Assessment on a widespread Hydrogen Refueling Station network for grid balancing of renewable electricity in Denmark 2035 and 2050

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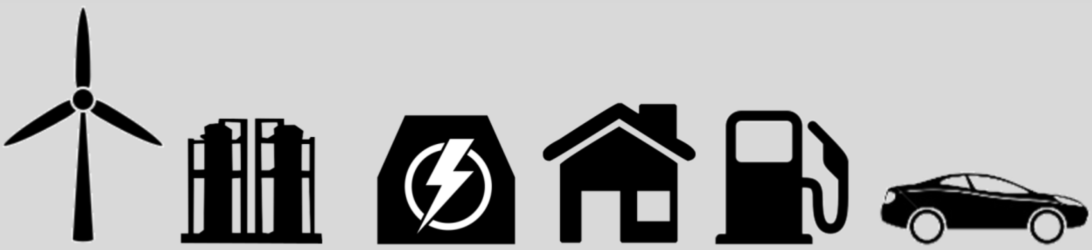

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Preface

This report presents the results of the research project MegBalance, which has been conducted with the support from the Danish research programme ForskEl, administered by the Danish Transmission System Operator (TSO) Energinet.dk and financed by energy consumers through the Public Service Obligation (PSO) tariff.

The main purpose of the MegaBalance project is to analyse the use of hydrogen refueling stations for balancing in the electricity system while producing green hydrogen for transport.

This report is prepared by Lasse Helleskov Ravn and Lotte Holmberg Rasmussen, Neas Energy, Jan Michalski, LBST GmbH, Mikael Sloth, H2Logic and Rasmus Høyrup Refshauge, EnergiMidt.

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Table of content

Abbreviations

€	Euro
CAPEX	Capital expenditures
CEEP	Critical excess electricity production
CGH_2	Compressed gaseous hydrogen
CHP	Combined heat and power
COP	Coefficient of performance
DEA	Danish Energy Association
DKK	Danish krone
DSO	Distribution system operator
FCEV	Fuel cell electric vehicle
FLH	Full load hours
H_2	Hydrogen
HRS	Hydrogen refueling station
LBST	Ludwig-Bölkow-Systemtechnik
LHV	Lower heating value
LP	Linear programming
NPV	Net present value
O&M	Operation and maintenance
OPEX	Operational expenditures
PSO	Public system obligation
PV	Photovoltaic
RE	Renewable electricity
SNG	Synthetic natural gas
TFC	Total fixed costs
TI	Total investment
TR	Total revenues
TRV	Total residual value
TSO	Transmission system operator
TVC	Total variable costs
UHF	Ultra high frequency
ULF	Ultra low frequency

Executive summary

The MegaBalance project has analyzed the potential for use of onsite electrolysis hydrogen production at Hydrogen Refueling Stations (HRS) for providing grid balancing of renewable electricity in Denmark in year 2035 and 2050.

Denmark is targeting a transformation to a fossil independent energy system onwards 2050 through increased renewable electricity production from wind turbines and electrification of the transport sector.

The basis for MegaBalance has been the Danish Energy Agency (DEA) "Wind scenario" where wind power capacity is significantly expanded to 8.5 GW in 2035 and 17.5 GW in 2050, creating increasing fluctuations in the power grid and hence demand for grid balancing services. The Wind scenario made by the DEA serves as the reference scenario which is compared to an alternative scenario:

To achieve a fossil independent transport sector by 2050 use of both Battery Electric Vehicles (BEV) and Fuel Cell Electric Vehicles (FCEV) is foreseen. In MegaBalance the basis is that share of FCEVs reaches 50% in 2050, whereas the remainder 50% is BEVs and hybrid vehicles. This will require a gradual expansion of the present HRS network in Denmark to 400 stations by 2035 and 700 by 2050.

In 2035 the net export is 7.92 TWh in the reference scenario that potentially can be consumed domestically for hydrogen production. In 2050 excess electricity of 5.49 TWh will reach a critical level (CEEP)[1] where export capacity on interconnectors is not sufficient, so either wind curtailment or increased domestic electricity consumption is required. In the alterative scenario with 50% FCEVs, the CEEP is reduced by 1.13 TWh when the electrolysers operates based load. This corresponds to a 20% reduction of CEEP compared to a scenario in which no FCEVs are implemented. Besides of addressing periods of CEEP, the need for balancing energy is also estimated in 2035 and 2050 to determine the electrolysers balancing potential when operated flexible.

MegaBalance has analyzed a scenario with electrolysis hydrogen production conducted onsite at each fueling station. To meet the hydrogen demand from the growing FCEV fleet, a base electrolyser capacity of 0.7 GW is needed in 2035 and 1.8 GW in 2050 (reference scenario). Electrolyser capacity may be further expanded to enable providing both negative and positive balancing by turning on-off the hydrogen production. The option of using fuel cells for conversion of hydrogen to electricity in periods with lack of electricity in the grid (positive balancing) has also been assessed.

In 2035 the electrolysis needed for hydrogen production in the mobility sector is able to satisfy the peak demand for negative balancing services in 2035, and an 8% increase of capacity to 0.8 GW will cover the need for positive balancing. The use of electricity

[1] Critical Excess Electricity Production (CEEP)

for hydrogen production will also help to reduce the overall electricity surplus in Denmark with 1.3 TWh (negative balancing) as well as to satisfy positive balancing demand of 0.4 TWh.

For 2050 the electrolysis capacity can meet the peak demand for positive balancing services and almost 50% of the negative balancing need. Positive balancing demand is satisfied with 0.8 TWh and amount of CEEP is reduced with 4.4 TWh.

Despite of increased investments in additional electrolyser and storage capacity, revenues from providing the balancing services have the potential to decrease specific hydrogen costs by 0.5 €/kgH2 to 1.5 €/kgH2. However from the economic perspective, the actual supply of balancing services strongly depends on the future development of balancing prices.

1. Introduction

1.1 Project background

The motivation for the MegaBalance project has been the increasing need for storing and balancing very high shares of fluctuating renewable electricity (RE) in a fossil independent energy system in Denmark from 2050.

Production, storage and conversion of hydrogen is acknowledged in several Danish and European strategic energy plans (Partnerskabet for brint og brændselsceller 2013, FCHJU 2014) as important contributions to flexibility in energy systems with a higher share of fluctuating renewable energy. Whereas several other ongoing projects are addressing the potential for use of hydrogen for boosting of the biomass potential, MegaBalance has focused on de-central hydrogen production and potential conversion at Hydrogen Refueling Stations (HRS).

The major car manufacturers are active on developing and preparing market introduction of fuel cell electric vehicles (FCEVs) which is creating a demand for hydrogen production and fueling. Early market regions are Japan, California and in Europe Germany, United Kingdom and Scandinavia including Denmark.

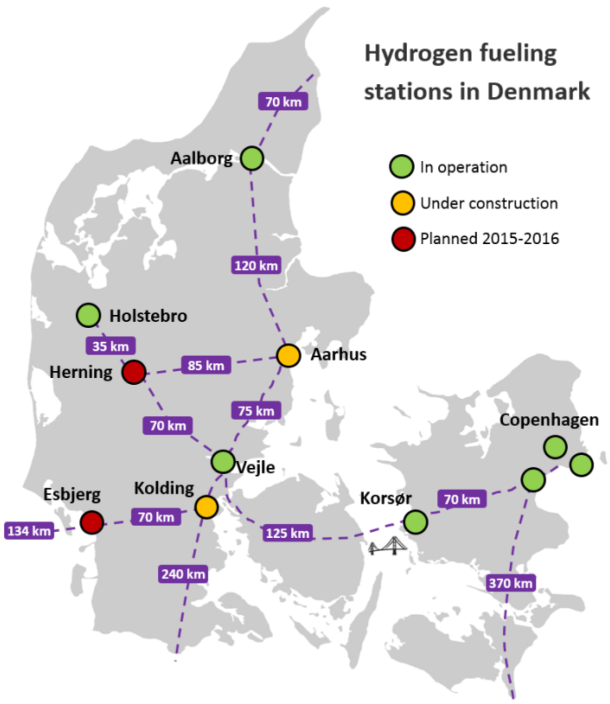


Figure 1: Map of Denmark with hydrogen fueling stations. Status September 2015 (Brintbiler.dk 2015)

In Denmark Hyundai has offered the iX35 FCEV since 2014 and Toyota have started sale of the Mirai in 2015. Honda is expected to introduce an FCEV model for Denmark during 2016 and several more car manufacturers are expected in the coming years.
Today, at the end of 2015 seven hydrogen refueling stations (HRS) are in operation throughout Denmark, with additional four planned during 2016 (see Figure 1). 50% of

the stations have onsite electrolysis production and the other 50% is supplied by hydrogen produced at a central electrolyzer facility.

The hydrogen production and fueling station network in Denmark is constructed and operated by several gas and energy companies in collaboration with technology providers. The network is expected to be expanded continuously as the share of FCEVs in the Danish car fleet grows. The overall potential is to reach 50% hydrogen in the car fleet by 2050 (Partnerskabet for brint og brændselsceller 2013), thereby contributing to the goal of fossil independence.

