasing diesel production limits. For every iteration up to the 7.5% limit, the optimal solution remains unchanged corresponding to the solution in scenario 3A. This solution includes investments in Myru and Heyga, but not in Hvalvik (see *table 5.2*). Interestingly, in all these cases, diesel generation is kept at 0, even though it is available. When the diesel limit reaches 10% or more, PHS investments are no longer optimal and production is shifted to diesel generators. The diesel production increases significantly, and up to the 15% limit both solar and batteries are included in the proposed system. From the

17.5% limit and upwards, the solution is stable, corresponding to the solution achieved in scenario 1A.



(a) System and technology costs **(b)** Production as share of demand

Figure 6.6: Sensitivity analysis 1, cost and production

Cost increases occur in the interval from the 20% to 7.5% limit, although the total increase in lifetime costs is relatively small at 250 mNOK, corresponding to <4%. In this interval, wind investments increase while solar and batteries are positively included. PtH_2 is not a part of the optimal solution for any limit when both PHS and hydro are available. Below the 7.5% limit, the solution corresponds to the solution in 3A.

As CAPEX in existing hydro capacity is not included in our model, the cost associated with hydro gives a somewhat skewed picture of the extent to which it is included. *Figure 6.6b* provides the production from each source, in which it is fairly evident that hydro is still an important contributor to energy production, delivering ~23% of demand even after diesel has taken over for new PHS investments at the 10% limit.

Even with significant hydro capacity, we observe that the generation from wind power is by far the largest source of energy. This is partly explained by the overcapacity that is needed in wind power, as the turbines produce regardless of the demand. This overproduction is to some degree utilized by storage technologies, especially PHS up to the 7.5% limit. We observe that total curtailment and efficiency losses decrease when diesel is included, as the needed capacity in intermittent wind power is reduced. Additionally, batteries and solar are included to a certain degree. Batteries reduce curtailment by allowing storage, while solar reduces the need for wind turbines, by providing other means of production. As production from solar and wind is not perfectly correlated, solar power can provide energy in some periods in which there is no wind, and vice versa, thus potentially reducing curtailments.

As shown both in *figure 6.6a* and *6.6b*, PtH_2 is not included when hydro and PHS is available. This is also apparent in the results from scenario 3A and 1A, which corresponds to the 0% and the 17.5% solutions presented in the graphs.

Figure 6.7 displays the installed diesel capacity (x^{diesel}) for all three sensitivity analyses. The blue bottom line shows that diesel is utilized at the 10% limit and upwards when PHS is available (Analysis 1). From the 10% limit and upwards, it corresponds to the installed capacity when PHS investments are unavailable, which is reasonable as the PHS restriction is no longer binding (Analysis 2). The green line displays the diesel capacity installed when hydro is excluded entirely (Analysis 3).

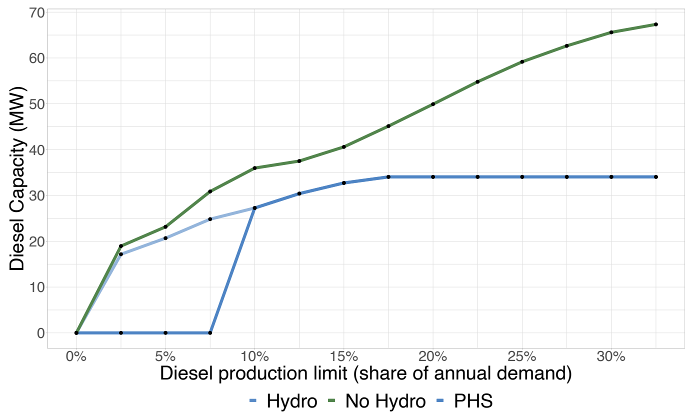
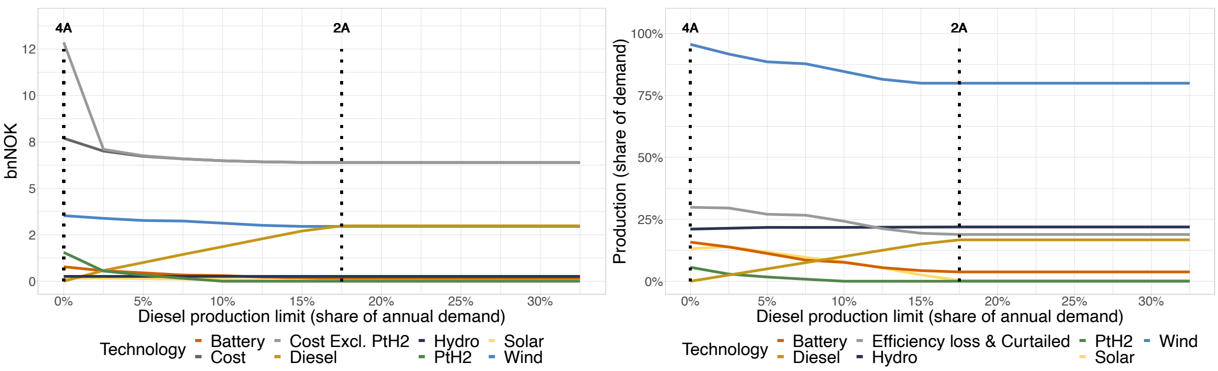


