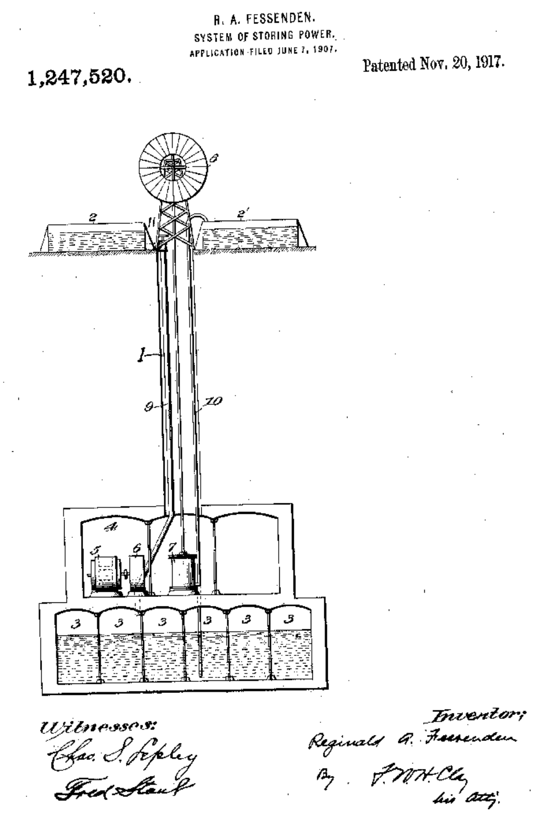
Benefits of Underground Pumped Hydro Storage (UPHS) in the Dutch power system



Schematic drawing of Underground Pumped Hydro Storage (UPHS) in the first UPHS patent, by R.A. Fessenden *(Fessenden, 1917)*.

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1 SUMMARY

Since COP21 there is international agreement on the problems caused by anthropogenic greenhouse gas emissions. These emissions originate for a substantial part from electricity production from fossil fuels. Most countries already invest in a transition towards renewable electricity production from solar and wind resources. The challenge is concerned with the intermittent nature of these renewables. Energy storage and demand response are both regarded as possible solutions to this challenge. However, a flat country like the Netherlands seems to be at a disadvantage with its unsuitable geography for the worldwide most common energy storage system; pumped hydro storage (PHS). The solution was proposed in a PHS that has an underground lower reservoir connected to a surface reservoir, thereby requiring no geographically elevation to be present.

This research investigated the possible benefits that can be achieved with underground pumped hydro storage (UPHS) in the Dutch power system. Literature research provided the results for possible benefits that UPHS could provide to a power system in general. Additionally, a model of the Dutch power system was developed using PLEXOS modeling software. The UPHS was compared to both battery energy storage (BES and BESXL) and demand response (DR), using scenarios. The model was run with each scenario for the model years 2017, 2020, 2025, 2030 and 2035. These future years had increased renewable capacity and shrinking thermal power generator capacity for each subsequent model year. The results from the model runs provided the basis for comparing the performance of UPHS, BES and DR in the Dutch power system.

Both literature research and model runs indicated that several benefits can be expected from implementing UPHS in the Dutch power system. The most important benefits are: The substantial reduction in unserved demand when thermal generator capacity cannot meet demand (observed in the 2035 model year). Less flexibility burden on thermal power generators, which results in less costs and less renewable curtailment. And the possibility store renewable production surpluses, thereby helping reduce the amount of CO_2 emissions from the power system.

The model results showed that the UPHS outperformed DR on all aspects, except the average electricity price which was lower in the DR scenario. The performance difference with the battery storage scenarios (BES and BESXL) is limited, as both energy storage technologies are similarly used in the power system. Further comparison showed that the benefits of UPHS compared to the BES are: Its dedicated application as grid energy storage, its longer lifetime and the possibility to implement it at a large scale. UPHS does not have to compete with other applications for key components. Battery based grid storage on the other hand will have to compete for Li-ion cells with the increasing electrification in the automotive industry. The substantial difference in lifetime of the storage systems also result in a favorable case for the UPHS system compared to BES. In the long run UPHS may even compete with gas turbines as peak load generator, because both have a similar COE (costs of electricity) in the 2035 model year.

2 PREFACE

This master's thesis was performed in context with promotional research that is performed at Utrecht University to the subject of Underground Pumped Hydro Storage in the Netherlands. My personal interest was triggered for the subject, due to its relevant nature and the possibility to contribute to knowledge on improving the sustainable performance of the national power system.

3 ACKNOWLEDGEMENTS

I would like to thank my supervisor, prof. dr. G.J. Kramer, for supporting me in the process of writing this thesis and providing me with feedback. The moments of feedback especially helped me to put the results of this research into perspective. A special thanks is expressed to ir. W.G. Zappa, for providing me some guidance in using PLEXOS modeling software.

This thesis would not have been possible without the publicly available data from; ENTSOE-E, KNMI and other data sources that are mentioned throughout the thesis. Energy Exemplar supported this thesis by providing me with a free student license for their power system modeling software PLEXOS. Thanks to these organizations for sharing their resources and products.

A final gratitude is expressed to my family that encouraged me during my years of study and this thesis in particular. A special thanks to my friends with whom working on this thesis till late was always possible and much better than working alone. Thank you.

4 INTRODUCTION

On December 12, 2015 the Paris climate agreement (COP21) was adopted by 195 countries (EC, 2017a; UN, 2015). It is the first legally binding global climate deal, with the agreement of limiting global warming to 2°C above pre-industrial average temperature and the aim for keeping it below 1.5°C (EC, 2017a; UN, 2015). Global warming is caused by an increase in atmospheric greenhouse gases (GHGs) resulting from human activity e.g. energy, agriculture and industry (IEA, 2016a; IPCC, 2013). It is estimated that 68% of anthropogenic GHG emissions are related to energy use (IEA, 2016a). Most of these emissions are CO_2 emissions that result from oxidation of carbon during fossil fuel combustion (IEA, 2016a). In anticipation of COP21, the European Commission (EC) pledged ambitious targets for 2030; a 40% reduction in GHG emissions compared to 1990 and a 27% renewable energy production (EC, 2017b). Each member state must contribute to this target and state their future climate efforts in a National Renewable Energy Action Plan (NREAP) (EC, 2017c). These NREAPs must include specific targets for renewable energy in the different energy consuming sectors (IEA, 2016b; EC, 2017c).

In the Dutch NREAP[1] the aim is to have a 37% share renewables in electricity consumption in 2020, next to a 9% share in heating and cooling and 10% in transport, summing up to a 14.5% share renewables in the energy sector (IEA, 2016b). Wind, solar, biomass will be used to achieve these goals for renewable electricity generation (MoEA, 2010). This poses a challenge on the reliability of the power system, where supply and demand is matched in real-time by dispatching of power generators (Pickard, 2012; Fares, 2015; Stram, 2016). Large scale implementation of renewable capacity can result in irregularities in electricity supply caused by sudden changes in wind speed or solar irradiance (Fares, 2015; Stram, 2016; Sturm, 2016; Pickard, 2015). Additionally, wind and solar power cannot be controlled like fossil fuel powered generators (Stram, 2016). This calls for flexible generating capacity or manageable demand to compensate for the unpredictable power output from intermittent renewables (Sturm, 2016; Stram, 2016).

Table 1: Worldwide energy storage per technology type (source: (Energystorageexchange.org, 2016))

Technology type	Projects	Rated Power (MW)	% capacity of total
Electro-chemical	695	1,637	0.96%
Pumped Hydro Storage	322	164,629	96.24%
Thermal Storage	193	3,211	1.88%
Electro-mechanical	50	1,568	0.92%
Hydrogen Storage	7	8	0.00%

Flexibility of the power system can also be increased by energy storage that can increase generating capacity or demand when charging (Stram, 2016; Fares, 2015). Pumped Hydro Storage (PHS) is currently the only economically viable and proven technology for large scale energy storage (Suberu, et al., 2014) (see Table 1 above for data on worldwide energy storage). The main constraint on PHS is the need for a site that is naturally suitable for a high and low water reservoir with sufficient water head and preferably located near a large energy sink (e.g. metropolitan area) (Pickard, 2015; Suberu, et al., 2014). A drawback is that suitable mountain sites are limited and often not located near densely populated areas, requiring expensive infrastructure to energy sinks (Pickard, 2015). The solution may be to locate the lower reservoir below ground in an Underground PHS (UPHS) system (Pickard, 2015).

[1] This NREAP is still based on the European targets for 2020, the new Dutch NREAP for the COP21 targets in 2030 was not available at the time of writing.

A relatively flat country like the Netherlands is naturally unsuitable for conventional PHS. To overcome this a UPHS project has been proposed, with the lower reservoir underground at a depth of 1400 meters and a generator capacity of 1400 MW (Sogecom BV, 2009a). This 1.8 billion euro project will be located at the Graetheide in Limburg. The aim of the project is to support the integration of intermittent renewables in the Dutch power system (Sogecom BV, 2009b). Other storage technologies, large scale technological and geographical variation in renewable sources, improving local energy management and trade between power systems are all alternatives to UPHS (Stram, 2016; Levine & Barnes, 2011). The aim of this research is to assess the potential benefits of UPHS in the Dutch power system and compare it with alternatives that can provide flexibility. This was researched by modeling the Dutch power system with different levels of renewable generator capacity, in line with targets and ambitions for the Netherlands.

5 INTRODUCTION TO UNDERGROUND PUMPED HYDRO STORAGE (UPHS)

5.1 LITERATURE ON UPHS

The idea of UPHS dates back to around 1907 when R.A. Fessenden filed a patent for a PHS system with the lower reservoir located below ground, which was granted in 1917 (Martin, 2011; Pickard, 2012; Fessenden, 1917). In it he states: "It has long been recognized that mankind must, in the near future, be faced by a shortage of power unless some means were devised for storing power derived from the intermittent sources of nature." (Fessenden, 1917). Fessenden recognized that geographically suitable locations for PHS are scarce. He argued that storage had to be a tenth of the costs of electricity generation from coal (Fessenden, 1917). Decades of little attention followed, until UPHS resurfaced in the 70s and 80s (Pickard, 2012; Martin, 2011). During this time 1-3 GW large scale U-PHS was considered to be the most economical scale, however no projects were actually implemented (Martin, 2011; Pickard, 2012; Pickard, 2015).

There are more recent publications related to U-PHS. One focused on small scale aquifer UPHS systems, that can store energy and provide water for agricultural purposes at the same time (Martin, 2011). Pickard (2012) focused on describing the history, present state and future of UPHS. He argues that historical hurdles (e.g. technology) for UPHS are overcome (Pickard, 2012). He also argues that mankind will have to switch to intermittent natural energy sources where UPHS storage may have an important role (Pickard, 2012). Another publication focused on the impact on groundwater flow of UPHS in abandoned mines (Pujades, et al., 2016) with a follow up on the efficiency impact of groundwater on open pit mine UPHS systems (Pujades, et al., 2017). There has also been done preliminary research on using an abandoned mine in Germany as UPHS (Montero, et al., 2016) (further information on the project is available via: upsw.de). Recent research on energy storage in the Netherlands does mention UPHS, but only includes conventional PHS in its calculations (DNV-GL, 2015). They conclude that PHS may be economically competitive with gas-fired back-up when used as daily or weekly storage (DNV-GL, 2015). High investment costs for PHS make it uncompetitive for longer storage times (e.g. seasonal storage) (DNV-GL, 2015).

Literature research shows that there are no commercial or pilot projects for UPHS. Nevertheless, there is abundant experience with closely related PHS technology that is commercially operating (Yang, 2016). Publications on UPHS show that the idea dates back to the start of the 20th century, and that the number of recent publications is rather limited. There is no publication available on how a UPHS system may function within the Dutch power system and there has not been any publication that modeled a UPHS for the Dutch power system. Closest analysis is the report from DNV-GL (2015) that includes PHS in a comparison study on energy storage systems for the Netherlands. The study does not mention the research variables they used for the PHS and may not fully represent a UPHS that will have a higher hydraulic head than typical for PHS.

5.2 THEORETICAL BACKGROUND

Energy storage can be divided in 4 main categories, mechanical, chemical, thermal and electrical (Evans, et al., 2012). For example, batteries store energy in the chemicals within them, thermal storage may be based on materials with a high heat capacity and electrical storage can be done with capacitors (Evans, et al., 2012). The most common form of mechanical storage is Pumped Hydro Storage (PHS), it represents 96% of the total worldwide energy storage and is a mature commercially available technology (Energystorageexchange.org, 2016; Sweetnam & Spataru, 2016). The principle behind PHS (and UPHS) is to store energy in the form of gravitational potential energy. Power output from a (U)PHS can be calculated with formula 1:

$$P = Q \cdot \rho \cdot H \cdot g \cdot \eta \tag{1}$$

Where P is the power output from the (U)PHS (W), Q is the water flow (m^3/s), ρ is the water density (kg/m^3), H is the hydraulic head (m), g is the gravitational acceleration (m/s^2) and η is the generating efficiency of the (U)PHS (%) (Martin, 2011). The calculation presented in formula 1 does not include the energy losses due to pumping water to the higher reservoir. Round-trip efficiencies include the pumping cycle and range from 60% for old facilities up to 85% for state-of-the-art facilities (Yang, 2016; Argonne, 2014).

Favorable geography is a prerequisite for PHS implementation, a typical hydraulic head of 200-300m should be naturally available (Pickard, 2015; Yang, 2016). The possibility for even higher hydraulic head differential is a benefit of UPHS (Pickard, 2012). The largest costs for UPHS construction will come from the amount of excavated material and increase less with excavation depth (Uddin & Asce, 2003). For an installation with a given capacity, the volume of the underground reservoir is inversely proportionate to the hydraulic head differential (Uddin & Asce, 2003). Now assume a system with a fixed energy storage volume and capacity, the reservoir volume and volume flow will be smaller with increasing hydraulic head (see formula 1). Placing the lower reservoir as low as possible increases the hydraulic head and increases costs only marginally. As a result it is preferable from cost perspective to place the lower reservoir as deep as possible underground (Uddin & Asce, 2003).

6 RESEARCH OBJECTIVE & QUESTIONS

The objective of this thesis is to research the potential benefits of a large scale UPHS system in the Dutch power system with different levels of renewable generator capacity. The UPHS system is compared to alternative flexibility measures, by designing different scenarios for a Dutch power system model. The main research question is:

What are the benefits of a 1.4 GW UPHS for the future Dutch power system and compared to alternatives?

The research question will be answered based on the answers to the sub questions:

1. What will the Dutch power system look like in the future, based on current targets/ambitions?
2. In what way can UPHS be beneficial for the future Dutch power system?
3. What benefits can be observed, when UPHS is modeled in a future Dutch power system model (compared to a reference)?
4. How does UPHS compare to alternatives in a future Dutch power system model on 1. Reliability, 2. Flexibility, 3. Costs and 4. Environmental performance?

7 METHODS

The sub questions in this research can be divided into two types of research: First, literature research to answer sub question 1 and 2. Second, modeling of the Dutch power system with different scenarios to answer sub question 3 and 4.

7.1 LITERATURE RESEARCH

Literature research was used to answer the first two sub questions. These questions were aimed to provide the scientific background for this thesis and direction and input for developing the power system model. Literature research was mainly performed via Google Scholar and Google. The preferred search engine was Google Scholar, because it specifically searches for scientific publications. However, Google provided better results for governmental publications or publications from consultancy institutes as well as news items on recent developments.

The first sub questions was used to get insight in the future developments of the Dutch power system. The annual energy outlook for Dutch government was used to make a scenarios on how the Dutch power system may develop in the future. These scenarios provided the basis for the future Dutch power system model. The scenarios were complemented by publications with technical parameters for power system modeling.

The second question discovered the function(s) that UPHS could fulfill in the (future) Dutch power system. The results provided the theoretical basis for benefits may be observed as results from the power system model. Publications on power system flexibility, energy storage, and PHS were consulted to answer this second sub question.

7.2 PLEXOS MODELING

7.2.1 Practical approach

PLEXOS Energy Exemplar was used to create the Dutch power system model. PLEXOS was selected based on its ability to model the economic dispatch of a power system with different levels of detail (Collins, et al., 2015; Pfenninger, et al., 2014). The possibility of modeling at a high resolution, modeling of emissions and the economic indicators make PLEXOS suitable for assessing the benefits that may be observed from UPHS in the Dutch power system.

A model was created to resemble the Dutch power system. This model was created specifically for this research, as there was no PLEXOS model for the Dutch power system available that could be adjusted to meet the research objectives. Battery storage and demand response were compared to UPHS by running different PLEXOS scenarios. These scenario runs were executed with different levels of renewable energy penetration, representing the expected power system generator mix for 2017, 2020, 2025, 2030 and 2035. The generator mix included increasing renewable capacity and decreasing thermal power generator capacity, based on the Dutch national energy outlook (NEV) (ECN, 2016).

The approach that was used to develop the Dutch power system model is visualized stepwise in Figure 1 below. Step 1 and 2 are described in more detail in chapter 13, the results from the other steps are presented in the remainder of this thesis. The results were used to answer sub questions 3 and 4

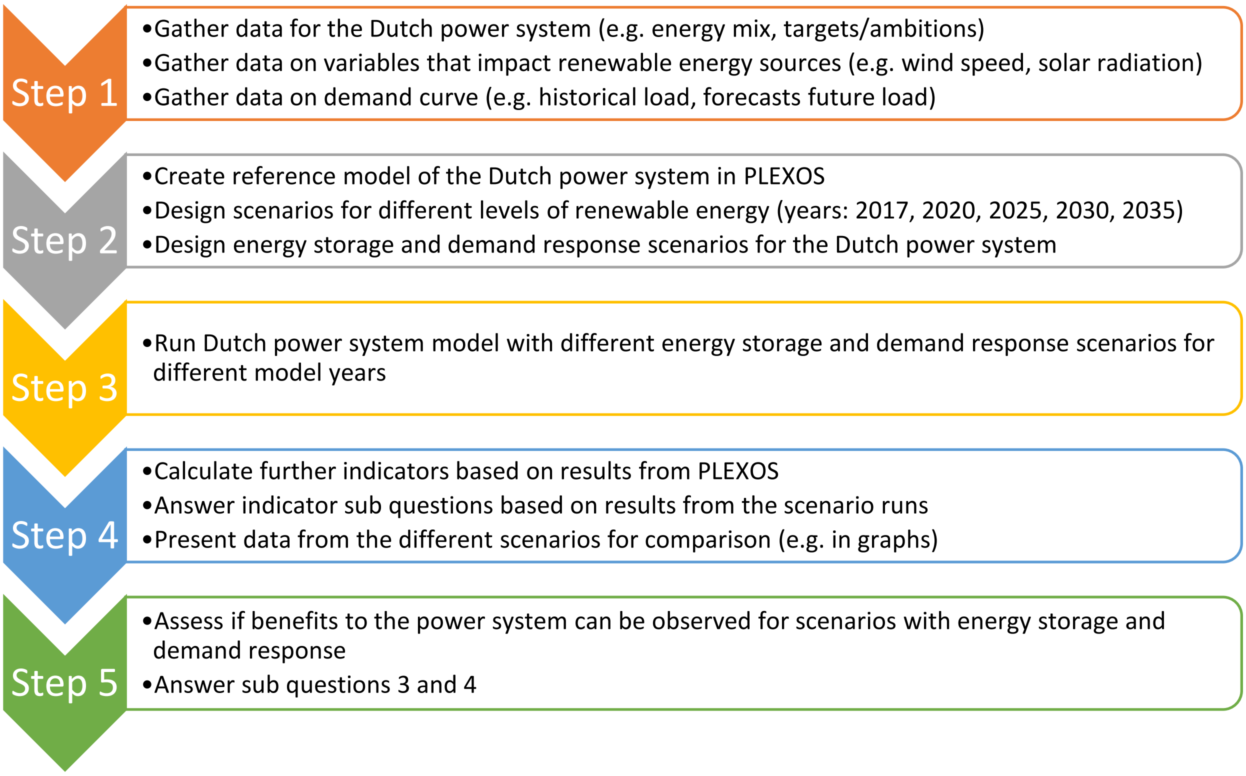

Figure 1: Stepwise approach for model development and results analysis

7.2.1.1 Scenarios

In the report five different scenarios were used for the Dutch power system model:

1. **Reference (Ref):** This scenario represented the Dutch power system without any type of energy storage or demand response system in place. This scenario was used as the baseline to which all other scenarios were compared.
2. **BES (Battery Energy Storage):** This scenario is in all respects identical to the Reference scenario, with the addition of a 900 MW li-ion battery storage system with a storage volume of 3,600 MWh.
3. **BESXL (Battery Energy Storage Extra Large):** This scenario adds a lithium ion battery storage system of 2,000 MW with a storage volume of 8,000 MWh to the reference scenario.
4. **DR (Demand Response):** This scenario adds the possibility to use demand response in the Dutch power system. The total annual use of demand response was set to be 528,587 MWh annually, with a daily and hourly use limit.
5. **UPHS (Underground Pumped Hydro Storage):** This scenario adds a pumped hydro system with a capacity of 1,400 MW and a reservoir volume with 8,000 MWh of storage volume to the reference model.

The scenarios were not used in a complementary manner, only in the respect that all scenarios are similar to the reference scenario with the addition of a different measure (i.e. energy storage or demand response) that helps increase power system flexibility. All scenario were run stand-alone and compared on difference in performance on the indicators discussed in 7.2.2.

7.2.1.2 Model years

Five different model years were used in the PLEXOS model. The modeled years are 2017 (current situation), 2020, 2025, 2030 and 2035. These model years represent the development of the generator park as predicted in the most recent Dutch energy outlook. The generator park is expected to develop toward less thermal generator capacity and more wind and solar capacity in the future. The model years can also be regarded as different levels of renewable integration in the power system while thermal power generator capacity is reduced. The figures for actual installed capacity per resource are discussed in chapter 8.2. Interested readers are referred to read appendix A (Chapter 13) for a detailed explanation on the PLEXOS model development, the assumptions and data used.

7.2.2 Theoretical approach

The flexibility measures (i.e. UPHS, battery storage and demand response) were assessed on a number of indicators calculated in PLEXOS. These indicators provided insight in reliability, flexibility, economic and environmental power system performance.

- Reliability was defined in this research as the ability of the power system to meet demand at all time. Its single indicator will be the *amount of unserved demand*. This indicator showed how much demand is not met because of a generation deficit.
- Flexibility was defined as the power system's ability to respond to a change in power supply or demand. The following indicators will be used to measure flexibility: *Renewable energy curtailment, number of starts and capacity factor of thermal power generators* and *flexibility measure performance*.
- The *electricity price, total start-up costs, total generation costs* and *cost to load* were used as indicators for economic performance. The *electricity price variance* was calculated using the Excel function for variance over the range of electricity prices in a scenario.
- Environmental performance was assessed based on the *CO_2 emissions from the power system*. The *emission intensity* was calculated by dividing the total CO_2 emissions with the total electricity generation. This resulted in an amount of CO_2 emission associated with producing one MWh of electricity.

The results for these indicators were formulated based on the structure presented in Figure 2. Each indicator was assigned to a certain performance pillar. The results from the different scenarios were presented alongside the results of a reference run for each model year. This provided the basis for comparison with a power system without a flexibility measure, and between the performance of different flexibility measures. These results provided the answer to sub question 3 and 4.

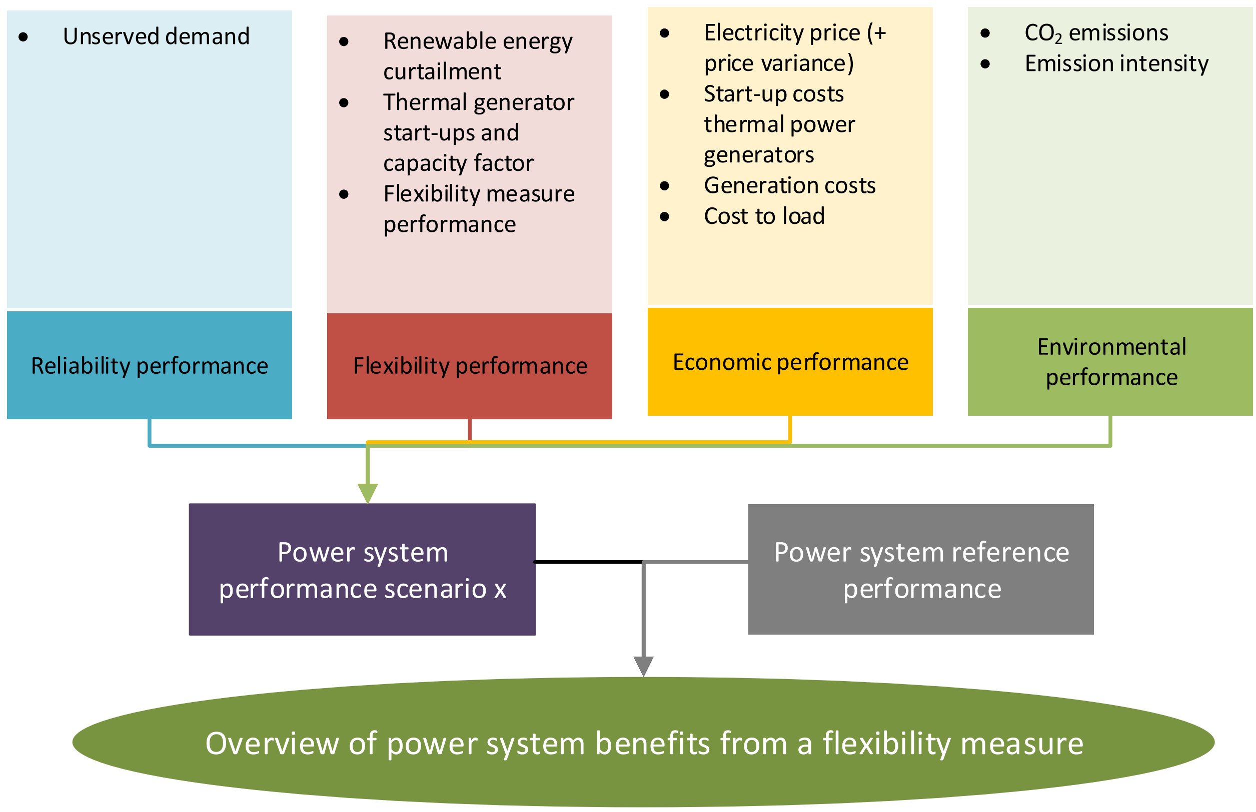

Figure 2: Schematic representation for the method used to answer sub question 4 and 5.

7.3 Data search

A variety of data for the Dutch power system was needed as model input. Input was based on data or forecasts whenever possible and available. Data from the ENTSOE-E was used for the demand curve (ENTSOE-E, 2016). Wind and solar power variability over the year was based on weather data from the KNMI (KNMI, 2017a). Performance indicators and technical characteristics of electricity generators and flexibility measures were based on several different publications (see chapter 13.4 and 13.8 for further details). The current generator mix in the Netherlands was obtained from ENTSOE-E and TenneT (ENTSOE-E, 2017; TenneT, 2017b). Future development of the generator mix was based on the Dutch energy outlook (Known as: 'Nederlandse EnergieVerkenning') (ECN, 2016). The data used in the power system model is discussed in chapter 13. Larger datasets such as the load profile, wind and solar production profiles were kept in separate Excel files.

8 BACKGROUND DUTCH POWER SYSTEM

8.1 ELECTRICITY SUPPLY

The Dutch power system has gone through several steps of development. Initially electricity was primarily generated by coal power plants. This was replaced by oil and natural gas, the latter was the larger source for electricity production. In 1973 the focus shifted towards electricity generation from oil due to policy measures related to the first oil crisis (Verbong & Geels, 2007). After the second oil crisis in 1979, the policy measures supporting oil electricity production were abolished and natural gas became an important energy source again (Verbong & Geels, 2007). From that moment the recurrence of coal as source for electricity generation can be observed. More recently, the growth decentral natural gas fired CHP (Combined Heat and Power) plants was stimulated by subsidies. Combined investment of utilities and industry resulted in overcapacity of natural gas fired CHP capacity (Verbong & Geels, 2007). Decentral CHPs are still used by industry and horticulture, surplus electricity production is delivered to the national electricity grid.

The CBS has data on electricity supply per source from 1998 till 2015. This data is presented in Figure 3, complemented with forecasted electricity supply from the Dutch energy outlook (ECN, 2016). It shows that renewables increased production share between 1998 and 2015. However, during recent years the increase is relatively small. It can also be observed that the share of coal in the energy mix increases substantially in 2015 compared to former years, while the share of natural gas decreased. The increased coal share is due to three new coal-fired power plants that were opened since 2013 (ECN, 2016). Production from coal is expected to decrease in the near future as a result of closing older coal power plants, in line with the Dutch energy agreement (ECN, 2016). Further expected developments are a substantial increase in renewables and the decommissioning of the nuclear power plant after 2030 (ECN, 2016).

The historic and forecasted growth in renewable electricity supply are presented in Figure 4. This figure shows that a renewable electricity supply growth is expected that has not been observed in the past. Between 2018 and 2020 the forecasted growth rate is highest at 54%. The largest part of the renewable energy supply will be provided by wind energy.

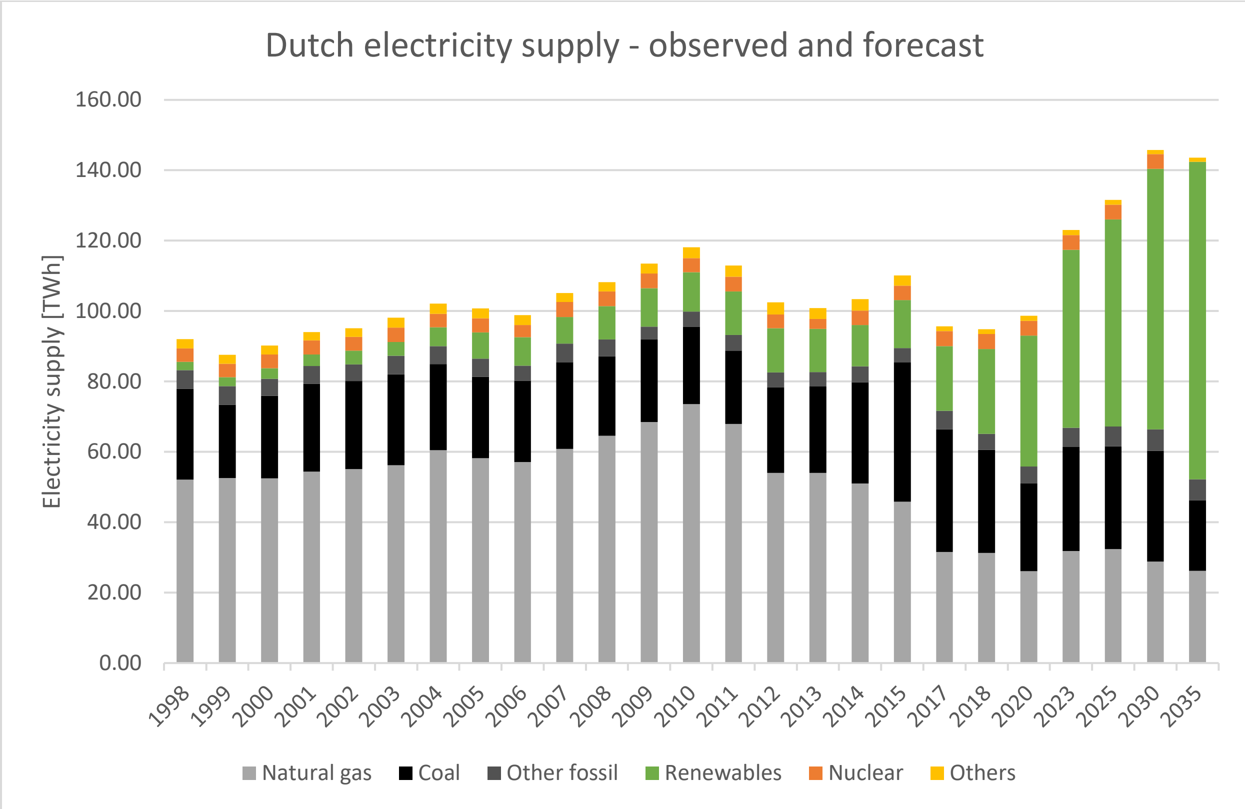

Figure 3: Dutch electricity supply by energy source. The data till 2015 is statistical data obtained from the CBS (CBS, 2017a), the data for later years is a forecast from the Dutch energy outlook of 2016 (ECN, 2016).

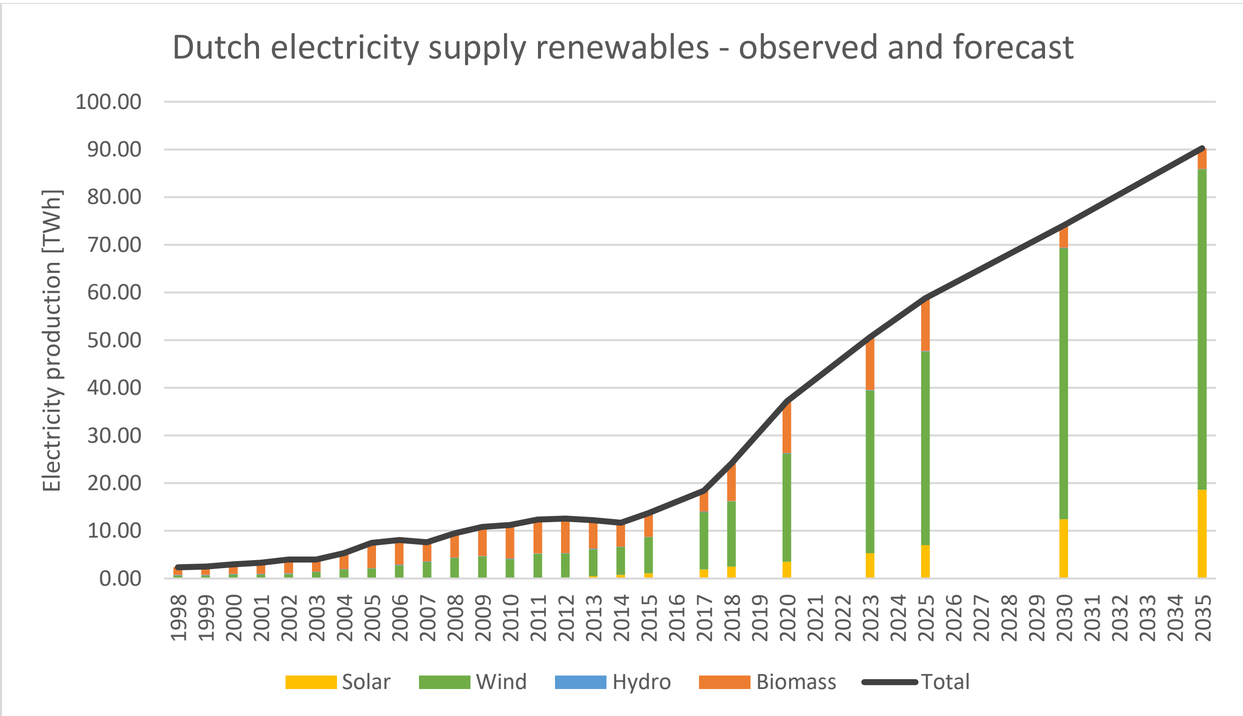

Figure 4: Dutch electricity supply from renewables. The stacked bars show the different renewables sources, the black line represents the total renewable energy supply and from 2015 the forecasted renewable energy supply. Statistical data till 2015 is presented, later years are based on the forecast in the Dutch energy outlook 2016 (ECN, 2016; CBS, 2017a).

8.2 Installed capacity

The Netherlands has seen substantial reduction in coal fired capacity in recent year, despite the installation of three large coal fired power plants (ECN, 2016). The reduction in coal capacity results from the energy agreement that states that the older coal fired power plants are to be closed. This can be observed in the figures for installed capacity in Table 2. The installed renewable capacity has seen substantial growth during the last two years. With a doubling in solar capacity, and almost a tripling in offshore wind capacity. Onshore wind and biomass had less capacity growth with 31% and 22% respectively.

Table 2: Installed capacity by primary energy source in MW. In recent years the renewable capacity has increased substantially. The coal fired capacity has reduced since 2015. Source: (ENTSOE-E, 2017).

	2015	***2016***	***2017***	***Growth 2015-2017***
Biomass	400	398	486	22%
Fossil Gas	19590	19914	19297	-1%
Fossil Hard coal	7270	5658	4608	-37%
Hydro Run-of-river and poundage	38	38	38	0%
Nuclear	492	486	486	-1%
Other	680	0	0	-100%
Solar	1000	1429	2039	104%
Waste	869	674	678	-22%
Wind Offshore	228	357	638	180%
Wind Onshore	2646	3284	3479	31%
Total Capacity	33213	32238	31749	-4%

The government has set targets for onshore wind capacity of 6,000 MW in 2020 and for offshore wind of 4,450 MW in 2023 (CLO, 2016). There are no specific targets for solar energy presented by the Dutch government. The initiative called 'national action plan solar power' does presents targets for solar PV (DNV-GL, 2016). Their targets are 4,000 MW in 2020 and due to success in recent years they target for 10,000 MW installed solar PV capacity in 2023 (DNV-GL, 2016). A forecast on generator capacity is presented in Figure 5, based on the Dutch national energy outlook (ECN, 2016). It shows that substantial growth in renewable capacity especially solar and wind is expected. While coal, decentral gas and nuclear capacity are expected to decrease. Central gas fired capacity will stay at roughly the same level in the near future and decrease after 2030. From the figures and forecasts, it can be concluded that overall development of the Dutch generator park will aim toward an increase in renewable generators and decrease in the number of fossil fueled thermal power generators.