A continuous roll-out and expansion of a hydrogen production and fueling infrastructure in Denmark could be utilized for balancing of renewable electricity.

1.2 General approach

The major objective of this analysis is to quantify and analyze the use of electrolytic hydrogen production for refueling of FCEVs at public refueling stations to emerge across Denmark in the coming years and a secondary use of the electricity in the electricity markets.

Two types of ancillary services are analyzed:

(1) Negative load services (down-regulation in the regulating power market), i.e. in times with a foreseen imbalance of higher power generation than electricity demand. In this case there could be hydrogen generation through electrolysis thus electricity consumption in order to even out the imbalances in the grid.
(2) Positive load services (up-regulation), i.e. by reducing electrolytic hydrogen production or by providing electricity from hydrogen operated fuel cells in periods with imbalances caused by lower electricity production than electricity demand.

Hydrogen refueling stations could hence play an important role as 'energy stations' in the future energy system. In future refueling stations the availability to reduce or provide electricity as well as to provide waste heat to local district heating grids are potential parameters for an economic optimization. In more detail, the approach comprises the following individual methodological steps:

- **Step 1 (Chapter 3):** The analysis of the future Danish power market in this chapter is based on the expected demand for electricity and power generation from renewable sources. The corresponding model provides insights into future energy balancing needs as well as expected hourly electricity prices.

- **Step 2 (Chapter 4.1):** The technical concept in this chapter includes on the one hand short techno-economic documentation of the required technology components at HRS and on the other the corresponding operation strategies for balancing services. In addition, the technical specification of relevant components gives a general indication of the potentially usable waste heat.

- **Step 3 (Chapter 4.2 and 4.3):** Based on the technical boundaries of the underlying system the analysis in this step indicates the overall technical requirements for an HRS network (i.e. required sizing and corresponding optimal operation mode) to provide full balancing services in the power market as specified in step 1.

- **Step 4 (Chapter 5.1 and 5.2):** The assessment in these chapters reveals the expected HRS network roll-out in order to satisfy the demand from the mobility sector in Denmark until 2050.

- **Step 5 (Chapter 5.3):** Based on the results from the previous steps (electricity prices and balancing needs from step 1, techno-economic data on the underlying system from step 2 and expected HRS roll-out from step 3) the economic optimization in this chapter indicates the level of balancing services provided by the HRS network for a given range of balancing prices.

The structure of the report is as follows. Chapter 2 provides a detailed description of the models used for the subsequent analyses. Chapters 3-5 include major assumptions and results on the Danish power market projections as well as technical and economic assessment of HRS balancing services according to the above-mentioned methodology. Chapter 6 draws a comprehensive conclusion.

2. Methodology and analysis models

2.1 EnergyPLAN model for energy system analysis

For the analysis in step 1 the energy system analysis tool EnergyPLAN is used for analyzing the future energy system and the need for balancing energy. EnergyPLAN is developed by the Sustainable Energy Planning Research Group at Aalborg University as a tool to simulate the operation of a national or a regional energy system. The EnergyPLAN model is able to analyze entire energy systems including the electricity, heating, cooling, industry, and transport sectors on an hourly basis. Figure 2 illustrates the inputs needed to the EnergyPLAN model and the outputs that can be generated. (EnergyPLAN 2015)

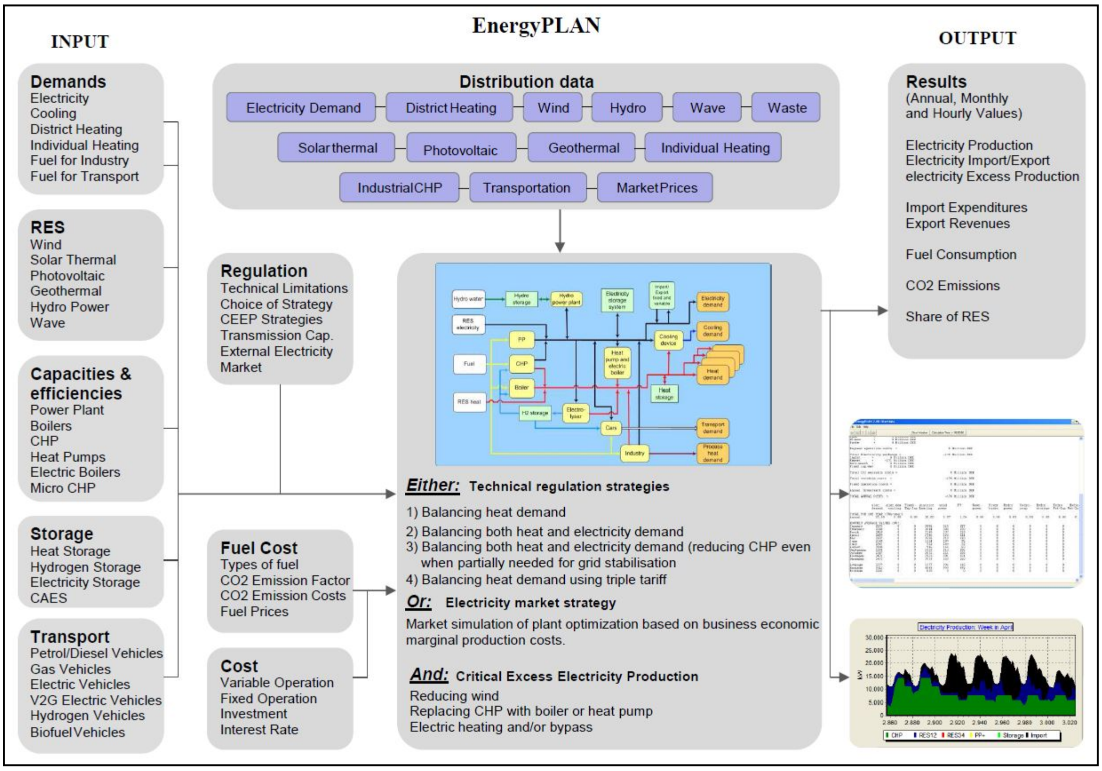


Figure 2: Overview of EnergyPLAN model. (Nielsen 2015)

The model is deterministic generating the same results if the inputs are the same. Inputs to the model are demands, renewable energy sources, energy plant capacities, fuel prices, distribution files and optional different regulation strategies (see below). Outputs from the model are energy balance and related annual productions, fuel consumption, import/export of electricity and gas and total costs.

Exogenous distribution files simulate hourly variations of demands and production based on the rated input capacities or annual consumption figures. In other words, distribution files represent the hourly fluctuations for production and consumption. A distribution file consist of 8784 numbers, one for each hour in the year (leap year). Every hour has a value between 1 and 0. If the distribution file is based on actual figures, the highest value is equal to 1 meaning that the production or consumption unit will produce or consume maximum, in relation to its installed capacity, in that particular hour.

There are two main regulation strategies: technical and market-economic. The technical optimization minimizes import and export of electricity and identifies the least fuel-consuming solution. The market-economic optimization strategy identifies optimal operation based on a business economic operation from the perspective of the single market participant. For the analysis in this study, the economic optimization is applied because this is assessed to be the best representation of how production and consumptions units are operated today.

Inputs are needed for determining the electricity market price and its response to import and export of electricity. A price distribution is added to the model, which reflects the hourly electricity price. In hours where the export capacity is fully utilized the market price is set to the marginal cost of the last activated unit in the system. In hours where the import or export capacity is not fully utilized the electricity market price is adjusted according to the equation below (Lund 2014):

$$p_x = p_i + \left(\frac{p_i}{p_o}\right) * Fac_{depend} * d_{Net-Import}$$

where

$p_x = New\ market\ price\ (DKK/MWh)$,
$p_i = Input\ market\ price\ (DKK/MWh)$,
$p_o = Basic\ price\ level\ for\ price\ elasticity\ (DKK/MWh)$,
$Fac_{depend} = Price\ elasticity\ (DKK/MWh/MW)$ and
$d_{Net-Import} = Trade\ on\ the\ market\ (MW, import\ positive\ and\ export\ negative)$.

The equation calculates a new hourly market price based on an input price profile, price elasticity and hourly trade. In a situation of import, the new market price will be higher than the import price because import is calculated as a positive value. On the other hand, the new market price will be lower in case of export, which is calculated as a negative value. Fac_{depend} and p_o are user determined variables and are higher than zero to make deviations between input and new market price profile.

Based on the fuel costs, a marginal cost of producing electricity is calculated for each of the flexible units determining the threshold price for when it is profitable to operate. All flexible production and consumption units in the system are operated in relation to the market price and the marginal cost of the individual unit[2].