Figure 6.7: Diesel capacity installed in sensitivity analysis 1, 2 and 3

6.2.2 Analysis 2: Excluding PHS investments

Figure 6.8a shows system costs when investments in PHS are excluded. At 0%, the solution corresponds to the solution in scenario 4A, while from the 17.5% and upwards it corresponds to the solution in scenario 2A. When PHS is excluded, PtH_2 is included in the optimal system for all solutions up to the 7.5% limit. After this, the other technologies



(a) System and technology costs

(b) Production as share of demand

Figure 6.8: Sensitivity analysis 2, cost and production

are more efficient in producing and balancing the system to satisfy the demand in the grid. We also observe that significant investments are made in solar power for the most restrictive diesel limitations. Both the solar, PtH_2 and battery capacity is replaced by diesel generators as the limit increase. Some of the wind turbines are also replaced.

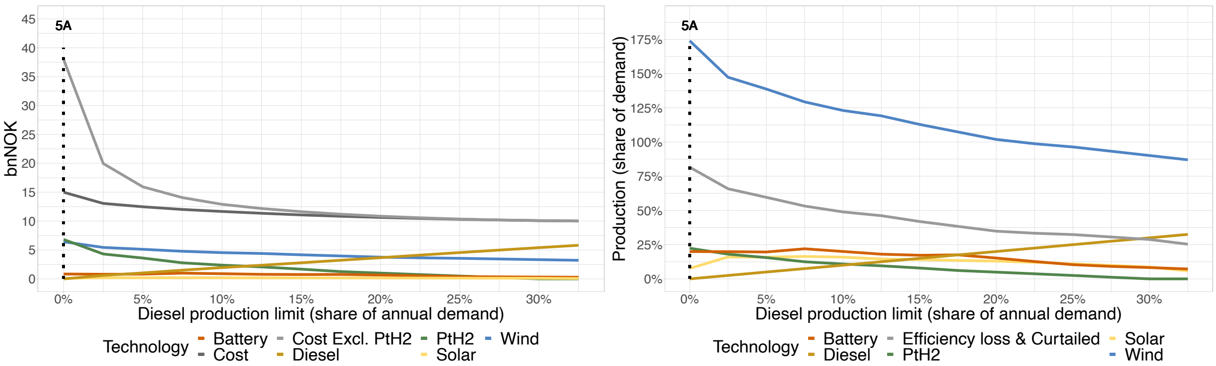
Analysis 2 shows that when PHS is excluded, the diesel limit becomes non-binding above the 17.5% limit. Increasing the RES penetration by imposing a tighter restriction on diesel generation increases costs. Reducing the limit to 10% almost halves the emissions, and only increases costs by 1.5%, regardless of the availability of PtH_2. Restricting the model further from 10% to 2.5% increases costs by ~8% when PtH_2 is available, and by ~9.4% when it is not. Finally, the transition to 100% RES penetration, or imposing a 0% diesel limit, increases costs by an additional 9.8% with PtH_2 and 81% without PtH_2. This shows that PtH_2 can be a valuable contributor to reduced total costs in the shift towards RES penetration.