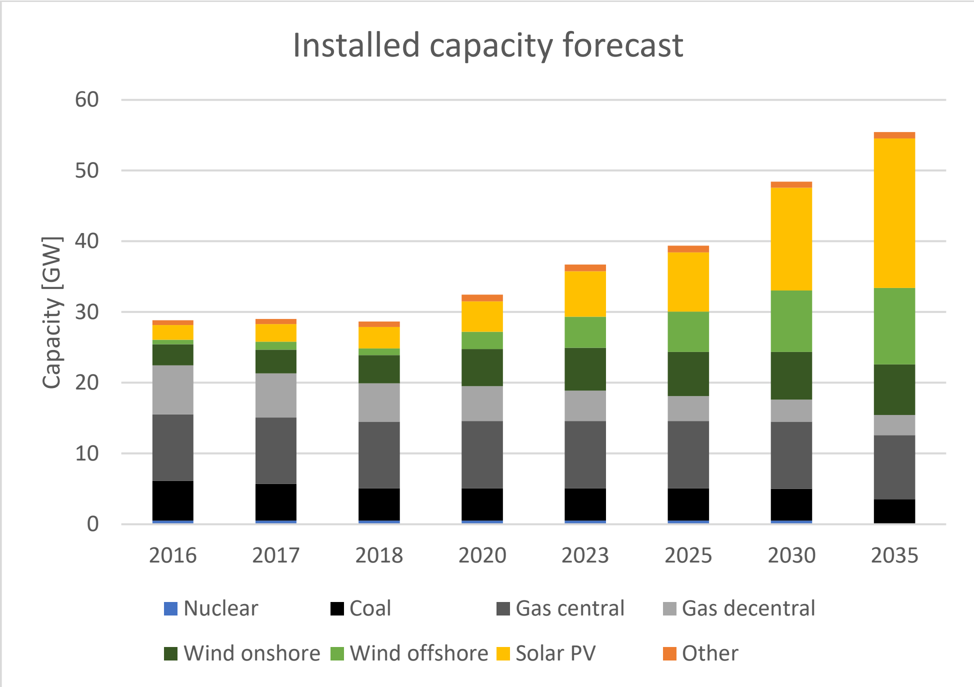

Figure 5: Dutch electricity capacity forecast, from the Dutch national energy outlook (ECN, 2016). These figures were used in the PLEXOS for modeling the future model years.

8.3 Electricity demand

It is probable that there will also be changes in demand side of the Dutch power system. These developments will depend on policy pressure that is exerted on electricity consumers, and therefore related to the political developments in the Netherlands. Dutch policy aims to increase the number of 'zero-emission' buildings, increase the number of electrical vehicles and build a smart grid to manage a decentralizing electricity grid (RVO, n.d.; ECN, 2016). This includes switching from natural gas heating to heat pumps and switching from fossil fuel powered cars to battery electric vehicles (ECN, 2016). The advantage of these developments is that demand response could be provided by heat pumps and battery packs in cars may even be used as distributed energy storage (Frontier Economics, 2015). This potentially increase flexibility of the demand side of the power system and may compete with large scale energy storage such as U-PHS.

8.3.1 Demand side management

Demand side management is the concept that encompasses different methods of load reduction/optimization, including energy efficiency, energy conservation and different types of demand response (Hungerford, et al., 2015). In this research only demand response (DR) was considered. DR is the regulation of load to optimize utilization of resources within the power system, usually switching peak demand to off-peak moments. This is applicable for flexible loads that can be turned on before actual use or can handle interruptions with little impact on the delivered service, e.g. air-conditioning, hot water boilers and swimming pool pumps (Hungerford, et al., 2015). This could result in higher total load, because of efficiency losses from heat transfer in pre-cooled buildings or heat loss from pre-heated water storage (Hungerford, et al., 2015). Demand response can be divided into subcategories based on the type of control over the DR resource (Hungerford, et al., 2015):

1. *Direct load control*, means that the TSO directly controls particular loads. This form of demand response is particularly suitable for regulatory services like reserve capacity.
2. *Dispatchable load* is;
    a. Where loads can bid into the market to reduce consumption instead of dispatching more expensive generation.

    b. Where loads have to bid into the market to purchase their electricity.
3. *Real time pricing*, is when the consumer is charged a price based on the time of consumption. This may be based on time of use or communicating real-time electricity prices with the aim to trigger consumers to use less during expensive peak hours.

There are several circumstances that make it difficult to implement DR. In the Netherlands there is sufficient overcapacity in the power system, this combined with the decreasing price of reserve capacity does not stimulate the development of DR (Movares, 2014). For industrial providers, the risk to their core business, how to operationalize DR and economical benefit are of great importance before large scale implementation can be expected (Movares, 2014). The barriers for implementing DR in households are identified as uncertainty on the benefits for distribution system operators (DSO's), regulation (from TSO) that does not support DR and the hardware and software to control appliances is still too limited (Weck, et al., 2016). Besides, the costs for installing and running a residential DR program are too high compared to the financial reward for DR flexibility (Weck, et al., 2016).

The research on the amount of DR capacity in the Netherlands is limited. The maximum daily potential is reported to be 1730 MW (ECN, 2014). It is known that the total available DR capacity increases when the constraint for response time is raised from 5 minutes to several hours (Movares, 2014). The value of DR is higher when the response time is lower, because revenue is higher for delivering faster reserve capacity. The electricity price volatility could be reduced by real time pricing demand response, as consumers may opt to shed demand earlier (Frontier Economics, 2015). This could create favorable circumstances for baseload capacity, e.g. coal-fired instead of gas-fired or storage capacity (Frontier Economics, 2015).

8.4 DUTCH ELECTRICITY MARKET

The Dutch electricity markets can be differentiated by the time-distance of trades from real-time delivery. The futures, day-ahead and intra-day markets are the main electricity markets. There is also an ancillary services market controlled by the TSO. (Frontier Economics, 2015; Ecofys, 2015)

The *futures (or forward) market* is where energy is traded up to years ahead of actual delivery (Frontier Economics, 2015). The market has standardized peak load (8-20) and base load (0-24) products (called futures) that cover electricity delivery to or from the Dutch high voltage grid for the contracted period (month, quarter or year) in the future (ICE ENDEX, 2017a; ICE ENDEX, 2017b). Participants can also trade options that give the right to deliver electricity at a fixed price or buy electricity at a pre-defined price (Frontier Economics, 2015). This market is suitable for long term trades, as futures can be traded up to a month before the delivery of the contracted electricity (ICE ENDEX, 2017a; Boots, 2011).

At the *day-ahead market* participants can optimize their position for the electricity delivery for the day ahead (Frontier Economics, 2015). Suppliers optimize their delivery obligations by deciding to produce themselves at their marginal production cost or to use the market for delivery (Frontier Economics, 2015). Buyers can make more detailed load forecasts and adapt their electricity portfolio (Frontier Economics, 2015). The day-ahead market is based on a two-side auction model where participants can send in demand and supply bids (APX, 2017a). After market closure a merit order is created along with matching of the demand and supply bids (APX, 2017a) (see Figure 6). This results in an hourly electricity price for the day ahead, which is the reference price for the market (APX, 2017a). The market closes 12:00 the day ahead of delivery, price limits are set at –500 €/MWh and +3000 €/MWh (APX, 2017a). The day-ahead market is coupled to the northern, western and southern European markets to include cross-border trade (Frontier Economics, 2015; APX, 2017a).

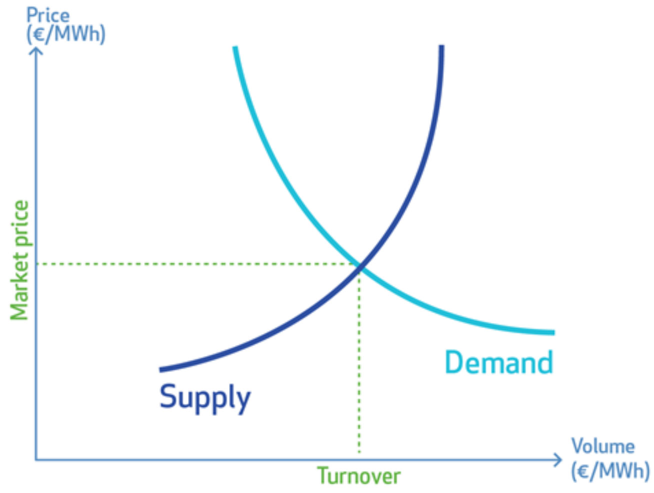

Figure 6: Setting the hourly price in a day-ahead market by matching supply and demand bids. Source: (Nord Pool, 2017a)

The *intraday market* is a continuous market where electricity can be traded up to 5 minutes before delivery (APX, 2017b; Frontier Economics, 2015). Intraday trades are used by participants to reduce the risk for unexpected imbalance prices charged by the TSO (TenneT) (APX, 2017b). An example is when a seller experiences a generator outage or when there is higher wind power generation than expected, both may cause a grid imbalance which could be mitigated by trades on the intraday market (Nord Pool, 2017b). The intraday market is connected to the Belgian and Nordic power markets, thereby connecting most of the Northern European markets (APX, 2017b; Nord Pool, 2017b). The minimum price is -99,999.90 €/MWh and a maximum of 99,999.90 €/MWh (APX, 2017b). The intraday market is expected to become larger and more important in the future, due to increasing capacity of renewables with unexpected output surpluses and shortages (Nord Pool, 2017b).

Within the Dutch power system, all large suppliers and consumers have their transactions covered by Balance-Responsible-Parties (BRPs) (Frontier Economics, 2015). These parties inform the TSO about their planned electricity transactions for the next day by submitting their e-programme (energy programme) (TenneT, 2017a). The TSO will provide balancing services to keep the electricity grid in balance, when the real amount of electricity that is consumed or supplied unexpectedly deviates from the BRP's e-programme (TenneT, 2017a). The responsible BRP will be a charged an imbalance payment, this gives incentive for BRPs to optimize their positions via the intraday market (Frontier Economics, 2015). The imbalance settlement is performed after real time delivery, prices are based on the marginal costs of balancing actions with a maximum of 100,000 €/MWh (Frontier Economics, 2015). The TSO will contract reserve capacity that is on standby to provide balancing services for the contracted period (Frontier Economics, 2015). The TSO uses separate auctions to contract the different types of reserve capacity:

- Primary reserve is automatic supply or demand response, used to rebalance the power system when a drop or peak in frequency is observed (Frontier Economics, 2015; Ela, et al., 2011). A disruption in the frequency is usually caused by an unpredicted event that affects supply or demand in the system (Ela, et al., 2011). The technical requirements for primary reserve capacity are, automatic activation within 30 seconds after the disruptive event and ability to provide capacity for at least 15 minutes (Regelleistung.net, 2017). Primary reserve capacity is contracted by the TSO via a weekly primary reserve auction. The provider of primary reserve capacity must provide a certain amount of Megawatt(s) symmetrical capacity during that week at their accepted price bid (Regelleistung.net, 2017; Ecofys, 2015). The symmetrical offer means that the provider offers both down and up regulation capacity (Regelleistung.net, 2017). Providers of primary reserve are paid per weekly amount of capacity that is contracted with the TSO (i.e. €/MW) (Ecofys, 2015). The average weekly price for primary reserve has dropped to €2526 per MW in 2016 from €3647 per MW in 2015 (Regelleistung.net, 2017).

- Secondary reserve is used to relieve and complement primary reserve. This reserve capacity is required to react automatically and be able to have complete activation within five minutes (Regelleistung.net, 2017). Secondary reserve helps restore the grid frequency to normal where primary reserve usually can only contain and partly restore the frequency disruption (Ela, et al., 2011). From these bids, contracts are made between suppliers and the TSO for secondary reserve (Ecofys, 2015). They include a price for the capacity (i.e. €/MW) and the amount of electricity (€/MWh) that is delivered to the grid as balancing service (Regelleistung.net, 2017). The secondary reserve market outcome is not publicly available, but it is reported that the average annual costs for secondary reserve in 2014 were 130,000 €/MW (Ecofys, 2015).
- Tertiary reserve functions to restore primary and secondary reserve capacity and can be regarded as replacement generators for lost capacity from other generators (e.g. wind power plants) (Frontier Economics, 2015; Ecofys, 2015). Tertiary reserve does not need to be as fast as the primary and secondary reserves it replaces (Ela, et al., 2011). It can comparatively slowly take over the load by balancing up or down to restore primary and secondary reserve functions (Ela, et al., 2011). Tertiary reserve must be able to respond within 7 minutes and fully operational within 15 minutes after a grid frequency disruption (Frontier Economics, 2015; Ela, et al., 2011). Tertiary bids can only be placed in blocks of 20MW instead of 1MW and 4MW for primary and secondary reserves respectively (Ecofys, 2015). Tertiary reserve providers get a pay-as-bid price for the capacity that is set available and a marginal price for the delivered electricity based on the day ahead market price (Frontier Economics, 2015; Ecofys, 2015).

The electricity markets have publicly available results in contrast to ancillary service markets for which results are limited available. The results from primary reserve market are publicly available, the results from the other reserve markets not. Other ancillary services (e.g. black-start capacity or reactive power capacity) are typically contracted between the TSO and the service provider, these contracts are not publicly available.

9 BENEFITS FROM U-PHS

There are two possible reasons described in literature for installation of a (U)PHS system (Fisher, et al., 2012):

1. Storage can support integration of intermittent renewables (e.g. wind and solar) in the power system.
2. Revenue streams coming from:
    a. Energy arbitrage
    b. Ancillary services
    c. Savings in operational costs of thermal power generators

The first of these two is explained by the need for more flexibility in the power system to accommodate renewable energy capacity. The second has an economic aim for possible revenue from energy storage. The three identified economic benefits are explained in more detail in the following subchapters.

9.1 POWER SYSTEM AND INTERMITTENT RENEWABLES

The power system is based on a virtually instantaneous delivery of electricity to loads (i.e. locations with demand) via the electricity grid (Stram, 2016). Supply and demand is initially matched via electricity markets, that have different closing times before real-time delivery of the electricity (Frontier Economics, 2015). The TSOs (Transmission System Operators) are responsible for the stable operation of the electricity grid, after electricity market closure. Balancing of the power system relies on the flexibility of components in the power system and is typically performed by ramping up or down of fast generators. Alternatives that could provide flexibility to the system are; energy storage, demand management and trade between interconnected electricity grids (Stram, 2016; NREL, 2014).

Renewable intermittent energy sources (solar and wind) may have relatively predictable daily and seasonal cycles (Stram, 2016). The challenge is in the real time output from these sources that is hard to predict precisely and impossible to control (Stram, 2016; Sturm, 2016). Solar and wind production is regarded as ‘free’ electricity on the market. These sources will therefore be the first capacity in the electricity market merit order (Gerke, 2014). This will challenge the grid’s flexibility, as other generators have to respond to this intermittency.

Usually not all load (i.e. demand) can be met by renewable energy sources at every time of day, this results in residual load that is provided by alternative power generators (often fossil fueled generators) (Gerke, 2014). The definition of residual load is the total load minus production from intermittent renewables capacity. A positive residual load is covered by dispatching conventional power plants, reducing manageable demand, discharging stored energy or importing electricity (Gerke, 2014). In the occasion of surplus supply of renewable energy, a negative residual load would result. As response TSOs could ramp up responsive demand, charge energy storage systems, convert surplus energy into chemical energy (e.g. hydrogen electrolysis) or export the electricity (Gerke, 2014). A last resort would be to curtail the surplus energy, this means that not all the energy available to a solar panel or wind turbine is delivered to the grid (Bird, et al., 2014).

The graph in Figure 7 demonstrates that the residual load resulting from renewables differs in pattern from the normal total load curve. The residual load curve for Germany is presented because of the high penetration of solar and wind capacity in the German power system (REN21, 2016).

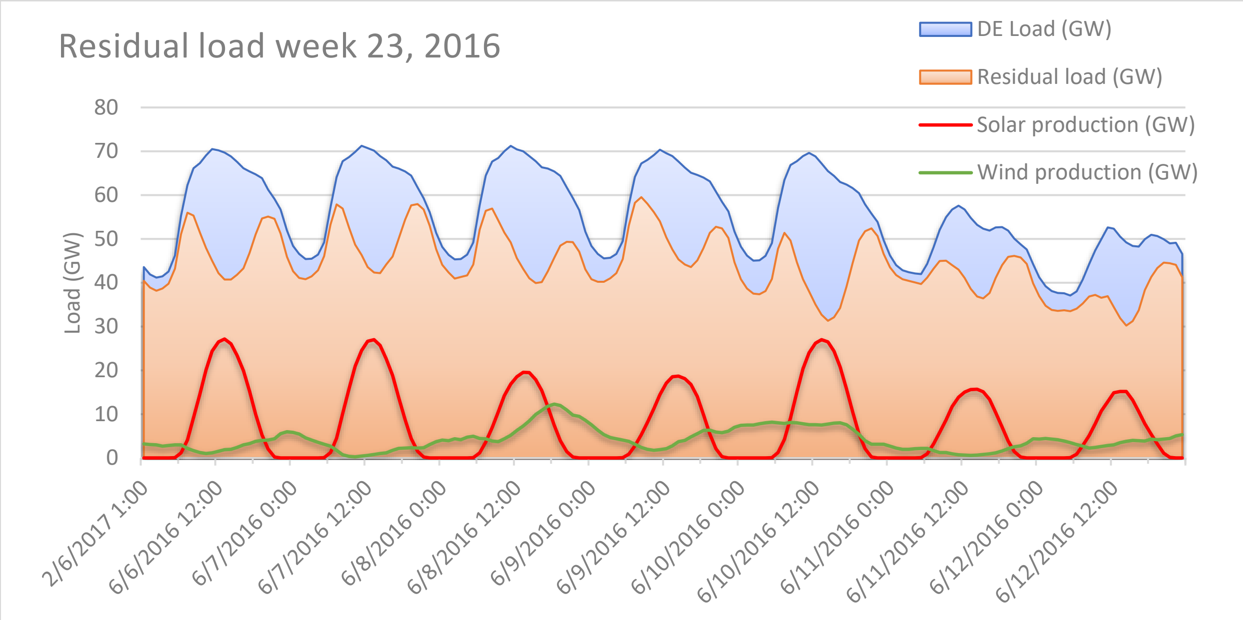

Figure 7: German load and residual load calculated based on solar and wind production for week 23, 2016 (graph based on data from: (ENTSOE-E, 2016) & (Fraunhofer ISE, 2016))

In Germany curtailed energy totaled 4,722 GWh in 2015, 2.6% of the total renewable energy consumed (Bundesnetzagentur, 2016). It shows that curtailment can be necessary even when the residual load is still positive. Figure 7 shows that the residual load has more shorter peaks and dips than the original total load profile. This means that there may be need for more flexibility in the power system to keep it reliable. Energy storage may be an important provider of flexibility. Storage can provide a bi-directional service of either creating demand or providing capacity to the grid. This makes it very suitable for increasing the flexibility of the grid.

An additional benefit of storage is that a negative residual load (i.e. renewables that would otherwise be curtailed) can be shifted to moments with a positive residual load. This increases the use of the renewable energy resource and reduces emissions from conventional generators that would have provided the positive residual load. During years where the residual load is not negative, the main benefit of storage will be the added flexibility. During later years with high renewable capacity, energy storage may shift negative residual load to moments of positive residual load (i.e. load shifting). Thereby counteracting the disruption that renewable capacity has on the residual load profile.

The residual load profiles for the 2017, 2025 and 2035 model years are presented in Figure 8, Figure 9 and Figure 10 respectively. These figures show that until 2025 there may be little negative residual load in the Dutch power system. The opposite can be said for 2035, where high negative residual loads may be observed.

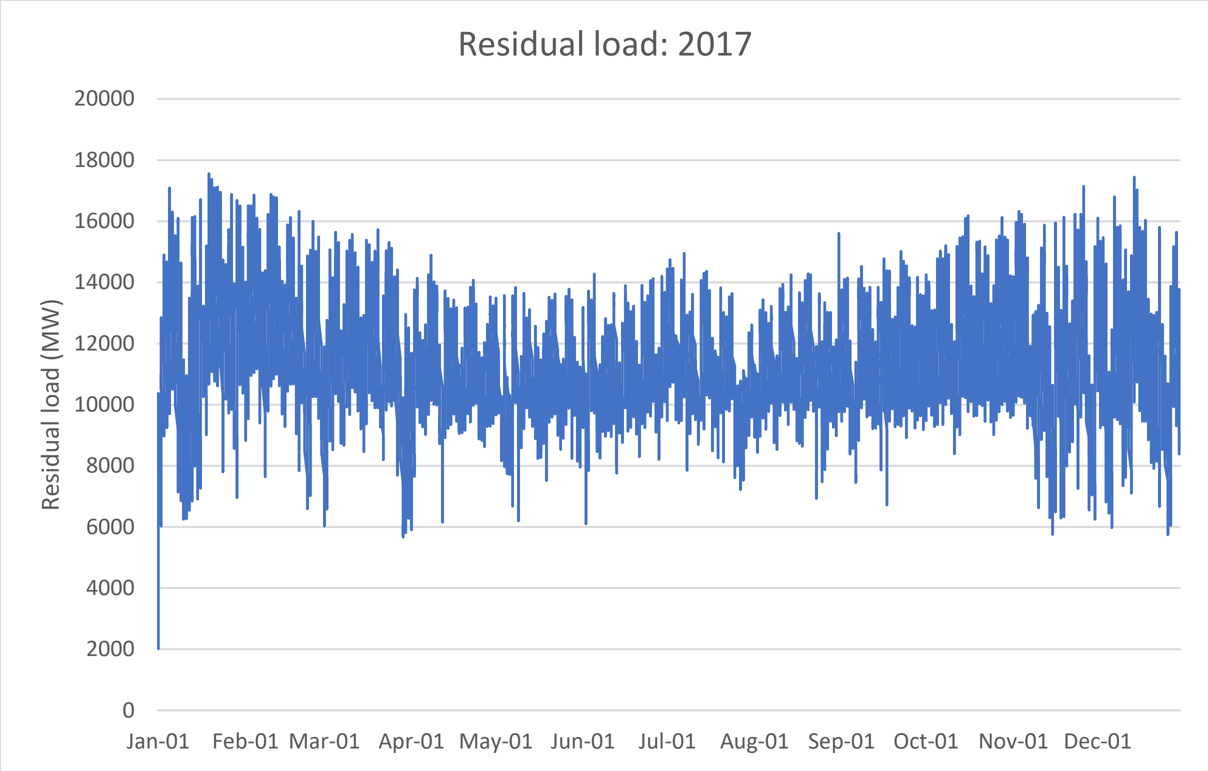

Figure 8: Residual load profile used in PLEXOS for model year 2017. The residual load stays above zero and is relatively stable, with normal occasions of peak and baseload.

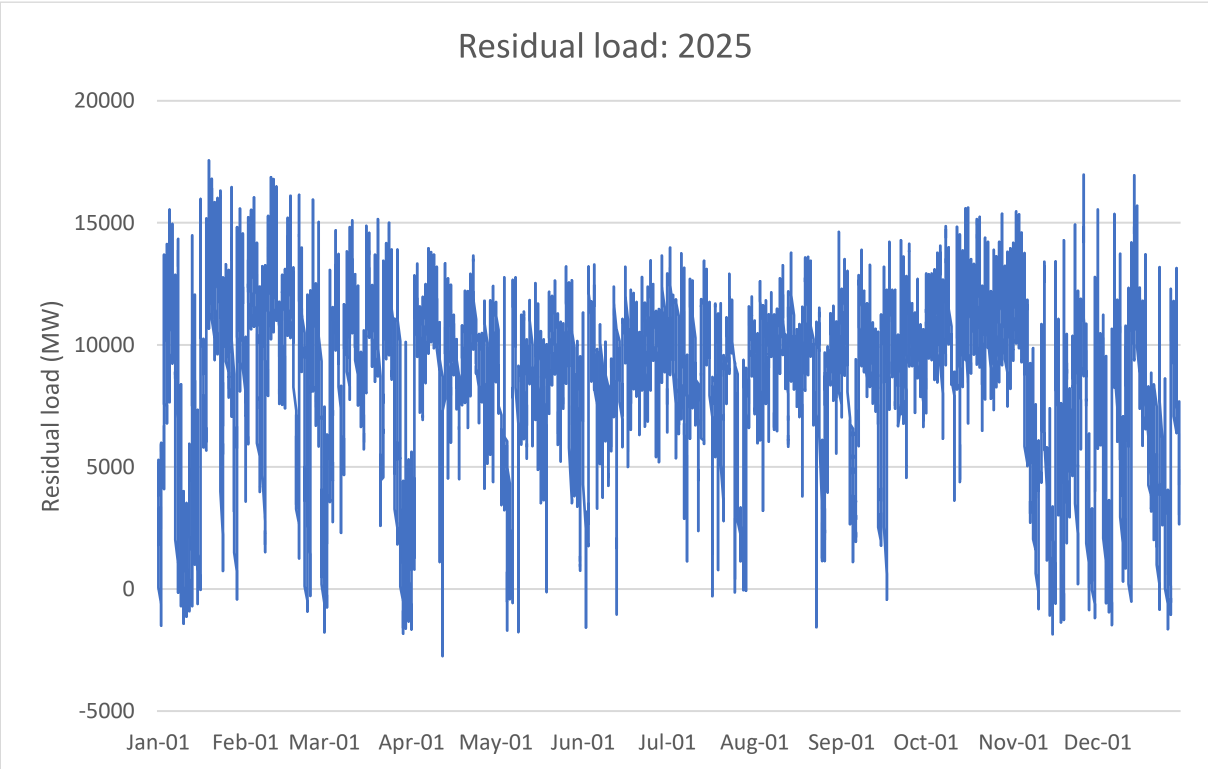

Figure 9: The residual load profile for model year 2025. The profile shows much more variation than the 2017 residual load profile, the result of higher renewable capacity. Even negative loads are observe when renewable capacity produces more than demand.

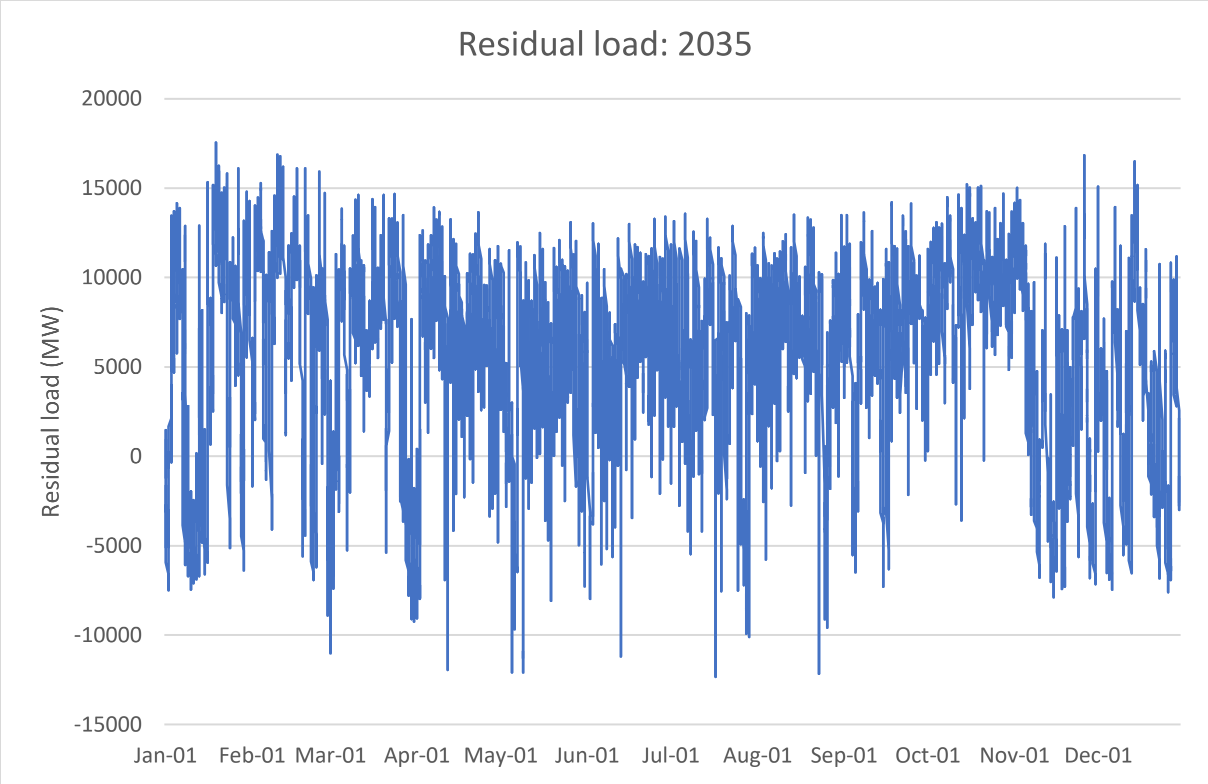

Figure 10: Residual load profile in the 2035 model year. Substantial negative residual loads can be observed during this year due to the very large renewable installed capacity in the Dutch power system. It may also be observed that not all load is met by renewables as a positive residual load can be observed during all months.

9.2 Energy arbitrage

Energy arbitrage is based on the price difference between base and peak load electricity market price. A storage system will store energy during low cost base load generation that typically occurs during the night. The stored energy will later be sold during peak load at higher peak prices. Figure 11 shows an example graph of the electricity price during the day with a preset buy and sell price limit, based on price forecasts. Depending on the market design, energy arbitrage will be performed on a daily basis, in either the day-ahead market, intraday market or both (Connolly, et al., 2011; Salles, et al., 2014).

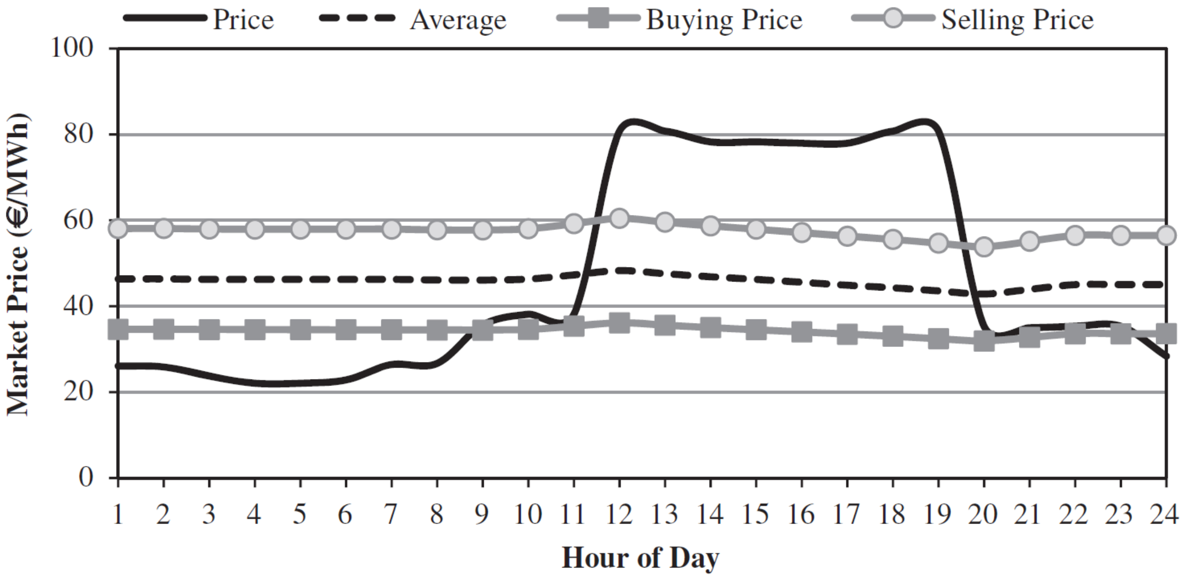

Figure 11: Example graph of the electricity price, where energy arbitrage is performed with a an arbitrage strategy based on a predetermined buying and selling price. Energy is bought when the electricity price is below the buying price level and sold when it is above the selling price level. Source: (Connolly, et al., 2011).

The most important indicators for energy arbitrage are; roundtrip efficiency, self-discharge, hours of storage and electricity price volatility (Bradbury, et al., 2014; Salles, et al., 2014). Roundtrip efficiency has a large impact on the electricity price differential required to generate revenue from stored energy. Self-discharge are the parasitical energy losses that reduce the overall efficiency of the system with time. A storage system with higher self-discharge requires substantial changes in electricity price within a shorter time period. Otherwise most of the stored energy will be lost before redelivery of energy is possible at a profit. Hours of storage is an indicator of the energy volume of a storage system. This indicator should be optimized to provide the maximum revenue at the electricity market. Load profiles are typically predictable with peak demand during day-time and baseload during night. A storage volume that can cover daily peak demand and recharge completely during night would be preferable. However, optimal sizes differ per storage type because of the other indicators that impact the daily amount of hours when profit can be generated with arbitrage (Bradbury, et al., 2014). Energy arbitrage is impossible without electricity price volatility. High price volatility results in a larger profit opportunity and price volatility during the day is required for lucrative energy arbitrage (Salles, et al., 2014).

Energy arbitrage is possible with a U-PHS system, the optimal storage volume would be for 7-8 hours of full capacity (Bradbury, et al., 2014). However, using energy storage only for energy arbitrage is economically risky because of several reasons. Firstly, revenue from energy arbitrage can differ substantially from year to year (Bradbury, et al., 2014). Secondly, certain electricity market mechanisms may be disadvantageous for energy arbitrage (Connolly, et al., 2011). For instance where market price settlement is performed after actual delivery which usually results in less revenue from energy arbitrage (Connolly, et al., 2011). Thirdly, energy arbitrage will have to compete with peak power generators, i.e. natural gas generators. This means that in a market with low gas prices, electricity price volatility will be less and thereby create a less favorable market for energy arbitrage (Bradbury, et al., 2014). Finally, more solar energy during midday will cause a reduced price volatility between base and peak load prices, resulting in reduced potential for energy arbitrage (Fisher, et al., 2012). In publications on energy arbitrage it is recognized that either the costs for energy storage has to be reduced or that storage should also provide ancillary services to become economically viable (Bradbury, et al., 2014; Fisher, et al., 2012; Connolly, et al., 2011).

9.3 Ancillary services

Ancillary services encompass a wide variety of services that ensure reliable operation of the electricity grid (Ecofys, 2014). Frequency control reserve, reactive power, black start and re-dispatch are ancillary services that receive payment for delivered service to the grid (Ecofys, 2015). Balancing reserves (primary, secondary and tertiary control reserve) are traded in an auction by the TSO (Transmission System Operator) (Ecofys, 2015). The other ancillary services receive remuneration based on bilateral contracts between provider and the TSO (Ecofys, 2015). Consequently not all ancillary service payments are reported publicly, this makes it difficult to make an assessment of the ancillary services market (Ecofys, 2015).

9.3.1 Frequency control reserve

Frequency control reserve can only participate on reserve markets when it can comply with the required operational prerequisites. Within control reserves, primary reserve requires the fastest and tertiary the slowest response time (Ecofys, 2015). The design of a U-PHS system will influence the suitability of the system to operate as control reserve (Argonne, 2014; Fisher, et al., 2012). Novel adjustable speed and ternary generator technology for PHS systems provide more flexibility in both generating and pumping mode (Argonne, 2014). These technologies also ensure that PHS systems can respond fast to mitigate frequency disruptions. Due to these technologies, PHS can outperform conventional thermal power generators in response speed and frequency restoration time (Argonne, 2014; Evans, et al., 2012). An example is the Dinorwig PHS plant in the UK, it can ramp up from no output to full capacity of 1.32GW in 12 seconds, it provides a storage volume of 9.1GWh (ARUP, 2017).

It is important to have market valuation and operational policy in place that supports provision of reserve capacity by energy storage (Ecofys, 2014). Energy storage systems differ from conventional generators in operating flexibility. The benefit from e.g. a 50MW storage system is that it can change from demand of 50MW to an output of 50MW within minutes, thereby providing the balancing flexibility of a 100MW gas turbine (Ecofys, 2014; Argonne, 2014). The drawback is that storage has to be 'recharged' by the same electricity system to which it provides services, in contrast to high availability of conventional generators that are supplied by natural gas, coal or oil infrastructure (Ecofys, 2014).

9.3.2 Reactive power

In the alternating current (AC) electricity grid, the voltage should be maintained at stable levels and is synchronized with the electrical current to provide optimal electrical power (Argonne, 2014; Ecofys, 2014). Reactive power is used to keep the voltage stable and synchronized with the current (Ecofys, 2014). Power generators or other electrical power management devices like capacitors or inductors can supply reactive power (Argonne, 2014). The reactive power supply is absorbed by loads (e.g. electric motors) and also used by AC systems to transmit power to loads (Argonne, 2014). Reactive power is provided by local sources, because it is impossible to transmit over large distances (Argonne, 2014). As a result, suppliers of reactive power typically have local monopolies for reactive power provision (Ecofys, 2015). Bilateral agreements between TSO and suppliers are used to settle the provision of reactive power in the Netherlands (Ecofys, 2015). These factors do not stimulate the development of a market (Ecofys, 2015).

9.3.3 Re-dispatch

Re-dispatching means that a power plant regulates power supply up or down upon instruction of the TSO (Ecofys, 2015). Re-dispatching is used to prevent grid congestion, overloading of operational components or exceeding of the voltage limit (Ecofys, 2015). The Dutch electricity grid is highly connected and aforementioned problems are not often observed (Ecofys, 2015). As a result there is no mandatory re-dispatch for power plant operators. Contracts are drawn up between operators and the TSO for locations where congestion risks are identified (Ecofys, 2015).

9.3.4 Black start

Power generators that can start up without being dependent on grid power can provide black start service (Argonne, 2014; Ecofys, 2015). Generators that have black start capability typically have battery backup or emergency power units that are used for restarting the generator (Ecofys, 2015). Black start capacity is used to restart the power system after a blackout by providing electricity to other power generators for startup (Argonne, 2014). This service is contracted bilaterally in the Netherlands in a yearly bidding tender by the TSO (Ecofys, 2015). Contracts have a fixed fee for the black start service and may cover yearly or longer provision of the service (Ecofys, 2015). Geographical spread of this ancillary service is required to restore from local blackouts (Ecofys, 2015).