2.1.1 Input from the Danish Energy Association

The Danish Energy Association (DEA) has provided an profile for hourly electricity prices in 2035, which is used as input for the EnergyPLAN model. DEA applies the

[2] Flexible heat production units in the district heating grid (boilers, CHP units and heat pumps) are compared on their heat production cost to determine the least-cost solution for producing the heat demand. Power plants produce electricity whenever the electricity price is higher than the marginal operation cost

Balmorel model to calculate hourly electricity prices based on different scenarios for the development of the energy system and fuel prices. These prices are based on a scenario in which electric vehicles and heat pumps are operated inflexible. Furthermore, the input fuel prices are from DEA's basic 2014 fuel price projection including additional business economic costs such as distributions tariffs (Capion 2015). The provided price profile is in 2012 prices but these are converted to 2014 prices by the price index in the basic projection (DEA 2014C).

2.1.2 Limitations to methodology

The market optimization in EnergyPLAN determines the optimal operation in relation to the input market price profile. Even though the EnergyPLAN model adjusts the input price profile according to the formula above (section 2.1), the model is not designed to calculate spot prices.

The input price profile from DEA is calculated based on the assumption that wind turbines shut down production (curtailment) if spot prices gets below 0 DKK/MWh[2]. However, the wind distribution file is based on figures without curtailment of wind turbines, which reflects that wind power is not used for balancing of the grid. This is chosen because this study seeks to analyze the potential for using hydrogen refueling stations for balancing the grid, which is assumed to be preferred compared to shutting down wind turbines. In this context, it may give a mismatch between hourly production and electricity price.

It is not possible to include more than one electricity market to the model. Therefore, there is not made an assessment of future balancing prices in the analysis.

2.1.3 Output from the model

The model simulates the system on hourly basis and therefore it is possible to determine volume and variations of electricity production from fluctuating renewables. The model does not generate the market price profile without adding an external market price profile. Based on the operation of the system and the import and export, it is possible to extract the market electricity price from the model and determine the price variations on hourly basis.

Critical excess electricity production (CEEP) is an output figure from the EnergyPLAN model. It indicates the amount of excess electricity that is not exportable. In other words, this is the electricity left in the system after the total demand is fulfilled and the total export capacity is utilized. Such situation is critical because it would result in a black out[3]. The CEEP is calculated for each hour of the year. On the other hand, an import problem can occur in a situation in which the electricity consumption cannot be covered by domestic production plus imported electricity. This is unlikely to happen since the system is designed to maintain security of supply. For the purpose of this

[3] This is unlikely to happen because new wind turbines are able to shut off their production. All wind turbines in 2035 and 2050 will be able to shut off if necessary.

analysis, the CEEP and import problems is assessed to reflect the critical need for balancing energy in the future energy system[4].

2.2 H2INVEST model for hydrogen refueling station simulation

The technical and economic assessment of the HRS balancing services in chapter 4 and 5 is based on the H2INVEST tool. This modelling framework has been developed by the consulting company Ludwig-Bölkow-Systemtechnik (LBST) in order to analyze the build of the HRS infrastructure from the technical and economic perspective. The model has been applied successfully in a number of projects for industry, politics and other interested stakeholders. In the context of this study three interrelated sub-models are utilized: (1) hourly electrolysis simulation sub-model[5], (2) HRS demand side sub-model and (3) HRS supply side sub-model[6].

2.2.1 Hourly electrolysis simulation sub-model

The mathematical problem of the hourly electrolysis simulation is defined as deterministic linear programming (LP) problem with the following objective function:

$$\max \mathrm{NPV} = \frac{(1+r)^T - 1}{r(1+r)^T} * \left[\left(\sum_{h \in H} TR_h - TVC_h\right) - TFC\right] - TI + \frac{1}{(1+r)^T} * TRV$$

where

- NPV is net present value of the HRS with onsite electrolysis and storage device,
- TR are total revenues in each hour *h* of a prototypical year,
- TVC are total variable costs (such as electricity costs) in each hour *h*,
- TFC are total fixed costs,
- TI are total investment outlays for each system component at the beginning of the planning horizon and
- TRV is the total residual value of each system component according to the remaining life time.

In this context the NPV of the facility takes into account initial investments at the beginning of a detailed planning horizon including *T* years, discounted residual value of all facility components based on the interest rate *r* (calculated as the remaining book value of each components after *T* years) as well as annual cash flows multiplied by an annuity factor to express the time value of money within the detailed planning horizon. The annual cash flow includes hourly revenues (e.g. from the supply of balancing services to the market) and variable costs (e.g. electricity costs at spot or balancing market) in each hour as well as fixed costs of a prototypical year.

[4] Critical balancing problem does most likely not reflect the actual need for balancing. Today Energinet.dk activates regulating power as preventive mean to secure the balance.
[5] Interested readers are reffered to (Bünger et al. 2015) and (PlanDelyKaD 2015) for a detailed model description.
[6] The HRS demand and supply side model has been recently applied within the HyTEC project (see HyTEC 2015 for more details).

The simultaneous decision variables are investment decisions in all components of the facility as well as production decisions such as purchase of electricity on the spot market or balancing market, sales of hydrogen to the mobility sector and supply of the balancing services to the power market. The technical constraints are represented by the capacity constraint of the facility (based on the initial capacity and additional investments), the minimum and maximum demand for hydrogen as a fuel and balancing services and storage constraints (i.e. the level of hydrogen in the storage must be always higher than a predefined minimum threshold and lower than its capacity).

In all scenarios of the subsequent analysis the demand in the mobility sector must be satisfied in each hour (i.e. minimal and maximal demand are equal and predefined). The same is true for the adequate balancing services within the technical assessment where the economic parameters are less important. For the economic assessment this constraint is relaxed in order to analyze the impact of different balancing prices on the optimal level of balancing services provided to the market by the HRS.

2.2.2 HRS demand and supply side sub-models

The HRS demand and supply sub-models are closely interrelated to each other. The demand side sub-model estimates the spatial distribution of the hydrogen demand and HRS locations based on the vehicle density in selected regions. In order to achieve this a predefined number of HRS is distributed among the square-shaped regions by minimizing the weighted average driving distance of all vehicles. Additional refueling stations are also located along major roads between large urban areas.

The sizing of refueling stations is then based on the actual hydrogen demand within a given radius. The results of the demand side sub-model are directly used for the supply side modelling. The major objective of this sub-model is to minimize the costs of hydrogen supply to all HRS based on a given set of production and delivery technologies. The mathematical problem is formulated as a mixed integer linear program assuming that hydrogen production, demand and hydrogen flows between different nodes (defined as refueling station or production site or delivery transshipment point) balance out each other in each node.

In general following assumptions are made for the analysis in the sub-models within this study:

- Hourly operation strategy (i.e. no minute wise time resolution)
- Copper plate assumption, i.e. all refueling stations represent one central H_2 generation and storage system
- Investment and production decisions are made simultaneously based on one prototypical year (i.e. for prototypical 8,760 hours)
- Perfect foresight of the hourly prices and profiles for the entire prototypical year
- No capacity payments (i.e. all regulating services are fully called by grid operator)

3. Danish power market projections for 2035 and 2050

The purpose of this chapter is to develop scenarios for the future energy system for 20135 and 2050 and analyze how an increased share of renewable electricity influences the need for balancing the electricity grid. Furthermore, the purpose is to develop scenarios for electricity prices and price variations. The output from this analyses is used as input for the analyses made in chapter 4 and 5. The scenarios reflect potential shares of renewable electricity that meets the political goals for renewable electricity in the given years. Therefore, the analysis will take its point of departure in specific scenarios developed by the Danish Energy Agency (DEA 2014B).

3.1 Scenarios for the Danish energy system

In 2014, the Danish Energy Agency published a report,"Energiscenarier frem mod 2020, 2035 og 2050", which describes four scenarios for the development of the energy system towards 2050. The scenarios are called: "Wind", "Biomass", "Bio+" and "Hydrogen". In the "Wind" and "Hydrogen" scenarios, the energy systems are highly electrified[7] and the energy demand is primarily supplied by wind power, while the other two scenarios are combustion based and primarily supplied by biomass.

The analyses conducted in this study will take its point of departure in the Wind scenario from the Danish Energy Agency's report. The reason for choosing the wind scenario as the reference scenario is based on the anticipation that Energinet.dk suggests the wind scenario as the preferable development path. Energinet.dk uses the wind scenario as base case in their analyses behind the report "Energikoncept 2030" published in April 2015. The purpose of that report is to point out possible cost-effective development paths for the energy system until 2035 and 2050 (Energinet.dk 2015B). One of the reasons that Energinet.dk chooses the wind scenario is because the biomass consumption is limited to be equal to the domestic biomass resource. The wind scenario is therefore assessed to have the highest security of supply on the fuel side.

Detailed figures from 2035 and 2050 are presented in the report. Representations of the systems are made by using production and consumption capacities and expected annual production/consumption figures from the wind scenario as inputs for the EnergyPLAN model. The input figures are presented in the following sections.

The analyses of the 2035 and 2050 wind scenarios are used as reference scenarios, which are compared to an alternative 2035 and 2050 scenario, respectively. The only difference between the reference and alternative scenarios is the transport sector. In the alternative scenarios FCEV's are included in the transport sector based on the assumptions described in chapter 4.