There is a slight increase in efficiency losses and curtailment from the 0% to 2.5% limits as more solar power is included, and storage capacity in both PtH2 and batteries is reduced, thus increasing the need to curtail energy. Hydro production remains stable, while PtH_2, batteries and solar are gradually replaced by diesel generation. Substantial amounts of wind turbines are also reduced as diesel generators are included to a larger extent.

As shown by the green line in *Figure 6.7*, diesel generator capacity increases gradually until reaching ~34 MW at the 17.5% limit, after which it is stable.

6.2.3 Analysis 3: Excluding hydro power and PHS

In this analysis, both hydro and PHS investments are unavailable to the model. At the 0% limit, the solution corresponds to the solution obtained in 5A, see *figure 6.9a* and *6.9b*. If the limit were increased sufficiently, beyond 32.5%, the solution would correspond to the one obtained in 6A, this however falls outside our graphs. The general trend is similar to the one in sensitivity analysis 2. As diesel is restricted, it is gradually replaced by PtH_2, batteries, wind and solar production. This increases total costs of the system. However, when both hydro and PHS are excluded from the model, PtH_2 contributes more to providing a cheap system that balances production and storage to meet demand, compared to analysis 1 and 2.



(a) System and technology costs **(b)** Production as share of demand

Figure 6.9: Sensitivity analysis 3, cost and production

Figure 6.9a shows the costs of the system and its components when including PtH_2. It also shows the total costs of a system if PtH_2 were not available. PtH_2 is included for all diesel limitations from 0% to 27.5%. We observe that increasing the RES penetration (restricting diesel production) increases the costs significantly more when excluding PtH_2, and this becomes more pronounced as the limit gets closer to 0%. Reducing the limit from 30% to 15%, halving the emissions of the system, increases costs by 9.8% when PtH_2 is available, and by 15.3% when it is not. Further reducing the emissions to one third, at the 5% limit, the costs increase by an additional 12.7% and 36.9% with and without PtH_s. Thus the benefit of allowing PtH_2 is significant. Finally, completely eliminating emissions makes PtH_2 highly attractive when hydro and PHS is unavailable. The final 5% reduction increases costs by 20.1% when PtH_2 is included, and by 138% when it is not, showing the significant benefit of PtH_2 in this particular case.

When excluding both hydro and PHS, the curtailment and efficiency losses naturally increase. Larger capacity in wind and storage technologies is needed to fulfill the demand and balance the system. We observe that as RES penetration increases, larger and larger overcapacities are necessary to fulfil the demand at a low cost. This is observed by the significant increase in the production from wind turbines. A result of this is that the efficiency losses and curtailment increase significantly, due to larger overcapacities in RES.

7 Discussion

In this chapter we start by discussing the general characteristics of a stand-alone power grid in light of our case study. We then discuss the relative attractiveness of the included storage technologies, comparing their strengths and weaknesses. We proceed with a discussion of the trade-off between increased RES penetration and increasing costs, as well as assesing the attractiveness of PtH_2 when targeting a 100% renewable energy system. We then present preliminary conclusions on the relevance of PtH_2 before we discuss the validity of our results and present external factors that might impact our preliminary conclusions.

7.1 General characteristics of a stand-alone power-grid

Based on our research and the model results, we observe that there are two main aspects of a system such as the one we model. Firstly, the overall energy production must be sufficient to meet the total demand. Secondly, the production must be timed so that the demand can be satisfied for every hour of the year, not only as an accumulated total. A trade-off between cheap energy production and dispatchable technologies that enables control of the production over the time-dimension is of key importance to achieve low total costs.