The generator design in PHS systems influences the capability for black start service. Generators with adjustable speed may be less suitable, because electronic power controls that regulate the output will require an external power source for start-up (Argonne, 2014). On the other hand, conventional and ternary generator types are suitable providers of black start capacity (Argonne, 2014).

9.4 Savings cost thermal power generators

The residual load profile that results from large amount of renewable capacity shows that conventional generators will have to provide more flexibility in the power system (see Figure 7). This means that thermal power generators will have to ramp, shut down and start up more often. Which may incur additional operating costs for thermal power generators and result in increased tear and wear of the equipment (Argonne, 2014). U-PHS can operate as load-leveling capacity, in contrast with the load following nature of thermal power generators (Argonne, 2014). The load leveling performed by UPHS may result in less ramping and start-ups by thermal power generators. The benefit that U-PHS could provide to the power system is from reduced costs for operation of thermal power generators (Argonne, 2014).

10 MODEL RESULTS

10.1 Reliability

10.1.1 Total generation

The total generation for all scenarios in the different model years is presented in Table 3. The same load profile was used for all modeled years and scenarios. This results in a total generation in the reference and DR scenario that is exactly the same from 2017 till 2030. In 2035 the total generation is lower in both scenarios, because of unserved demand. The total generation is higher in scenarios with a storage system, due to cycles of charging and discharging. The BESXL scenario has the highest total generation in all modeled years, followed by the UPHS scenario. This is caused by higher generation by the capacity of 2000MW compared to the 1400MW of the UPHS system.

Table 3: Total generation for all scenarios in the different scenario years in MWh.

	Ref	**BES**	**BESXL**	**DR**	**UPHS**
2017	112,943,154	113,967,264	115,148,138	112,943,154	114,128,641
2020	112,943,154	113,979,277	115,154,767	112,943,154	114,521,338
2025	112,943,154	113,965,834	115,060,916	112,943,154	114,455,911
2030	112,943,154	114,041,479	115,371,074	112,943,154	114,769,989
2035	112,897,442	114,252,197	115,766,976	112,923,056	115,282,129

10.1.2 Unserved demand

There is no unserved demand in all model years up to 2035. In 2035 all scenarios experience unserved demand. The scenario with BESXL has least unserved demand, followed closely by UPHS, BES, demand response (DR) and finally the reference scenario. The results for unserved demand are presented in Figure 12. It can be observed that the addition of storage or demand response in the power system reduces the amount of unserved demand substantially in 2035. However, in all scenarios it is insufficient to prevent all unserved demand.

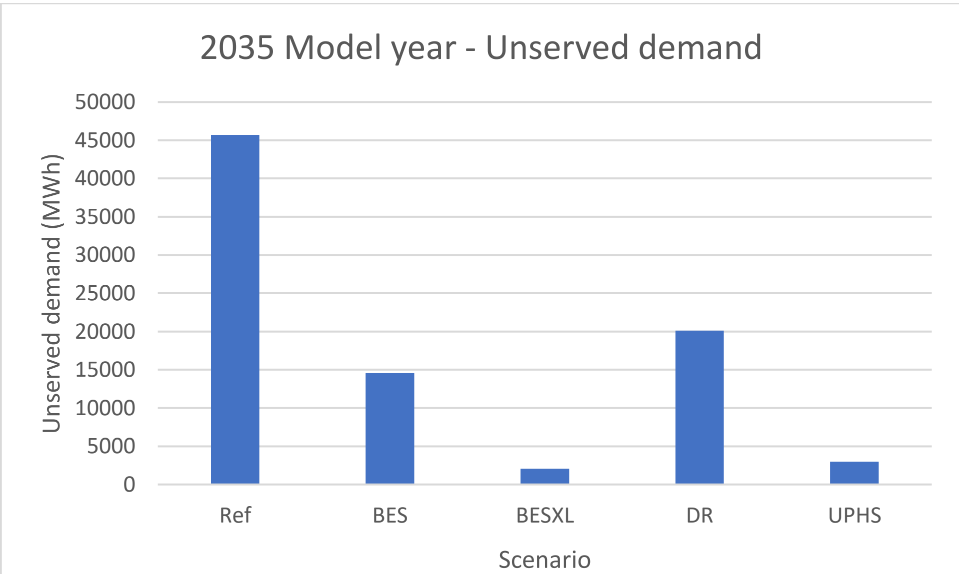

Figure 12: Unserved demand in 2035 for the different scenarios.

A closer look at the unserved demand for all scenarios reveals that a large share of the unserved demand occurs on January 19. This has two causes, firstly the low solar energy production has a short production period due to the winter season and secondly the absence of wind energy production. At

17:00 the unserved demand is largest in all scenarios, the total thermal power generator capacity is only 15224 MW while the peak demand is 17555 MW. The unserved demand is presented in Table 4 for all scenarios for the 18th,19th and 20th of January in the 2035 model year.

Table 4: The unserved demand for all scenarios during the period from January 18 till January 20, presented per day for each scenario for the 2035 simulation.

	Reference	**BES**	**BESXL**	**DR**	**UPHS**
18-Jan	0	0	0	0	0
19-Jan	10441	6439	2039	7295	2073
20-Jan	3879	122	0	1370	0

In Figure 13 the load and supply profile is presented for the reference scenario. In the UPHS scenario (presented in Figure 14) the amount of unserved demand is substantially less, due to the additional capacity provided by the UPHS. Load shifting is performed by storing energy from thermal power generators during low demand at night, to redeliver this during peak demand at daytime. The impact on the load profile is that demand during night increases compared to the reference load profile.

BESXL (Figure 16) shows an impact on the load profile that is similar to that of UPHS, a notable difference is that the BESXL recharges a little bit during solar production peaks. It performs slightly better than UPHS, due to its higher flexibility, which results from the larger capacity of 2000 MW. The BESXL is not used at full capacity during peak demand around 17:00 January 19th. This seems to show that battery storage has a capacity to energy volume ratio that is less suitable for intraday load shifting. The storage volume is insufficiently large to let the battery generate at full capacity during the hours when it is needed most. UPHS on the other hand seems to have a better capacity to energy volume ratio to prevent unserved demand, as it is used at full load capacity during peak demand.

Generating and recharging behavior similar to BESXL and UPHS can be observed for BES (Figure 15). Load shifting is performed to prevent unserved demand only at a smaller scale than BESXL and UPHS. In the BES scenario there is also some charging of the battery during the solar peak around 10:00-12:00 (January 19th), to ensure the battery is charged to its maximum for availability from 16:00-20:00. The smaller capacity and volume make the battery less suitable for dealing with the lack of thermal power generator capacity and absence of renewable production than the larger BESXL and UPHS.

The load profile for DR (Figure 17) is the same as the reference profile, due to the lack of charging of storage during low demand at night. And because the demand response was modeled as a power generator instead of having a direct impact on the load profile. The difference is that demand response is able to reduce unserved demand compared to the reference scenario. DR is less effective in reducing unserved demand than both storage systems, due to the lack of load shifting capability in DR.

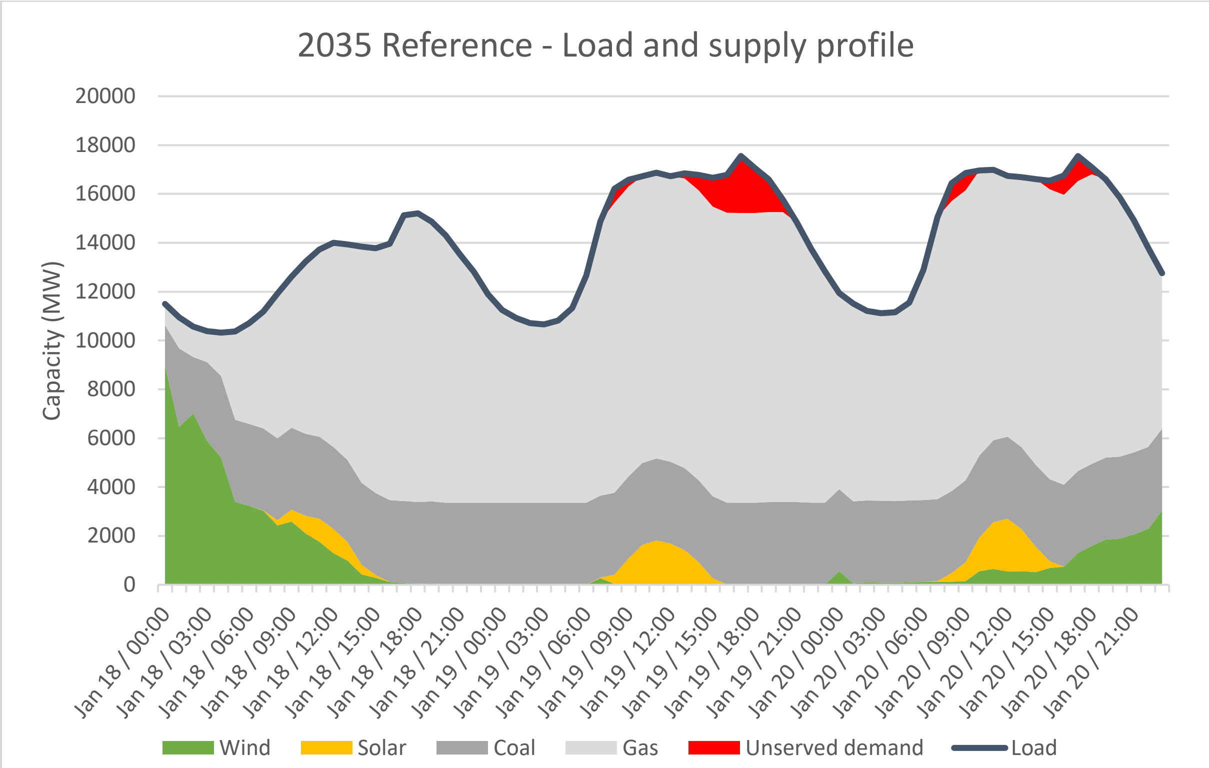

Figure 13: Load and supply profile for the 2035 reference scenario for Jan 18 - Jan 20. The thermal power generator capacity is not sufficient to meet demand when the supply of renewables is limited.

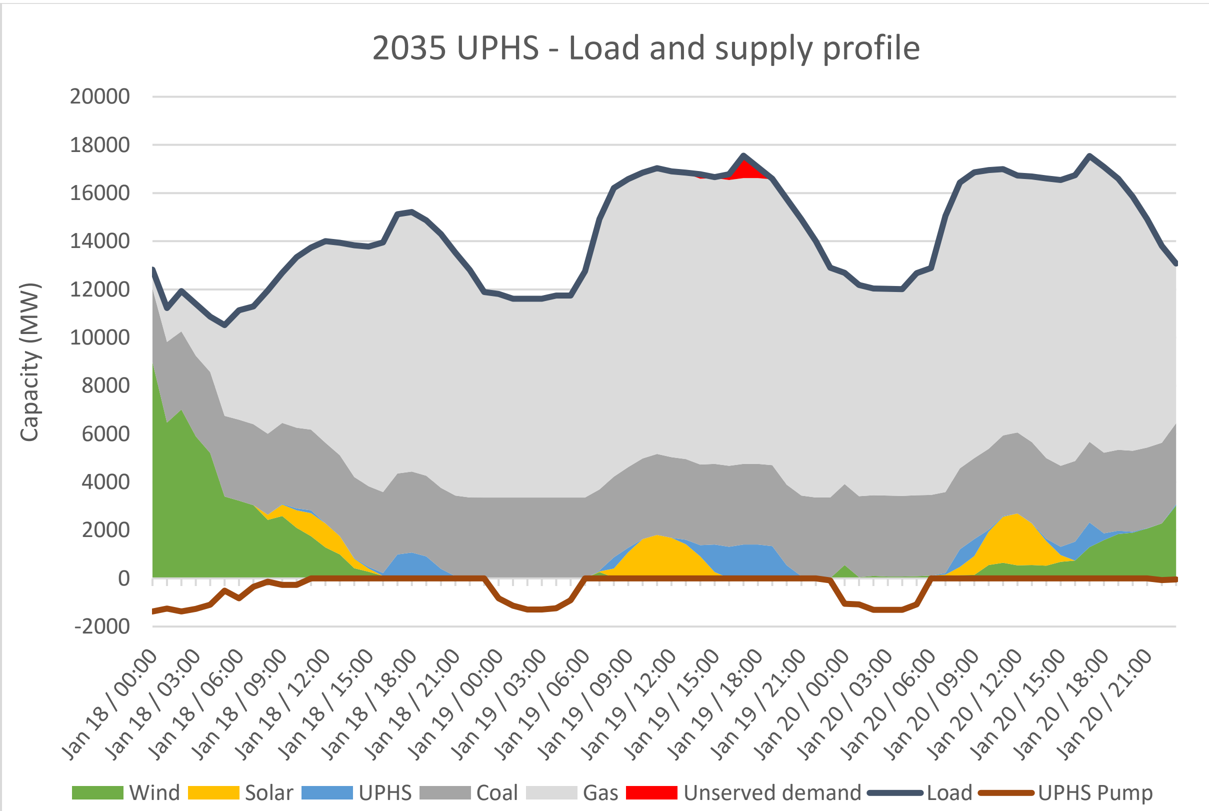

Figure 14: Load and supply profile for the 2035 UPHS scenario for Jan 18 - Jan 20. In the UPHS scenario energy is stored during low load periods at night and redelivered the next day when the amount of renewable supply is low. The dark red line shows the moments when the UPHS is in pump mode, this increases the total load compared to the reference scenario.

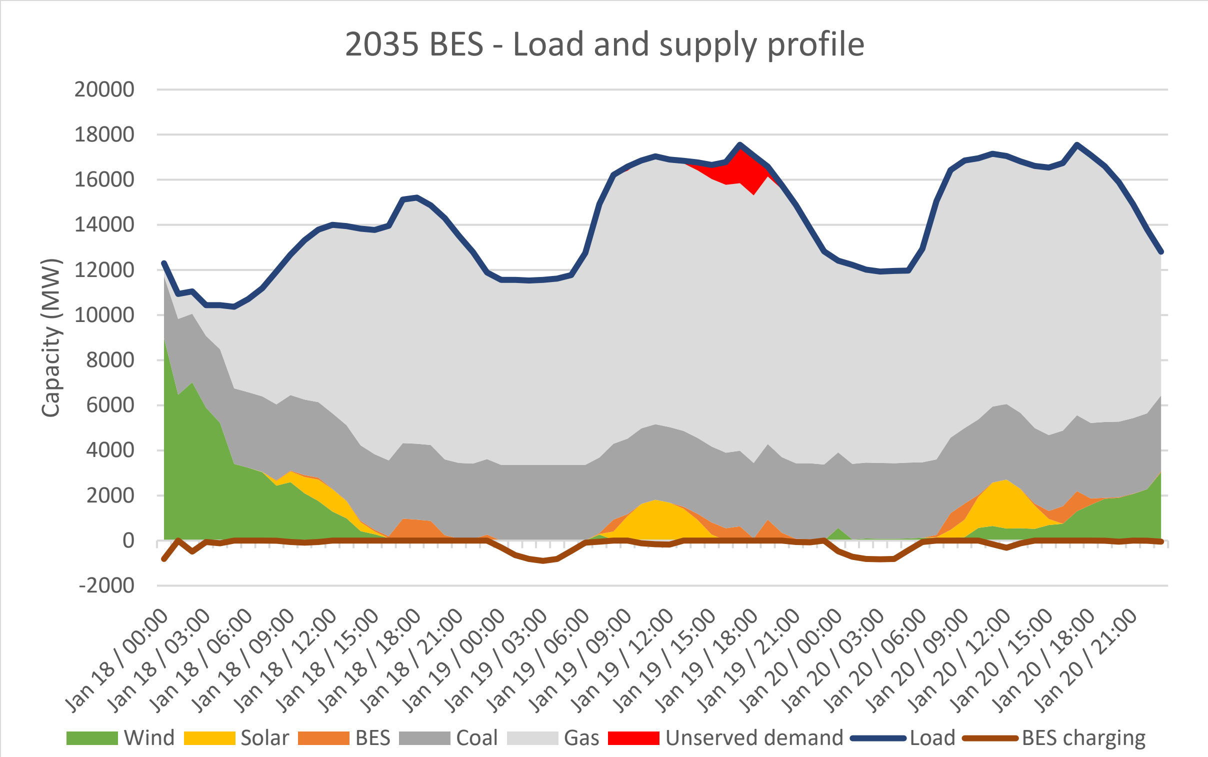

Figure 15: Load and supply profile for the 2035 Battery scenario for Jan 18 - Jan 20. The battery is charged when there is capacity available, to deal with moments when there is not enough renewable generation and thermal power generator capacity to meet demand.

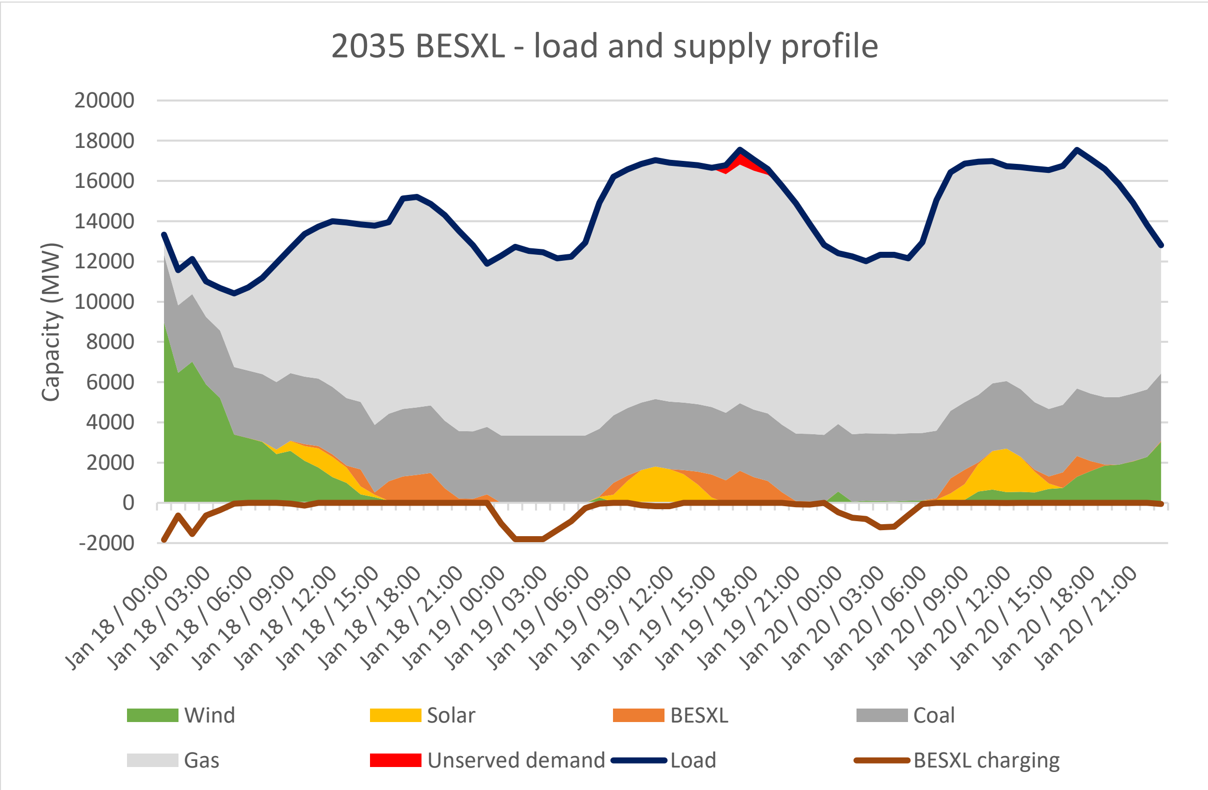

Figure 16: Load and supply profile for the 2035 BESXL scenario. The capacity of 2000MW is almost sufficient to prevent all of the unserved demand, however the total storage volume of 8000 MWh is insufficient and BESXL can therefore not always be used at its full capacity when needed.

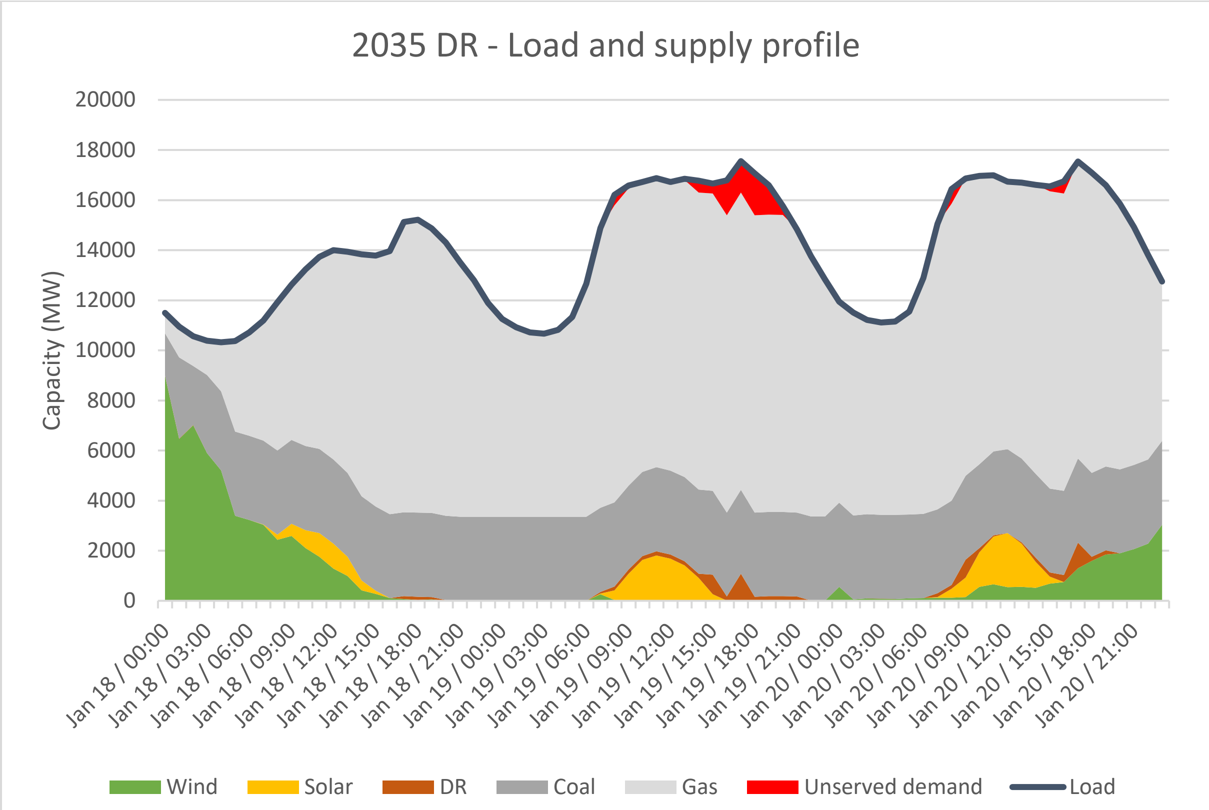

Figure 17: Load and supply profile for the 2035 DR scenario for Jan 18 - Jan 20. The DR scenario does not have the ability to store energy for later use, the load profile is therefore similar to the reference scenario. DR does reduce the amount of unserved demand compared to the reference scenario.

10.2 Flexibility

10.2.1 Renewable energy curtailment

There is no curtailment of renewable energy observed for all scenarios during 2017 (see curtailment results in Figure 18). During the other model years the reference scenario experiences curtailment of renewables. In the 2020 model year there is some curtailment of renewables in the reference, BES and DR scenario. The UPHS and BESXL scenarios do not experience curtailment in the 2020 model year. The UPHS and BESXL have the lowest curtailment, with slightly less curtailment for BESXL. Oversizing storage does not provide additional benefit to grid on curtailment prevention. The additional curtailment reduction by UPHS and BESXL is limited compared to BES during the first model years.

The DR scenario has slightly less renewable energy curtailment than the reference scenario. The performance difference is large between the storage systems and DR, because DR cannot perform load shifting like storage systems.

3.2 TWh of renewable energy is curtailed in the reference scenario in 2030 and a substantial increase in curtailment is observed for all scenarios in 2035. During these later years the presence of UPHS or BESXL will reduce curtailment more effectively than the alternatives (i.e. DR and BES). This is also clearly visible in Table 5, where the difference in curtailment with the reference scenario is presented. It is especially notable that BESXL prevents more solar curtailment and UPHS slightly more wind curtailment in 2035. This is caused by the BESXL's higher capacity, which enables it to take up more energy in a shorter period of time. This gives it an advantage during solar production peaks that are often shorter than periods of high wind power production. The absolute values for curtailment are available in tables in chapter 14.

The BES system is mainly limited by its capacity and storage volume compared to the larger UPHS and BESXL. In the earlier years this has a limited impact on its performance to reduce renewable curtailment. In later years this difference grows in favor of the larger storage systems.

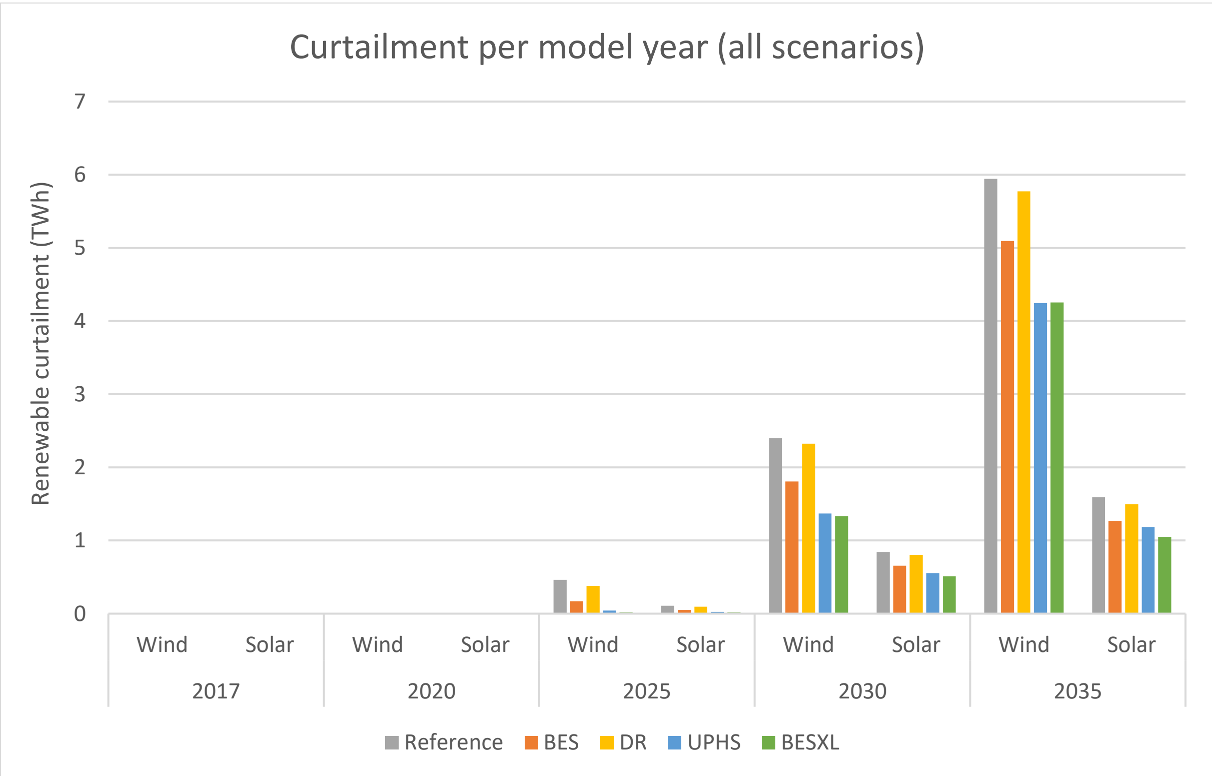

Figure 18: Curtailment per model year for all scenarios. It can be observed that BESXL and UPHS are substantially more effective in load shifting than the alternatives BES and DR.

Table 5: Difference in renewable curtailment (in MWh) compared to reference scenario. Higher values mean better performance. The model year 2017 is not included, because no curtailment was observed. The relative reduction in renewable energy curtailment compared to curtailment in the reference scenario is presented in brackets.

Year	***Source***	***BES***	***BESXL***	***DR***	***UPHS***
2020	Wind	1,074 (-74%)	0 (-100%)	3,014 (-26%)	0 (-100%)
	Solar	692 (-64%)	0 (-100%)	1,997 (+3%)	0 (-100%)
2025	Wind	289,686 (-63%)	443,939 (-96%)	81,977 (-18%)	416,991 (-91%)
	Solar	57,098 (-53%)	88,949 (-83%)	10,028 (-9%)	79,946 (-75%)
2030	Wind	591,194 (-25%)	1,064,067 (-44%)	76,485 (-3%)	1,029,904 (-43%)
	Solar	186,530 (-22%)	331,529 (-39%)	41,201 (-5%)	290,780 (-34%)
2035	Wind	849,941 (-14%)	1,689,516 (-28%)	167,353 (-3%)	1,695,151 (-29%)
	Solar	321,677 (-20%)	543,027 (-34%)	94,728 (-6%)	404,881 (-25%)

In Figure 19 the total renewable production and curtailment are presented in a bar chart. This figure shows that curtailment is limited in 2020 and 2025 relative to total production. It might be concluded that the Dutch power system is sufficiently flexible to prevent the largest part of curtailment until 2025, and storage is not necessarily needed to support renewable integration in the power system up till 2030.

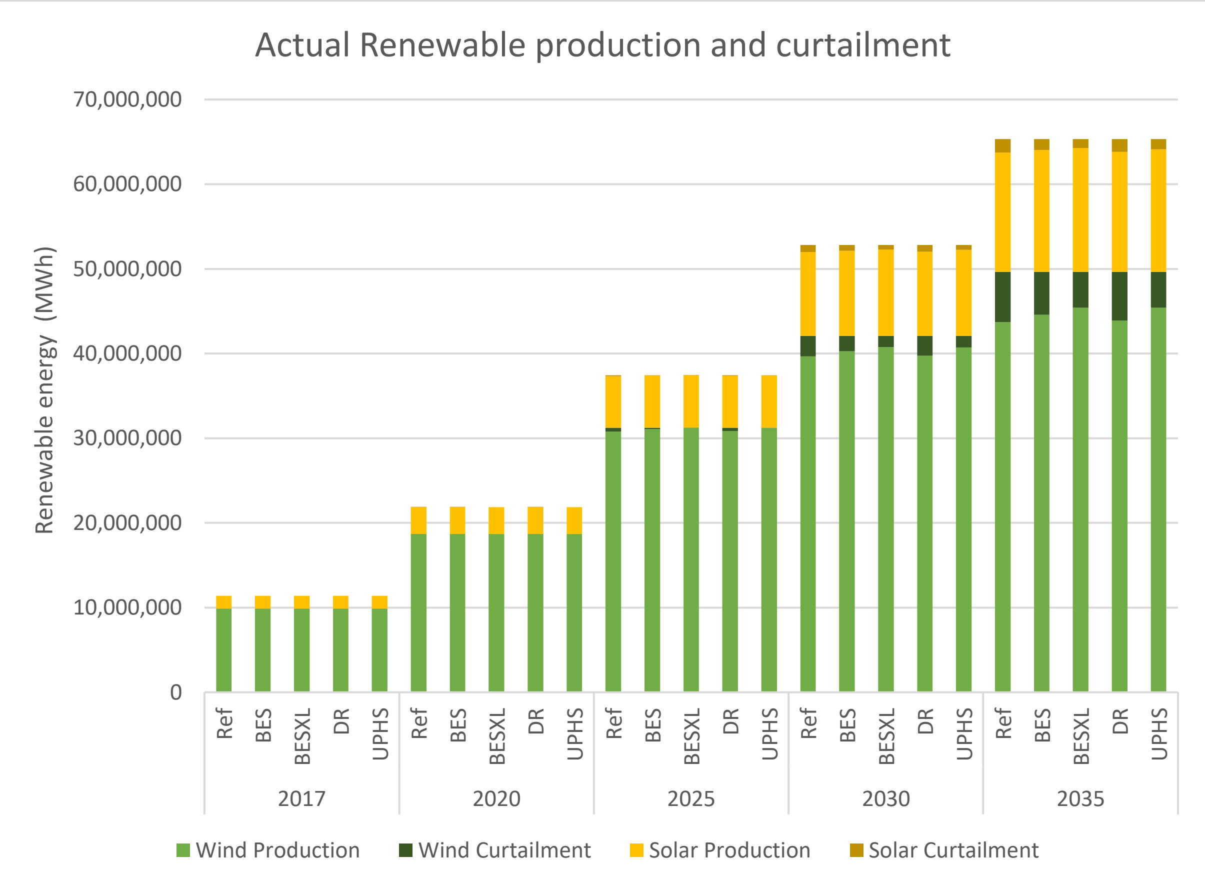

Figure 19: Bar chart with renewable energy production and curtailment sorted by model year and scenario. The height of the bar is the total potential production from renewable energy sources for the model year, the green and yellow bars represent actual energy production from wind and solar sources respectively. The dark yellow represents the solar energy curtailment and dark green the wind energy curtailment. Curtailment is negligible until 2025.

During Nov 17 – Nov 19 there is surplus wind power production in the 2030 model year. The total curtailment results (in Table 6) show that BESXL prevents most curtailment during these days, closely followed by UPHS. BES is limited by capacity and especially volume compared to BESXL and UPHS. DR does not compare in performance with energy storage when there is overproduction of renewables.

Table 6: The renewable energy curtailment for all scenarios from Nov. 17 - Nov. 19 in the 2030 model year. The BES and UPHS scenarios have significantly less curtailment compared to the reference and DR scenario. Values in the table are in MWh.

	Wind curtailment	*Solar curtailment*	*Total curtailment*	*Difference with Ref*
Ref	76,239	2,804	79,043	0
BES	53,723	424	54,147	-24,896
BESXL	38,450	245	38,695	-40,348
DR	71,781	3,947	75,728	-3,315
UPHS	43,248	0	43,248	-35,795

The load profiles Figure 20 - Figure 24 show how the presence of demand response or energy storage helps reduce curtailment of renewable energy. Two mechanisms can be observed that are used to prevent curtailment of renewables:

1. In the reference scenario (Figure 20) gas fired capacity is kept online to meet reserve capacity requirements during periods where renewable energy could provide all demand. In scenarios with DR, BES(XL) or UPHS less or no gas fired capacity stays online, because reserve capacity can be provided by DR, BES(XL) or UPHS. This results in less curtailment of renewables, since DR, BES(XL) and UPHS do not require minimum stable operation levels and have nearly instantaneous start-up and response times.
2. Load shifting is performed in the scenarios with energy storage; Renewable energy that is curtailed in the reference scenario, is stored and redelivered to the grid when renewable supply is low or during peak demand. Load shifting is much more effective in reducing renewable curtailment than the switch from conventional generators to storage or DR as capacity reserve (as can be seen in Figure 20 - Figure 24).

The three storage scenarios (i.e. BES, BESXL and UPHS) show similar moments of load shifting. The amount of load shifting is naturally limited by the capacity and storage volume of the storage system. A notable difference is the impact of the substantially larger capacity of BESXL. In the BESXL scenario there is no use of coal power plant capacity during peak demand of November 18 (12:00-20:00). This is in contrast with the BES and UPHS scenarios, where coal capacity is required to meet demand at those times.

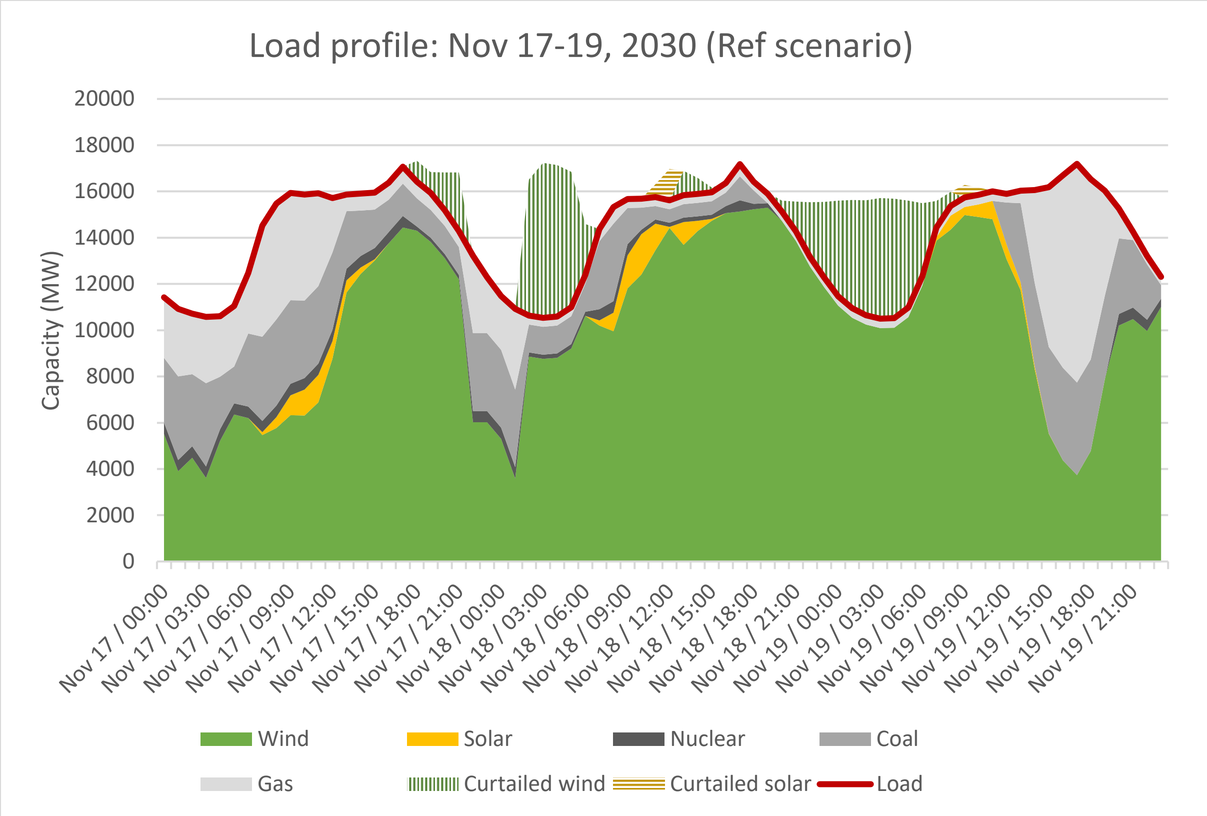

Figure 20: Load profile for the reference scenario for November 17-19 in the 2030 model year. The power system experiences a surplus of wind power production that leads to curtailment of solar and wind production. During the night of Nov 18 to 19, gas fired capacity is kept online as reserve capacity. This leads to additional curtailment of available wind energy.