[7] In the mobility sector electric vehicles and electrolyzer producing hydrogen for biofuels are implemented. Heat pumps are implemented in the heat sector.

3.2 General model assumptions

All input data are based on the report from DEA. Due to differences between the two models additional assumption (e.g. for specific efficiencies) are needed to align the two model approaches. All assumptions for the purpose of this analysis are mentioned in the following. In the EnergyPLAN model the central combined and heat power (CHP) plants are capable of operating in condense mode. Therefore, it is assumed that the central CHP plants can operate full electrical capacity without producing heat.

As mentioned in chapter 2, distribution files are used to distribute consumption or production figures on hourly basis. The wind, solar and electricity demand distribution files are provided by DEA. The profiles are actual production and consumption figures from the same analysis as the input electricity price profile, to maintain the relationship between productions and price figures. DK1 (West Denmark) production and consumption figures are used as input for the EnergyPLAN model.

DEA assumes 4,000 MW capacity on interconnectors to Norway and Sweden and additional 2,000 MW to Germany. Therefore, a total of 6,000 MW import/export capacity is assumed as input for the EnergyPLAN model.

3.3 Fuel costs in 2035 and 2050

For the calculation of the hourly electricity prices, DEA has used the basic fuel price projection, made by the Danish Energy Agency. To keep prices consistent, the input fuel prices for the EnergyPLAN model are also from Danish Energy Agency's basic projection and not from their scenario report[8].

Table 1 illustrates the fuel costs used as input for the EnergyPLAN model. The fuel costs reflect the cost at the plant. In the Danish Energy Agency's basic price projection, fuel costs are forecasted until 2035. The same prices are assumed to apply for both 2035 and 2050. The same input electricity price profile is also used for the 2050 scenarios. All costs are in 2014 prices.

Fuel	Plant and production units	Fuel costs in 2035 (DKK/GJ)	Fuel costs in 2050 (DKK/GJ)
Natural gas	Distributed CHP	78.3	-
Waste	Incineration	-20	-20
Straw	Central CHP and boilers, distributed boilers	47.9	47.9
Wood chips	Central CHP	56.0	56.0
Wood pellets	Central CHP	78.9	78.9
SNG	Distributed CHP	152.0	154.0

Table 1: Fuel cost in 2014 prices from Danish Energy Agency's report

[8] The fuel cost projection in the two reports are not completely the same. It is likely due to the reports are made at different times.

The central CHP units are assumed to use both straw, wood chips and wood pellets and therefore an average price of the three biomass products is used as input cost for the central CHP plants. Boilers in the distributed district heating grid does only use straw as fuel. In 2050, natural gas is phased out at decentralized CHP plants, which will operate on synthetic natural gas (SNG). SNG is upgraded biogas. Furthermore, all central CHP plants are shut down in 2050. There is no price projection of SNG in the basic price projection and therefore, is the price of SNG assumed to be the same as in the scenario report.

Upgraded biogas with a direct injection into the natural gas grid is traded on the same conditions as natural gas. In 2035, approximately 45% of the gas consumption consists of SNG while the remaining 55% is natural gas. For the purpose of the analysis, it is assumed that grid gas is taxed. In 2015, the tax on natural gas for CHP units is 69.68 DKK/GJ (SKAT 2015) and the tax in 2035 is assumed to remain unchanged. In 2050, the gas consumption consists entirely of SNG produced from biogas and therefore it is assumed that no tax is paid for the consumption of grid gas in 2050.

Energy taxes and operation and maintenance (O&M) costs are based on figures from the Danish District Heating Association or the Technology data catalogue (DEA 2015). Table 2 illustrates the O&M costs.

Unit	O&M cost
CHP unit	67.5 DKK/MWh_{el}
Boiler	5 DKK/MWh_{Th}
HP	20 DKK/MWh_{el}
Gas turbine	7 DKK/MWh_{el}

Table 2: O&M costs on different units.

Finally, a CO_2 quota price is added to the model. In 2035, the CO_2 quota price is 314 DKK/ton, which is based on DEA's projection of fuel prices (DEA 2014C).

3.4 Reference scenario in 2035

The energy system in 2035 is to a large extent based on wind power production. To integrate the high production from wind power, the transport and heat sectors are highly electrified. An extensive domestic production of biofuels is expected, which also integrates the transport sector with the district heating- and electricity sectors.

3.4.1 Installed production and consumption capacities and annual energy production figures in 2035

The total installed wind turbine capacity is 8,500 MW. DEA calculates with 3,076 and 4,116 annual full load hours for onshore and offshore wind power, respectively. This results in an annual production of 10.77 TWh/a for onshore and 20.71 TWh/a offshore wind power. Future wind power turbines will have more full load hours, which means that the same production from wind power can be achieved by less installed capacity. The production from PV is estimated to be at 1.39 TWh/a. Otherwise, electricity is produced from CHP plants while gas turbines are installed as backup capacity.

The hourly production from the fluctuating renewables are determined by the distribution files as described in chapter 2 whereas the flexible capacity is operated in relation the market price as described in chapter 2.

The district heating system is divided in a central and a distributed district heating system. In the reference scenario, only the three newest of the existing central power plants remain in 2035 and all of them are converted from coal fired to biomass fired. Besides heat production from the central power plants, heat is produced from waste incineration, distributed CHP plants, heat pumps, geothermal heat, solar thermal plants, industrial waste heat and biomass boilers. Waste incineration plants only produce heat in the central district heating areas. The distributed CHP plants are fueled by gas from the gas grid. A thermal storage capacity of 40 GWh is assumed for both central and distributed district heating areas.

The waste input is 11.11 TWh/a and the efficiency is assumed to be 71% heat and 24% electricity at the waste incineration plants. The incineration plants operate base load supplying a flat curve of heat, for district heating, and electricity to the grid. The same applies for the industrial waste heat. The annual heat production from the solar collectors is distributed on the same distribution file as used for the PV installations.

In the transport sector there is 1034 MW electrolyzer capacity installed producing hydrogen used for synthetic fuel production via hydrogenation. There are no fuel cell vehicles nor any other direct use of hydrogen. The waste heat from the production of biofuels and SNG, via biogas hydrogenation, is used for district heating.

In the gas sector, approximately 45% of all gas consumption comes from SNG. The SNG is produced from biogas via conventional purification technologies or hydrogenation. 306 MW electrolyzer capacity is installed, which produces the hydrogen for biogas hydrogenation resulting in a production of 4.5 TWh SNG. The efficiency of electrolysis is 58%. The conventional SNG production amounts to 4.6 TWh.

Table 3 illustrates the inputs for the EnergyPLAN model in terms of production and consumption capacities or annual productions for the different units. Geothermal heat is not included in the analysis.

Sector	Technology	Installed capacity	Annual Production	Characteristics
Power	Onshore wind power	3,500 MW_e	10.77 TWh	Annual FLH 3076
	Off-shore wind power	5,000 MW_e	20.71 TWh	Annual FLH 4116
	Solar power	1,000 MW_e	0.85 TWh	Annual FLH 849
	Gas turbines	900 MW_e		Assumption: η_e = 55.0 %
	Small-scale CHP	1,026 MW_e		Assumption: η_e = 48.5 %
	Large-scale CHP	1,421 MW_e		Assumption: η_e = 50.0 %
	Industry CHP		0.67 TWh	Base load supply
	Waste incineration plants		2.67 TWh	Waste input: 11.11 TWh/a, assumption: η_e = 24%
District Heating – central	Solar DH		0.28 TWh	
	HPs	83 MW_e		COP = 3
	Large-scale CHP	1,269 MJ/s		Assumption: η_t = 44.7%
	Boilers	2,300 MJ/s		Assumption: η_t = 100 %
	Waste incineration plants		7.61 TWh	Waste input: 11.11 TWh/a, assumption: η_t = 71.0 %
			0.89 TWh	
	Waste heat industry		1.04 TWh	Base load supply
	Waste heat biofuel plants			226 MW heat, 4976 FLH, base load supply
District Heating – distributed	Solar DH		0.69 TWh	
	HPs	133 MW_e		COP = 3
	Small-scale CHP	900 MJ/s		Assumption: η_t = 42.6 %
	Boilers	2,300 MJ/s		Assumption: η_t = 100 %
	Waste heat industry		0.42 TWh	Base load supply
	Waste heat biogas hydrogenation		0.35 TWh	Base load supply
Transport	Hydrogen plant	1,034 MW_e		
	Synthetic fuel production		4.39 TWh	Biokerosene and biodiesel
Gas	Biogas production		7.50 TWh	
	Hydrogen plant	306 MW_e		Hydrogen, effiency 60% (assumption)
	SNG – conventional		4.60 TWh	
	SNG – hydrogenation		4.50 TWh	
Storage	Hydrogen storage			
	Synthetic fuel storage			
	Heat storage – central	40 GWh		Assumption
	Heat storage – distributed	40 GWh		Assumption

Table 3: Inputs for the EnergyPLAN model in 2035 in terms of installed production and consumption capacity or annual production figures.