This trade-off also relates to the trade-off between curtailment and efficiency losses. Large overcapacity in inexpensive RES leads to large curtailment, as excess energy is not utilized. On the other hand, establishing large storage capacities is expensive and leads to storage efficiency losses, thus also reducing the total utilization of generated power. Even though eliminating efficiency losses completely might seem optimal in some senses, they are unavoidable whenever RES penetration increases to the extent that it exceeds demand. The energy must then either be curtailed or stored, leading to efficiency losses either way. From a cost-efficiency or an environmental perspective, some efficiency losses are likely to be optimal as RES production is relatively cheap and environmentally friendly, counteracting the effect of efficiency losses.

RES such as wind and solar provide relatively cheap energy production, but are hard to utilize fully as the generation is not dispatchable, as discussed above. Diesel generators and hydro are dispatchable production sources, providing means of balancing the grid. Diesel generation has a negative environmental impact and is generally expensive due to high variable production costs. It is however dispatchable, simple to implement and only restricted by the availability of imported diesel. Hydro is limited by the topography and climate of the given location. Furthermore, hydro can be combined with the installation of pumps, extending its potential to also be an active storage method. Batteries and PtH_2 are other active storage methods, although all the energy stored must originally be produced by another source of generation. Furthermore, there are significant efficiency losses associated with these storage technologies, and their costs are generally high.

7.2 Comparison of storage technologies

In our system, we consider three active storage technologies: PHS, li-ion batteries and PtH_2. PHS provides a high roundtrip efficiency of ~83% but requires significant investment costs and a suitable topography. The investment costs also depend on the topography and climate of the specific location, potentially increasing costs. Furthermore, PHS has close to zero variable OPEX, but some fixed OPEX given the installed capacity.

Batteries have high roundtrip efficiencies of 91%, but suffer from self-discharge over time. Furthermore, the investment cost of batteries is high, but as their charge and discharge times are low, the energy stored can quickly be dispatched to the grid.

PtH_2 requires both an electrolyzer, storage tanks and a fuel cell. The roundtrip efficiency is relatively low at ~35.5% due to low efficiency in both electrolyzer and compression (71%), and fuel cell (50%). Even though the PEM electrolyzer and fuel cell are expensive system components, a major benefit of PtH_2 is the cost of storage itself. Storing 1 MWh of energy in hydrogen costs approximately 3.5% of storing the same energy in a battery, not including costs related to the electrolyzer or the fuel cell (Petkov and Gabrielli, 2020). Additionally, in PtH_2 the storage capacity can be scaled independently from the conversion capacities, enabling large storage with small conversion capacities.

Based on these inputs to the model, we understand the general trade-off between storage technologies. PHS is generally best given that the topography allows normal investment costs. Batteries are advantageous when storing smaller amounts of energy over shorter periods of time as they are highly flexible in operation and have a relatively high efficiency.

Batteries do however have a high CAPEX, and are too costly to be an attractive option to store large amounts of energy over longer periods of time. PtH_2 is a cheap storage method, but the conversion of energy to and from H_2 is inefficient and conversion capacity is expensive. Thus, PtH_2 is best for slowly building up a large storage of H_2 with a small electrolyzer over time. This large storage is relatively cheap, and can be utilized to cover longer periods of low production from wind or solar through a fuel cell.

7.3 RES penetration and increasing costs

The Faroe Islands are targeting a 100% renewable energy system by 2030 (Katsaprakakis et al., 2018), an achievable ambition based on our results. The Faroe Islands have high winds and a topography that allows significant capacities in wind and hydro power. There is also a potential to extend the current hydro power capacity to include pumps, allowing active storage through PHS. Achieving a 100% renewable system implies excluding diesel generators, as shown in scenario 3A. This system is just marginally more expensive than the overall lowest cost in scenario 1A. Imposing diesel-restrictions and achieving a 100% renewable energy system increases the 20-year lifetime costs by 1.82%. Neither of these scenarios include any capacity in PtH_2, and our results thus indicate that PtH_2 is not an attractive technology to utilize at the Faroe Islands due to the alternative potential for active storage available in PHS.