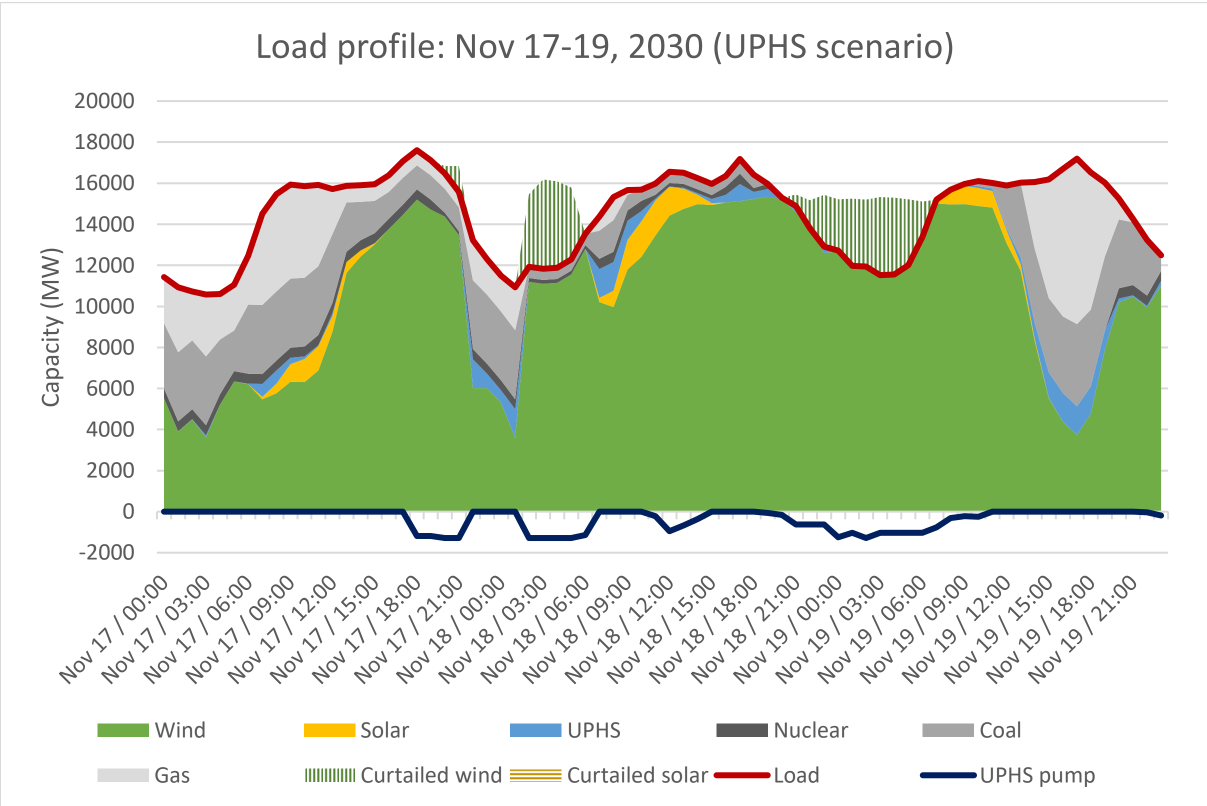

Figure 21: Load profile for the UPHS scenario for November 17-19 in the 2030 model year. Load shifting is performed by the UPHS at moments of high renewable production. UPHS also ensures that there is sufficient capacity reserve so gas fired capacity does not have to stay online, when renewable production is high enough to meet demand.

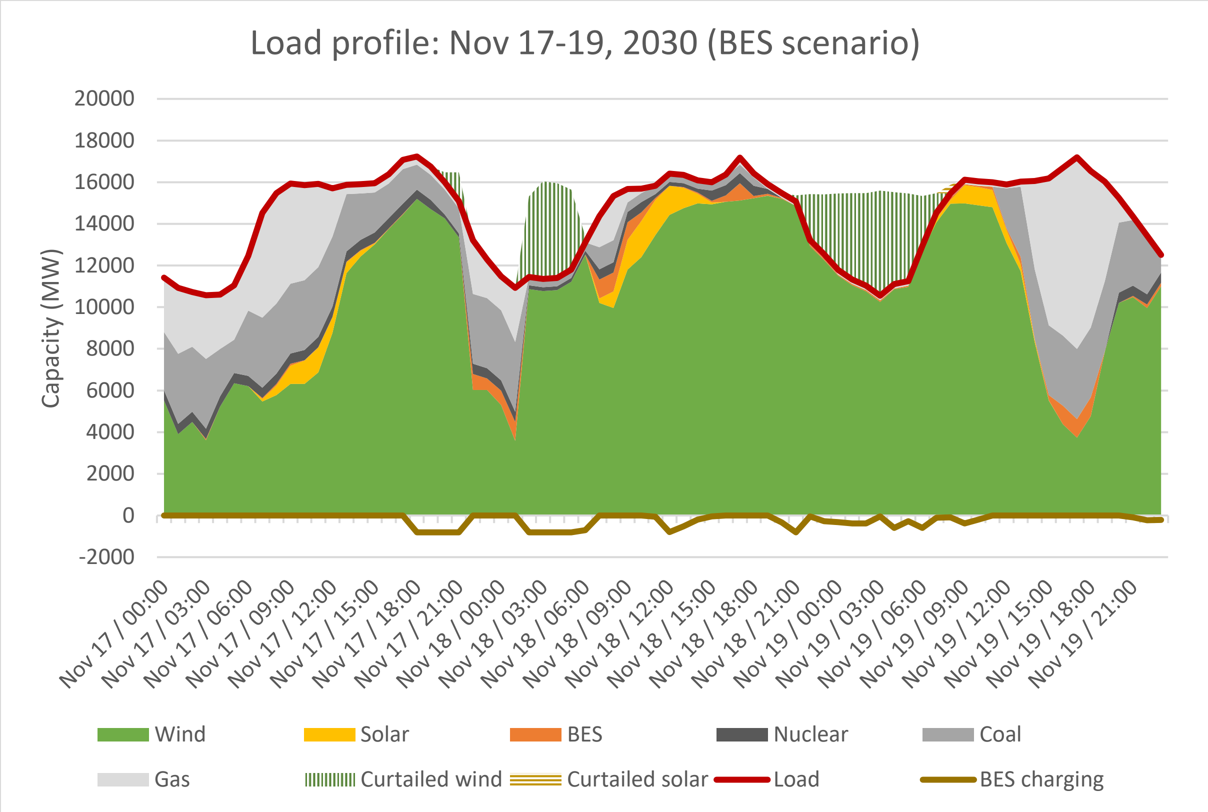

Figure 22: Load profile for the BES scenario for November 17-19 of the 2030 model year. The power system with BES still requires some natural gas capacity as reserve capacity, even when wind capacity could provide all load. Load shifting is performed at similar moments as observed for the UPHS scenario.

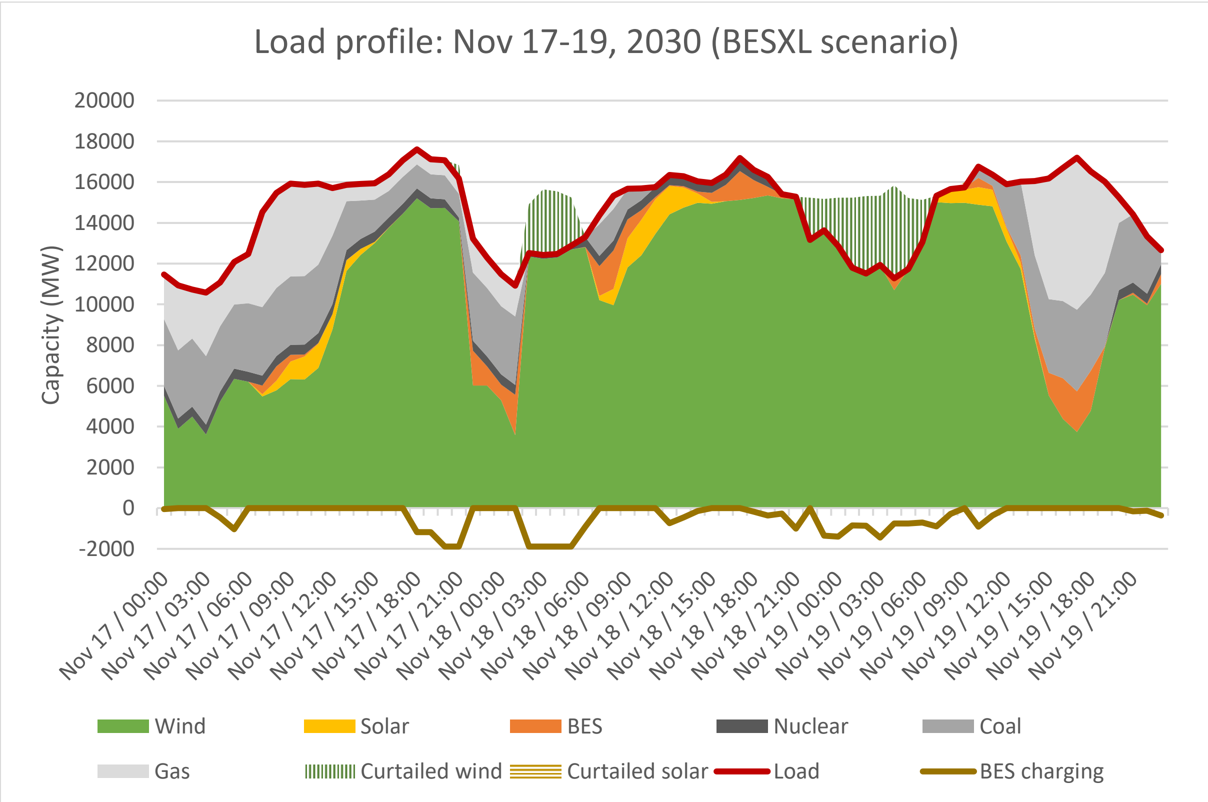

Figure 23: Load and supply profile for the BESXL scenario during 2030 model year. A notable difference compared to BES and UPHS is that no coal capacity is used to meet demand from 12:00-20:00 on November 18. Load shifting and the use of energy storage as reserve capacity can also be observed in this scenario.

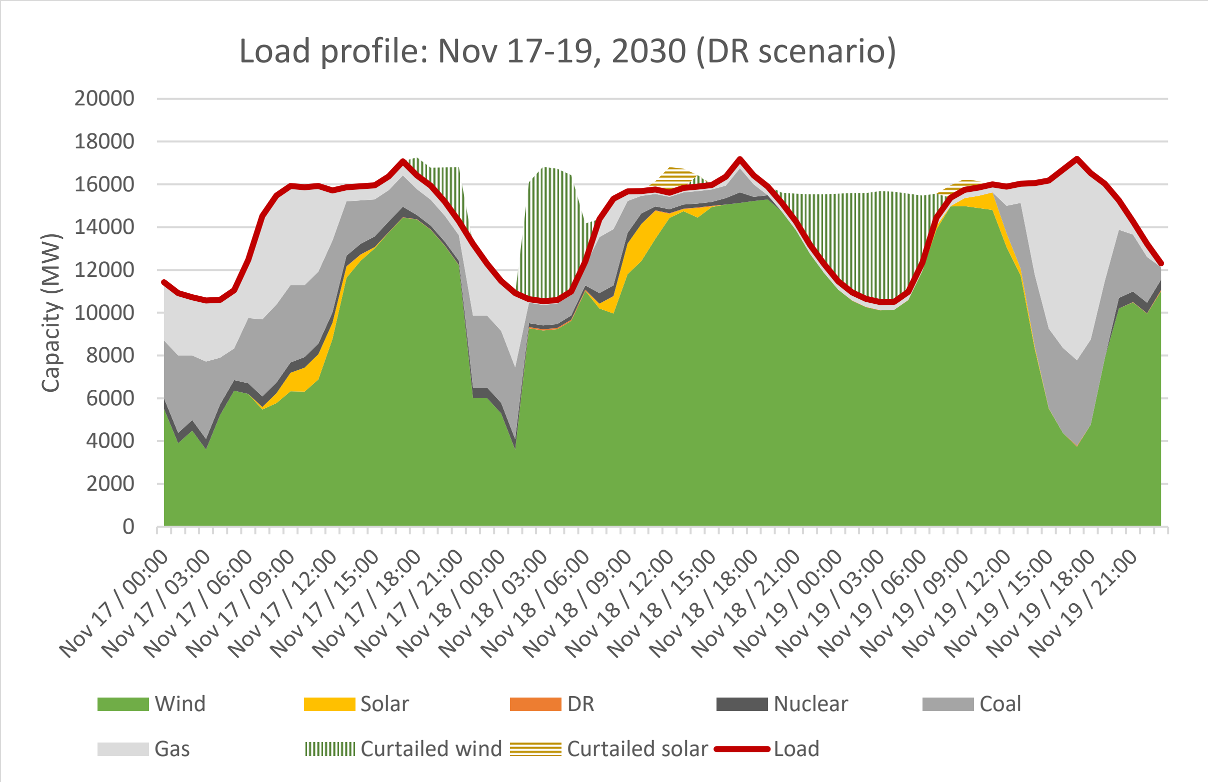

Figure 24: Load profile for the DR scenario from November 17 till November 19 of the 2030 model year. DR cannot store surplus renewable production. The reduction in curtailment is therefore substantially less than the UPHS and BES scenarios. However, DR can provide some reserve capacity when almost all load is provided by wind. This reduces the amount of gas fired capacity that has to stay online, thereby increasing the total production from renewables slightly.

10.2.2 Thermal power generator start-ups

The number of thermal power generator start-ups indicates how often generators have to be restarted as a result of changes in demand or renewables supply. The number of starts is reduced in all scenarios with storage or demand response compared to the reference scenario. It is notable that DR has less generator starts than BES in all scenario years and in 2030 even less than the scenario with UPHS. The total number of thermal power generator starts are presented in Figure 25. The BESXL scenario has least thermal power generator start-ups, a result of the large flexibility it provides the grid.

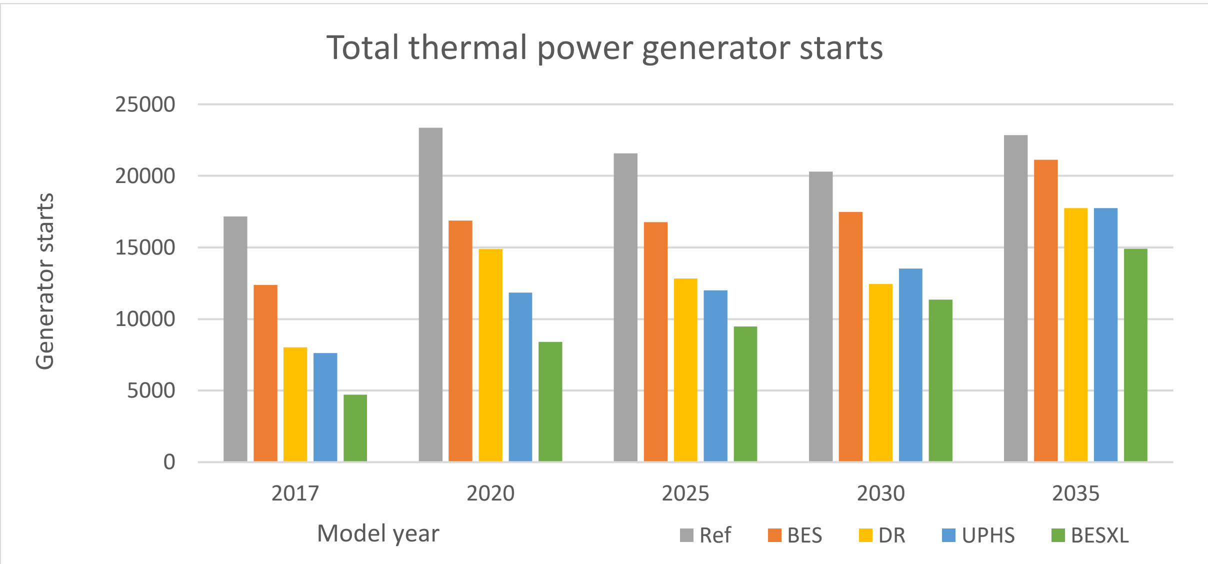

Figure 25: Total thermal power generator start-ups per model year and scenario. It shows that BESXL has least generator starts. DR performs well with regard to the total number of generator starts.

The results for central and decentral generator starts in the 2030 are presented in Table 7. The DR scenario has substantially less small decentral generator starts compared to other scenarios, while DR had more large central generator starts than the BES(XL) and UPHS scenario. This is because of characteristics of DR, it can respond instantly to demand changes without start-up costs. This shows that DR is particularly suitable to prevent start-ups by small peak generators.

In the reference scenario, the number of starts by both large central and small decentral generators is highest. The central thermal power generator starts are reduced substantially in the BES(XL) and UPHS scenario compared to the reference and DR scenario. The difference is caused by the fact that BES(XL) and UPHS are charged during night, this increases system load and reduces the need for shutting down central thermal power generators that provide baseload. This results in less central generator starts for these scenarios compared to the DR and reference scenario.

Table 7: Central and decentral generator starts for each scenario in the 2030 model year.

	Central thermal power generators	***Decentral thermal power generators***
Ref	2,917	17,373
BES	2,415	15,060
BESXL	1,936	9,409
DR	2,819	9,639
UPHS	2,113	11,401

10.2.3 Thermal power generator capacity factors

The capacity factor shows the amount of time a generator operates at full capacity relative to the theoretical maximum production in the modeled timeframe. The result is expressed as a percentage.

The first general observation is that the base load generators (e.g. Nuclear, new CP and new CCGT) have typically very high capacity factors in the 2017 and early scenario years. This capacity factor decreases in later scenario years. This is caused by the increasing amount of 'free' renewable energy that replaces production from baseload generators.

The second observation is that the capacity factor of peak generators (e.g. Gas engines, Gas Turbines (GT)) increases from 2017 to 2020. There is a slight decrease in capacity factors for gas engines in 2025 and 2030. The capacity factors for peak generators increases substantially in 2035. For gas turbines there is a slight increase in capacity factor each subsequent year after 2017. It can be explained by the increase in intermittent renewables combined with a shrinking thermal power generator park, this increases the use of peak generator capacity. The year 2035 is an exception compared to former model years, because the total installed thermal power generator capacity is smaller than occasional peak loads. It results in much higher capacity factors on peak generators and also relatively little reduction in baseload generator capacity factors compared to former years.

In BES(XL) and UPHS scenarios the capacity factor for gas turbines and gas engines (i.e. peak generators) is substantially lower than the DR and reference scenarios. A slightly higher capacity factor for baseload generator can be observed in the BES(XL) and UPHS scenarios compared to DR and the reference. This is the result of load shifting performed by both storage systems that stimulates the use of baseload generators. All values for thermal power generator capacity factors are presented in a table In chapter 15. The results for the capacity factors are further discussed per model year in the descriptions of Figure 26 - Figure 30.

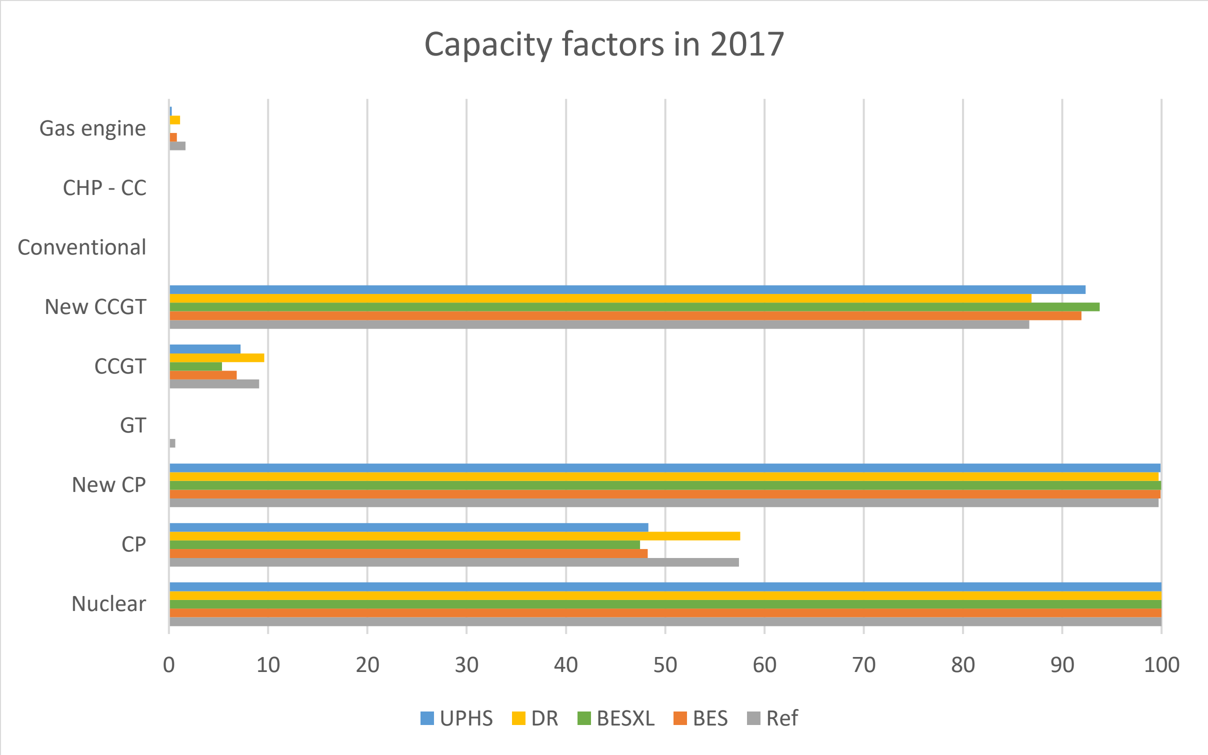

Figure 26: Capacity factors of thermal power generators in the 2017 model year. All baseload generators (i.e. Nuclear, New CP (coal power) and new CCGT (combined cycle gas turbine) in merit order) are used almost the whole year at full capacity in all scenarios. There is a clear difference between the scenarios with regard to the mid load generators. CP (coal power) and CCGT (combined cycle gas turbine) have higher capacity factors in the DR an Reference scenarios than in the storage scenarios. This is also the case for peak load generators that are almost never used due to overcapacity in the power system.

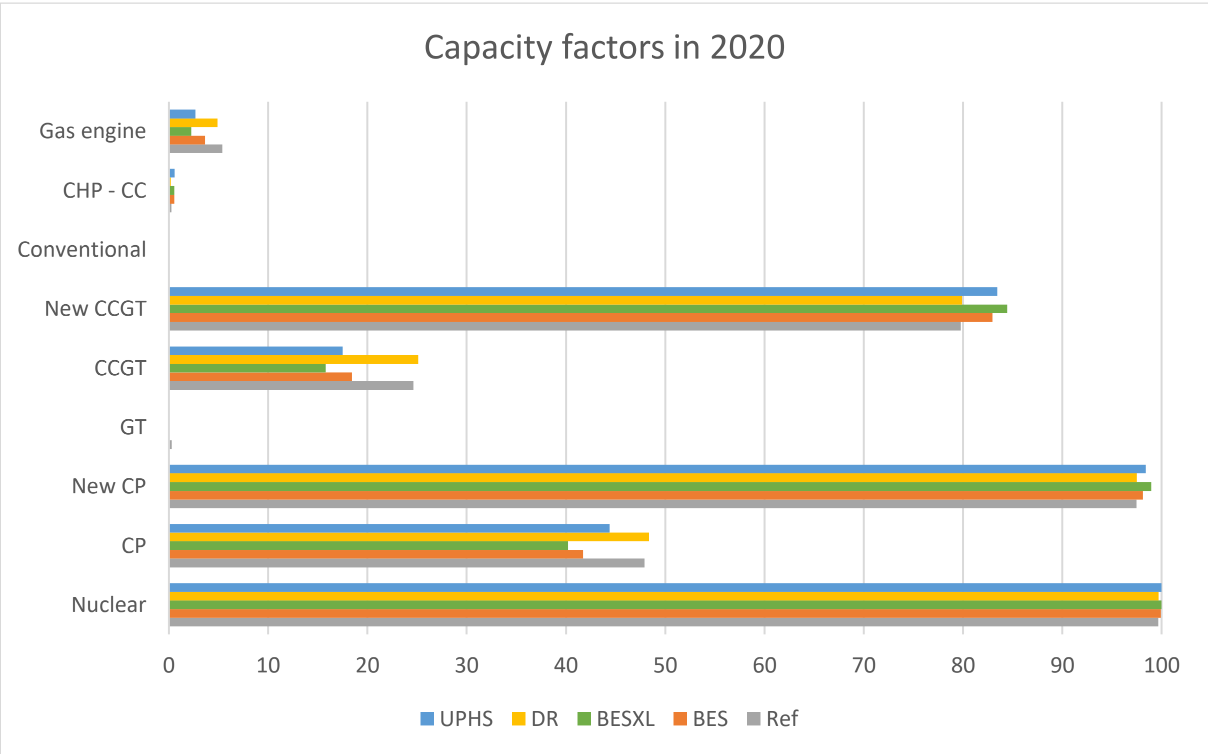

Figure 27: Capacity factor of thermal power generators in 2020 for the different scenarios. Compared to the former model year, there is some reduction in the capacity factors of baseload generators. Also an increase in the capacity factors of gas engine and CCGT capacity can be observed, while the use of CP is reduced compared to the former year. The conventional gas boiler is decommissioned after 2017, and does not have a capacity factor here and in the next model years.

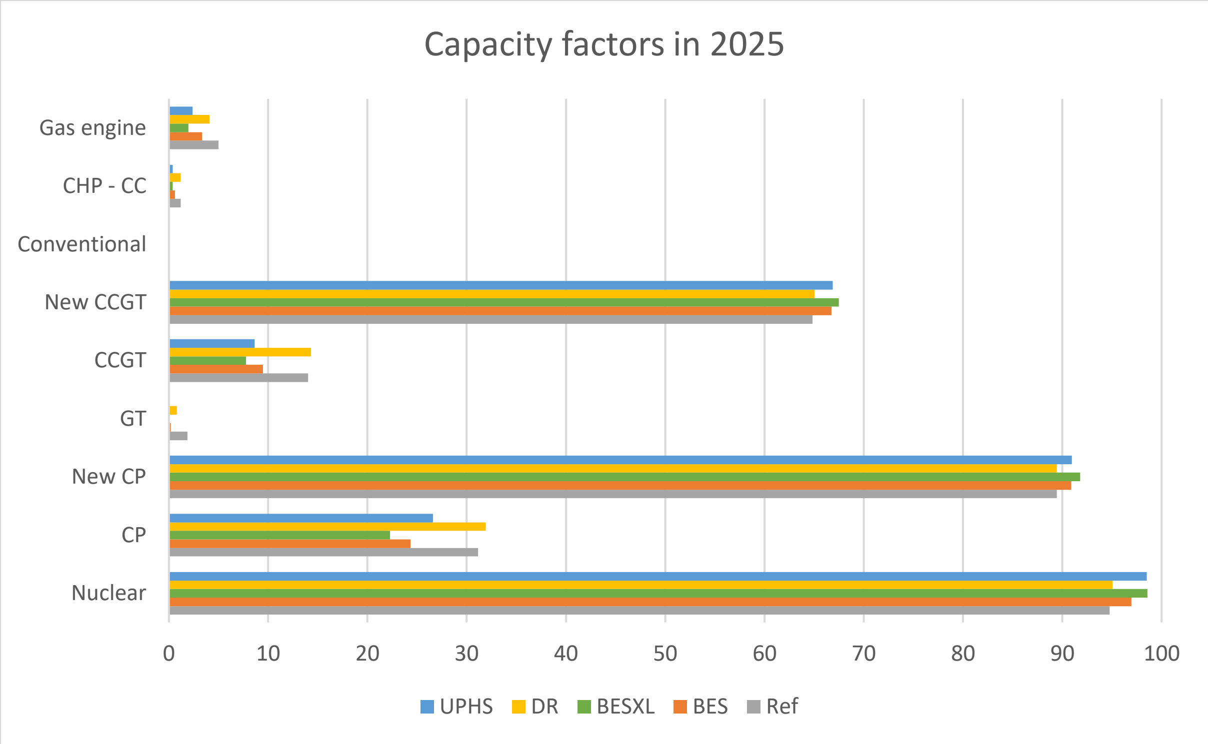

Figure 28: Capacity factor for thermal power generators in 2025. Again the capacity factors of base and mid load generators decrease. On the other hand the capacity factors for gas engines decrease slightly compared to the former model year. Notable is that the use of GT (gas turbine) and CHP -CC (combined heat and power – combined cycle) increases slightly. The scenarios with storage (i.e. UPHS, BESXL and BES) have typically higher capacity factors on baseload capacity and lower capacity factors on mid and peak load generators.

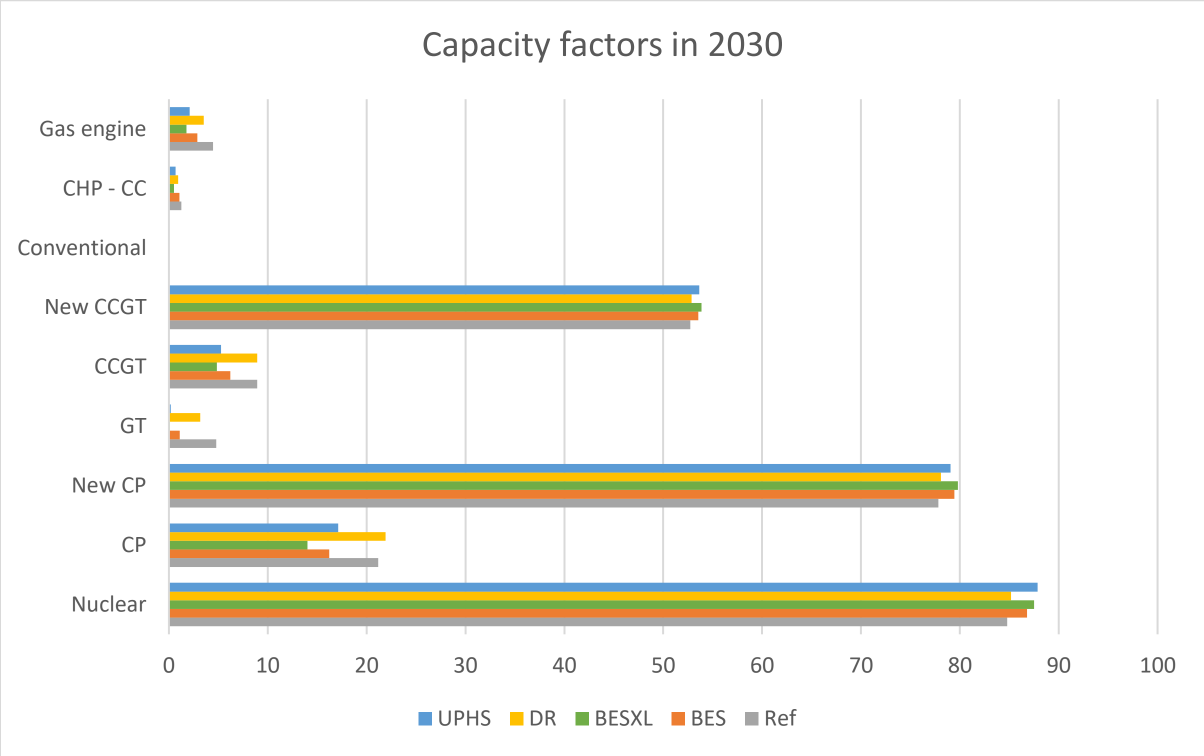

Figure 29: Capacity factors for thermal power generators in 2030. Again a decrease in capacity factors for base and mid load generators can be observed. Peak load generators have roughly the same capacity factor as in 2025, with exception of GT capacity that experiences an increase in capacity factor.

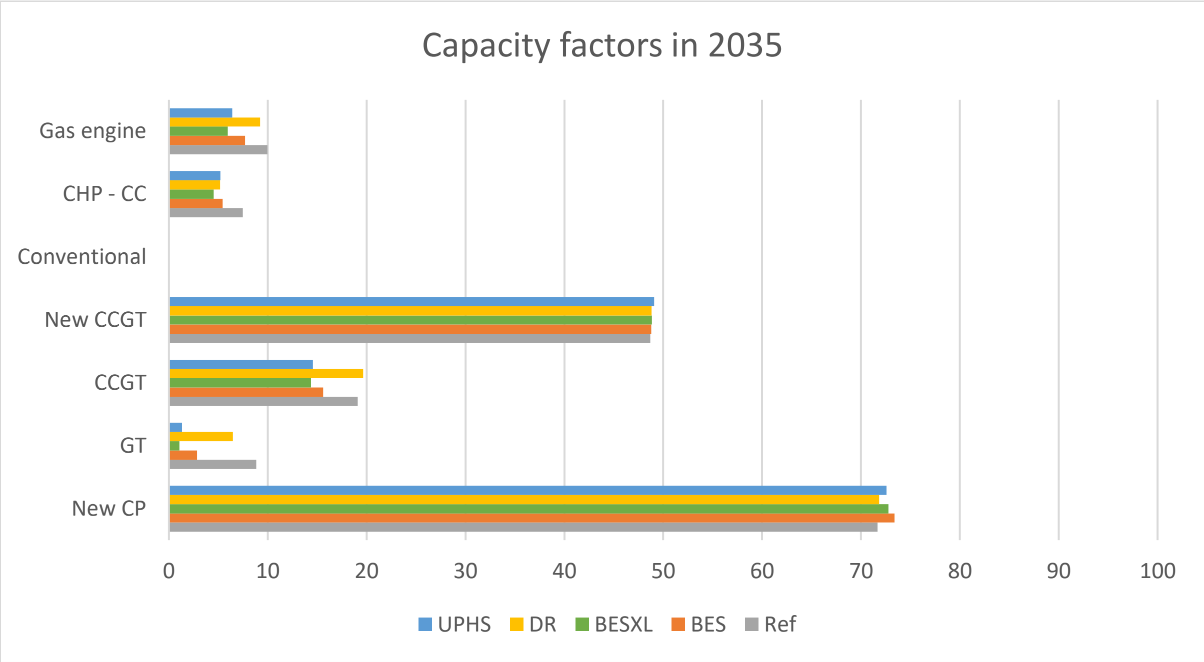

Figure 30: Thermal power generator capacity factors in 2035 model year. The first observation is the lack CP and nuclear capacity in the power system in 2035, the result of decommissioning the last of these types generators. The capacity factors for baseload generators still decreases. The New CCGT capacity factor reduces relatively less than that of New CP and an increase in the capacity factor for CCGT can be observed. Both are the result of moments of capacity shortage when renewables are not available. It also increases the use of peak load capacity (mainly the cheaper peak load capacity CHP-CC and gas engines). GT capacity factor is substantially lower in storage scenarios, as this is the first peak generator that is replaced by energy storage as peak generator.

10.2.4 Flexibility measure

In this subchapter the performance of each flexibility measure (i.e. DR or energy storage) is discussed based on the model results. There are no reference scenario results presented for any of the modeled years, as the reference scenario has no flexibility measure in place.

The total electricity generated by each flexibility measure is presented in Figure 31. For DR this is not actual generation, but the amount of demand reduction that has been called upon by the TSO. The results show that BESXL generates the most of all flexibility measures during all modeled years. The use of DR is substantially less than the generation by the storage technologies. The generation by flexibility measures increases with each subsequent modeled year. Except between 2020 and 2025, where the use of storage systems reduces slightly in 2025 compared to 2020.

It is difficult to find a direct cause for this decrease in generation for energy storage from 2020 to 2025. The main changes in the generator park, are a decrease in installed decentral gas capacity (i.e. peak generator capacity) and a substantial increase in wind and solar capacity. The total renewable capacity is around 20 GW in 2025, which is about 2-4 GW higher than weekly peak demand in the load profile. The generator mix as it is modeled for 2025 is probably more suited to meet demand as overproduction by renewables is less substantial than in the later model years. While the use of baseload generators is still substantial, compared to later years. This may cause less profit opportunity for storage. DR does experience an increase in generation between 2020 to 2025, proving that the flexibility is required when renewable capacity grows.