3.4.2 Annual energy consumption in 2035

The specific energy demand is either calculated from capacity and full load hours or estimated based on figures illustrating fuel consumption in the individual energy sectors in DEA's report.

The classic electricity consumption is calculated based on the capacity and annual full load hours. DEA write in the report that the capacity of the classic electricity consumption is 5,217 MW and the annual full load hours corresponds to more than 5,000 hours.

The annual full load hours is assumed to be 5,100 resulting in an annual electricity consumption of 26.61 TWh in 2035.

The input for the individual heat pumps are given to the model as an annual heat demand and a coefficient of performance (COP) factor. The COP is calculated from the electrical capacity and heat output. DEA distinguish between air and ground source heat pump that has a COP of 4 and 4.5, respectively. The annual heat demand is calculated based on installed capacity and annual full load hours. The two types of heat pumps is modelled as a total heat demand with an average COP factor of 4.25. It results in an electricity demand of 3.32 TWh. The electricity consumption for electric vehicles is estimated to be 4.17 TWh.

The total heat demand for district heating is 30.56 TWh/a divided in 12.22 TWh/a and 18.33 TWh/a for distributed and central district heating area, respectively. The specific energy demands used as input for the EnergyPLAN model are illustrated in table 4.

Sector	Category	Demand	Characteristics
Electricity	Electricity – Classic*	26.61 TWh	5217 MW, annual FLH 5100
	Electricity – Individual HP	3.32 TWh	COP = 4.25 (average air and ground source HPs)
	Electricity – Vehicles**	3.47 TWh	
	Electricity – Biogas production	0.11 TWh	12 MW, 8760 FLH
	Electricity – SNG production (conventional)	0.21 TWh	24 MW, 8760 FLH
		4.96 TWh	
	Electricity – H_2 production for biofuel hydrogenation	0.37 TWh	
		0.14 TWh	42 MW, 8760 FLH
	Electricity – HP in industry		
	Electricity – Electric boilers in industry		
Heat	Heat demand for DH – Central	18.33 TWh	
	Heat demand for DH – Distributed	12.22 TWh	
	Heat demand for individual dwellings	21.78 TWh	
Fuel	Transport demand – Electricity	3.47 TWh	
	Transport demand – Grid gas	2.22 TWh	
	Transport demand – Hydrogen for biofuel production	2.88 TWh	600 MW hydrogen, FLH 4794
		11.11 TWh	
	Industry – Grid gas	3.96 TWh	
	Industry – Biomass	7.77 TWh	
	Individual – Biomass		

Table 4: Specific energy demands included in the EnergyPLAN Model. *Classic electricity demand includes all electricity demand besides "new" electricity demand such as electric vehicles, HPs, electric boilers etc. **Includes vehicles, vans, MCs, busses and trains.

In DEA's scenario the 1,034 MW electrolyzer capacity is modelled as interruptible consumption. In the EnergyPLAN model the electrolyser capacity is modelled as flexible within one day meaning that the demand is freely distributed within a 24 hour period according to the electricity balance i.e. in hours with high electricity production and during night time. The annual electricity demand of 4.96 TWh is equal to a demand of 13.58 GWh/day that corresponds to approximately 13.13 full load hours with the installed electric capacity.

Electricity for electric boilers in industry is modelled as flexible within one week. The consumption is freely distributed over a period of 168 hours (one week) according to electricity balance. The electric boilers are assumed to have a high level of flexibility because they have few full load hours FLH in Danish Energy Agency's scenario.

Electricity for SNG production and heat pumps in industry are assumed to operate base load. The purification plants (conventional SNG production) and the heat pumps in industry are operating base load in the Danish Energy Agency's scenario.

In the model, the hourly electricity demand for transportation is assumed to be equally distributed from 08:00 PM to 07:00 AM to reflect that recharging of batteries occurs when people are off from work.

3.5 Alternative scenario in 2035

There is no FCEV included in the transport sector in the 2035 wind scenario made by DEA. However, in the 2035 alternative scenario it is assumed that the car fleet are different compared to the wind scenario. Besides the transport sector, the energy systems in the two scenarios are identical.

The distribution of vehicles is based on a scenario from the HyTEC project.[9] In 2035, it is assumed that the total car fleet for personal transportation is divided on 32% FCEVs, 44% battery/hybrid cars and 23% diesel/gasoline cars. In 2050 50% of the total car fleet is expected to be FCEVs

Table 5 illustrates the electricity consumption for personal transportation in the FCEV 2035 wind scenario.

Car type	Electricity demand (TWh/a)
FCEV	5.80
Battery	1.26
Hybrid	0.32
MCs, vans, busses, trucks and trains	1.33
Total	**8.71**

Table 5: Electricity demand for personal transportation in the 2035 alternative scenario.

In the 2035 reference scenario, the electricity demand in the transport sector is 3.47 TWh/a of which 1.33 TWh/a is estimated to be consumed by motor cycles (MCs), vans, busses, trucks and trains. This demand is added to the FCEV 2035 wind scenario.

[9] HyTEC (Hydrogen Transport for European Cities) is a project on introducing hydrogen technologies as a solution for low carbon transport for cities taking place from September 2011 to December 2014. It was co-funded by the European Union and was carried out by 15 partners from five Member States from the private and public sectors. The major aims of the project were (1) creating two new European hydrogen vehicle deployment centers in cities with a need for low emission urban transport solutions, (2) securing strategic and political buy-in from political and industrial stakeholders and (3) providing a template for similar projects in the UK, Scandinavia and more widely across Europe using lessons learnt from the project (HyTEC 2015).

Therefore, the total electricity demand for battery/hybrid vehicles are 2.91 TWh/a and 5.80 TWh/a for FCEVs resulting in a total consumption of 8.71 TWh/a.

This is a significant increase of the electricity consumption compared to the original 2035 wind scenario. However, it is also a more ambitious scenario in relation to phase out of petrol and diesel cars. In the original 2035 wind scenario, the transport sector is described as 25% of the way towards 100% renewable transport sector. Another reason for the higher electricity consumption is due to the infrastructure efficiency. In the HyTEC scenario, it is assumed that the hydrogen infrastructure has an efficiency of 64% while the efficiency of the battery infrastructure is 97%. The lower efficiency related to produce and fuel hydrogen contributes to the higher electricity consumption in the transport sector. However the faster fueling time and longer range achieved with FCEVs, compared to BEVs may be required for electric propulsion to emerge to the medium to larger passenger vehicle segments and thus achieving a larger share of fossil independence the transport sector.

The electricity demand for battery and hybrid cars are distributed as in the 2035 reference scenario. For the sake of simplicity, the production of hydrogen is assumed to be base load production meaning that the electricity consumption is equally distributed in every hour of the year.

3.6 Energy system outputs for 2035 scenarios

The figures as described above are used as input for the EnergyPLAN model. The only difference between the two 2035 scenarios is the electricity consumption in the transport sector, which is higher in the alternative scenario.

3.6.1 Total electricity production and consumption

Figure 3 and figure 4 illustrates the total electricity production and the total electricity consumption in the 2035 reference scenario and the 2035 alternative scenario, respectively.

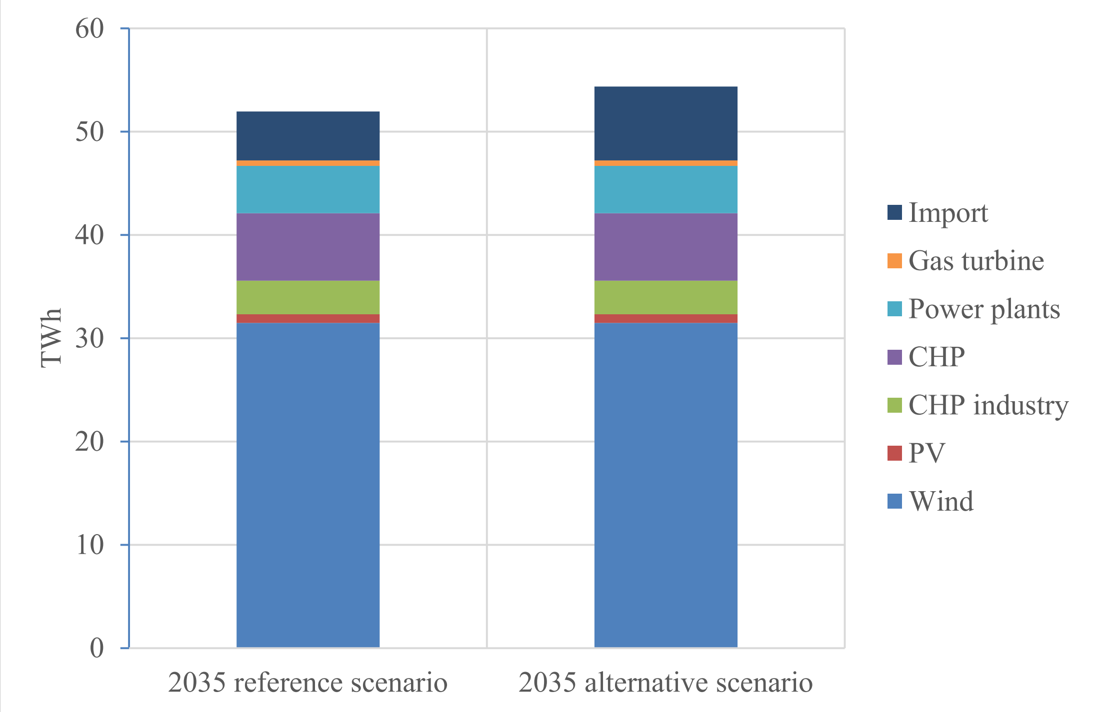


Figure 3: Total electricity production in 2035 by individual production units including import.