In a hypothetical location with similar weather conditions as the Faroe Islands, but without the topography to enable significant hydro power capacity, PtH_2 becomes more attractive. This can be seen in sensitivity analysis 3. *Figure 6.9a* provides the same solution as 5A at the 0% diesel limit. Increasing RES-penetration by limiting diesel production from 30% to 15% increases costs by 9.8%. The reduction from 15% to 5% increases costs by an additional 12.7%, while the final 5% reduction increases costs further by an additional 20.1%. The corresponding cost-increases in a system excluding PtH_2 are significantly higher, at 15.3%, 36.9% and 138% respectively. From this it is apparent that there are increasing marginal costs of reducing emissions, and the trade-off between high costs and low emissions becomes evident. In a hypothetical system as this, a goal of 100% renewable energy production might not be optimal. From an economic standpoint, it is expensive, and from an environmental standpoint, the added cost might be better spent on other alternatives for emission-reduction. We do not make specific calculations on the emissions, and we do not suggest how this trade-off should be considered. Nevertheless, the significantly increasing marginal costs to emission reduction is an important aspect of a system such as the one we model, especially when hydro power and PHS are unavailable.

We also note that it is reasonable to consider maintaining diesel generators as a backup. They can be used if there are failures in the system, or if the demand exceeds the expected peak and there is no stored energy available to cover the excess demand.

The discussion of the cost-emission trade-off presented above is somewhat simplified. It excludes emissions and other negative environmental impacts from production and installation of the different technologies. This can include emissions from manufacturing, consumption of limited resources such as water, metals, available land-space, or the installation or production itself can affect wildlife or nearby human population. The estimation of such negative impacts should not be neglected when developing a system intended to minimize emissions or environmental impacts. Even though we cannot conclude how this would impact the optimal system exactly, we can present some potential effects. As an example, reducing the available diesel generation could potentially induce a need for overcapacity in wind turbines, as seen in sensitivity analysis number 3, *figure 6.9b*. However, the environmental impact from the additional overcapacity in turbines might outweigh the emissions saved from limiting the diesel generation, counteracting the intention.

7.3.1 Preliminary conclusion of PtH$_2$ attractiveness

The results as obtained by the model show that PtH$_2$ is an attractive option in scenarios 4 and 5. It provides total lifetime cost-savings of 5.161 bNOK and 22.988 bNOK respectively. Both these scenarios exclude diesel generation and investment in PHS. Scenario 5 excludes all types of hydro power.

Relating to these scenarios are the sensitivity analyses 2 and 3 respectively. *Figure 6.8a* in sensitivity analysis 2 shows that allowing only 2.5% production from diesel generators eliminates most of the savings from PtH$_2$. There are however still savings even at the 5% and the 7.5% diesel production limits. However, sensitivity analysis 3 shows that PtH$_2$ provides significant cost-savings even when diesel generation is included to a larger extent.

Even though the savings of including PtH_2 decrease significantly with increasing diesel production, the savings at the 15% diesel limit are still 564 mNOK, or about 4.9%, as portrayed in *figure6.9a*. From an environmental perspective, reducing emissions by 92.3%, from the 32.5% to the 2.5% diesel limit, costs 3.045 bNOK when including PtH_2 and 9.951 bNOK when PtH_2 is restricted. Thus, allowing PtH_2 can significantly contribute to reducing the costs of shifting production towards RES when hydro power is not available.

Our results suggest that PtH_2 has significant potential to reduce total system costs. These results are however limited to the specific scenarios in which there is little to no available production from dispatchable sources, and active storage in pumped hydro is unavailable. We thus conclude that technology for hydrogen production and storage at the current time is not a generally attractive storage solution. However, in some specific cases where dispatchable production is limited and import of electricity is unavailable, the technology can provide considerable benefits in terms of cost savings. When dispatchable production is only available from non-RES, such as diesel, PtH_2 can contribute significantly to the shift towards RES production by reducing costs of balancing systems with larger penetrations of RES.

7.4 Validity of results

Generally, the results presented in this thesis are intended to highlight the most relevant aspects affecting PtH_2 inclusion in an optimal off-grid, stand-alone energy system, rather than determining the exact system to implement at the Faroe Islands. To assess the validity of our results, we discuss the most important simplifications and limitations of the model as well as external factors that can impact the results presented. We comment on how we believe this impacts the results.