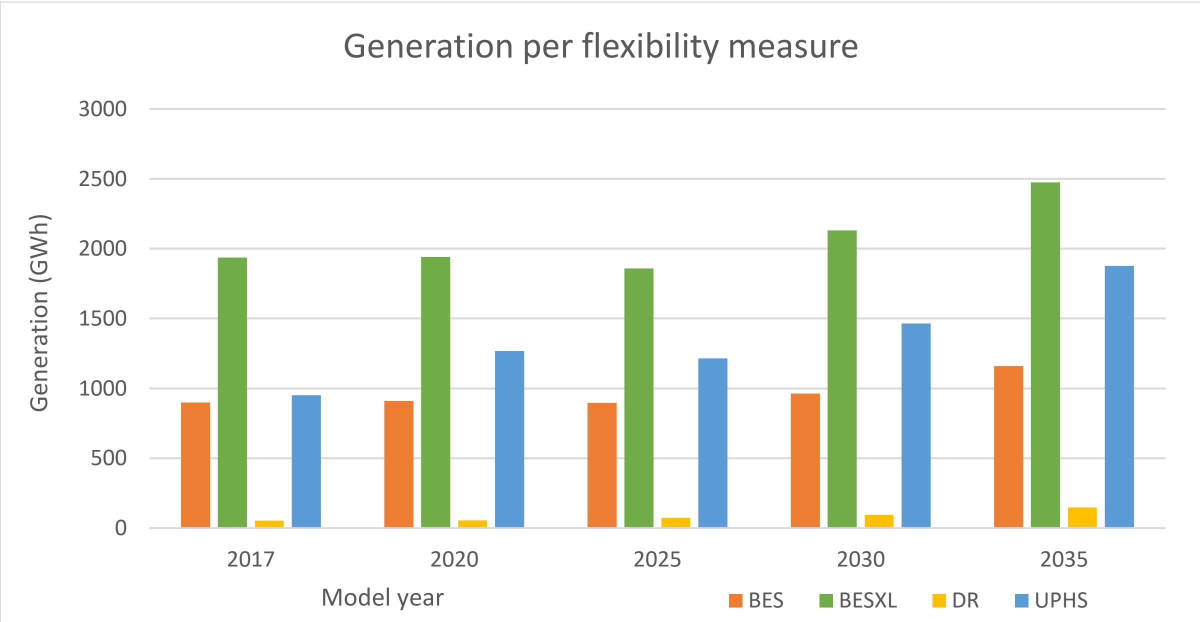

Figure 31: Generation per flexibility measure in GWh. This figure shows that BESXL generates most followed by UPHS and BES. DR does not compare in energy volume with energy storage.

The capacity factor of each flexibility measure was calculated based on actual generation divided by the theoretical maximum amount that could be generated. The theoretical maximum DR delivery was 528,587 MWh. The theoretical maximum generation by the storage systems was calculated using formula (2):

$$Max\ generation = (\text{max capacity} \cdot (8736 - (8736/1 + roundtrip\ efficiency))) \qquad (2)$$

The formula takes into account the time needed to charge the battery and UPHS, to provide the maximum output possible in the 8736 hours that were modeled.

The results for the capacity factor of flexibility measures are presented in Table 8. Battery storage has generally a high capacity factor, due to the high roundtrip efficiency of the lithium battery that makes it profitable at a smaller price difference. UPHS has a higher capacity factor in the final two modeled years. DR has the lowest capacity factor especially in the earlier model years. During those years it is often cheaper to dispatch thermal power generators, due to the relatively high costs per MWh for DR and the overcapacity in the power system.

BESXL shows a higher capacity higher capacity factor than UPHS in the first three model years. This is caused by the higher roundtrip efficiency for BESXL compared to UPHS. However, it has a lower capacity factor then the smaller sized BES. This may be the result of the impact that charging a large capacity has on the electricity price. Charging a 2000 MW battery at full capacity has a substantial impact on the demand side of the electricity the market, a larger impact than charging a battery of 900 MW. It may result in a higher price for charging that could make full-capacity charging unprofitable, resulting in less use of the BESXL compared to BES relative to their respective capacities (i.e. lower capacity factor).

Table 8: The capacity factor of flexibility measures in the different modeled scenario years.

	BES	**BESXL**	**DR**	**UPHS**
2017	24.51%	23.75%	9.93%	17.52%
2020	24.79%	23.82%	10.55%	23.29%
2025	24.47%	22.81%	13.93%	22.33%
2030	26.26%	26.14%	17.76%	26.96%
2035	31.61%	30.38%	27.72%	34.53%

The profit generated by the flexibility measures is presented in Table 9. These values do not include the operation and maintenance costs. BES shows the largest profit figures in the early model years. BESXL generates less profit than BES in the early mode years, due to its large impact on the electricity market.

In the year 2035 the profit of all flexibility measures is substantially higher than the years before. This is caused by momentary increases in the electricity price to the VoLL (Value of Lost Load), that was set at 10,000 €/MWh in PLEXOS. The flexibility measures are often dispatched at these moments and profit from these price peaks. The profit per flexibility measure is six times higher in 2035 compared to the former year. The only exception is BESXL, that has a substantially lower profit figure in 2035 than both BES and UPHS. This is the result of one hour less unserved demand compared to the UPHS scenario, resulting one less hour of generation at the VoLL price. More generation during periods with VoLL pricing increases profit for energy storage and DR.

Table 9: Profit per flexibility measure, operation and maintenance costs are not included. Values are in euros.

	BES	**BESXL**	**DR**	**UPHS**
2017	€ 10,692,078	€ 3,406,386	€ 24,366	€ 1,206,897
2020	€ 7,570,022	€ 7,095,982	-€ 51,221	€ 4,704,784
2025	€ 16,323,788	€ 14,742,091	€ 2,428,798	€ 14,328,611
2030	€ 31,855,078	€ 36,261,792	€ 2,873,426	€ 32,194,943
2035	€ 202,218,922	€ 134,552,032	€ 196,367,141	€ 201,442,184

The profit per MWh (Table 10) is overall highest for BES and in 2025 for DR, while it is lower for BESXL compared to UPHS. In the first year both BES and BESXL have a higher specific profit than UPHS, the result of a higher roundtrip efficiency for the battery storage technology. The BES scenario always has a substantially higher specific profit than the larger energy storage in the BESXL and UPHS scenarios. Due to its smaller size it can 'cherry-pick' the most profitable energy arbitrage periods over the year. BES also disrupts the market prices less than larger storage due to having less capacity available on the market and less capacity in demand.

DR mainly exploits the moments of extreme electricity prices to generate profit. As a result it generates almost no profit per MWh in the first two years. During those years the power system is still characterized by overcapacity and little renewable capacity. This makes DR often the price setting energy 'source' which causes the net profit for DR to be low. In 2035 it exploits the VoLL situation during the hours of unserved demand optimally, this results in the highest profit per MWh for all scenarios. However it should be recognized that DR is the scenario that performs least on most other indicators.

The comparison between BESXL and UPHS is more interesting as both storage systems have the same energy volume (i.e. 8000 MWh), only with a capacity advantage for BESXL (2000 MW vs. 1400 MW). The BESXL has a better average profit in 2017 than the UPHS, this is caused by the higher roundtrip efficiency. The UPHS has higher profit per MWh in the following years. The difference comes mainly from the difference in total generation, due to the shorter charging and discharging cycle possible by the BESXL. BESXL generates much more than UPHS in all model years, this means that BESXL can use more opportunities for energy arbitrage to its fullest, this does not necessarily increase the average profit. The difference in 2035 is mainly caused by the extra hour of unserved demand observed in the UPHS scenario. It shows how large the impact of an additional period with VoLL prices is on the total (Table 9) and average profit (Table 10).

Table 10: Average profit per MWh of generation (in €/MWh).

	BES	BESXL	DR	UPHS
2017	€ 11.90	€ 1.76	€ 0.46	€ 1.27
2020	€ 8.33	€ 3.66	-€ 0.92	€ 3.72
2025	€ 18.19	€ 7.93	€ 32.99	€ 11.81
2030	€ 33.08	€ 17.03	€ 30.61	€ 21.97
2035	€ 174.47	€ 54.36	€ 1,340.35	€ 107.33

10.3 Economy

10.3.1 Electricity price

The electricity price is an important indicator for the performance of the power system. It shows how expensive electricity is on average, a high average price can be an indication of an unreliable power system where capacity scarcity may occur[2]. The lowest price shows the costs that result from dispatching the cheapest marginal generator. The highest on the other hand shows the highest marginal price for the most expensive moment of electricity generation in the model. The price variance shows the variation of all the price values from the average price (i.e. electricity price volatility).

In all scenarios the lowest observed electricity price in the reference year is €35,08 per MWh. In later years the lowest price is €0 per MWh, due to the larger amount of renewable production that has no marginal production costs. The highest electricity price is around €170 per MWh, except for the year 2035 where the highest price in all scenarios is €10,000 per MWh during hours with unserved demand. When unserved demand occurs in the power system, the VoLL (Value of Lost Load) price is charged (€ 10,000 per MWh in PLEXOS). The average price differs slightly between the scenarios and is presented in Table 11.

The scenarios with energy storage have a higher than reference average electricity price in 2020, 2025 and 2030. In 2017 and 2035 the average price is lower than the reference scenario. The low average price in 2017 is caused by the energy arbitrage that is performed by storage systems between cheap baseload and expensive peak load generators. The higher price during 2020, 2025 and 2030 may be caused by less shutting down of baseload generators. Keeping these generators online during baseload hours where renewables could be the marginal generator affects the average electricity price. Keeping baseload generators online may be done to charge energy storage for use during peak demand. In 2035, the average price is determined by a few occasions of the VoLL being the settlement price, this causes electricity price spikes that impact the average.

The average price is higher in the DR scenarios due to the high price of using DR (€ 125 per MWh). 2035 is the only model year where the average price is lower than the reference scenario. The average is largely affected by the VoLL during that year. DR can prevent some occasions of VoLL pricing, the result is a lower average price than the reference scenario.

Table 11: Average electricity price for all scenarios for the different modeled years. Values are in €/MWh.

	Ref	BES	BESXL	DR	UPHS
2017	€ 42.40	€ 42.37	€ 41.83	€ 44.02	€ 41.93
2020	€ 41.72	€ 42.09	€ 42.23	€ 43.04	€ 42.41
2025	€ 38.08	€ 38.66	€ 39.35	€ 38.76	€ 39.33
2030	€ 33.32	€ 34.09	€ 34.34	€ 34.07	€ 34.61
2035	€ 104.12	€ 69.63	€ 47.33	€ 85.36	€ 53.64

The electricity price variance shows the volatility of the electricity price in the specific scenario (electricity price variance is presented in Table 12). The higher the price variance is, the larger the spread of electricity prices is around the average electricity price. A highly volatile electricity price indicates that the potential for energy arbitrage is larger. The scenarios with a storage system have

[2] Chapter 11.4 provides an elaboration on actual market mechanisms in the energy only market, and capacity investment incentives. The role of storage is also briefly discussed.

lower electricity price variance than the reference scenario, a result of the energy arbitrage performed by energy storage. In the reference year and 2020, the DR scenario has a higher price variance than the reference scenario. Because of the relatively high marginal price of DR compared to thermal power capacity. In later model years the DR scenario has a less volatile electricity price. The UPHS and BESXL scenarios have the least price variance overall. Their large capacity enables more energy arbitrage than in the BES scenario, thereby reducing the volatility of the electricity price even more.

Table 12: Variance in the electricity price for the different scenarios and years. The larger the variance, the larger the spread of electricity price values is around the average price.

	Ref	**BES**	**BESXL**	**DR**	**UPHS**
2017	165	122	17	205	17
2020	65	52	32	88	40
2025	225	121	151	190	94
2030	369	296	243	360	250
2035	700,778	363,122	148,013	520,955	204,716

10.3.2 Start-up costs thermal power generators

The total start-up costs for thermal power generators are the costs to the system from starting a generator after shutdown. The total start-up costs increase with each subsequent year in all scenarios. The increasing costs for generator starts shows that the supply side of the power system responds to the increasing amount disruptive renewable capacity. Unpredictable renewable capacity forces generators to stop and restart more often, as was noticed in the number of thermal generator starts (see Figure 25). It also forces generators with more expensive start-up costs to shut down and restart. The higher number of starts and more expensive starts result in a higher total costs for starting up generators in each subsequent scenario year. The only exception is from 2017 to 2020 for the BES scenario, where the start-up costs decrease slightly in all scenarios.

There is no direct connection between the number of start-ups (in Figure 25) and the total start-up costs (in Figure 32). DR has less generator starts than the BES scenario in each year, while the start-up costs are not always lower. In the early years the start-up costs are higher for BES than for DR. In later years this is turned around and BES has lower total start-up cost. This is caused by the different types of generators that are started, large generators are more expensive to start than small generators.

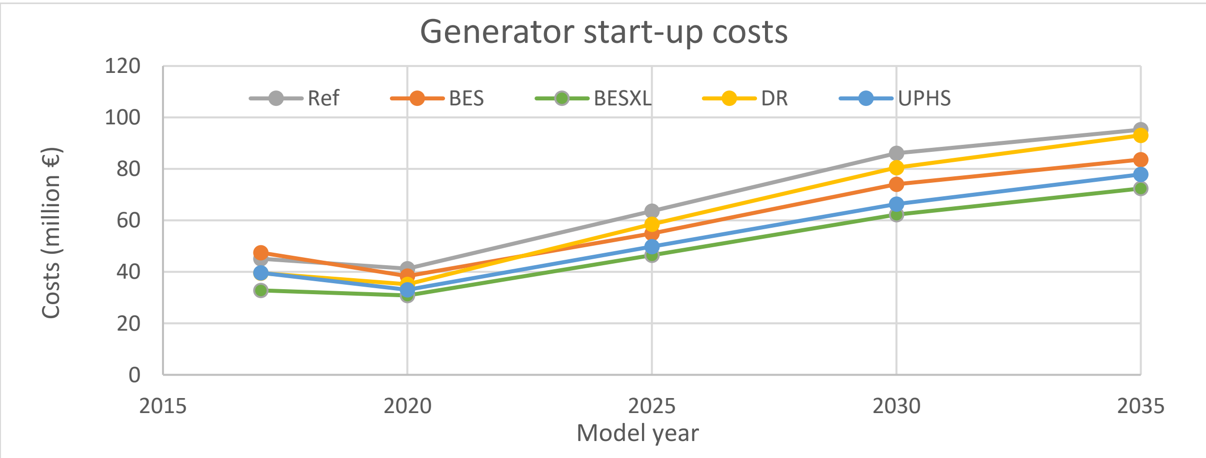

Figure 32: The development of generator start-up costs during the model years for all five scenarios. BESXL outperforms all other scenarios by providing the most flexibility with its large capacity and storage volume.

10.3.3 Total generation costs

The total generation costs are the actual total costs made by the power generators to produce the amount of delivered electricity. It includes the total fuel costs and other variable production costs. The total costs for electricity generation decreases each subsequent model year. The decrease is caused by increasing renewable production that has no variable production costs. In 2017 storage technologies (i.e. BES(XL) and UPHS) have higher total generation costs than the Ref and DR scenario, due to higher total generation in the power system. The energy arbitrage by BES(XL) and UPHS show result in all following other years. The total generation costs are lower than the Ref and DR scenarios, despite higher total electricity generation. The difference in generation costs between DR and Ref are small and not noteworthy. The difference between BESXL, UPHS and BES are caused by the higher storage volume and capacities, that results in more storage of renewable energy and higher capacity factors for cheap baseload generators. The BESXL outperforms the UPHS, due to its higher capacity and roundtrip efficiency. All results for the total generation costs are presented in Table 13.

Table 13: Total generation costs for electricity provided to the power system.

	Ref	BES	BESXL	DR	UPHS
2017	€ 2,778,490,517	€ 2,782,399,111	€ 2,779,105,825	€ 2,778,021,679	€ 2,782,103,351
2020	€ 2,512,466,204	€ 2,503,318,687	€ 2,495,527,843	€ 2,513,393,551	€ 2,498,874,194
2025	€ 2,059,383,727	€ 2,036,053,656	€ 2,023,171,941	€ 2,055,884,721	€ 2,027,188,038
2030	€ 1,706,045,855	€ 1,665,261,894	€ 1,642,667,351	€ 1,701,528,876	€ 1,648,144,211
2035	€ 1,619,186,979	€ 1,558,649,752	€ 1,521,666,556	€ 1,616,224,161	€ 1,532,703,237

10.3.4 Total cost to load

The cost to load is the price paid by the demand side of the electricity market for the delivered electricity (presented in Table 14). It is calculated in PLEXOS by the total amount of load multiplied by the electricity price at that moment of load. The difference between the generation costs and cost to load does not give the total net profit, because fixed O&M, strategic reserves and start-up costs are not included in generation costs.

The cost to load results show the same trend as average electricity price, where the scenarios with DR or energy storage have higher cost to load than the reference scenario. In 2035 the cost to load is affected by the VoLL price. In scenarios with a flexibility measure in place the cost to load was lower, because less periods with unserved demand were observed. In the other scenarios the high price of DR and the additional load on the power system from charging BES(XL) and UPHS increase the cost to load compared to the reference scenario.

Table 14: Cost to load for modeled scenarios. Cost to load is calculated by PLEXOS by the product of load and electricity price.

	Ref	BES	BESXL	DR	UPHS
2017	€ 4,849,520,752	€ 4,844,288,082	€ 4,771,646,502	€ 5,052,051,420	€ 4,789,308,108
2020	€ 4,786,819,167	€ 4,824,425,774	€ 4,831,877,251	€ 4,951,045,300	€ 4,859,119,380
2025	€ 4,381,598,707	€ 4,434,826,756	€ 4,496,481,024	€ 4,466,049,863	€ 4,502,334,341
2030	€ 3,824,857,465	€ 3,905,150,713	€ 3,930,708,650	€ 3,912,425,697	€ 3,965,535,111
2035	€ 13,649,365,721	€ 8,976,249,535	€ 5,857,267,902	€ 11,185,941,210	€ 6,763,835,296

10.4 Environmental

The CO_2 emissions are the single environmental indicator included in the model. The total CO_2 emissions for each scenario and model year are presented in Table 15. All scenarios with flexibility measures show reduced emissions compared to the reference scenario. Addition of DR results in the least emission reduction of all scenarios. In the first three model years, the emission reduction in the BES scenario is larger than for UPHS. In the last two years UPHS outperforms the BES system with the lower CO_2 emissions. Overall the BESXL scenario has the lowest CO_2 emissions of all scenarios.

In the first three modeled years the capacity factor of coal power plants (CP) is slightly higher in the UPHS scenario than in the BES scenario, BESXL has the lowest capacity factor on CP generators. These generators emit almost twice the amount of CO_2 per MWh compared to gas fired generators, affecting the total emissions when they are used more often. The UPHS scenario also has a higher total generation in all model years than the BES scenario (see Table 3). This causes the BES scenario to have lower CO_2 emissions than the UPHS scenario in 2017, 2020 and 2025. In the last two model years (i.e. 2030 and 2035) this is the other way around, because of higher capacity factors for the nuclear power plant and a slightly lower capacity factor on coal capacity overall in the UPHS scenario. UPHS also has higher renewable production, this contributes to emission reduction.

BESXL had the least emission in all model years due to its large volume and capacity. It can outperform the UPHS by achieving even higher capacity factors on efficient baseload capacity and lower capacity factor on inefficient mid and peak load capacity.

Table 15: Total CO_2 emissions from the power system per scenario for the different modeled years. Values are presented in Megaton CO_2, in brackets the relative reduction in emissions compared to the reference scenario is shown.

	Ref	**BES**	**BESXL**	**DR**	**UPHS**
2017	52.9	51.9 *(-1.91%)*	51.8 *(-2.11%)*	52.9 *(-0.09%)*	51.9 *(-1.87%)*
2020	45.7	45.3 *(-0.83%)*	45.3 *(-0.91%)*	45.7 *(-0.05%)*	45.5 *(-0.42%)*
2025	38.3	37.8 *(-1.26%)*	37.7 *(-1.61%)*	38.2 *(-0.22%)*	37.9 *(-1.07%)*
2030	32.0	31.4 *(-1.71%)*	31.1 *(-2.77%)*	31.9 *(-0.29%)*	31.3 *(-2.28%)*
2035	28.7	28.3 *(-1.48%)*	27.8 *(-3.19%)*	28.5 *(-0.75%)*	27.9 *(-2.88%)*

The absolute emission reduction compared to the reference scenario is presented in Table 16. The highest emission reduction occurs in 2017. The emission reduction for BES, BESXL and UPHS in 2017 can be accounted to the reduction in capacity factor for CP capacity (i.e. older coal power plants), and the increased use of new CCGT capacity (new Combined Cycle Gas Turbines) compared to the reference scenario. The second generator type is more efficient and emits substantially less CO_2. Emission reduction decreases substantially in the next model year.

In 2020 the amount of renewable capacity is increased compared to 2017, this requires more need for flexible response by thermal generators, storage or DR. The electricity price is relatively involatile in 2020, so there is less opportunity for using storage profitable. Besides, the thermal generator park has capacity surplus in 2020. This results in more use of less efficient thermal generators instead of energy storage or DR, causing a relatively small difference in emissions between the reference scenario and the scenarios with storage or DR.

In the years after 2017 the installed gas powered capacity is reduced by decommissioning of most of the old gas power plants. The old coal power plant capacity is also reduced. This results in more use of new CCGT capacity in the reference scenario and use of the remaining new coal power plants (new CP) that is more similar to the use of these generators in UPHS and BES(XL) scenarios. These newer generators are more efficient and thereby emit less CO_2. These developments in the thermal generator park and increasing renewable capacity result in overall lower emissions in all scenarios (including the reference). The difference in CO_2 emission between the reference scenario and storage scenarios is therefore smaller in all years subsequent to 2017. The absolute CO_2 emission reduction compared to the reference scenario is presented in Table 16.

Table 16: The absolute emission reduction (in Megaton CO_2) compared to the reference scenario for each years.

	BES	BESXL	DR	UPHS
2017	1.01	1.12	0.05	0.99
2020	0.38	0.42	0.02	0.19
2025	0.48	0.62	0.08	0.41
2030	0.55	0.88	0.09	0.73
2035	0.43	0.92	0.21	0.83

It shows that storage and DR may help reduce CO_2 emissions, nevertheless increasing renewable capacity has the largest impact on reducing power system emissions. The results show that in early years the impact that storage has on emissions is governed by achieving higher capacity factors on more efficient thermal generator capacity (with less emissions than less efficient capacity), and on nuclear capacity (that has no direct CO_2 emissions). This mechanism still occurs in a power system where renewable capacity grows (i.e. model year 2020 and 2025), but to a smaller extend. The impact from adding renewable capacity is substantially larger than the impact that storage has on emission reduction. The other advantage that energy storage can provide was observed in model years with renewable overproduction. During those years (i.e. 2030 and 2035) the storage system stores renewable overproduction, that is back to the grid at a later time. Consequently reducing CO_2 emissions.

11 DISCUSSION

11.1 Research overview

Not all benefits (discussed in chapter 9) that could result from implementing an UPHS were captured in the PLEXOS model. The ancillary services (9.3) network congestion reduction, black start, and re-dispatch are not captured in the model. Reserves were modeled to a limited extend, as there was no elaborate reserve market modeled. Modeling of reactive power is not possible in PLEXOS, because power quality is not included in the software.

The interaction between the power system, flexibility measure and increasing renewable capacity (9.1), energy arbitrage (0) and savings on operating costs of thermal power generators (9.4) were captured in the PLEXOS model. Thermal power generators may have additional costs due to ramping, that can cause wear on generators. Ramping costs were not included in the model, while start-up costs were included.

The focus of this research is on the performance of UPHS. First the comparison between the UPHS and reference scenario is made. Second the benefits from UPHS are compared to benefits observed for other flexibility measures (i.e. DR, BES and BESXL). These scenarios are compared on the four main indicators, reliability, flexibility, economy and environment.

11.1.1 UPHS compared to Reference

Reliability is increased with the addition of a UPHS. The amount of unserved demand in the 2035 scenario is reduced substantially compared to the reference scenario. However, one UPHS system has insufficient capacity and storage volume to prevent all unserved demand in a power system with less thermal power generator capacity than peak demand.

Flexibility increases substantially with the addition of a UPHS. The number of generator start-ups is almost halved in all model years. The curtailment of renewables is reduced by the presence of UPHS in later model years. The UPHS also reduces the flexibility burden for thermal power generators, it stimulates the use of baseload capacity over mid and peak load capacity.

Economy performance is dependent on what effects are regarded as beneficial. The average price is higher with the presence of UPHS, except for the reference year and 2035. A similar trend is observed for cost to load that is closely related to the electricity price. It means that the consumer price for electricity is increased slightly by the presence of UPHS compared to the reference scenario. The electricity price variance is reduced substantially compared to the reference. This means that prices are more constant and potential for price arbitrage is reduced.

From the perspective of the generator park there is benefit from installing an UPHS. The total costs for generator starts is reduced. Next to this, the total costs for generation are reduced compared to the reference scenario. The model year 2017 is an exception to this observation. It is notable that generation costs are lower in the UPHS scenario despite a larger amount of electricity generation by the generator park.

Environmental benefits are observed when a UPHS is implemented in the power system. The CO_2 emissions in the UPHS scenario are lower than in the reference scenario for all model years. This is achieved despite the higher system load from storage efficiency losses.

11.1.2 UPHS compared to DR

UPHS outperformed DR with regard to **reliability**. UPHS prevented substantially more the unserved demand than DR did in the 2035 scenario year.

UPHS also outperformed DR with regard to **flexibility**. The renewable energy curtailment is lower for the UPHS scenario in all the model years. On the other hand DR helps reduce thermal power generator starts to a total number of starts that is similar to the number of starts in the UPHS scenario. It is notable that DR reduces the number of starts by peak generators, while UPHS prevents more large baseload generators from shutting down and restarting.

Economy: The DR scenario has substantially higher price variance than UPHS. The average electricity price is lower in the DR scenario than in UPHS scenario, except for the reference year and 2035. The cost to load shows a result similar to the average electricity price. It means that DR has a more volatile electricity market, where the average price over the year is slightly lower than in the UPHS scenario. The DR scenario has higher thermal generator start-up and total generation costs in all modeled years.

DR is outperformed by UPHS with regard to **environmental** performance, because less CO_2 is emitted in the UPHS scenario during all model years.

11.1.3 UPHS compared to BES

The **reliability** performance of the BES scenario comes close to the UPHS scenario. However, the BES scenario still has substantially more unserved demand in 2035, due to the smaller capacity and storage volume of the BES.

Flexibility: The reduction in renewable curtailment for the BES and UPHS scenario are almost similar in 2020. The difference in curtailment reduction grows in favor of UPHS in the subsequent model years. UPHS prevents double the amount of wind curtailment in 2035. The BES scenario also experiences more generator starts in all scenario years.

The **economic** performance of BES scenario shows lower average electricity prices except in 2017 and 2035. The cost to load follows the same trend as the average electricity price. BES has a higher price variance in all scenario years than the UPHS scenario. The UPHS scenario has lower costs for thermal power generator start-ups and lower total generation costs than the BES scenario.

The **environmental** performance of the BES and UPHS are almost similar in the first three model years. The total CO_2 emissions are lower in the BES scenario for 2017, 2020 and 2025. After that the UPHS starts outperforming the BES system due to its larger energy storage volume that can store more renewable energy.

11.1.4 UPHS compared to BESXL

The UPHS and BESXL are energy storage systems similar technical specifications. The main differences are the higher roundtrip efficiency (87% vs. 80%) and larger capacity (2 GW vs 1.4 GW) for the BESXL system. Energy storage volume is equal at 8 GWh for both systems.

The **reliability** of the power system is slightly better in the BESXL scenario. BESXL experiences less unserved demand in 2035. This is the result of its higher capacity, but still the storage volume limits its ability to prevent all unserved demand during longer periods of peak demand without wind power and little solar power.

Flexibility: The BESXL has a more flexible capacity to energy volume ratio than the UPHS, it can reproduce the UPHS exactly by providing a capacity of 1.4 GW, but can also deliver its full capacity of 2 GW for a shorter period. This means that it can profit more from short periods of extreme overproduction by renewable sources. The model results show that the BESXL scenario has slightly less curtailment of renewables, compared to UPHS relatively more solar curtailment is prevented than wind. In 2035 the UPHS scenario even experiences less total wind curtailment than the BESXL scenario. There is a substantial difference in the number of generator start between the BESXL and UPHS scenario. The higher flexibility of BESXL enables it to reduce generators starts more than the UPHS does.

Economy: The average electricity price differs only slightly between the two scenarios for the first four model years. The final model year (2035) has a substantially lower average price in the BESXL scenario due to one less hour with VoLL pricing than in the UPHS scenario occurs. The cost to load follow the observations for the average electricity price. Notable are the lower generator start costs and the slightly lower variance in electricity price in the BESXL scenario.

Environmental performance is slightly better for the scenario with BESXL. The maximum difference is 0.2 Mton less CO_2 emissions in favor of the BESXL scenario.

11.2 REMARKS

11.2.1 Limited model for demand response

The method used for modeling demand response is limited compared to a realistic implementation of demand response. PLEXOS does not have a dedicated function for model demand response, a limitation that comes from its focus on the supply side of the power system. Demand response was therefore modeled as a power generator with no start costs, a fixed SRMC, unlimited ramp rates and no emissions. DR had a restricted amount of daily capacity provision, based on the load profile and a maximum daily energy volume. In this way it was possible to model the flexibility DR can provide within capacity and volume boundaries.

In reality demand response depends on many different factors that are not entirely captured in the used method. There are many different sources that could provide demand response. Large industrial users that can participate on the electricity market with load reduction bids. Residential consumers that could make demand decisions based on real-time pricing. The expected increase in electrical heating and air conditioning and the increase in electric vehicles based on battery storage, these could also participate in demand response. All of these DR sources will have different availability over the day, and may have different prices based on the moment of use.

An elaborate model is needed to capture all these different types of demand response. Because they may vary on many different aspects from each other, like availability over time, human behavior, environmental factors and economics. This level of detail was impossible to capture in the time available for this research. For researchers that want to model demand response in PLEXOS, the report by Edmunds et al (2017) may be useful. It uses a method with a more elaborate approach to demand response modeling than this report.

11.2.2 Future load profile

The load profile has been kept constant in every model year for all scenarios. This was done so that results could be compared between the model years. However, in reality an increase in total electricity consumption is expected in the Dutch energy outlook. In the Dutch energy outlook, the changes that may occur in the structure of the load profile are not discussed.

In this research it was discovered that there may be unserved demand in 2035 if the load profile stays the same. However if peak demand will decrease and baseload increase, it may be possible that there is no unserved demand in the power system. Alternatively, the amount of unserved demand may increase when peak demand increases compared to load profile used in this report. This second statement is probably more realistic in light of the expected increase in electricity consumption for the future. Additional research on load profile development would be beneficial for future modeling research.

11.2.3 High resolution data

The initial plan was to run the power system model at a sub-hourly resolution. The limitation was the unavailability of data with sub-hourly resolution on wind speeds, solar irradiance or renewable production. Consequently an hourly resolution was used for the model.

A higher resolution will provide more detailed insight in the flexibility of the power system. Because a generator is now modeled as either on or off for one full hour. While some generators could start and shut down within an hour at a higher model resolution. Another advantage of higher resolution is that is provides the possibility to represent variability in renewable sources in more detail.

11.2.4 Data on power generators

A variety of data sources were used to create the list of thermal power generators and the operational characteristics. Often there was no specific data available for the operational characteristics of the Dutch power generator park. As a result aggregate data, retrieved from scientific publications, was used based on the type of generator. This limits the accuracy of the representation of each single power generator represented in the model. As performance characteristics were not based on specific generator data from the operators of all Dutch generators. This generalization makes that possible performance nuances were not captured for specific generators.

For future modeling it is beneficial to have a dataset or publicly available list of the power generator park with operational characteristics per generator. This would reduce the time needed to search for data on the generator park and the actual number and type of generators in the energy mix. Next to this it would increase the representation of real-world performance of power generators in the power system, if the operational characteristics of the power generators could be based on actual data from operators. However it is probable that power generator owners will be reluctant to share this generator specific data publicly, because of competitive electricity producers.

11.2.5 Inclusion of interconnection

The Dutch electricity grid has interconnections with the German, Belgian, United Kingdom and Norwegian electricity grids (ECN, 2016). A new grid connection with Denmark is under construction (ECN, 2016). It is expected that interconnection with the German and Belgian grid will be expanded in future. An overview of the currently installed interconnection an future expansions is provided in Table 17 below:

Table 17: Interconnections of the Dutch electricity grid with neighboring countries, capacity in Megawatt. The NL-BE connection is not expanded simultaneously, the BE-NL connection will be finished earlier. Data from Dutch National Energy Outlook (ECN, 2016).

INTERCONNECTIONS [MW]	2017	2020	2025	2030
NL-DE	2450	4450	4450	5000
NL-BE (BE-NL)	1400	1400 (2400)	2400	2400
NL-DK	0	700	700	700
NL-UK	1000	1000	1000	1000
NL-NO	700	700	700	700

Interconnections were not included in the model in this research. The choice had to be made between modeling a simplistic power system in the neighboring countries or not including the interconnections. It would have taken too much time to create a detailed model for all connected neighboring power systems. However, the inclusion of a simplistic neighboring power system would not represent variability in load and renewable energy output that may be experienced in these neighboring countries.

Further research could aim at modeling the interconnected Northern European power systems. This would require research into the generator park and its expected future development, renewable output and the load profile for all the interconnected countries. The effects of spatial variation of renewable resources could be captured with such an elaborate model. However, the development of such a model would be time intensive.

11.3 ECONOMIC ANALYSIS

11.3.1 Fuel price sensitivity

Fixed fuel prices were used for all model years (2.33 €/GJ for coal, 4.68 €/GJ for natural gas and 0.13 €/GJ for nuclear). Historical market results shows that fuel prices can differ substantially from time to time. This may influence the total net profit from flexibility measures. High prices may increase net profit due to larger price differences and low prices may decrease net profit as result of smaller price differences. The 2030 model year has been re-run for all scenarios with combinations of highest and lowest market prices obtained during literature research. The results show the sensitivity of profit per flexibility measure to fuel prices.

Table 18: The lowest and highest fuel prices obtained from market results.

	Low price (€/GJ)	High price (€/GJ)
Coal	1.18	2.48
Gas	3.51	5.99
Nuclear	0.12	0.20

The 2030 model year has been re-run with four different fuel price scenarios. Nuclear and coal are regarded as baseload fuels and gas is regarded as peak load fuel. The price scenarios are:

1. Low prices for all fuels
2. High prices for all fuels
3. Low prices for baseload fuels (coal and nuclear) and high price for peak load fuel (gas)
4. High prices for baseload fuels (coal and nuclear) and low price for peak load fuel (gas)

The net profit for flexibility measures is affected by changing the fuel prices. Results from the additional runs with different fuel prices are presented in Table 19, the number indicates which price scenario was used. '2030' is the result that was found in the original model run for 2030.

Table 19: Total profit per flexibility measure for the year 2030 with different fuel prices. O&M costs for the flexibility measure are not included. The numbers correspond to the price scenarios presented above, '2030' is the original result.

Price scenario	BES	BESXL	DR	UPHS
2030	€ 31,855,078	€ 36,261,792.31	€ 2,873,426	€ 32,194,943
1	€ 25,261,245	€ 107,412,394.75	€ 1,989,069	€ 26,571,179
2	€ 35,456,816	€ 119,493,407.69	€ 5,501,023	€ 38,035,355
3	€ 38,417,176	€ 121,521,705.21	€ 2,635,251	€ 41,573,382
4	€ 29,879,259	€ 33,391,751.88	€ -150,175	€ 31,878,492

The effects that the fuel price scenarios have on the net profit of flexibility measures are almost always similar for all flexibility measures. It either increases or decreases net profit. The net profit decreases when all fuel prices are low (scenario 1), this is due to the fact that the price variance (Table 20) decreases. The net profit increases when all fuels have high prices (scenario 2). Net profit is highest for storage measures when there are low fuel prices for baseload fuels and high prices for peak load fuels (scenario 3). In case of DR the net profit is reduced in scenario 3, compared to the original model results. Profit is negative for DR when the price of baseload fuels is high and the price of peak fuel is low. Both storage systems have positive net profit in scenario 4, however it is slightly lower than with the original model prices.

The BESXL scenario shows very different results than the other scenarios. In price scenarios 1-3, the BESXL scenario has unserved demand. This results in substantially higher profit generated by the BESXL than all the other scenarios, due to VoLL prices during some hours. These results should not be compared to the other results as this would show an unrealistic profit difference compared to the other scenarios. The cause for the unserved demand is the high wind production during the night of February 20th (see Figure 33). A longer look-ahead period (in PLEXOS) could prevent the unserved demand in the BESXL scenario. It would also make the comparison with the other scenarios unfair, as the optimization for the generator park may be better with longer look-ahead.