In both scenarios, more than half of the production is produced by wind power. In the FCEV scenario, more power is imported compared to the wind scenario. It indicates that it is cheaper to import the extra needed capacity compared to produce it domestically.

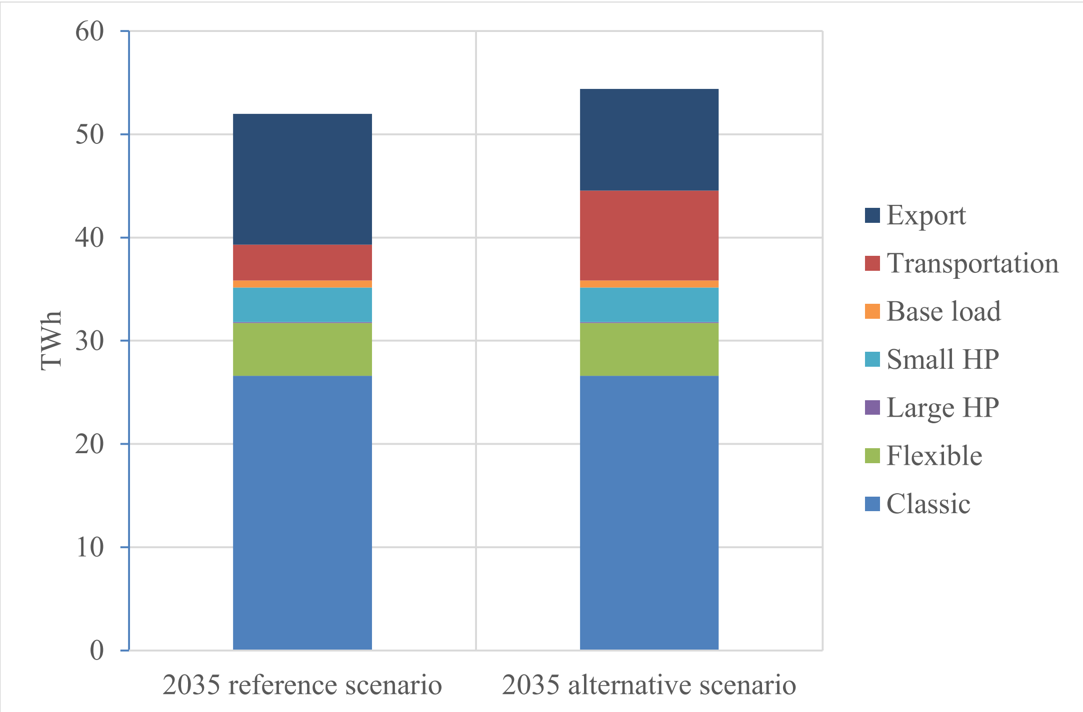


Figure 4: Total electricity consumption by individual consumption units including export. Flexible electricity demand includes H_2 production (electrolysis) for hydrogenation and electric boilers in industry. Base load consumption includes electricity consumption for biogas production, SNG production (conventional) and HPs in industry.

On the consumption side, the total electricity demand is increased in the alternative scenario compared to the wind scenario due to an increased electricity demand in the transport sector. The export of electricity is reduced because more power is consumed domestically. Therefore, the total consumption is higher in the FCEV scenario.

3.6.2 Renewable energy volume and variations

The output from the model is a hourly power output from RE in MW, which is equal to the hourly production in MWh. In this analysis, renewable energy is based on fluctuating sources i.e. wind and solar. The electricity is generated from wind power (onshore and offshore) and PV installations.

In both scenarios, the installed capacity and distribution files for wind and photovoltaic (PV) are identical. EnergyPLAN is a deterministic model meaning that the same outputs are generated from the same inputs. Since RE capacities and distribution files are the same, production and fluctuations are identical in both scenarios.

Figure 5 illustrates the hourly PV and the total RE power output in both scenarios. The total installed RE capacity is 9,500 MW.

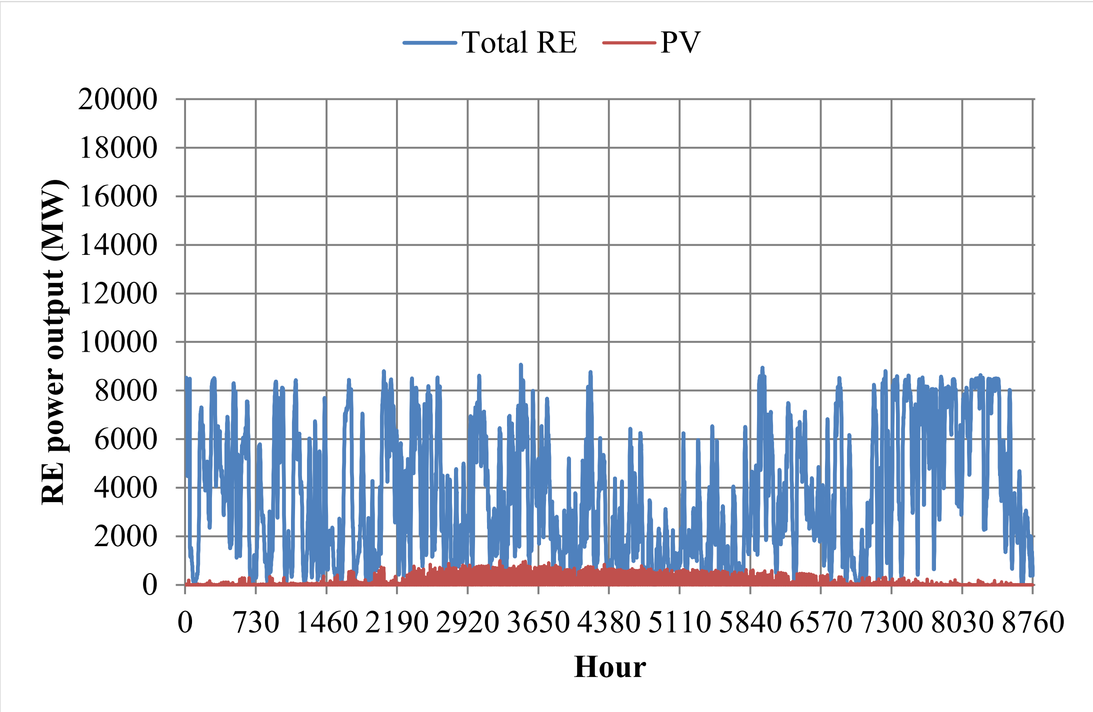


Figure 5: Hourly fluctuations of PV and total renewably energy production in 2035.

An average month has 730 hours, which in the figure is used to indicate each month in the year. As seen in the figure the production from RE varies significantly. The PV installations obviously produce most electricity during the summer months, while the production from wind power are more equally distributed over the year. In July and August the production from wind power seems to be lower than in the rest of the year. The maximum hourly power output from RE plants occurs in May with 9,077 MW. In

17 hours of the year the electricity production from RE is 0 MWh. It indicates significant hourly variations during the year.

3.6.3 Electricity market prices in 2035 scenarios

Estimation of electricity market spot prices is always related to great uncertainty. The estimation of the market prices in 2035 is based on a price profile from the Danish Energy Association, which is described in chapter 2. EnergyPLAN adjusts the input price profile in relation to import and export of electricity (see chapter 2).

Figure 6 illustrates the hourly electricity market prices output from the EnergyPLAN model sorted from maximum to minimum. The 2035 market price estimations are compared to the actual 2014 DK1 spot prices (prices from Energinet.dk).