7.4.1 Deterministic model

The model developed is deterministic, meaning that there is no randomness in the model. We use a single set of data in all scenarios, and we do not consider stochastic parameters. The data for demand is not from the same year as the weather data, but they are matched on dates to best capture the seasonal covariance in the data.

As we have a deterministic model, we can identify specific hours of the year that might impact the model more significantly than others. An interesting observation is that hour 8002 is the hour without any wind or irradiation that has the highest demand, 73.6 MWh. This sets a lower limit on the total production capacity that must be available through other sources, either hydro, diesel, batteries or PtH_2. In all scenarios, the total implemented generation capacity across these technologies is larger than this lower bound, and this is thus not the sole restrictive hour for the model.

Even though the model is deterministic, we believe it provides interesting results as the general trend and covariance of data is sufficiently captured. It is reassuring that the observation at hour 8002 does not restrict the model in any scenario. Variation in the data would likely impact the final investments in each technology slightly, and this would be important if the model were to be used to determine the exact system to be implemented on the Faroe Islands. Our thesis is however focused on capturing the general trade-off between technologies, and we believe a deterministic model is sufficient in determining the relevance of PtH_2 technology in balancing an isolated energy system. We are confident that normal variation in the data would provide similar results in terms of PtH_2 inclusion in every scenario.

7.4.2 Perfect foresight

The model is operated with perfect foresight, meaning that it knows what the weather and demand will be like for the entire year when running the optimization. This enables the model to optimize perfectly given the input data, which in reality would not be possible. For example, by knowing how long energy will be stored before being dispatched, the model can decide on the "optimal" storage technology for that extra energy. This implies that a real system operating on set rules for when and where to dispatch energy would require additional capacities to account for the losses caused by sub-optimal operation given the difference between expected and realized parameters such as weather and demand. This also affects the final price and capacities installed in the system, and makes the model less relevant for deciding on an exact system to implement. However, our intention is to evaluate the general relevance of PtH_2, and we believe this model with perfect foresight is sufficient in determining this relevance.

7.4.3 Geographic area seized by the proposed systems

The optimal systems found in some scenarios are quite land-intensive, meaning that they require significant space to implement. Scenario 5B implements 351 wind turbines and 158 MW of solar capacity, requiring significant space which might not be available. Even though we have taken this into account when setting restrictions for the maximum capacity to be installed, this could imply political or physical constraints in the geography of the island, or go against public opinion. The implemented capacity of 19,808 MWH (600,000kg) H_2 storage in scenario 5A also requires a significant amount of space. This corresponds to 1,200 pressurized tanks of 500 kg each, requiring roughly 10,000-15,000 m^2. The area itself is likely not to be restrictive, but the safety and regulations of implementing such large capacities of hydrogen storage needs to be considered. There might be limitations on how much hydrogen can legally be stored under high pressure, or there might be safety or security requirements that increase the costs of the implementation.

There are however other options that can potentially be capable of tackling this problem. In Sweden there exists natural gas storage systems in lined rock caverns, able to store 740 tonnes of hydrogen at 200 bar (Andersson and Grönkvist, 2019). This could potentially be a more attractive solution for storing the amounts proposed by our model in scenario 5A. However, this option cannot be implemented anywhere as it requires the right geological conditions. We do not evaluate the possibility of doing this, but note that such large hydrogen storage systems are possible given the right conditions.

7.4.4 Faroe Island-specific parameters and data

The case study of the Faroe Islands means we consider input parameters and data that are applicable specifically to the Faroes. The optimal solution will likely differ significantly if the model were applied in other locations with different characteristics.

The currently installed hydro power capacity of 39 MW on the Faroe Islands is included in the model without CAPEX. This is done for several reasons. Firstly, it is difficult to estimate the investment cost of building the reservoirs and the generator capacities at the specific location. Secondly, as the hydro power capacity is already installed and has traditionally been used to a great extent in the Faroes (SEV, nda), it is reasonable to believe it is an attractive production option to include in the system. We thus omit these costs as they are unlikely to affect the relative trade-off between the other technologies. The attractiveness of hydro power is unlikely to be reduced as diesel is restricted or as additional non-dispatchable capacities in wind and solar are included, as these require balancing. Furthermore, in scenario 3A and 3B, additional investments in hydro power are made, confirming that additional hydro power (with pumped capacity) is an attractive option when diesel production is excluded.