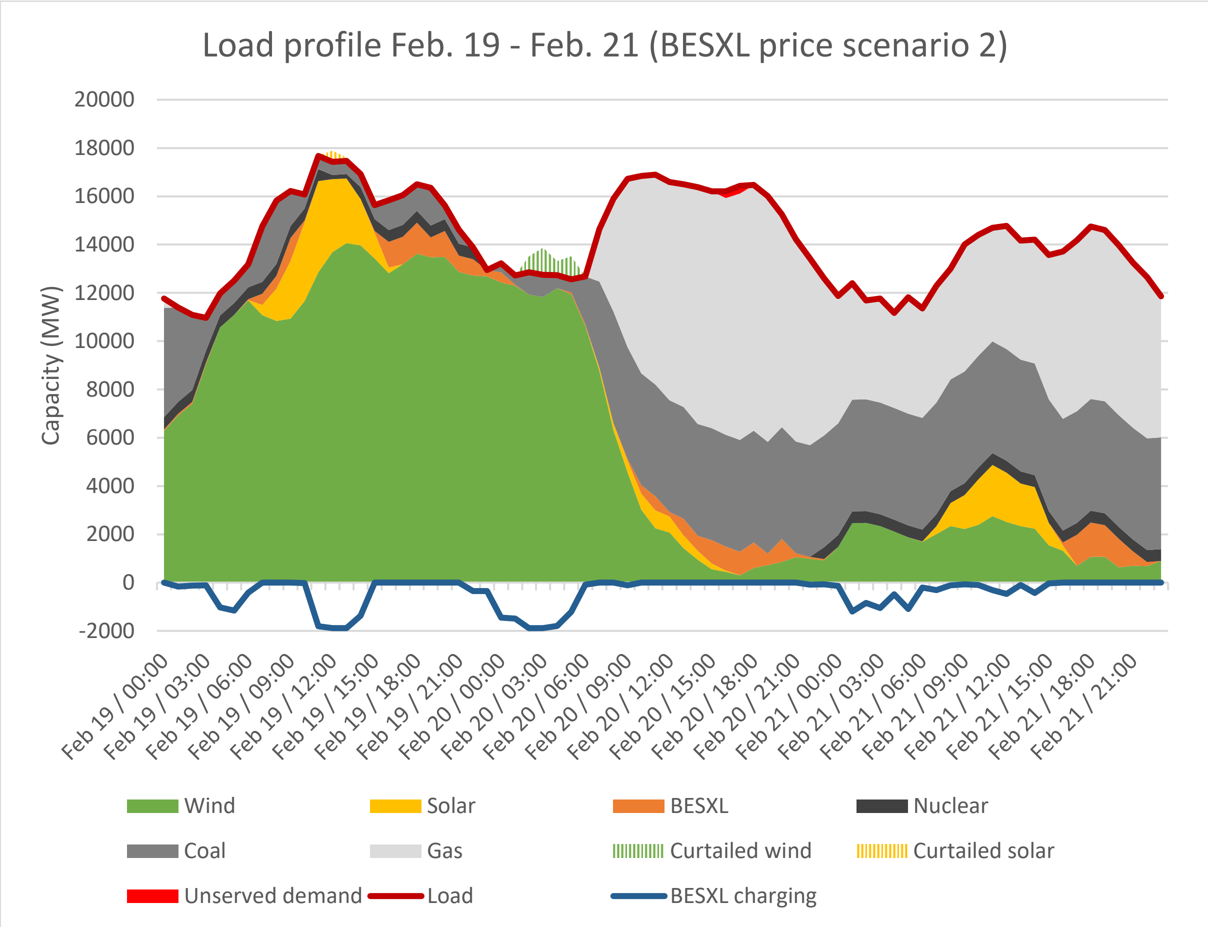

Figure 33: The load profile for Feb 19th-21st for the BESXL scenario with price scenario 2. The look ahead of 6 hours was insufficient to optimize the generator park to respond to the peak demand on Feb 20th around 16:00 unserved demand was observed in the model. The sudden drop in wind power production during the night of Feb 20th puts stress on the generator park and the BESXL system to respond.

There seems to be a clear connection between the electricity price variance and the net profit from storage systems (compare Table 20 with Table 19). A higher price variance results in higher net profit and vice versa. The BESXL scenario shows extraordinary high price variance in price scenarios 1-3, due to the VoLL price of €10,000 /MWh. The other two price scenarios show that the BESXL would normally have the lowest price variance of all scenarios and also lowest profit per MWh.

Table 20: Price variance for the price scenario re-run of the 2030 model year.

Price scenario	Ref	BES	BESXL	DR	UPHS
2030	369	296	243	360	250
1	285	201	136585	232	173
2	517	378	136383	483	366
3	529	435	136448	509	375
4	289	239	193	264	225

Price variance alone does not explain the net profit figures completely. The total profit depends also on the total amount of generation by the flexibility measure. In Table 21, the profit per MWh (€/MWh) is presented. It shows that the profit per MWh is highest for energy storage in the model with the original fuel prices. DR has a higher profit per MWh in price scenario 2, this is caused by overall higher electricity prices, which makes DR more competitive. In all other price scenarios DR has less profit per MWh than in the original price scenario.

Table 21: Profit per MWh (€/MWh) for the different price scenarios in the 2030 model year.

Price scenario	BES	BESXL	DR	UPHS
2030	€ 33.08	€ 17.03	€ 30.61	€ 21.97
1	€ 21.65	€ 47.06	€ 28.52	€ 18.58
2	€ 29.18	€ 51.36	€ 43.17	€ 21.38
3	€ 29.87	€ 49.01	€ 20.76	€ 20.48
4	€ 23.82	€ 12.72	-€ 3.05	€ 18.96

The results in Table 22 show how the price scenarios influence the capacity factor (i.e. use) of flexibility measures. More use at a lower profit per MWh can still result in higher total profit. This can be observed for price scenario 2 and 3 where the capacity factor of BES and UPHS are higher than the original model price scenario, while the profit per MWh is lower. In scenario 1 and 4 the profit per MWh and the price variance is substantially lower for BES, the higher capacity factor does not neutralize this. The result is less total profit. The same can be observed for UPHS, however in price scenario 1 the capacity factor is also slightly lower than with original fuel prices. An important factor influencing the use and profit from storage seems to be the natural gas price. These generators will often be price setting at moments when storage generates electricity. At a higher natural gas price (i.e. price scenarios 2 and 3) storage systems are stimulated to generate more electricity.

DR is also used more often when peak fuel prices are high, because at higher gas prices it is more competitive with gas fired peak generators. At low peak fuel prices the use of DR decreases, as substantially less profit can be generated. In scenario 4 there is a negative profit for DR. This is due to the need for flexibility, DR provides flexibility without start-costs and may be preferred over thermal power generators for short irregularities. In the model the generator is not always rewarded its SRMC, therefore DR can be used at a price lower than SRMC. This results in a negative profit for DR.

Table 22: Capacity factors of the flexibility measure for all price scenarios of the 2030 model year.

Price scenario	BES	BESXL	DR	UPHS
2030	26.26%	26.14%	17.76%	26.96%
1	31.81%	28.01%	13.19%	26.31%
2	33.14%	28.55%	24.11%	32.73%
3	35.07%	30.43%	24.02%	37.34%
4	34.20%	32.21%	9.32%	30.93%

11.3.2 Net present value flexibility measures

The profit results obtained from PLEXOS do not include the annual O&M costs for the storage systems. The annual O&M costs are € 22.5 million for BES, € 14 million for UPHS and € 50 million for BESXL (detailed explanation on sources in chapter 13.8). In early scenario years the annual costs are higher than the benefits. In 2030 and 2035 the profit generated is higher than the annual O&M costs. The annual profit generated by UPHS and BES was around € 32 million and around € 36 million for BESXL in 2030. In 2035 the annual net profit is substantially higher than in 2030 for both storage systems.

To compare the performance of UPHS, BES and BESXL, the net present value (NPV) was calculated. A positive value for NPV suggests that a project can be considered economically attractive (Blok, 2009). The NPV was calculated with the formulas below (Blok, 2009):

$$NPV = -I + \frac{B - C}{\alpha} \tag{3}$$

Where:

I = initial (capital) investment
B = annual benefits
C = annual costs
α = capital recovery factor

$$\alpha = \frac{r}{1 - (1 + r)^{-L}} \tag{4}$$

Where:
r = discount rate
L = lifetime of the storage system

The net profit for DR was substantially lower than for the storage systems. Besides, no clear investment and operational costs were found for DR. Therefore DR was not included in NPV calculations. The BESXL was only included in NPV calculations for the normal model runs and not for the re-runs of 2030 with fuel price scenarios. Because of its additional profit due to unserved demand in some the fuel price scenario model re-runs.

A discount rate of 5% was used in the NPV calculation. The input for annual costs and lifetime are available in Table 36, where the characteristics of BES and UPHS are summarized. The NPV calculation was performed for all model years and for the model re-runs with different fuel prices in chapter 11.3.1.

The results (Table 23 and Table 24) show that both BES and UPHS do not have a positive NPV. This was to be expected when the annual profit obtained from model runs and the annual O&M costs are compared. In the model years from 2017 till 2025 (for BESXL even till 2030) the NPV has a negative value that is more negative than the initial investment. This is caused by the annual loss that is generated during these years. In 2030 the annual profit is higher than the annual costs (for BES and UPHS), a small part of the investment costs are paid back, however the NPV is still negative. The smaller negative value for BES and UPHS is explained by the lower investment costs for the BES installation than the UPHS (€ 0.9 billion vs € 1.8 billion for UPHS). In 2035, both BES and UPHS have a positive NPV, this is the result of the VoLL pricing that occurs that year. The larger NPV for UPHS is mainly the result of a substantially longer expected lifetime than the BES.

It is unlikely that VoLL prices (caused by unserved demand) will occur often in a real-world power system, as this would cause blackouts and disruption in the national grid. However, it is not unlikely that a storage system can benefit from these situations when they occur and electricity prices are likely more volatile in reality than in the PLEXOS model. This is discussed in more detail in chapter 11.4.

The NPV results for BESXL show that this storage system does not even have a positive NPV in 2035. This is the result of a very high initial investment (€ 2 billion), less profit in 2035 due to less VoLL pricing periods and a relatively short lifetime like BES (10 years vs 40 for UPHS).

Table 23: NPV results for BES and UPHS for all modeled years.

Scenario year	**BES**	**UPHS**	**BESXL**
Reference	-991,177,644	-2,019,517,959	-2,359,783,535
2020	-1,015,285,335	-1,959,497,420	-2,331,293,453
2025	-947,691,072	-1,794,361,335	-2,272,252,225
2030	-827,762,567	-1,487,791,402	-2,106,082,798
2035	487,741,877	1,416,336,622	-1,347,111,623

In Table 24 the NPV results are presented for the re-runs of the 2030 model with different fuel price scenarios. In the best case scenario for storage systems (i.e. scenario 3), the NPV is still negative. It shows that having an optimal price scenario does not increase the NPV sufficiently to make BES or UPHS economically attractive in the 2030 model year. The BES has a less negative NPV than UPHS, this is caused by the difference in investment for the storage systems.

Table 24: NPV for BES and UPHS for the 2030 model year. The numbers for price scenario show the NPV associated with the different price scenario re-runs in chapter 11.3.1, model indicates the NPV calculation for the 2030 scenario year.

Price scenario	**BES**	**UPHS**
Model	-827,762,567	-1,487,791,402
1	-878,678,398	-1,584,290,054
2	-799,950,901	-1,387,575,268
3	-777,091,786	-1,326,865,957
4	-843,019,318	-1,493,221,412

The NPV results shows that BES, UPHS and BESXL are not economically attractive when energy arbitrage is the only source of income. Additional income may be generated when ancillary services are provided by the energy storage systems, or when scarcity pricing comes into play (discussed in more detail in chapter 11.4.

11.3.3 Costs Of Electricity

The COE (Costs-Of-Electricity) shows what the annual costs for the storage systems (Blok, 2009). The calculation method is based on the investment costs multiplied by the capital recovery factor α and the annual costs divided by the total annual energy production. The formula for the COE is given below:

$$COE = \frac{\alpha \cdot I + OM + F}{E} \tag{5}$$

Where:
α = the capital recovery factor (calculated with formula (4))
I = initial (capital) investment
OM = annual operation and maintenance costs
F = annual fuel costs
E = annual electricity production

In the calculations no fuel costs were included, because assumption was made that the storage systems were only charged with 'free' renewable electricity. The other values were the same as for the NPV calculation in chapter 11.3.2 and the annual electricity production was obtained from the PLEXOS model results in Figure 31. The COE calculation was performed for the UPHS, BES and BESXL storage systems. The results (Table 25) show what the annual costs for generating 1 MWh of electricity during a specific model year.

Table 25: COE results for the BES, UPHS and BESXL scenarios during the different model years. The UPHS has the lowest COE of all storage systems. There were no costs for charging storage included in the COE calculation. The values are in € per MWh generated by the storage system.

Model year	BES	UPHS	BESXL
2017	155	125	160
2020	153	94	159
2025	155	98	166
2030	144	81	145
2035	120	63	125

The COE decreases in each subsequent model year for all storage systems, a result of more electricity generation at the same annual costs. The exception is the decrease in the capacity factor for all storage systems from 2020 to 2025, causing the COE to increase. The UPHS has a lower COE than the BES and BESXL systems. This difference is caused by the substantially longer lifetime for UPHS compared to the battery technology. A longer life reduces the annualized investment costs (the α·I factor in formula (5)) by reducing the value for the capital recovery factor α (see formula (4)).The larger battery storage has a slightly higher COE than the smaller battery storage. The slightly lower capacity factor for the BESXL compared to the BES, makes it more expensive per MWh with regard to investment and O&M costs.

The UPHS can compete with gas turbine peak generators on COE, when the UPHS is charged with free surplus renewables. These GTs have a COE of € 106 per MWh at a capacity factor of 10% and € 64 per MWh at a capacity factor of 40%, the COE is still € 57 per MWh at capacity factor of 80%. The UPHS however cannot compete with new coal power capacity that has a COE of € 43 per MWh at a capacity factor 90% and € 49 per MWh at a capacity factor of 70%. If the capacity factor of new coal power plants would decrease to around 50% the COE would come close to that of UPHS, at € 60 per MWh. It shows that the UPHS may be a suitable alternative to adding new gas fired capacity in a future power system with high renewable capacity.

The battery storage systems are more expensive than conventional power generators. This difference may be bridged by reduction in battery costs and an increased lifetime, both may be achieved by innovation in lithium ion battery technology (The Economist, 2017). The values used for the calculation of the COE for gas turbines and new coal power plants are presented in Table 26 below:

Table 26: Values used for calculating the COE of a gas turbine (GT) and a new coal power plant (New CP). Heat rate, Variable O&M and Fixed O&M are similar to the values used in the PLEXOS model (see chapter 13.4.3). The other values were based on the IEA's World Energy Outlook for power generator investment costs (IEA, 2016c).

	GT	**New CP**
Heat rate (GJ/MWh)	10.43	7.83
Fuel costs (€/GJ)	4.68	2.33
Capacity costs (€/kW)	500	2200
Variable O&M (€/MWh)	0.8	3.5
Fixed O&M (€/kW-year)	9	25
Lifetime (year)	20	30
Discount rate (%)	5	5

11.4 UPHS IN REAL-WORLD ELECTRICITY MARKETS

The PLEXOS model simulated an energy-only market for all generators, with strategic reserves. This means that all generators bid their marginal production costs (i.e. mainly fuel costs) in the electricity market. The clearing price is the highest accepted bid on the market, and all infra-marginal (i.e. producing) generators will receive the clearing price for the electricity they produce in that specific time-slot. As a result peak generators will make very little or no profit in an energy only market. This was also observed in the results obtained from PLEXOS, generators at the end of the merit order (i.e. peak generators) do not make profit in the model. In a real-world market, mid and peak load generators may bid higher than their short run marginal costs when there is capacity shortage (Rooijers, et al., 2014; Oren, 2003). This additional price on the marginal production costs is the scarcity rent. Peak generators depend on scarcity rents to cover the fixed costs for the capacity they have available in the power system (Oren, 2003). Baseload generators cover their capacity costs by the infra-marginal rent, the difference between the market clearing price and the generator's marginal production cost (Oren, 2003).

The energy only market relies on two mechanisms to ensure the adequacy of supply, the first is demand response and the second the scarcity rent (Oren, 2003) (the market mechanisms are illustrated in Figure 34). Both mechanisms rely on the elasticity of demand and the competition on the supply side of the power system. Typically electricity demand is inelastic, because of the critical role of electricity in the economy (Oren, 2003; Rooijers, et al., 2014). This provides the opportunity for peak generators to increase the electricity price by raising the scarcity rents, the demand will reduce (slightly) as response to this price increase (Oren, 2003). Economic theory predicts that these two mechanisms will result in a long-term equilibrium with an optimal capacity stock; where peak generators cover their capacity costs exactly by scarcity rents, while the scarcity rent induces sufficient demand response to create a market balance between supply and demand (Oren, 2003).

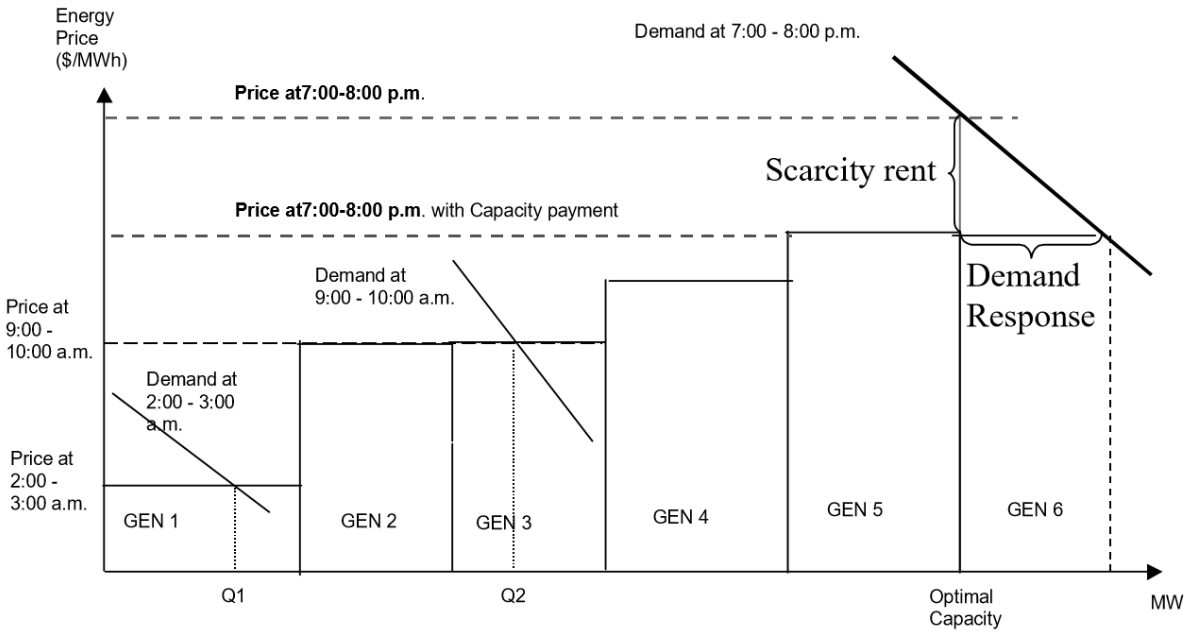

Figure 34: Example of market clearing at different demand levels. It shows that charging a scarcity rent induces demand response, resulting in a lower capacity settlement at a higher than marginal electricity price. If Gen 6 is available in the power system, the risk of charging a scarcity rent would be too high for Gen 5, as it may become extra marginal due to competition from Gen 6. However, if Gen 6 is not available in the power system, Gen 5 can charge a scarcity rent to increase its profit and induce a demand response that results in a total demand that can be met by the power system. Figure from: (Oren, 2003).

These market mechanism affect the behavior for capacity investment in the long-term. Overcapacity in the power system increases competition and reduces the opportunity to charge scarcity rents (Rooijers, et al., 2014). This results in decommissioning or mothballing of generators that cannot cover their capacity cost (Oren, 2003; Rooijers, et al., 2014). This reduces the total installed capacity, thereby reducing competition between peak generators and restoring the opportunity to charge scarcity rents.

A lack of competition, due to shortage of capacity, increases the scarcity rents. This produces profits in excess of the profit needed to cover capacity costs (Oren, 2003). These high profits provide an incentive for investment in new capacity. Additional capacity should restore the market equilibrium by increased competition (Oren, 2003). In reality this results in cyclical behavior for capacity investments (Rooijers, et al., 2014). Periods with capacity shortage and periods with capacity surplus were observed to follow each other for installed capacity in the Dutch power system (Rooijers, et al., 2014).

Rooijers et al (2014) observed that the electricity price is substantially more volatile in an electricity market with shortage of capacity than in a market with overcapacity; little competition that results in high scarcity rents. In 2006, the Dutch power system experienced shortage of capacity, leading to excessive electricity prices at the day ahead market for capacity usage of around 80% and above (Rooijers, et al., 2014). This provided the incentive for investment in new capacity, namely gas engines, combined cycle gas turbines and coal power plants (Rooijers, et al., 2014). In 2011, the day ahead market prices showed much less volatility and substantially less excessive prices at high capacity usage due to overcapacity in the Dutch power system, the result of new installed gas engines and CCGTs (Rooijers, et al., 2014). In 2011 the new coal power plants were not operational, Rooijers et al. (2014) predicted that this would increase overcapacity and reduce price volatility even more. Recent publications show that some old power plants are already decommissioned and other are planned to be decommissioned (ECN, 2016), because of environmental targets and arguably to reduce the current overcapacity in the Dutch power system. The Dutch day ahead market observations by Rooijers et al. (2014) are presented in Figure 35.

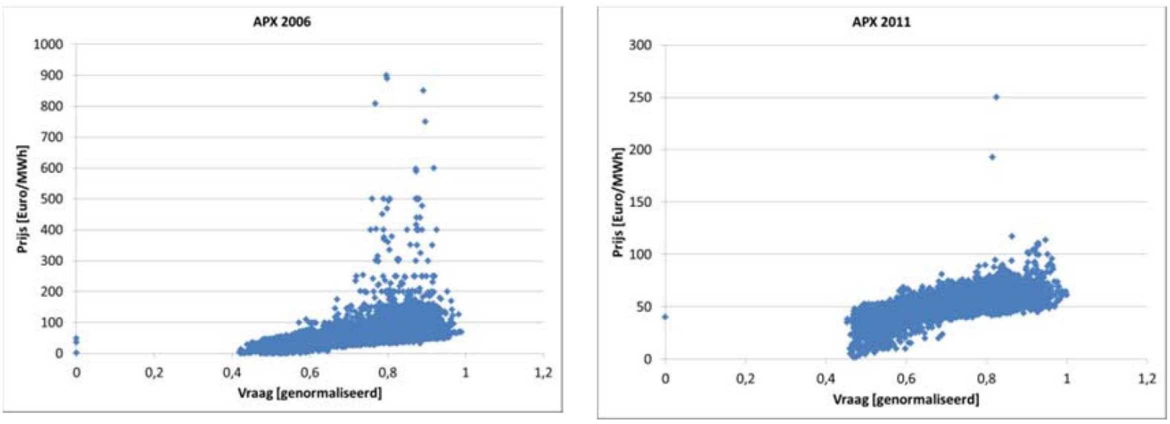

Figure 35: The results for the Dutch day ahead market in 2006 on the left and in 2011 on the right. The horizontal axis shows the normalized load and the vertical axis the market clearing price. It shows that the price was substantially more volatile in 2006 than in 2011, and that excessive prices occurred more often in 2006. Illustration from (Rooijers, et al., 2014).

The increasing renewable capacity in the Dutch power system will impact the electricity market and influence the capacity investment incentives. Renewable capacity does not have marginal production costs and will always bid in the electricity market with prices below baseload capacity. It can also be approached from the residual load (i.e. demand) perspective. Renewable capacity is always used when wind or solar power is available, resulting in a residual load that is less than the total load on the power system. Lower load results in even more overcapacity on the electricity market, resulting in even more competition between generators. Figure 36 shows this with two merit order curves, one with low and one with high renewable capacity.

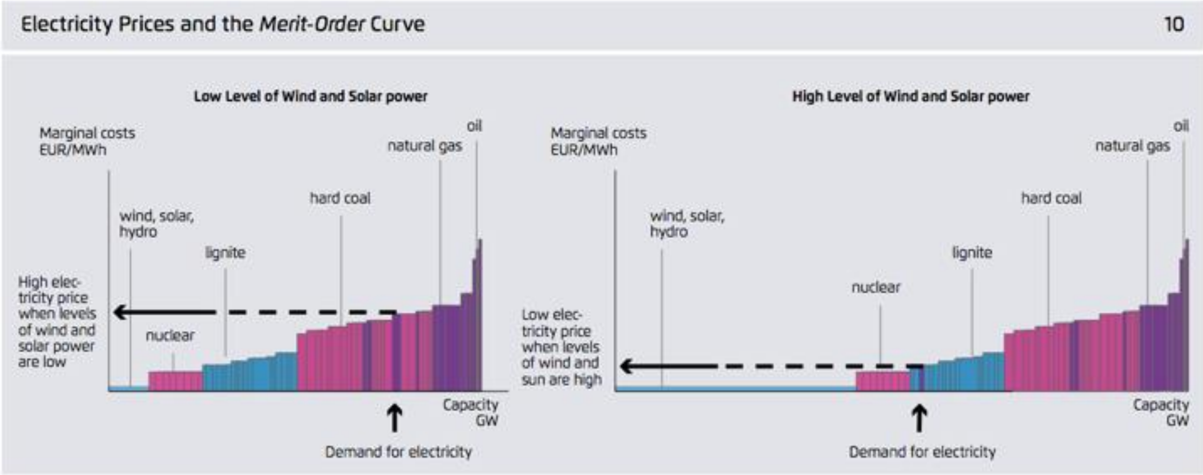

Figure 36: Merit order with low renewable capacity on the left and with high renewable capacity on the right. High renewable capacity results in substantially lower electricity prices as expensive generators have become extra marginal. Source: (Americaspowerplan, 2013).

Rooijers et al (2014) argue that new coal power plants can provide sufficient flexibility to follow the residual load profile, pushing flexible mid and peak load generators to the realm of extra-marginal capacity. A result will be lower prices as expensive peak load generators will not set the market clearing prices. The expectation is that mid load generators and old coal capacity will exit, as they are not be able to cover capacity costs in this new market equilibrium.

It also increases the pressure on new coal capacity that relies on infra-marginal rent to cover capacity cost. New coal power plants may be the price setting (i.e. marginal) generator in the future Dutch power system with a high renewable capacity. This could make it impossible for baseload coal power plants to cover capacity costs with infra-marginal profits and provides opportunities for investment in flexible peak generator capacity in the long term. These generators have lower investment and fixed costs than coal power plants at the trade-off of higher operational costs, this makes them economically better suited to function at a lower capacity factor than coal power plants (Rooijers, et al., 2014).

The demand response and scarcity rent mechanism discussed here were not included in the PLEXOS model. In reality the profit generated by storage may be substantially higher due to charging of scarcity rents, this is particularly applicable to the 2030 and 2035 model years where thermal power generator capacity is small compared peak load. In a real-world electricity market this would lead to high scarcity rents on the electricity market, in the PLEXOS results this was not observed. The only price peaks that were observed are the VoRS (Value of Reserves Shortage) or VoLL (Value of Lost Load) prices, VoLL prices were only observed in 2035 and in 2030 with for BESXL scenario with fuel price scenarios in chapter 11.3.1. VoRS prices were observed when a shortage of strategic reserves occurred, the price was set at € 100 per MWh in the PLEXOS model. This can be observed in Figure 37 - Figure 39, these figures show the electricity price plotted against the normalized load (i.e. demand).

Figure 37 shows the market results from the 2017 UPHS model run. There is overcapacity in the power system, as can be observed by the even spread of electricity prices. There is only one occasion with a shortage of reserve capacity, this results in a price peak of € 160 /MWh. Figure 38 shows the results for the 2030 UPHS model run. In this scenario there is substantially more renewable capacity installed. Electricity prices that are around € 0 per MWh for renewables can be observed, conventional generator capacity ranges around the € 30 to € 60 per MWh, the price peaks are again caused by VoRS prices. Figure 39 shows the electricity prices for the 2035 UPHS scenario, the main difference is the occurrence of VoLL prices have a large impact on the shape of the graph. However a closer look at the largest number of prices show a similar picture as the 2030 UPHS scenario, the main difference is then more VoRS pricing. Scarcity rents would normally be observed for the 2030 and 2035 scenario, as there is shortage of capacity during these scenario years. The scarcity rents would fill the gaps between VoRS and VoLL energy prices observed in the figures below.

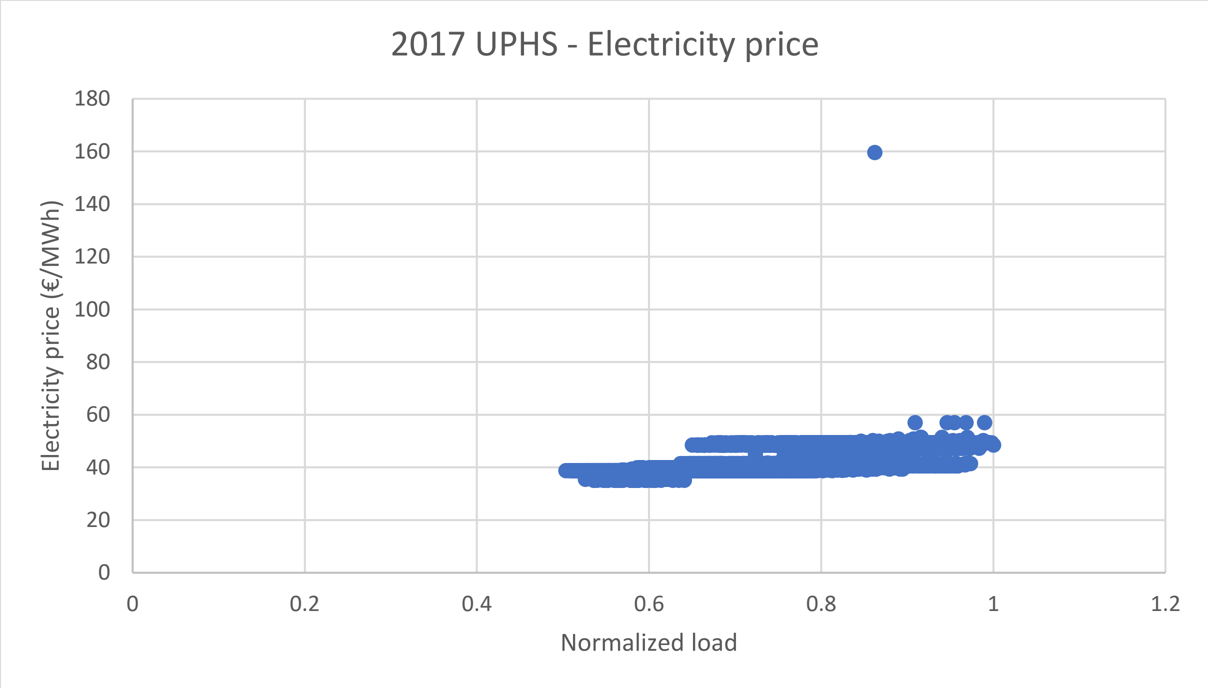

Figure 37: Electricity price plotted against the normalized demand for the 2017 UPHS scenario. It can be observed that there is one occasion of VoRS, where the electricity price is substantially higher than standard.

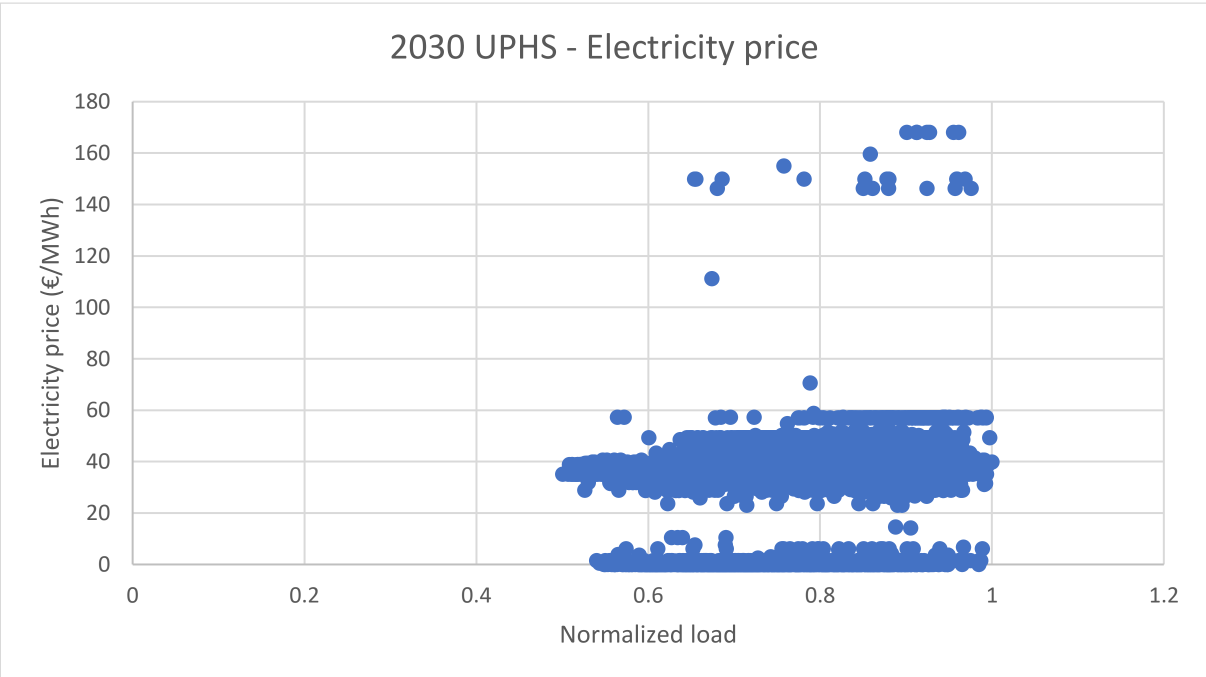

Figure 38: The electricity price plotted against the normalized demand for the 2030 UPHS scenario. There are more occasions with VoRS pricing, it can also be observed that the electricity price is much more often around 0 €/MWh due to renewable capacity.

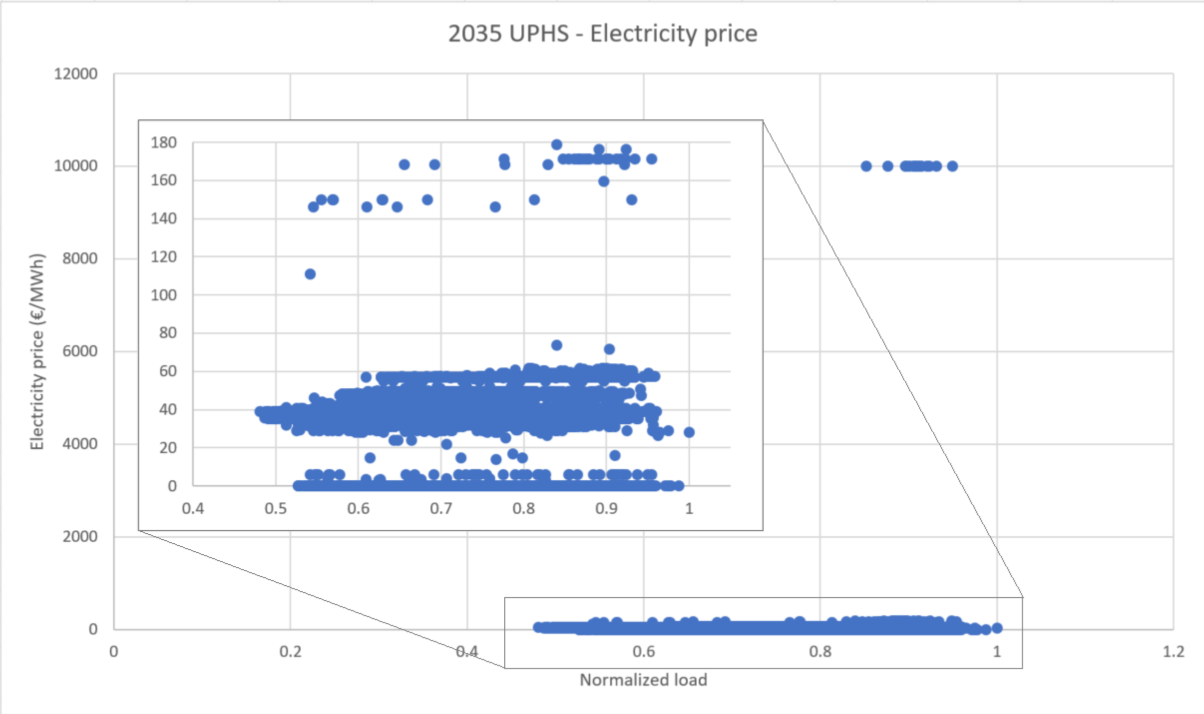

Figure 39: Electricity price plotted against the normalized load for the 2035 UPHS scenario. The outtake shows a close-up of the main price spread that has the same vertical axis scale as Figure 37 and Figure 38. The graphs show that there is a large gap between the VoLL prices (€10,000/MWh) and the main price spread, there is also a substantial gap between the VoRS prices (around €150/MWh) and the main price spread, this indicates that there is no scarcity rent charged by generators.

The role of energy storage is not discussed in the articles of Rooijers et al. (2014) and Oren (2003). Energy storage would normally compete with gas fired peak generator capacity and may be regarded as a peak generator. Rooijers et al. (2014) observed that smaller faster implemented projects (i.e. gas engines) can respond earlier to the scarcity rent incentive for capacity investment. These projects could profit more than the projects with long construction times (i.e. coal power plants). This is a drawback for UPHS, that has expensive capital investment and a project construction time that could take about a decade compared to four months for battery storage projects (BNEF, 2017).

It is difficult to predict the development of the electricity market and the power system. The national aim is to increase the renewable capacity in the future. With that given fact modeled in PLEXOS, the results show that lower capacity factors may be observed for mid and baseload generators (chapter 10.2.3) in a power system with increasing renewables. The average electricity price was also observed to decrease in the later model years (chapter 10.3.1). This puts even more stress on the profitability of mid and baseload capacity, due to less inframarginal profit. This may, as Rooijers et al. (2014) predicted, result in a reduction in mid and baseload capacity.

The model results show an increase in the use of peak generators and energy storage in future model years with high renewable capacity. This proves that an opportunity occurs for these types of capacity in a power system with high renewable capacity. Besides, energy storage does not depend on the inframarginal rent for its profit, but rather on the price difference between peak and base load. Figure 37 - Figure 39 show that the electricity price volatility increases with increasing renewable capacity. The additional opportunity for charging scarcity rents would increase the profitability of energy storage (both BES and UPHS system). Especially in a power system with large renewable generator park installed, peak generators and energy storage will have monopoly during periods of low wind and solar production. Providing the opportunity for charging excessive scarcity rents. The future electricity markets may therefore have a remuneration scheme for having capacity available in the grid, instead of energy only prices (Oren, 2003; Rooijers, et al., 2014).

11.5 Future of UPHS and BES

The UPHS and BES systems rely on two different technologies for energy storage. This chapter aims to explain the different characteristics of both technologies, compare the advantages and disadvantages for both technologies and make an assessment for the future role both may play in the Dutch power system.

11.5.1 Overview

An overview of the UPHS and BES technologies are provided in Table 27.

Table 27: Overview of the PHS and BES technologies. The main sources used are: (BNEF, 2017; The Economist, 2017).