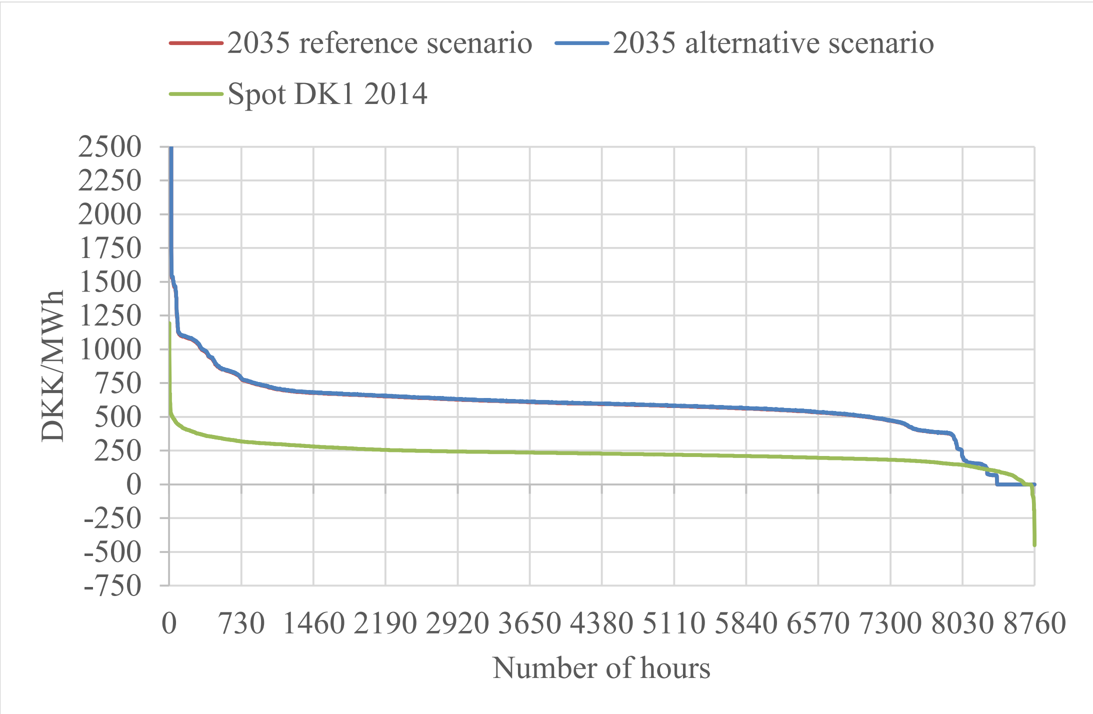


Figure 6: Hourly spot prices from the 2035 scenarios and actual 2014 DK1 spot prices sorted from maximum to minimum.

It is clear that the electricity price in 2035 is expected to be higher than today. For most hours, the price is between 500-750 DKK/MWh in the two 2035 scenarios but also higher prices occur. The market price reaches the maximum price of 22,350 DKK/MWh (3,000 €/MWh) in 6 hours and 13 hours for the wind scenario and the FCEV wind scenario, respectively. In 2014, there were no incidents where the price reached the maximum price in the market. A price of 0 DKK/MWh occurs for approximately 380 hours in the two 2035 scenarios, which indicates significant price variations on hourly basis. The figure indicates larger price variations in the future compared to today.

Table 6 shows statistical figures calculated from the three price profiles.

	2035 reference scenario (DKK/MWh)	2035 alternative scenario (DKK/MWh)	2014 DK1 spot (DKK/MWh)
Minimum	0	0	-450
Maximum	22,350	22,350	1,193
Average	623	627	229
Standard deviation	1,040	1,044	76

Table 6: Statistical price figures from the two 2035 scenarios and actual 2014 DK1 prices.

It has to be mentioned that the average spot price in 2014 was the lowest in a period of 5 years (2010-2014). The average price for that period is 310 DKK/MWh including both DK1 and DK2. The higher standard deviation indicates significantly higher variations in 2035 compared to today. The prices in the two 2035 scenarios deviate slightly due to the higher electricity consumption in the 2035 alternative scenario.

3.6.4 Balancing needs in 2035 scenarios

In the analysis there is 6,000 MW import/export capacity to neighboring countries. As described in chapter 2, the CEEP is an indication of a critical balancing problem in the energy system. Theoretically, an import problem could also occur if the domestic production capacity and the import capacity is too low to supply the demand for electricity. This is not expected as the system is designed to maintain security of supply in the electricity sector.

Table 7 illustrates import and export figures from the 2035 reference scenario and Table 8 illustrates the same figures for the 2035 alternative scenario.

	Import	Export	CEEP
Total (annual)	4.75 TWh	12.67 TWh	0 TWh
Minimum (hourly)	0 MW	0 MW	0 MW
Maximum (hourly)	3,670 MW	5,994 MW	0 MW
Average	541 MW	1,443 MW	0 MW

Table 7: Import and export figures from 2035 reference scenario.

As it can be seen in the table the hourly maximum import is 3,670 MW and the hourly maximum export is 5,994 MW, which is close to the maximum export capacity. However, no import problems nor CEEP occurs in the system. The total export is significant higher than the import.

	Import	Export	CEEP
Total (annual)	7.33 TWh	9.69 TWh	0 TWh
Minimum (hourly)	0 MW	0 MW	0 MW
Maximum (hourly)	4,201 MW	5,256 MW	0 MW
Average	834 MW	1,103 MW	0 MW

Table 8: Import and export figures from 2035 alternative scenario.

In the alternative scenario, the total import has increased and the total export has decreased compared to the 2035 reference scenario. This reduction can be expected since the total electricity consumption is increased. The maximum hourly export has decreased by approximately 750 MW, which is positive since the maximum hourly export capacity was close to the limit of 6,000 MW. However, it can be concluded that there is no balancing problems in both of the two 2035 scenarios.

3.7 Reference scenario in 2050

The energy system is highly electrified and wind power produce the majority of the electricity. The consumption of biomass is limited to 250 PJ, which corresponds to the Danish potential for biomass production.

3.7.1 Installed production and consumption capacities and annual energy production figures in 2050

In 2050, the installed wind capacity is 17.5 GW distributed on 3,500 MW onshore and 14,000 MW offshore wind power. All central power plants are closed down and the installed electrical capacity at the distributed CHP plants is reduced compared to 2035. On the other hand, the backup gas turbine capacity is increased to 4,600 MW.

In 2050, more waste heat is utilized, from the increased share of biofuel plants, in the central district heating area, which to some degree compensate the loss of the thermal capacity from the central power plants. In report from DEA it is only the thermal capacity of the waste heat that is mentioned. To calculate the annual heat production, the waste heat is assumed to have 4,433 FLH, which is equal to the full load hours on the electrolyzers that produce the hydrogen for the biofuel production. In the distributed district heating area the HP capacity is doubled compared to 2035 while the thermal capacity at the distributed CHP plants is reduced.

In the transport sector, the electrolyzer capacity for synthetic fuel production is increased significantly. The same requires the electrolyser capacity that produces hydrogen for SNG production because the entire biogas, in 2050, is upgraded via hydrogenation. Table 9 illustrates the inputs for the EnergyPLAN model in terms of production and consumption capacities or annual productions for the different units in 2050.

Sector	Technology	Installed capacity	Annual Production	Characteristics
Power	Onshore wind power	3,500 MW_e	10.77 TWh	Annual FLH 3076
	Off-shore wind power	14,000 MW_e	57.62 TWh	Annual FLH 4116
	Solar power	2,000 MW_e	1.70 TWh	Annual FLH 849
	Gas turbines	4,600 MW_e		Assumption: $\eta_e = 55.0$ %
	Small-scale CHP	684 MW_e		Assumption: $\eta_e = 48.5$ %
	Large-scale CHP	0 MW_e		Assumption: $\eta_e = 50.0$ %
	Industry CHP		2.67 TWh	Base load supply
	Waste incineration plants		2.77 TWh	Waste input: 11.54 TWh/a, assumption: $\eta_e =$ 24%
DH – central	Solar DH		0.56 TWh	
	Heat Pumps	78 MW_e		COP = 3.2
	Large-scale CHP	0 MJ/s		Assumption: $\eta_t = 44.7$%
	Boilers	2,300 MJ/s		Assumption: $\eta_t = 100$ %
	Waste incineration plants		8.19 TWh	Waste input: 11.54 TWh/a, assumption: $\eta_t =$ 71.0 %
			0.89 TWh	
	Waste heat industry		4.78 TWh	Base load supply
	Waste heat biofuel plants			902 MW heat, 4433 FLH, base load supply
DH – distributed	Solar DH		1.39 TWh	
	Heat Pumps	250 MW_e		COP = 3.2
	Small-scale CHP	600 MJ/s		Assumption: $\eta_t = 42.6$ %
	Boilers	1,800 MJ/s		Assumption: $\eta_t = 100$ %
	Waste heat industry		0.42 TWh	Base load supply
	Waste heat biogas hydrogenation		0.77 TWh	Base load supply
Transport	Hydrogen plant	4,138 MW_e		
	Synthetic fuel production		17.53 TWh	Biokerosene and biodiesel
Gas	Biogas production		11.70 TWh	
	Hydrogen plant	1,226 MW_e		Hydrogen, effiency 60% (assumption)
	SNG – conventional		0 TWh	
	SNG – hydrogenation		18 TWh	
Storage	Hydrogen storage			
	Synthetic fuel storage			
	Heat storage – central	40 GWh		Assumption
	Heat storage – distributed	40 GWh		Assumption

Table 9: Inputs for the EnergyPLAN model in 2050 in terms of installed production and consumption capacity or annual production figures.

3.7.2 Annual energy consumption in 2050

The assumptions mentioned in section 3.4.2 also apply for the system in 2050. The classic electricity consumption is slightly decreased compared to 2035 but the electricity consumption for transport sector is increased significantly for both electric vehicles and for hydrogen production.