The weather and demand data used in the thesis is also Faroe Island-specific. In a hypothetical off-grid scenario such as in an isolated desert community, the model would likely yield a solution where solar panels would account for the majority of electricity production. Furthermore, as desert climates are relatively stable in regards to high daily temperatures and solar irradiation, it is likely that solar production can cover the majority of demand. Long-term storage options for grid-balancing will thus be less relevant to implement in such a scenario as the storage requirements would mostly be to cover demand during the night. This illustrates that the results are likely to vary depending on the specific location of the system, and our results can not directly be generalized to other climatic zones.

As shown in *figure 4.1*, the system modeled only considers wind, solar hydro and diesel generators as original production technologies. There are numerous other potential technologies that can be used, such as biomass, tidal and nuclear energy. Additionally, there exists other storage technologies not included in our model. Most promising is that of compressed air energy storage (CAES), which might have a potential for seasonal energy storage. It is reasonable to believe that allowing additional technologies could alter the results as presented from our model, as the trade-off between cheap production and balancing through storage will change. If additional production sources are available, grid-balancing might become less challenging. If the additional sources are dispatchable, they are undoubtedly good for balancing the system. However, even if they are non-dispatchable, they can contribute by diversifying the production so that the total generation is more stable and predictable. We do however believe the most important technologies used at the Faroe Islands are included, and that this provides interesting results. However, for a specific implementation of PtH_2, all possible technologies should be considered.

7.4.5 Future developments

The analyses presented in chapter 6 do not consider uncertainty in the input parameters, expected technology improvement or innovations in alternative energy storage options leading to reduced costs or increased efficiencies. With the search for clean energy solutions, technology improvement and innovation is impacting many industries.

Multiple energy storage solutions are under development that can potentially compete with PtH_2 to become the favorable choice for energy storage. In addition to existing CAES technology, emerging startup companies are looking into various ways of storing energy through technologies such as underground pumped hydro storage, liquid air storage and new battery technology (StartUs Insights, 2020). Many of these emerging technologies might have universal potential for grid-support and balancing and compete with H_2.

Hydrogen innovation and initiatives

In order to constitute a more cost-effective solution, funding and production scale-up of PtH_2 technology is necessary. The International Energy Agency (2019) in a report conclude that the time is right for governments and industries to scale up technologies and bring down costs to allow for an increased use of hydrogen energy solutions.

Schmidt et al. (2017) estimate that for water electrolysis technology, R&D funding can reduce capital costs by up to 24% within 2030. Production scale-up alone has a cost reduction impact of up to 30%. Furthermore, some improvements in the lifetime of such systems are expected given significant R&D spending. The efficiency improvements to the technology are likely to be small. H_2 storage technology is also under development, and if technologies such as metal hydride canister storage becomes commercially available for large-scale storage, H_2 storage could be achieved in a more secure way and require far less space to install. Metal hydride also reduces the need for H_2 compression, thus saving electricity used in compressors. With the increasing demand for clean fuels in the mobility industry, PEM fuel cells for electric vehicles emerge as a potent candidate. Even though the transport sector is the primary driver of technological innovation, R&D for general PEM fuel cell technology will increase, thus also spurring growth and improvement in the stationary fuel cell segment (Fortune Business Insights, 2018). As with electrolysis technology, improvements in fuel cell technology can be expected in terms of costs and durability. In spite of this, the expected improvements in efficiency are small (Kim et al. (2016); Whiston et al. (2019)). The global PEMFC market size is projected to reach USD 47.6 billion by 2026, a substantial increase compared to USD 0.91 billion in 2018.