	UPHS	*BES (Li-ion)*
Maturity	The PHS technology is very mature, PHS has worldwide the largest share in installed energy storage capacity (Energystorageexchange.org, 2016). And according to BNEF (2017) also the largest capacity of to-be installed capacity.	The Li-ion battery was introduced 26 years ago (The Economist, 2017). The technology is mature in the sense that it has been used in a wide variety of applications.
Scale	PHS systems are typically large scale energy storage systems that can provide multiple hours of full-load capacity. Installations often provide several Gigawatt hours of energy storage.	Li-ion is the most popular battery storage technology on the market. The application ranges from mobile hand-held devices up to grid-scale stationary energy storage that can provide full-load for up to 4 hours (AES, 2016b). The battery systems are easily scalable and can currently be installed with a storage capacity of up to a few hundred Megawatt hours (AES, 2016b).
Costs	The costs for UPHS are € 225 per kWh capacity for the specific project in Limburg (this is a cost estimate before the project is actually implemented). For conventional PHS the costs may be reduced substantially if there is a suitable location (BNEF, 2017) .	The costs for Li-ion batteries have dropped substantially since recent years. The costs for Li-ion cells (main component for a battery pack) were € 1,000 per kWh in 2010, now the costs have dropped to the range of € 130-200 per kWh. (The Economist, 2017). BNEF on the other hand reports the battery prices to be around € 273 per kWh (BNEF, 2017). The forecast shows that the price for Lithium cells will drop even further, but is expected to level out around € 100-140 per kWh (The Economist, 2017).
Lifetime	The PHS technology has a long lifetime. Even after the lifetime of the turbines, the structures that are left can often be used to retrofit the PHS facility and extend its usable life.	The lifetime of Li-ion batteries is limited by the number of cycles it can support. The electrodes will degrade with use of the battery, the battery is unusable once the electrodes are fractured too much from charging and discharging.
Advantages	- The advantage of UPHS is the long experience with the technology. - The large scale at which it is normally implemented (i.e. Gigawatt hours of energy storage). - Flexibility is ensured by variable speed turbines. In a system with multiple of these turbines it is possible to charge with one turbine and generate with another, improving flexibility even further.	- Technology with much research invested, due to cars and mobile devices that profit from technology improvement. - Prices are expected to decrease. - The market does is not limit to grid-scale energy storage. The technology can be used in a wide variety of applications. - Easily scalable to local and grid needs - Fast implementation (known projects were finished within 4 months).

	- The large spinning turbines are better suited to smooth out frequency issues in the grid than PV or battery storage.	
Disadvantages	- Unable to provide regional ancillary services. Because capacity will be available from one large central location for the storage system. - The price is not expected to decrease substantially in the future. Besides prices will be very project specific. - Long construction and permitting periods (at least for projects in the US)	- History of being flammable when the technology is not properly implemented (Samsung Galaxy Note 7 catching fire). - The implementation for stationary grid storage has to compete with applications like car batteries and to less extend with mobile appliances. - Production capacity has to be expanded to meet growing demand for Li-ion cells.
Future potential	There may be some development in turbine and pump technology. However these are already very mature technological components, as PHS system have been around for a long time. The innovation may be performed with small-scale UPHS, that functions both for agricultural use as for energy storage purposes (Martin, 2011).	The production capacity for the technology is planned to be expanded substantially. The current focus is also not only limited to the car industry, as Tesla already introduced their stationary home-battery. The storage challenge from Elon Musk to help Australia deal with the large imbalances caused by renewable sources shows that there is interest in using batteries as grid balancing energy storage. Battery development focuses on improving the battery components (e.g. electrodes and electrolyte) and chemistry, which may increase the battery's energy density.

11.5.2 How will the production capacity of Li-ion batteries develop?

The Li-ion battery production capacity is expected to grow from 103 GWh per year in 2016 to 278 GWh per year in 2021 (Hirtenstein, 2017). The table below shows the estimated values obtained from the bar chart presentation in the original source (Hirtenstein, 2017):

Table 28: Expected growth in worldwide lithium ion battery production capacity (Hirtenstein, 2017) .

YEAR	LI-ION PRODUCTION (GWH PER YEAR)
2016	103
2017	124
2018	144
2019	190
2020	235
2021	278

Other sources report different figures for the production capacity development of lithium ion cells. 27.9 GWh per year in 2016 and 173.5 GWh per year in 2020 (Desjardins, 2017). These figures are clarified in the China Daily as the expected production capacity growth for China alone (Blain, 2017). The increasing Li-ion battery production capacity is vital to support growth in BEVs (Battery Electric Vehicles) (The Economist, 2017).

The IEA published an expected growth for world-wide number for electric vehicles in their EV outlook 2017 (IEA, 2017). They estimate that the number of electric vehicles is 20 million in 2020, 55 million in 2025 and 114 million in 2030, based on the targets set in the Paris climate agreement (IEA, 2017). The historic observations for electric vehicles show that the number of EVs were in 0.17 million in 2012, 0.4 million in 2013, 0.7 million in 2014, 1.25 million in 2015 and 2 million in 2016 (numbers obtained from a graph) (IEA, 2017). It shows that the number of BEVs is expected to increase substantially in the near future. This will result in a similarly substantial increase in demand for lithium ion batteries.

The figures for BEV growth are compared to growth of Lithium ion battery production capacity worldwide. Three scenarios for car batteries were assumed, (1) an average car battery of 25kWh, (2) an average battery of 50 kWh and (3) and an average battery of 75 kWh. To put the battery sizes into perspective, a 24 kWh Nissan Leaf has a theoretical range of 190 km (Autoweek, 2016), a 50 kWh Tesla model 3 will have a range of 330 km and the 75 kWh model a range of 465 km (Lambert, 2017). The cumulative battery capacity in BEVs and the cumulative production of lithium ion batteries were calculated with 2016 as start year. For the cumulative Li-ion battery production, the expected growth in production capacity from Table 28 was used, complemented by the assumption that Li-ion production capacity would grow annually with 50 GWh between 2021 till 2023, 60 GWh annually for 2024 till 2026 and with 70 GWh annually for 2027 till 2029.

In Figure 40 the expected cumulative worldwide Li-ion battery production from 2016 till 2030 is presented compared to the cumulative amount of batteries needed for BEVs worldwide from 2016 till 2030 (if the BEV growth in the Paris agreement scenario is achieved (IEA, 2017)).

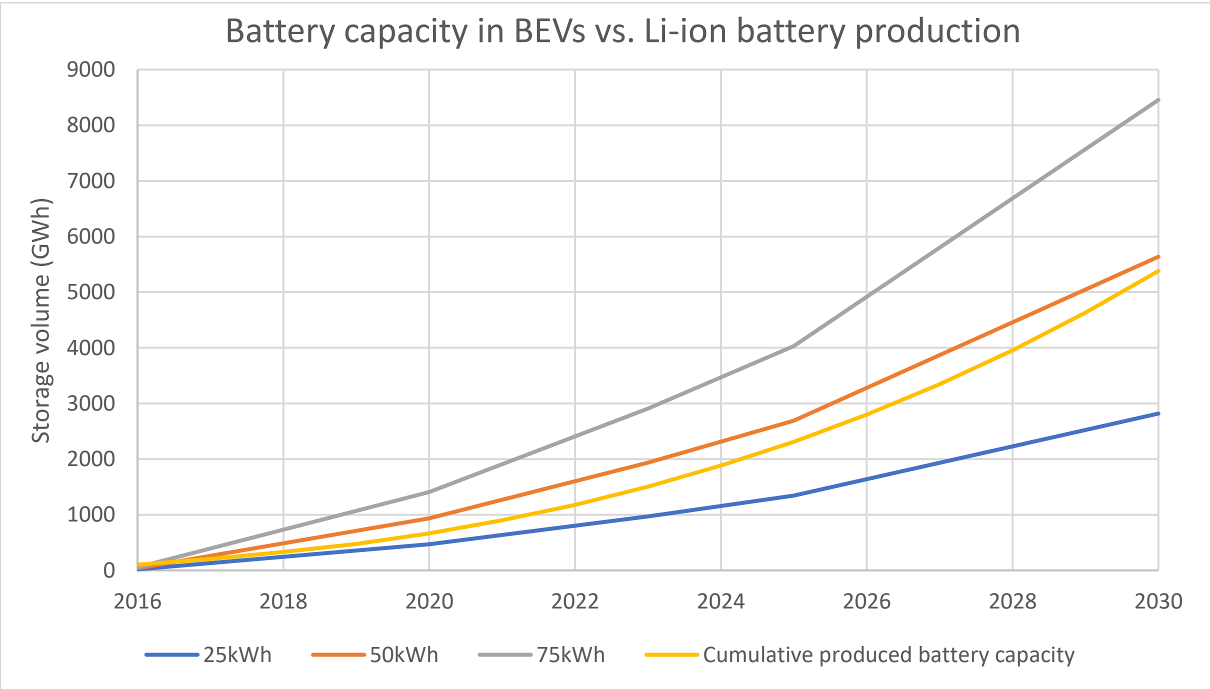

Figure 40: The expected cumulative amount of batteries in BEVs worldwide compared to the cumulative production of lithium ion batteries from 2016 till 2030. The cumulative lithium ion battery production is presented by the yellow line. The cumulative battery capacity in BEVs worldwide is presented for an average battery capacity per car of 25 kWh, 50 kWh and 75kWh by the blue, grey and orange line respectively. The graph shows that it seems unlikely that the average battery size in BEVs will exceed 50 kWh.

Figure 40 shows that the production increase can keep up with the growth of BEVs if the average battery capacity is 25 kWh. The growth in battery production capacity cannot keep up with the expected growth in BEVs if the average battery in the cars is 50 kWh. Unless the production capacity grows faster than expected till 2021 (Hirtenstein, 2017) and assumed till 2030, or when the BEV car park grows less than expected in the IEA EV outlook 2017 (IEA, 2017). The first would result more cumulative produced Li-ion capacity while the second would reduce the cumulative demand for BEV lithium batteries, both could result in a car mounted battery with a higher average capacity.

Lithium ion batteries are also used in mobile consumer devices (and other applications) that may compete with batteries for BEV production. The difference between cumulative Li-ion battery production and the cumulative capacity in BEV with an average battery of 25 kWh is not that large in the near future (around 2020). This could result in shortage of Li-ion battery production, as recent announcements of new BEVs by manufacturers often advertise with larger battery capacities: The 2018 model Nissan Leaf will have a 40 kWh battery, an upgrade from the old model that had 30 kWh (Krijgsman, 2017). The mainstream model 3 from tesla will have two editions, 50 and 75 kWh (Lambert, 2017). The Volkswagen E-Golf got a larger battery in a recent upgrade, from 24.2 kWh to 35.8 kWh (Klaver, 2017). These examples show that car manufacturers aim to increase the capacity of battery packs, rather than staying around the 25 kWh battery size.

A battery system the size of 3,6 GWh to 8 GWh will probably never be implemented, considering the intended growth in BEVs and the cumulative Li-ion. The comparison between cumulative BEV mounted batteries and cumulative worldwide Li-ion production showed that future growth in Li-ion battery production is more likely to be reserved for car manufacturing instead of stationary grid energy storage. However, it should not be disregarded that future cars may have vehicle-to-grid (i.e. V2G) options that enable BEVs to function as distributed energy storage when connected to a charging station, e.g. the new Leaf (Krijgsman, 2017).

11.5.3 How much can car mounted batteries deliver to the Dutch grid in the future?

The number of registered plug-in electric vehicles are logged every year on January 1st in the Netherlands (CBS, 2017b). The number of registrations are presented in the table below:

Table 29: Number of registered BEVs (Battery Electric Vehicles) and PHEVs (Plugin Hybrid Electric Vehicles) in the Netherlands at the start of each year (CBS, 2017b).

Year	**BEV (Battery Electric Vehicle)**	**PHEV (Plug-in Hybrid Electric Vehicle)**
2015	7,400	36,750
2016	9,950	76,250
2017	13,709	95,725

Ortec consulting reports that the Dutch government has a target for 100% BEVs in car sales in 2035 and that a resolution that aims for 100% BEVs in car sales in 2025 is under discussion (Leenman, et al., 2017). They also report that the share of PHEVs will reduce substantially in the near future, this can already be observed in the small growth between 2016 and 2017 compared to the growth between 2015 and 2016 (see Table 29).

The annual new car sales for personal transportation was between 382,593 and 555,846 cars for the period from 2007 till 2016 (CBS, 2017d). The car park for personal transportation grew from 6.3 million cars in 2000 to 8.2 million in 2017 (CBS, 2017e).

A simple estimate was made for the battery capacity that would become available to the Dutch grid, as a result of growth in BEVs with V2G (i.e. vehicle-to-grid) functionality. The assumptions made are as follows:

1. The sales of EVs (Electric Vehicles) will be dominated by BEVs instead of PHEVs in the near future (Leenman, et al., 2017). Therefore the assumption is made that the EV sales will only consist of BEVs that have V2G functionality.
2. Logging a trendline (exponential or polynomial in Excel) on development of car sales does not give a realistic figure for the share of BEVs in the future. The annual growth for BEV sales as

reported by Leenman et al. (2017) were used, combined with the average annual number of new car registrations (CBS, 2017d):

   a. Leenman et al (2017) report two scenarios for EV growth, one with the 100% BEV car sales in 2025 and one with 100% BEV car sales in 2035. To reach full BEV sales in 2025 they report an annual growth in BEV sales of 80% and for the 2035 BEV sales target, the growth is 30% annually (Leenman, et al., 2017).
   b. There is annual average of 428 thousand new car registrations observed from 2012-2016 (CBS, 2017d), this was assumed to stay constant. So for the scenario of 100% BEV sales in 2025, it was assumed that 428,000 new BEV registrations were observed from 2025 onward. For the 2035 the 30% annual growth in sales was used, as 100% BEV sales were not reached until 2035.

3. The average size of the car battery was assumed to be 40 kWh per car, this may be an overestimation for the current situation. However, it is in line with the earlier mentioned announcements for new BEVs and may be achievable considering the growth in Li-ion battery production.
4. These cars will have the main purpose of personal transportation and will not be available to the grid at all time. It was assumed that 10% of the battery storage volume in BEVs will be available for use as energy storage in the grid.
5. It was assumed that the lifetime of a BEV is around 12 years. Mainly based on the roughly 8 years warranty that manufacturers provide with their BEV batteries (Lagowski, 2017). From 2007 till 2016 on average 78% of new car registrations was offset by scrapping or export of old cars. This was also assumed for BEVs where 78% of 12 year old BEVs were assumed to be scrapped or exported annually. This meant that in 2028 the 78% of BEVs sold in 2016 were scrapped or exported, and so on for the following years.

The results for BEV battery capacity available to the grid is presented in the graph below (Figure 41):

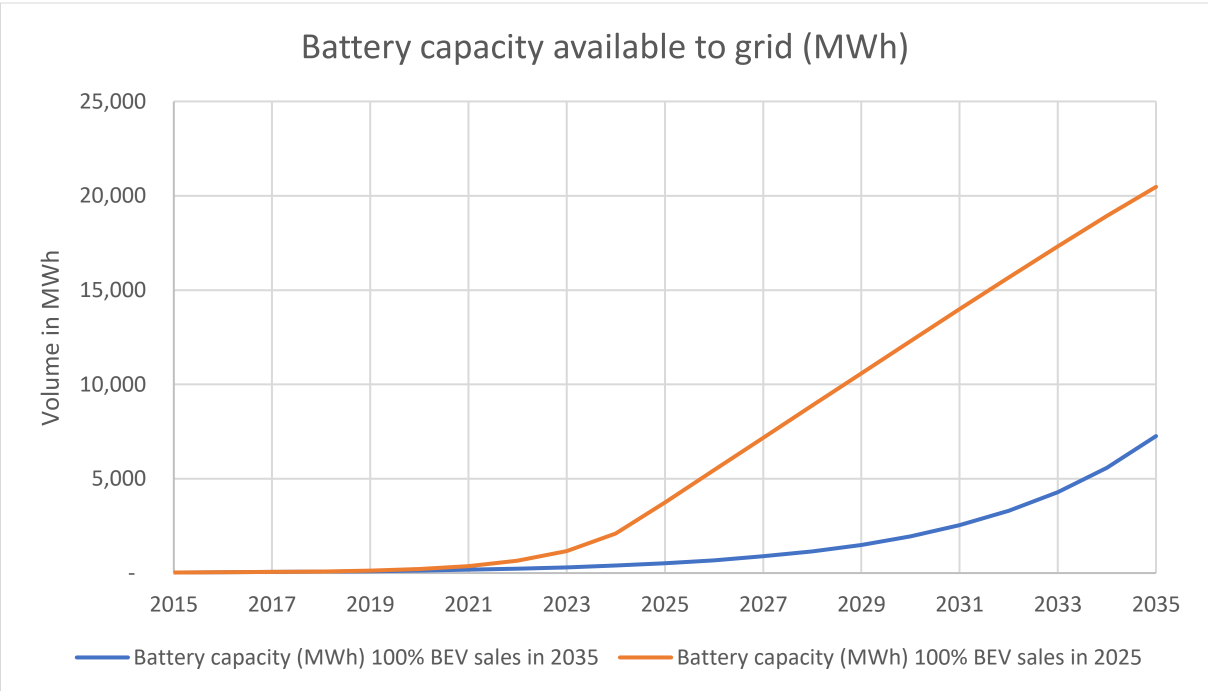

Figure 41:Total battery capacity available to Dutch grid from BEVs (Battery Electric Vehicles) with V2G (Vehicle-to-Grid) functionality. Here the assumption was made that 10% of the total battery capacity in cars would be available as grid energy storage with an average car battery of 40 kWh. The orange line represents the scenario in which all Dutch car sales consist of BEVs from 2025 (80% annual growth in BEV sales from 2017) and the blue line represents the scenario in which all car sold are BEVs in 2035 (30% annual growth in BEV sales from 2017).

The results (in Figure 41) show that the amount of available energy storage from BEVs may range from 7.3 to 20.5 GWh in 2035. This requires 1.8 million to 5.1 million BEVs on the Dutch roads with an average battery of 40 kWh, a substantial change in the car park within 18 years. The results from PLEXOS showed that somewhere between 2030 and 2035 there is need for energy storage in the Dutch power system (or new capacity at least). In 2030 the storage that BEVs can provide the grid may range between 1.9 GWh to 12.3 GWh. The potential for V2G energy storage may be large, however the 100% BEV sales in 2025 target seems overambitious. Meaning that the future energy storage from V2G is more likely around the range of the full BEV sales target for 2035 (i.e. blue line in Figure 41).

The availability of BEV batteries to the grid will not occur naturally with a growing number of BEV registrations. Both grid operators and car owners must be willing to invest and cooperate with a V2G system. As it should be taken into account that all of these distributed batteries are privately owned. The benefit for the electricity grid may be similar to that of dedicated stationary energy storage, but the benefit for the car owner was found to be very small or even negative (Loisel, et al., 2014). Degradation of the car battery outweighed the financial remuneration for having the car available for V2G energy storage (Loisel, et al., 2014). Besides, the required upgrades, associated costs and challenges for creating an electricity grid with smart BEV charging infrastructure should also not be underestimated (Mwasilu, et al., 2014).

12 CONCLUSION

Literature reports a variety of benefits that underground pumped hydro storage (UPHS) can provide the future Dutch power system. It can help integrate renewable energy in the power system, by its flexible switch from demand to supply and the possibility to store surplus renewable production for later use. Energy arbitrage and provision of ancillary grid services can be source of income. Possibilities for ancillary services are, control reserve, reactive power, re-dispatch and black-start. The presence of UPHS may also reduce the operational costs thermal power generator capacity. Most of the theoretical benefits were captured in the PLEXOS model, the results showed that:

1. The challenge is to prevent unserved demand in a power system that has a thermal power generator capacity that is smaller than occasional peak demand. The presence of a UPHS reduced the amount of unserved demand substantially compared to the reference power system without storage. One UPHS system with 1.4 GW capacity and 8 GWh storage volume was insufficient to prevent all unserved demand in 2035.
2. UPHS will increase the flexibility of the power system. The amount of renewable curtailment and the number of thermal power generator starts were reduced substantially. The presence of UPHS also reduced the stand-by operation of thermal power generators for reserve provision.
3. The presence of UPHS may increase the average price for electricity slightly, while decreasing price volatility substantially. A clear benefit was the lower total generation cost with a UPHS in the power system.
4. The UPHS stimulates the use of more efficient baseload generators in the early years and store renewable surplus in later years with high renewable electricity production. Thereby reducing the CO_2 emissions from the power system, even when there was no renewable curtailment observed in the model year.

The UPHS was compared to demand response (DR) and two sizes battery energy storage (BES and BESXL). The results showed that UPHS outperformed DR on all aspects measured. The difference in performance with battery storage is small and depended mainly on the size of the battery storage system. The BES scenario had slightly while and the BESXL had slightly less CO_2 emissions and renewable curtailment than the UPHS scenario. The same was observed for most other indicators. The net present value calculations indicated that UPHS, BES and BESXL are not economically attractive when the only source of income is price arbitrage, except for the year 2035 where both UPHS and BES have a positive NPV. The cost-of-electricity calculations showed that UPHS has the advantage over BES technology (due to is longer lifetime) and can be competitive with gas turbines in the future.

A more in depth view into the electricity market showed that energy storage may increase its profits by charging scarcity rents, a detail that was not be captured in the PLEXOS model. This opportunity occurs when the power system experiences capacity shortage, as may be observed in a future power system with high renewable resources. Further comparison between the BES and UPHS technology showed that BES may reduce its costs in the future, while UPHS construction costs are project specific. The Li-ion battery production capacity is expected to increase substantially in the future. However most of the additional batteries on the market are likely to be used for BEV (Battery Electric Vehicle) production. These car-mounted batteries could be used as distributed energy storage, but the disappointing financial reward for BEV owners and costs for the smart charging infrastructure may limit the attractiveness of this application. UPHS on the other hand can provide all the benefits of battery storage, does not have to compete with alternative technology applications and has a substantially longer lifetime.

13 APPENDIX A: APPROACH POWER SYSTEM MODELING IN PLEXOS

13.1 MODELING PARAMETERS

PLEXOS version 7.4 was used for constructing the Dutch power system model. MOSEK Rounded relaxation solver was used for running the model, as the integer optimization solver was not available in the student license of PLEXOS. The rounding up value was set at 0.75 with a relative gap of 0.01%, to prevent that generators would produce negative power output or production below the minimum stable level to prevent start-up costs (as this was observed with a lower value for rounding up). The model was executed for 364 days and at an hourly resolution with period optimization per day and a look-ahead of 6 hours (Deane, et al., 2014). December 31 is not included in the model, because the load dataset did not include the first 6 hours for January 1st of 2016, as these were required for the look-ahead optimization.

13.2 LOAD PROFILE

Load data was obtained from the ENTSOE-E database with an hourly resolution for the year 2015 (ENTSOE-E, 2016). This year has been selected because most databases have final values for this year, e.g. wind speeds and solar irradiance. The difficulty with the load profile is that it may change because of changes in the power system. The development towards more electrification of the transport sector and electrical heating of buildings may impact the load profile (Deane, et al., 2012). According to the ECN energy outlook, the demand will increase in the long term (ECN, 2016). The ECN (2016) source does not mention that the load profile that might have a different shape, due to future changes on the demand side of the power system (ECN, 2016). Therefore the decision was made to keep the load profile constant for all scenario years. This also made the results from all scenarios and all model years directly comparable, as changes in the demand profile were not included.

Another important factor is the level of detail required for the load data. Preferably, the model would have been executed with a high (sub-hourly) resolution to capture the ramping of thermal power generators in detail. However, the only data for wind speeds and solar irradiance for the Netherlands in 2015 had an hourly resolution. Therefore hourly resolution load data was, to stay consistent with the data resolution for wind speeds and solar irradiance.

13.3 FUELS

Three types of fuels were considered in the power system model; coal, nuclear (uranium) and natural gas. These types are the main energy sources that power the Dutch thermal power generator park, sources like biomass and waste were not included in this research.

13.3.1 CO_2 emission factors

Direct CO_2 emissions from burning fossil fuels were included in this research. Natural gas and coal fired generators were assumed to have CO_2 emissions in the power system model. The emission factors that were used are (Vreuls, 2005):

- Natural gas: 56.1 kg CO_2/GJ
- (Bituminous) Coal: 94.7 kg CO_2/GJ

The CO_2 emission price was set at €18 per ton CO_2.

13.3.2 Fuel prices

The ICE Endex prices for Coal on the API2 Rotterdam Coal futures market is currently (April, 2017) 69.35 US$ per metric ton, early 2016 the price was exceptionally low at 36.75 US$ per metric ton and peaked in November (2016) at 77.35 US$ per metric ton (ICE ENDEX, 2017c). The price is expected to decrease with the currently observed trend, as the price for 2018 coal futures was 63.70 US$ per metric ton (ICE ENDEX, 2017c). The average price for coal futures (for 2017 to 2019) was used as coal price for the power system model. This price is 72.59 €/metric ton (ICE ENDEX, 2017c). The heating value used for coal is 28.7 MJ/kg (Vreuls, 2005). A conversion factor of 0.921014 €/$ was used to calculate the fuel price in euros.

The ICE Endex futures price for natural gas differs over time, the average is around 16 €/MWh (ICE ENDEX, 2017d). The last trade price was 14.937 €/MWh(April, 2017), the highest price in the last 2 years was 21.553 €/MWh (in May 2015) and the lowest 12.65 €/MWh (in April 2016). The average price of natural gas futures from 2017 to 2020 was used in the power system model. This is an average price of 16.84 €/MWh (ICE ENDEX, 2017d).

Uranium was priced at a spot price of 33.00 $/lb and long term price of 33.00 $/lb (Cameco, 2017). Long term prices will be used because it is logical for a nuclear power plant operator to procure uranium well in advance of the production of electricity. The highest price in the last 2 years was 49.50 $/lb (start of 2015) and the lowest 30.00 $/lb (in December 2016) (Cameco, 2017). The heat that can be obtained from 1 kg of uranium was assumed to be 500 GJ in a normal nuclear reactor as in the Netherlands (World Nuclear Association, 2016). For uranium the most recent price was used as input for the power system model.

Fuel prices are based on the sources mentioned above. The fuel prices used are the futures average prices obtained on April 5, 2017. In case of uranium the long term price was used because futures were not available:

- (Bituminous) Coal: 2.33 €/GJ
- Natural gas: 4.68 €/GJ
- Nuclear: 0.13 €/GJ

13.4 Thermal power generators

In the PLEXOS model thermal power generators are dispatched by the solver based on the production costs. Operational characteristics are required to accurately capture the performance and electricity production costs of thermal power generators. Central and decentral capacity are discussed separately, because the Netherlands has a large decentral generator park that is not listed in sources like ENTSOE-E and TenneT.

13.4.1 Central thermal power generators

ENTSOE-E has a publicly available list of the central power generators connected to the Dutch electricity grid (ENTSOE-E, 2017). The list with installed generators at the start of 2017 was used as input for the power system model. The data was combined with data from TenneT and online sources to get better insight in the types of power generator (TenneT, 2017b). The operational characteristics were then assigned based on the type of generator. These operational characteristics were obtained from literature where generator characteristics are reported. The used sources are referred to in Table 31, where an overview of the generator operational characteristics is provided.

13.4.2 Decentral thermal power generators

Decentral generator capacity are mostly gas-fired Combined Heat and Power (CHP) systems (ECN, 2016). Decentral CHP capacity is typically used in the horticulture sector and chemical industry, where both heat and power are used in the production process (ECN, 2016). The total capacity of this decentral CHP generator park is currently around 6,107 MW (based on ENTSOE-E total installed gas fired capacity minus central installed gas fired capacity, this value is similar to the capacity reported in the National Energy Outlook of 2016 (ECN, 2016; ENTSOE-E, 2017)).

There is no overview available with installed decentral generators. Therefore, a different approach than for central generators was used to model this decentral capacity. The most recent statistical data on the number and type of decentral generators is from 2007 (Ecofys, 2011). This source reports the decentral CHP park consisted of 4235 gas engine CHP units and only 52 combined cycle CHP units (Ecofys, 2011). This shows that the decentral capacity consists of multiple small generators in the range of 1-5 MW and a few larger decentral CHP systems (Ecofys, 2011). In the model it was assumed that around 5% of the decentral capacity consisted of CHP – CC (combined cycle) and the remaining 95% consisted of CHP – gas engines. The size of the generators was assumed to be 25 MW for the CHP – CC and CHP gas engines total capacity was divided equally over large (50 MW) and small (20 MW) units. This simplification was done to reduce calculation time in PLEXOS. To account for possibly lost flexibility, the minimum stable generation capacity was reduced compared to larger power generators of similar type. Table 30 contains decentral installed capacity in the reference scenario and Table 31 shows the operational characteristics for the power generators.

Table 30: Input for decentral CHP capacity in the Dutch power system. Based on combined data from (Ecofys, 2011; ENTSOE-E, 2017; ECN, 2016).

	CAPACITY PER UNIT	UNITS
CHP - CC	25 MW	10
CHP - GAS ENGINE	50 MW	59
CHP - GAS ENGINE	20 MW	146
TOTAL		215

13.4.3 Technical characteristics thermal power generators

Table 31: Thermal power generator characteristics used in the PLEXOS power system model. Values are based on different sources, average values were use where multiple sources are mentioned.

Type of generator	Fuel	Efficiency (%)	Heat rate (GJ/MWh)	Variable O&M costs (€/MWh)	Max rated capacity (MW)	Min stable generation (MW)	Ramp rate (% of max capacity /min)	Min up/down time (h)	Start cost (€/MW)	Fixed O&M costs (€.kW^{-1}yr^{-1})
New CP	Coal	46%[1,4]	7.83	3.5[6,8]	100%	35%[6]	4%[6]	4[7]	75[6]	25[6,8]
CP	Coal	39.2%[1,4]	9.18	3.5[6,8]	100%	40%[6]	3%[6,8]	5[7]	75[6]	25[6,8]
New CCGT	Gas	55%[1,2,4]	6.55	1.53[2]	100%	45%[6]	6%[6]	3[7]	57[6]	15[6]
CCGT	Gas	44.6%[2,4]	8.07	1.2[6]	100%	45%[6]	5%[6,8]	4[7]	57[6]	15[6]
Conventional	Gas	38.5%[5]	9.35	0.82[5]	100%	40%[6]	3%[6]	4[7]	50[7]	10
GT	Gas	34.5%[2,4]	10.43	0.8[6]	100%	20%[7]	15%[6,8]	0.25[7]	23[6]	9[6]
Nuclear	Nuclear	33%[3]	10.91	0[6]	100%	37.5%[6,8]	5%[6,8]	24[6]	75[6]	100[6,8]
CHP – CC	Gas	42%[6]	8.57	6[6]	100%	35%	5%[6,8]	4[7]	57[6]	15[6]
CHP – Gas engine large	Gas	41%[6]	8.78	7[6]	100%	25%	50%[9]	0.25[9]	23[6]	10
CHP – Gas engine small	Gas	41%[6]	8.78	7[6]	100%	25%	50%[9]	0.25[9]	23[6]	10

1. Source: (ECN, 2007)
2. Source: (Deane, et al., 2012)
3. Source: (Eurelectric, 2003)
4. Source: (Seebregts & Volkers, 2005)
5. Source: (Energinet, 2012)
6. Source: (Brouwer, et al., 2015)
7. Source: (SEM, 2011)
8. Source: (Black & Veatch, 2012)
9. Source: (Wartsila, 2017)

13.5 Wind power generators

Data on the amount of installed capacity and the location of wind turbines was retrieved from windstats.nl (Windstats.nl, 2017). The installed capacity was sorted by province to create production curves for wind power per province. The reference year for installed wind generator capacity is 2017, similar to the reference for generator capacity. The wind speed data for both onshore weather stations (KNMI, 2017a) and offshore weather stations (KNMI, 2017b) was obtained from the KNMI (Royal Dutch Meteorological Institute). The year 2015 was used as wind profile for all locations, as it is the same year as the load profile used. The aggregate of wind speed was used when more than one meteorological station was available in a province in 2015. Offshore weather station wind data was selected for locations that are near the Dutch coast and near the currently installed offshore wind parks. Wind speed is measured at 10m, the data was therefore converted to the wind speed at a height of 80m which was assumed to be the average hub height for the wind turbines. There are also some typical wind speeds that influence turbine behavior (Boer, et al., 2014):

- Cut-in wind speed: 4 m/s. This was assumed to be the wind speed at which the turbines would start generating power.
- Rated wind speed: 15 m/s. The wind speed at which generators reach their rated (maximum) power output.
- Cut-out wind speed: 25 m/s. Above this wind speed turbines are shut down to prevent damage.

The following formulas show the calculation method used to create the wind power production profile. Formula (6) below was first used to convert the wind speed data to wind speeds at a height of 80 m (Twidell & Weir, 2015):

$$U_z = \frac{U_s * \log\left(\frac{z}{x}\right)}{\log\left(\frac{10}{x}\right)} \tag{6}$$

Where:

U_z = The windspeed at height Z (i.e. hub height of 80m in this research)
U_s = The windspeed at 10m height
x = the roughness height in m (0.2mm for offshore and 100mm onshore)

The method used for creating the wind power production profile is described below and was based on the method and formulas (7- 8) in (Twidell & Weir, 2015) and (Boer, et al., 2014):

Power in the wind is:

$$P = \frac{1}{2}\rho A u^3 \tag{7}$$

Power from wind turbine is:

$$P_T = \frac{1}{2}\rho A u^3 C_P \tag{8}$$

Where:

P = Power in the wind, subscript T is for power from wind turbine
ρ = Density of wind
A = Area of turbine blades
u = wind speed at hub height
C_p = Power coefficient of the turbine

The calculation of wind power output was performed based on the total installed capacity in each province and offshore. In general four regions of operation can be defined based on the wind speed. The power output differs per region of operation. The regions of operation and the associated power output (P) calculation method are presented below (Twidell & Weir, 2015):

1. The wind speed (u) is lower than the cut-in wind speed (u_{ci}):
$$\mathrm{P} = 0 \tag{9}$$
2. The wind speed (u) is higher than the rated wind speed (u_r) and lower than the cut-out wind speed (u_{co}) (P_R = the rated power for the province):
$$\mathrm{P} = \mathrm{P}_R \tag{10}$$
3. The wind speed (u) is higher than the cut-out wind speed (u_{co}):
$$\mathrm{P} = 0 \tag{11}$$
4. The wind speed (u) is higher than the cut-in wind (u_{ci}) speed and lower than the rated windspeed (u_r). This was calculated based on the total installed capacity P_R in each province. The formula used is derived from the formula 8 for wind power output:
$$P = P_R \cdot \left(\frac{u^3}{u_r^3}\right) \tag{12}$$

With formulas 9-12 described above, a power curve was created for each province that looks similar to the example power curve in Figure 42. This method was applied to simplify the power system model in PLEXOS. Otherwise, wind curves had to be calculated for all 2399 turbines that are currently installed in the Netherlands (Windstats.nl, 2017), based on wind data from the nearest weather station. The wind capacity was assumed to be always available, in reality wind turbines will require maintenance from time to time. This assumption was made to make sure that the model does not make the entire capacity of a province unavailable, which could cause unrealistic disruption in the power system model. This was inherent to the choice of modeling wind power per province instead of per turbine.

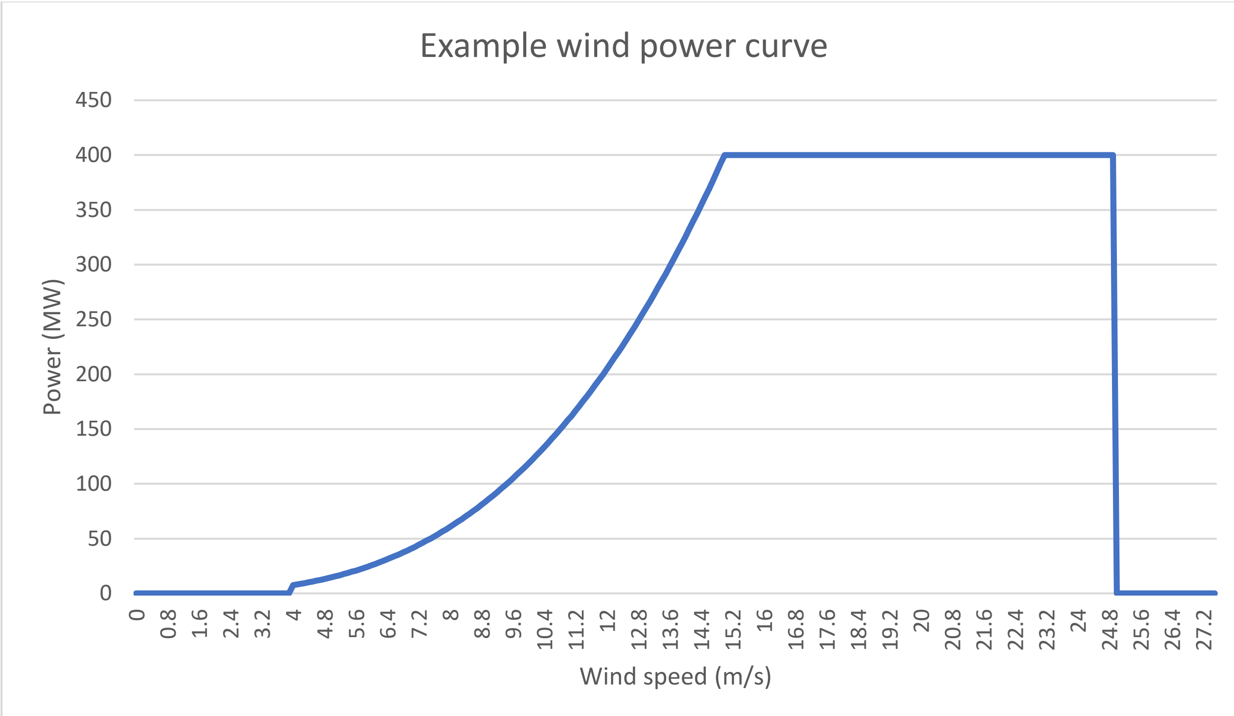

Figure 42: Example of the wind power curve per province based on the wind speed. In the graph, it is assumed that the total installed wind turbine capacity is 400MW. Cut-in wind speed of (4 m/s), rated wind speed of (15 m/s) and cut-out of wind speed (25 m/s) are as in the power system model.