The importance of utilizing hydrogen technology on a large scale has received increasing attention in later years. Companies such as the U.S.-based truck company Nikola is investing heavily in hydrogen technology for long-haul transport (Nikola Motors, 2020), and Airbus is committed to bringing zero-emission, hydrogen-based commercial aircrafts to market by 2035 (Airbus, 2020). In December 2017, the Government of Japan (2017) launched a strategy to reach net-zero emissions by 2050 through extensive investments in hydrogen technology. The European Commission (2020) did the same for Europe in July 2020. With substantial investments to support hydrogen projects, in addition to considerable tax reductions for companies investing in hydrogen technology research, development, infrastructure and production, costs associated with hydrogen technology can be substantially reduced. Strategies such as these have the potential to attract investors and accelerate the energy shift towards a widespread use of renewable energy sources and hydrogen production and consumption on a global basis. According to Bank of America (2020), the shift to a hydrogen economy can provide investment opportunities of USD 11 trillion over the next 30 years.

Even though we feel confident that PtH_2 is likely to be part of the solution for some stand-alone energy systems, we cannot exclude the possibility that technology improvement and innovation of cheaper and more efficient energy storage solutions will provide lower costs to the overall system. Depending on how the various technologies develop, the least-cost system will change. A more thorough investigation of the expected developments in technologies and the impact of innovation in RES production, PtH_2 technology and its competing energy storage solutions should be completed to fully understand the value of PtH_2. With that being said, hydrogen energy solutions are gaining traction in industries and governments worldwide. Their combined initiatives have the potential of improving PtH_2 technology in general, allowing for a widespread utilization of hydrogen energy solutions. This can not only strengthen the role of PtH_2 as a method of balancing electrical grids, but reinforce its stance in the global energy economy as a whole, which can help ease the transition to a more widespread use of clean, secure and affordable energy solutions.

8 Conclusion

The purpose of this thesis is to determine what characteristics of a multi-energy system make hydrogen energy storage technology, PtH_2, an attractive option to balance the power in an isolated off-grid power system. By attractive, we refer to cost-efficiency, meaning how PtH_2 can contribute to reduce lifetime costs of installing and operating a system able to satisfy the continuous demand of the grid.

Purely by assessing the technical characteristics of PtH_2 technology, we understand some elements that potentially make hydrogen a cost-effective storage medium. The round-trip efficiency of PtH_2 is relatively low, and costs associated with conversion capacities both to and from hydrogen are significant. However, a major benefit of PtH_2 is that the costs of storage itself is relatively cheap, enabling large-scale energy storage over longer periods of time. Furthermore, the individual components of PtH_2 can be scaled individually, allowing small conversion capacities to slowly build up a large storage of energy over time to cover longer periods of underproduction from RES.

The results presented in chapter 6 reinforce this belief. Hydrogen energy storage can be a highly attractive technology whenever dispatchable production from other sources is limited. Specifically, we find that in the absence of hydro power, PtH_2 can be a significant contributor to reducing overall system costs. This can be especially relevant for governments seeking to reduce emissions by increasing RES penetration. Additionally, when diesel generation is restricted and the potential for hydro power is sufficiently limited, PtH_2 can contribute to significant cost reductions for the overall system. It is however important to note that the scenarios in which PtH_2 is attractive are highly specific, and we can not generally conclude that PtH_2 is an attractive storage technology for stand-alone grids.

Through the discussion we present additional external factors that might impact the results presented in chapter 6. As hydrogen has received an increasing amount of attention and significant resources are applied to improve the technology, it is reasonable to assume that the attractiveness of PtH_2 will increase compared to alternative technologies. However, significant research is also conducted on other storage technologies, and there are numerous startups seeking to provide new and better storage solutions. Additionally, the results we present are specific to the case of the Faroe Islands. Taking additional storage or production technologies into consideration might yield different results. In general, any potential application of PtH_2 should be evaluated individually to account for all local factors that can impact the attractiveness of PtH_2.

We do not currently believe hydrogen energy storage will receive a widespread application in electricity grids, but we do believe it can significantly contribute to reduced costs in specific cases in which alternatives are not sufficiently available. How the technology develops and what other alternatives emerge, remains to be seen. Hydrogen will undoubtedly have a role in the future of the worlds' energy solutions, but the extent to which it is applied as a method of grid-balancing, is yet to be determined.

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