The data used for wind power generation for the model 2017 year is summarized in Table 32. It contains the data for installed capacity, total production and capacity factor for each province and offshore during the 2017 model year, that resulted from the Excel calculation. The calculation method was used for all 12 provinces and offshore capacity for the five different model years, resulting in 65 datasets with wind power production profiles. For future model years the assumption was made that the capacity per province would grow proportional to the national expected increase in installed wind capacity. For offshore capacity there is a separate growth indication that was used for the offshore wind capacity.

Table 32: Input of capacity per province and calculation results from excel based on wind data and method above (capacity factor and electricity production for the 2017 model year based on the installed wind turbine capacity in 2017 (Windstats.nl, 2017)).

PROVINCE	# TURBINES	TOTAL CAPACITY (MW)	CAPACITY FACTOR	ELECTRICITY PRODUCTION IN 2017 (TWH)
DRENTHE	9	21.15	0.1357	0.025
FLEVOLAND	653	1186.44	0.2395	2.489
FRYSLÂN	324	194	0.2681	0.456
GELDERLAND	42	82.39	0.0974	0.070
GRONINGEN	221	445.98	0.2555	0.998
LIMBURG	6	12.25	0.0884	0.009
NOORD-BRABANT	119	218.66	0.0971	0.186
NOORD-HOLLAND	319	352.3	0.3018	0.931
OFFSHORE	289	957	0.3714	3.114
OVERIJSSEL	17	42.5	0.0795	0.030
UTRECHT	13	25.08	0.1173	0.026
ZEELAND	220	349.42	0.2801	0.857
ZUID-HOLLAND	167	360.11	0.2381	0.751
TOTAL	2399	4247.28		9.942

13.6 Solar power generators

According to the ENTSOE-E the total installed solar capacity in the Netherlands was 2039 MW at the start of 2017 (ENTSOE-E, 2017). The method used for creating the solar power output was based on the method used by Brouwer et al (2015). The average hourly solar irradiance curve from 32 KNMI weather stations for the year 2015 was combined with the total solar electricity production in 2015 to create a solar power output profile. The assumption was made that solar power output was linearly proportional to the solar irradiance. The solar power production in 2015 was 1122 million kWh, from a total installed capacity of 1515 MW (CBS, 2017c). The production was assumed to increase proportional with the increase in installed capacity from 2015 to 2017 (or later model years). This calculation method results in a total solar power production of 1.51 TWh for the solar installed capacity of 2017. The same method was applied for the other model years. Examples for the solar power output profiles in the 2017 model year are presented for the first seven days of June (Figure 43) and December (Figure 44). During winter, the solar production has a lower peak and a shorter production period during the day than during summer. Solar peak production may also differ substantially between days.

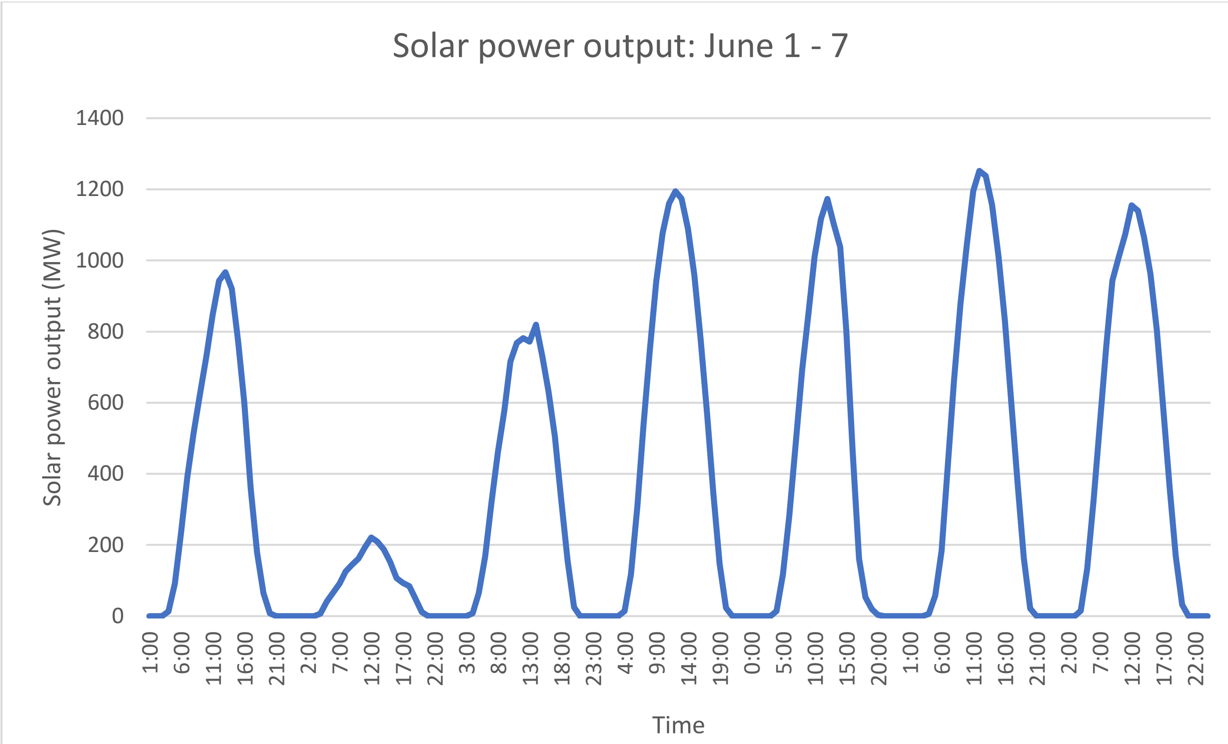

Figure 43: Solar power output in the model year 2017 from June 1st till June 7th.

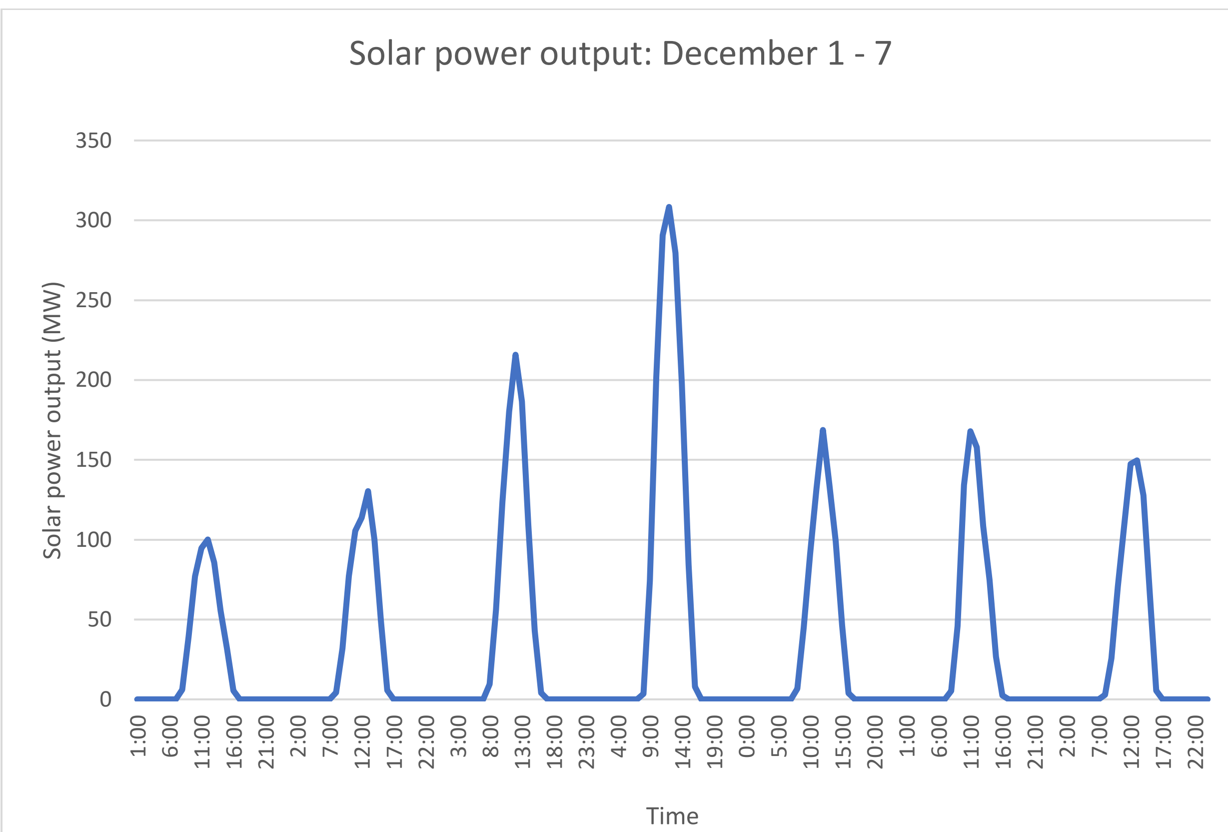

Figure 44: Solar power output in the model year 2017 from December 1st till December 7th.

13.7 Reserves

Three types of reserve were modeled in PLEXOS, primary, secondary and tertiary reserve. The TSO requires certain capacities per reserve type and has specific operational requirements before a provider can participate in a reserve market:

- 96 MW up and down regulation capacity is required as primary reserve. This capacity must be able to fully activate within 30 seconds and deliver 50% of its capacity in 15 seconds (Ecofys, 2015). Pricing of primary reserve is based on pay-as-bid principle where a weekly price is paid for reserved capacity (the produced electricity is not remunerated) (Ecofys, 2015). The average price in 2016 was 2486 €/MW per week for all reserve regions (DE and AUT included) and for NL specific reserves 2526 €/MW per week (Regelleistung.net, 2017).
- The TSO requires 300 MW symmetric secondary reserve capacity, effectively providing a total of 600 MW reserve capacity (300 MW up and down) (Ecofys, 2015). Operational requirements are; start-up within 30 seconds and a minimum ramp rate of 7% per minute and full activation within 15 minutes (Ecofys, 2015). The annual price for capacity was €130,000 per MW in 2014, energy is remunerated based on marginal costs of the highest accepted bid (Ecofys, 2015). More recent publications of remuneration for secondary reserves were not available.
- For tertiary reserve capacity requirement is +300 MW and – 350 MW. It must be able to have full activation in 15 minutes but has no minimum ramp rate requirement (Ecofys, 2015). Remuneration is provided for the amount of capacity a provider sets available (these figures are not publicly available) and for energy produced, based on the day-head price + €200 per MWh of electricity production (Ecofys, 2015).

Table 33 summarizes the characteristics for the three types of reserve, the values were based on the Ecofys report (2015). Modeling the Dutch reserves market in detail within PLEXOS would have been to elaborate and did not fit in the timeframe of this research. Therefore, default operation of reserve procurement was used in PLEXOS. VoRS (Value of Reserve Shortage) was included. It is the price for not meeting the required amount of reserve capacity, this was set at €100 per MW capacity.

Table 33: Reserve requirements based on (Ecofys, 2015).

	Req. Provision up (MW)	Req. Provision down (MW)	Full activation (sec)	Duration (sec)	Energy Usage (%)	Min ramp rate (%/min)	Capacity price (€/MW)	Energy price (€/MWh)
Primary reserve	96	96	30	900	10	200	2500 per week	-
Secondary reserve	300	300	900	3600	10	7	130,000 per year	Marginal bid
Tertiary reserve	300	350	900	4500	10	-	-	230

Generators may be able to provide different types of reserve, mainly depending on their operational characteristics. Within the model, the generators were selected based on the type of generator. Table 34 contains an overview of the generators and what type of reserve they were assumed to be able to provide:

Table 34: Overview of generator types and the types of reserve they can provide.

Reserve type	**Generator type**
Primary	UPHS, battery (BES), Demand Response (DR), Gas Turbine (GT) and New Combined Cycle Gas Turbine (New CCGT)
Secondary	All primary generator types + Combined Cycle Gas Turbine (CCGT)
Tertiary	All generators except Nuclear and intermittent renewables (Solar and Wind)

13.8 Flexibility measures

13.8.1 Characteristics U-PHS

The U-PHS storage volume will be limited by the size of the lower reservoir, because it will impose the highest capital costs. The project's current design is for a system with a capacity of 1400MW and 8 GWh of storage volume (Herrewijn, 2011; Sogecom BV, 2009a; Huynen, et al., 2012). Huynen et al (2012) report a UPHS project specific capital costs of 1.8 billion euro (€ 1,285.7 per kW) and operational costs of € 120 million per year for this project. The capital costs are in line with the costs reported for PHS capital costs in scientific publications. The reported capital costs ranges from $600 per kW, to $2000 per kW (Evans, et al., 2012; Lopez, 2015; Frontier Economics, 2015).

Huynen et al. (2012) report an annual O&M cost of € 120 million for UPHS. Operational costs for PHS are reported to be in the range of $15 to $150 per kWh-year (Lopez, 2015). These operational costs are relatively high compared to the annual operating costs of $14.57 per kW-year reported by Argonne (2014). Frontier economics (2014) reports a higher O&M cost of € 26 per kW-year. This value is in line with the operating costs for large hydro power plants of 2.0%-2.2% of capital investment (IFC, n.d.). These costs include the replacement of parts and refurbishment of a hydro power plant (IFC, n.d.). The O&M costs for PHS systems are substantially lower in other publications (Table 35). An average annual O&M cost of 5.23 €/kW is found in these sources. For calculation of the average, values were corrected with inflation correction and conversion to euros.

Table 35: Reported O&M costs for PHS systems from different publications.

Description	Value	Unit	Source
Pumped hydro	2.5	$/kW-year	(Poonpun & Jewell, 2008)
Taum Sauk	5.64	$/kW-year	(Galvan-Lopez, 2014)
Northfield Mountain	5.28	$/kW-year	(Galvan-Lopez, 2014)
Ludington	2.12	$/kW-year	(Galvan-Lopez, 2014)
PHES	3.8	€/kW-year	(stoRE, 2012)
PHS	7.04	£/kW-year	(Locatelli, et al., 2015)

Reported lifetime for PHS varies substantially between different authors, 25 years (Lopez, 2015) or 40-60 years (Evans, et al., 2012), 50 years (Argonne, 2014). This research assessed a novel implementation of

PHS, the lifetime was therefore assumed to be 40 years. This relatively short for pumped hydro storage, as most hydro storage plants will be refurbished to extend the lifetime.

The capital costs were based on the reports for the UPHS project in Limburg (Huynen, et al., 2012; Sogecom BV, 2009a) and operational characteristics were obtained from reports on conventional PHS systems (Argonne, 2014; Evans, et al., 2012). The operational costs were assumed to be € 10 per kW-year, because of lower O&M values reported in multiple publications and because of the relatively short lifetime that was used (during which little refurbishment is likely to be performed). The operational characteristics for UPHS are summarized in Table 36.

13.8.2 Characteristics battery storage

Battery storage was modeled in PLEXOS with the batteries object. The specific battery technology considered here is Li-ion battery storage. This technology has been used successfully in many mobile consumer appliances and is currently the leading technology for energy storage in battery electric vehicles (Nykvist & Nilsson, 2015). Large scale storage for grid application is also possible with Li-ion batteries, as showed recently by the installation of a battery storage system in the Dutch province Zeeland (AES, 2016a). However the current commercial capacity of 10 MW to 100 MW with 30 minutes to 4 hours operation, is smaller than PHS (AES, 2016b).

Lithium ion batteries have high roundtrip efficiencies of 75%-90% and can provide full capacity within a second (Lopez, 2015; Pellow, et al., 2015; AES, 2016b). A charging efficiency of 87.4% and a discharging efficiency of 100% were used in the PLEXOS, resulting in a round-trip efficiency of 87.4%[3]. The lifetime of lithium ion batteries is often expressed in cycles instead of years, for Li-ion this is in the range of 500-4000 cycles of (Lopez, 2015) or elsewhere reported as 4500 cycles and a life of 5-15 years (Evans, et al., 2012). Capital costs are reported in the range of $1500 to $6000 per kW (Lopez, 2015), $4000 per kW (Evans, et al., 2012) and $1800/kW (Manuel, 2014). However, AES Energy Storage claims a price of $1000 per kW installed for a system that can deliver four hours of full capacity (Lyons, 2014). Annual operational costs are reported to be larger than $1200 per kWh (Lopez, 2015), however this value seems highly unrealistic compared to other sources. Reported annual fixed O&M costs range from $0.5-51/kW (Viswanathan, et al., 2013), or $10/kW-year with variable O&M of $0.3/MWh for a 2 hour Li-ion battery storage system (Manuel, 2014). These values do not include variable O&M, even with variable O&M of around $7/MWh (Viswanathan, et al., 2013) they are much cheaper than reported by Lopez (2015). The diversity of reported values shows that there is still a high uncertainty O&M costs of battery storage.

In this research it was assumed that an investment equivalent to UPHS capital costs would be invested in battery storage. Initially capital cost for lithium-ion battery storage was assumed to be €2000 per kW. Investing a similar resulted in a total battery capacity of 900 MW with a storage volume of 3600 MWh. Recent publications (The Economist, 2017) show that the figure of €1000 per kW is more realistic. Therefore the model was also run with a battery of 8000 MWh which was slightly more expensive than the UPHS system. For modeling this capacity was divided over 9 and 20 units of 100 MW with 4 hours full load operation (current highest battery capacity for a plant in late stages of development (AES, 2016b)). The operational costs were assumed to be €25/kW-year, which corresponds to annual O&M costs of 22.5

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[3] The 100% discharge efficiency is not realistic, and was accounted for in the charging efficiency. This was necessary to ensure correct operation of the BES system during model runs. Test runs with the used PLEXOS settings gave faulty results.

or 50 million euro for the 900 MW and 2000 MW battery system respectively. The operational characteristics that were used in this report are presented in Table 36.

Table 36: Operational characteristics of UPHS and Li-ion battery storage, derived from sources as described in chapters 13.8.1 and 13.8.2.

Description	UPHS	Li-ion	Unit
Round-trip efficiency	80	87.4	%
Lifetime	40	10	years
Ramp rate generating	200	Unlimited	MW/min
Ramp rate charging	200	Unlimited	MW/min
Capacity lower reservoir/ storage volume	8,000	400 (3,600 or 8,000 total)	MWh/unit
Capacity higher reservoir	8,000	-	MWh
Max generator capacity	200	100	MW
Total units	7	9 or 20	units
Total capacity	1400	900	MW
Minimum output	10	0	MW
Pump (charge) load	1400	900	MW
Fixed O&M	14 million (€ 10/kW-year)	22.5 or 50 million (€ 25/kW-year)	€ per year
Capital cost	1.8 billion (€ 1,285.71 /kW)	0.9 or 2 billion (€ 1,000 /kW)	€

13.8.3 Modeling demand management

The PLEXOS power system modeling software has its main focus on modeling the supply side of the power system. The connection with the demand side of the power system is the load profile, this data was based on historical load data. However, this load profile cannot be influenced by PLEXOS to respond to market prices or be regulated by the solver to optimize the load profile. A possible approach is to change the load profile by shifting peak load to base load times (Hungerford, et al., 2015; Wagner, et al., n.d.). This would have to be done by manually altering the load profile based on a certain calculation method for load shifting.

A different approach was used to model demand response (DR). DR was modeled energy limited generator with a different available capacity each hour (Edmunds, et al., 2017). The DR generator was limited to a daily amount of energy production (MWh) and had a variable available output during the day (MW). This provided the possibility to vary the available amount of demand response over the day and during different seasons. A drawback is that a rebound effect from demand response cannot be captured with this method. For instance, if air conditioning is shut down for load reduction, it would be expected that the unit will have to operate in the near future in order to keep the building at the right temperature. This rebound effect can be expected for most DR sources, because DR is only a secondary function of most

DR sources (Edmunds, et al., 2017). Edmunds et al (2017) used data with different demand response classes; residential water heating and cooling (air conditioning), outdoor lighting, commercial cooling, ventilation and lighting. These different classes of demand response all have different times of operation, so not all are available at the same capacity during each time of day and there may also be differences over the year, due to seasonal use of certain DR sources (e.g. air conditioning, electric heating, etc.). This level of detail was not captured for DR in this research.

There is limited data available on both operational characteristic and O&M costs for DR in the Netherlands (ECN, 2014). It is estimated that there is 1730 MW of DR potential in the Netherlands at an operational cost range of € 300-500 per kWh (ECN, 2014). Within the ECN's research the assumption is made that the costs for DR range from € 0-300 per MWh in an exponential curve for a total of a daily 1.5 GWh of demand regulation (ECN, 2014). Edmunds et al (2017) used three different price tiers of initially $136/MWh, $600/MWh and $1,000/MWh, this was altered to $80 /MWh, $105 /MWh and $130 /MWh because DR was rarely used at these high prices. Both price ranges were not based on actual data, which shows that estimating or calculating the actual costs for DR are difficult and not often performed (Edmunds, et al., 2017).

This research used a fixed DR price of €125 per MWh delivered, in reality it is probable for the price to increase with increasing DR delivery to the power system. The capital costs for implementing a smart grid in the Netherlands was estimated at a total cost of €4.6 billion (Blom, et al., 2012). The costs come for a large part from residential installation. The capital costs for utilities and industry are estimated at 0.2 and 0.7 billion euro with annual operational costs of 0.3 and 0.7 billion euro, the operational costs include replacement of defect components and software updates (Blom, et al., 2012). These values were not used in further calculation, because there seems to be high uncertainty surrounding the costs of DR and because the operational costs are substantially higher than income that was generated by DR in the model runs.

The method for modeling demand response was based on the method used by Edmunds et al (2017). This means that DR was modeled as a generator with a variable maximum output, a limited daily energy production and no ramping limitations. The availability profile for DR capacity was created by assuming that 9.7% of hourly load is available as DR capacity. This percentage was based on the reported maximum DR potential of 1730 MW which is 9.7% of highest peak demand value in the load dataset. Linking the capacity availability of DR to the actual load was based on the DR capacity profile reported in Edmunds et al (2017). Their profile shows similarities to the typical load profile of the power system, i.e. DR availability increases during the mornings, stays relatively high during daytime and starts to drop in the evening, down to its lowest level of availability during night. The amount of available energy in DR was calculated per day. The amount of energy that could be delivered was based on the maximum available DR capacity each day and it was assumed that this capacity could be delivered for 1 hour on that day. Which means that if the peak DR capacity on a day would be 1730 MW, then there would be 1730 MWh of energy available for DR on that day. This method is similar to the method used by Edmunds et al (2017). The daily available DR for the whole year is shown in Figure 45 and available capacity for a week (May 1 till May 7) is plotted in Figure 46.

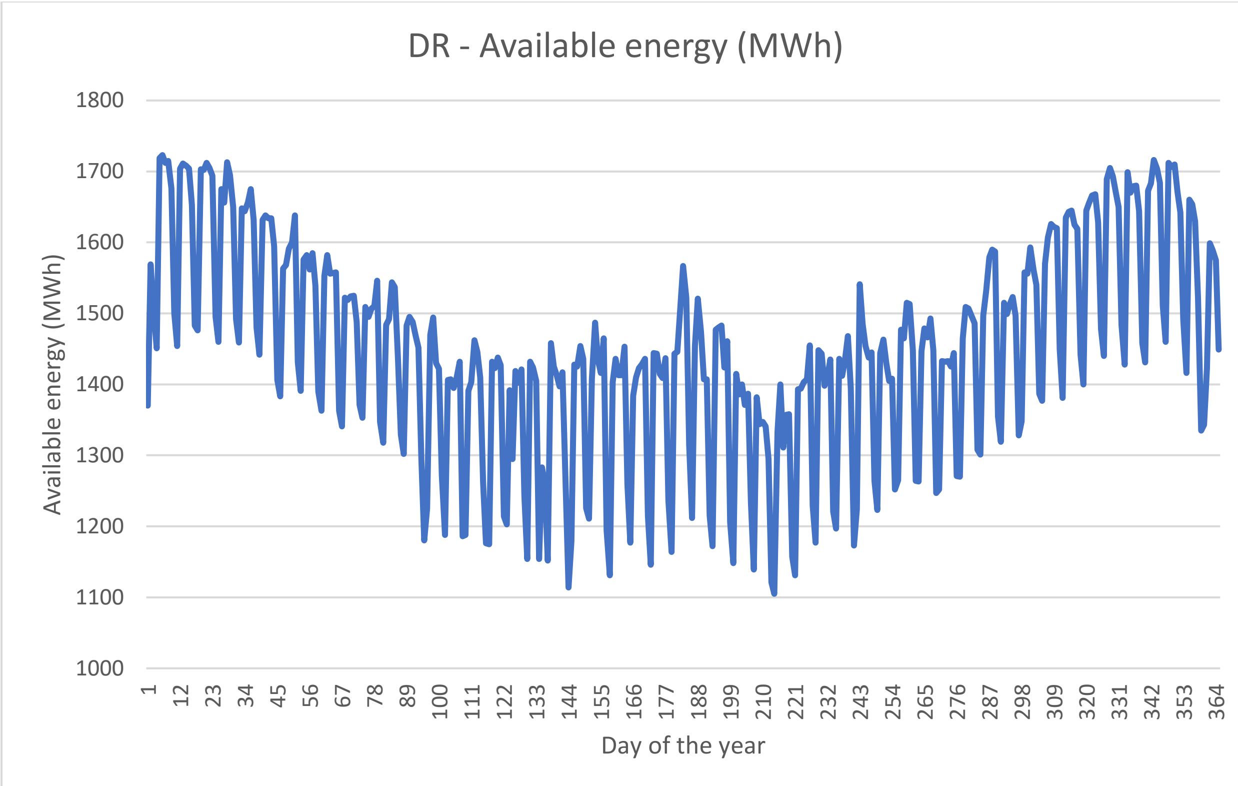

Figure 45: Daily amount of available energy that can be used for DR (Demand Response). The graph shows that availability of DR differs between weekends and normal weekdays.

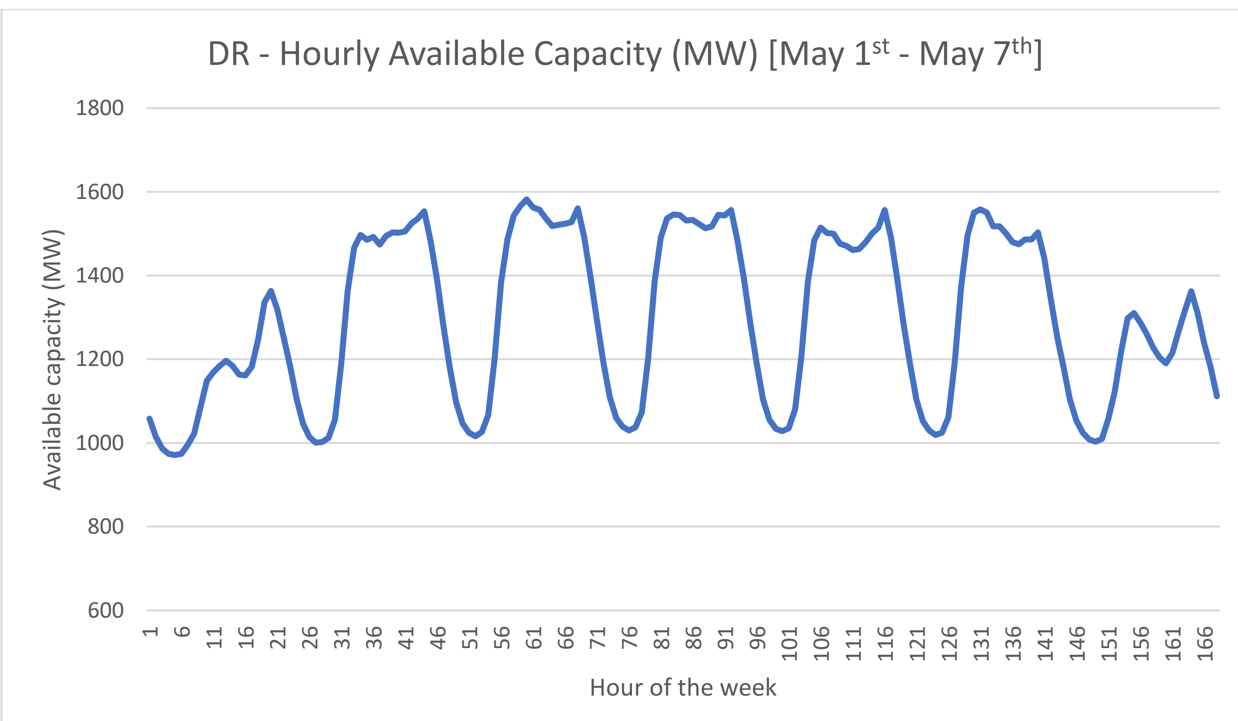

Figure 46: The maximum DR capacity in MW per hour of the day, plotted for 1 week (from May 1 till May 7 in model data, based on the original 2015 data calendar this is from Sunday till Saturday).

13.9 SCENARIOS YEARS

As reference model year, the year 2017 was used and four scenario years were created for the years 2020, 2025,2030 and 2035 based on the Dutch energy outlook (ECN, 2016). Within these scenarios the prices of fuels and all other costs are kept constant as well as generator operational characteristics, wind speed, solar irradiance and load profile. The generator park was assumed to change as reported in the Dutch energy outlook (published in 2016 by ECN). Decrease in fossil capacity and substantial increase in renewable capacity are expected according to the energy outlook. The installed capacity per fuel type for each scenario is presented in Table 37.

Table 37: Total installed capacity per fuel type, as used in the power system model.

Capacity in MW	**2017**	**2020**	**2025**	**2030**	**2035**
Coal	5698	4628	4628	4628	3355
Nuclear	492	492	492	492	0
Gas - Central	13624	9500	9500	9500	9029
Gas - Decentral	6120	4940	3530	3085	2840
Subtotal thermal power generators	*25934*	*19560*	*18150*	*17705*	*15224*
Wind - Onshore	3290	5267	6217	6735	7166
Wind - Offshore	957	2418	5699	8721	10793
Solar	2039	4317	8375	14506	21154
Subtotal renewable generators	*6286*	*12002*	*20291*	*29962*	*39113*
Total installed capacity	32220	31562	38441	47667	54337

14 APPENDIX B: TABLES RENEWABLE ENERGY CURTAILMENT

Table 38: Total wind energy curtailment for each scenario during all model years, the values are in MWh.

	Ref	BES	BESXL	DR	UPHS
2017	0	0	0	0	0
2020	90,561	4,975	680	73,485	1,593
2025	460,514	170,828	16,575	378,537	43,523
2030	2,398,455	1,807,261	1,334,388	2,321,970	1,368,551
2035	5,942,053	5,092,111	4,252,536	5,774,700	4,246,901

Table 39: Total solar curtailment for all scenarios during all modeled years, the values are in MWh.

	Ref	BES	BESXL	DR	UPHS
2017	0	0	0	0	0
2020	9,190	2,668	577	8,212	2,216
2025	106,729	49,631	17,780	96,701	26,783
2030	843,257	656,727	511,727	802,056	552,477
2035	1,590,127	1,268,450	1,047,100	1,495,399	1,185,246

15 APPENDIX C: THERMAL POWER GENERATOR CAPACITY FACTORS

Table 40: Thermal power generator capacity for the reference scenario and the battery (BES) scenario. Values are percentages, 'na' indicates that a generator type was not available that year.

Scenario			**Ref**					**BES**		
Year	***2017***	***2020***	***2025***	***2030***	***2035***	***2017***	***2020***	***2025***	***2030***	***2035***
Nuclear	100	98.47	94.76	84.80	na	100	99.67	96.96	86.81	na
CP	57.43	44.34	31.14	21.19	na	48.24	38.18	24.34	16.20	na
New CP	99.70	95.74	89.46	77.84	71.67	99.88	96.60	90.89	79.45	73.40
GT	0.64	0.48	1.87	4.79	8.85	0.07	0.07	0.20	1.10	2.85
CCGT	9.09	22.14	14.04	8.93	19.11	6.84	16.37	9.49	6.21	15.61
New CCGT	86.68	75.66	64.85	52.73	48.71	91.93	78.46	66.75	53.55	48.79
Conventional	0.00	na	na	na	na	0.00	na	na	na	na
CHP - CC	0.00	0.26	1.18	1.25	7.47	0.00	0.50	0.62	1.05	5.44
Gas engine	1.68	5.00	4.99	4.47	9.98	0.82	3.32	3.36	2.89	7.68

Table 41: Thermal power generator capacity factor for the demand response (DR) and UPHS scenario. Values are percentages, 'na' indicates that a generator type was not available that year.

Scenario			**DR**					**UPHS**		
Year	***2017***	***2020***	***2025***	***2030***	***2035***	***2017***	***2020***	***2025***	***2030***	***2035***
Nuclear	100	98.60	95.06	85.19	na	100	99.85	98.51	87.88	na
CP	57.57	44.62	31.92	21.93	na	48.31	40.37	26.61	17.13	na
New CP	99.71	95.80	89.44	78.09	71.83	99.90	96.96	90.97	79.06	72.58
GT	0.00	0.00	0.79	3.17	6.45	0.00	0.01	0.06	0.19	1.33
CCGT	9.62	22.49	14.33	8.93	19.63	7.21	15.58	8.62	5.27	14.56
New CCGT	86.91	75.88	65.04	52.85	48.81	92.34	78.91	66.87	53.65	49.08
Conventional	0.00	na	na	na	na	0.00	na	na	na	na
CHP - CC	0.00	0.19	1.18	0.92	5.17	0.00	0.51	0.37	0.68	5.20
Gas engine	1.11	4.42	4.10	3.53	9.23	0.30	2.41	2.37	2.10	6.42

Table 42: Capacity factors for the BESXL scenario for all modeled years. The values are capacity factor in percentage, 'na' indicates that the generator type was not anymore available in the capacity mix.

Scenario	**BESXL**				
Year	***2017***	***2020***	***2025***	***2030***	***2035***
Nuclear	100.00	99.90	98.58	87.50	na
CP	47.46	36.58	22.27	14.01	na
New CP	99.95	97.67	91.79	79.80	72.79
GT	0.00	0.01	0.02	0.09	1.07
CCGT	5.36	13.89	7.76	4.86	14.37
New CCGT	93.75	79.71	67.48	53.89	48.84
Conventional	0.00	na	na	na	na
CHP - CC	0.00	0.49	0.39	0.50	4.54
Gas engine	0.14	2.04	1.97	1.79	5.96

16 APPENDIX D: CENTRAL GENERATOR PARK NL

Table 43: Dutch central thermal power generator park, YES or NO indicates the presence of the power generator in the scenario year. Generator list obtained from (ENTSOE-E, 2017) and (TenneT, 2017b). The presence of generators was based on capacity forecasts per fuel type (ECN, 2016). Characteristics per generator type are presented in Table 31.

Power plant name	Fuel	Type	Max cap. (MW)	2017	2020	2025	2030	2035
Amer	Coal	CP	643	YES	YES	YES	YES	NO
ASP003	Gas	CCGT	224	YES	NO	NO	NO	NO
Borssele 30	Nuclear	Nuclear	492	YES	YES	YES	YES	NO
Centrale Lage Weide	Gas	CCGT	247	YES	YES	YES	YES	YES
Claus (1)	Gas	New CCGT	1275	YES	YES	YES	YES	YES
Claus (2)	Gas	Conventional	638	YES	NO	NO	NO	NO
Den Haag	Gas	CCGT	112	YES	YES	YES	YES	NO
Diemen	Gas	New CCGT	684	YES	YES	YES	YES	YES
eem220-ec-3	Gas	CCGT	359	YES	NO	NO	NO	NO
eem220-ec-4	Gas	CCGT	359	YES	NO	NO	NO	NO
eem220-ec-5	Gas	CCGT	361	YES	NO	NO	NO	NO
eem380-ec-6	Gas	CCGT	359	YES	YES	YES	YES	NO
eem380-ec-7	Gas	CCGT	360	YES	YES	YES	YES	YES
Eemshaven	Coal	New CP	1554	YES	YES	YES	YES	YES
Eemshaven (1)	Gas	New CCGT	1326	YES	YES	YES	YES	YES
GDFSUEZ_NL_EC-22	Gas	GT	131	YES	NO	NO	NO	NO
Hemweg (coal)	Coal	CP	630	YES	YES	YES	YES	NO
Hemweg (gas)	Gas	New CCGT	435	YES	YES	YES	YES	YES
LLS150FL-5	Gas	New CCGT	437	YES	YES	YES	YES	YES
LLS380 FL-4	Gas	New CCGT	435	YES	YES	YES	YES	YES
Maasvlakte (1)	Coal	CP	535	YES	NO	NO	NO	NO
Maasvlakte (2)	Coal	CP	535	YES	NO	NO	NO	NO
Maasvlakte (3)	Coal	New CP	1070	YES	YES	YES	YES	YES
Merwedekanaal 11	Gas	CCGT	103	YES	NO	NO	NO	NO
Moerdijk	Gas	GT	774	YES	YES	YES	YES	YES
MVL380 CR10	Coal	New CP	731	YES	YES	YES	YES	YES
MVL380 EG-1	Gas	CCGT	860	YES	NO	NO	NO	NO
Pergen 1	Gas	GT	130	YES	YES	YES	YES	YES
Pergen 2	Gas	GT	130	YES	YES	YES	YES	YES
Rijnmond	Gas	New CCGT	840	YES	YES	YES	YES	YES
Rijnmond II	Gas	New CCGT	427	YES	YES	YES	YES	YES
RoCa	Gas	CCGT	220	YES	NO	NO	NO	NO
Sloecentrale	Gas	New CCGT	864	YES	YES	YES	YES	YES
Swentibold	Gas	New CCGT	209	YES	YES	YES	YES	YES
TNZ150 ELSTA	Gas	GT	456	YES	YES	YES	YES	YES
Velsen	Gas	Conventional	869	YES	NO	NO	NO	NO

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