The demand for district heating is decreased both in central and distributed areas compared to 2035. In Table 10, the specific energy demands used as input for the EnergyPLAN model are illustrated.

Sector	Category	Demand	Characteristics
Electricity	Electricity – Classic*	25.34 TWh	5217 MW, annual FLH 5100
	Electricity – Individual HP	3.83 TWh	COP = 4.25 (average air and ground source HPs)
	Electricity – Vehicles**	12.50 TWh	
	Electricity – Biogas production	0.17 TWh	19 MW, 8760 FLH
	Electricity – SNG production (conven-	0 TWh	
	tional)	18.34 TWh	Hydrogen efficiency 58%
	Electricity – H_2 production for biofuel hy-	1.46 TWh	167 MW, 8760 FLH
	drogenation	1.19 TWh	
	Electricity – HP in industry		
	Electricity – Electric boilers in industry		
Heat	Heat demand for DH – Central	15.83 TWh	
	Heat demand for DH – Distributed	10.56 TWh	
	Heat demand for individual dwellings	17.70 TWh	
Fuel	Transport demand – Electricity	12.50 TWh	
	Transport demand – Grid gas	6.94 TWh	
	Transport demand – Hydrogen for biofuel	10.63 TWh	2400 MW hydrogen,
	production	4.17 TWh	4433FLH
	Industry – Grid gas	10.11 TWh	
	Industry – Biomass	0.03 TWh	
	Individual – Biomass		

Table 10: Specific energy demands included in the EnergyPLAN Model. *Classic electricity demand includes all electricity demand besides "new" electricity demand such as electric vehicles, HPs, electric boilers etc. **Includes vehicles, vans, MCs, busses and trains.

3.8 Alternative scenario in 2050

As for the 2035 scenario, the 2050 reference scenario is also compared to an alternative scenario in which FCEVs are included in the transport sector. In the 2050 alternative scenario, it is assumed that 51% of the car fleet is FCEVs, 45% are battery/hybrid and 4% are gasoline/diesel cars. Table 11 illustrates electricity consumption in the transport sector in 2050.

Car type	Electricity demand
FCEV	10.27
Battery	1.43
Hybrid	0.36
MCs, vans, busses, trucks and trains	4.8
Total	**16.85**

Table 11: Electricity demand for personal transportation in the 2050 alternative scenario.

The total electricity demand for battery/hybrid vehicles is 6.58 TWh including MCs, vans, busses, trucks and trains. For comparison, the transport sector is 12.5 TWh in the

2050 reference scenario. The total need for electricity in the transport sector is increased in the 2050 alternative scenario. In EnergyPLAN, the electricity demand is distributed as in the 2035 alternative scenario.

3.9 Energy system outputs for 2050 scenarios

The two 2050 scenarios are calculated in the EnergyPLAN model based on the figures in the Tables 9-11.

3.9.1 Total electricity production and consumption

Figure 7 and Figure 8 illustrates the total electricity production and total electricity consumption in the wind scenario and the FCEV wind scenario, respectively.

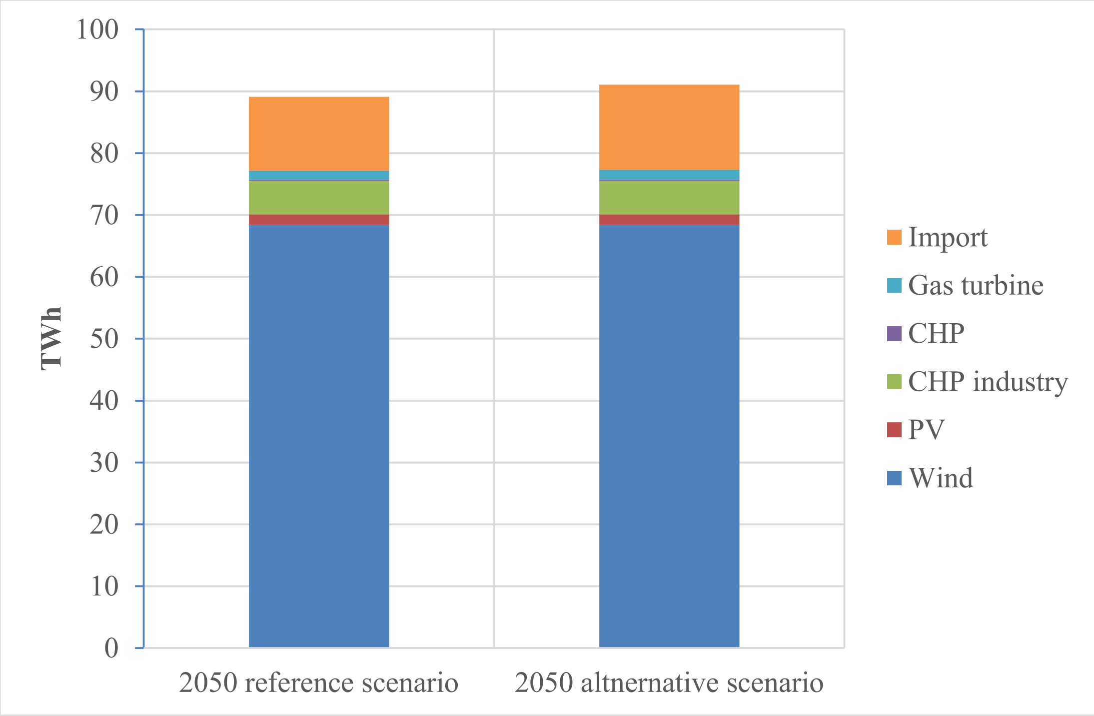


Figure 7: Total electricity production by individual production units including imported electricity in the two 2050 scenarios.

In both scenarios, the wind power produces the majority of electricity. The gas turbines are activated slightly more often in the alternative scenario. The import is higher in the alternative scenario compared the reference scenario due to higher electricity consumption in the transport sector.

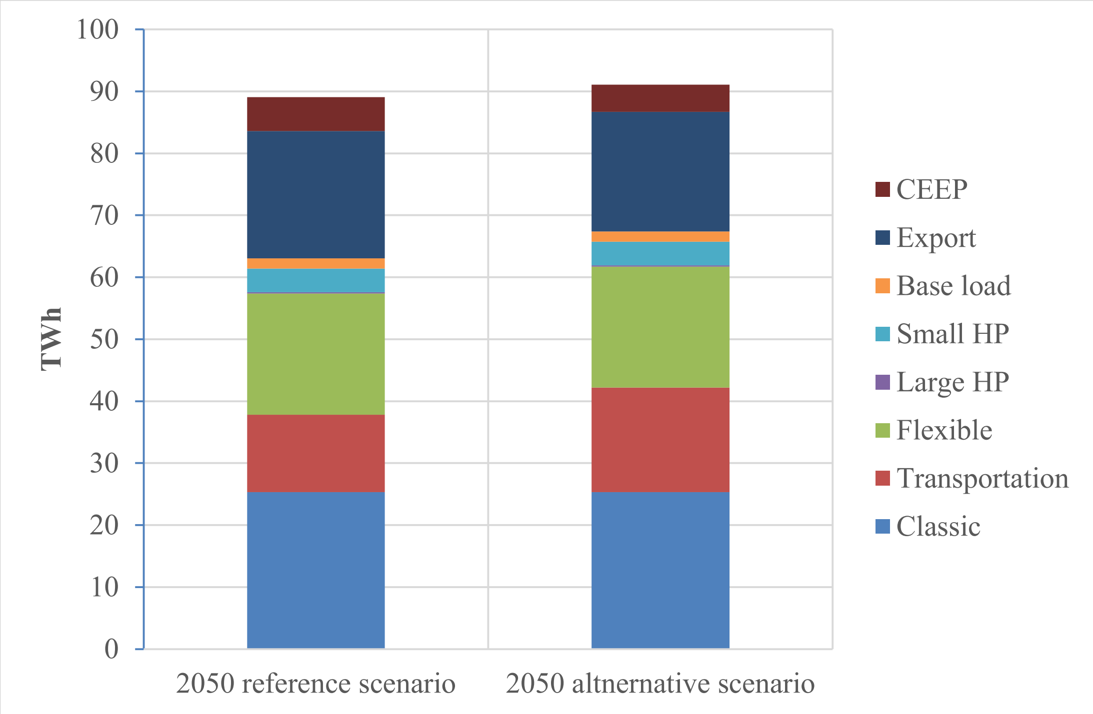


Figure 8: Total electricity consumption by individual consumption units including export in the two 2050 scenarios. Flexible electricity demand includes H_2 production (electrolysis) for hydrogenation and electric boilers in industry. Base load consumption includes electricity consumption for biogas production, SNG production (conventional) and HPs in industry.

On the consumption side, the increased consumption in the transportation sector reduces the export and CEEP. This is elaborated in section 3.9.4.

3.9.2 Renewable energy volumes and variations

The distributions for wind and solar are the same as in the 2035 scenarios but the installed capacity are obviously higher (19,500 MW). Figure 9 illustrates hourly production capacities for renewable energy.

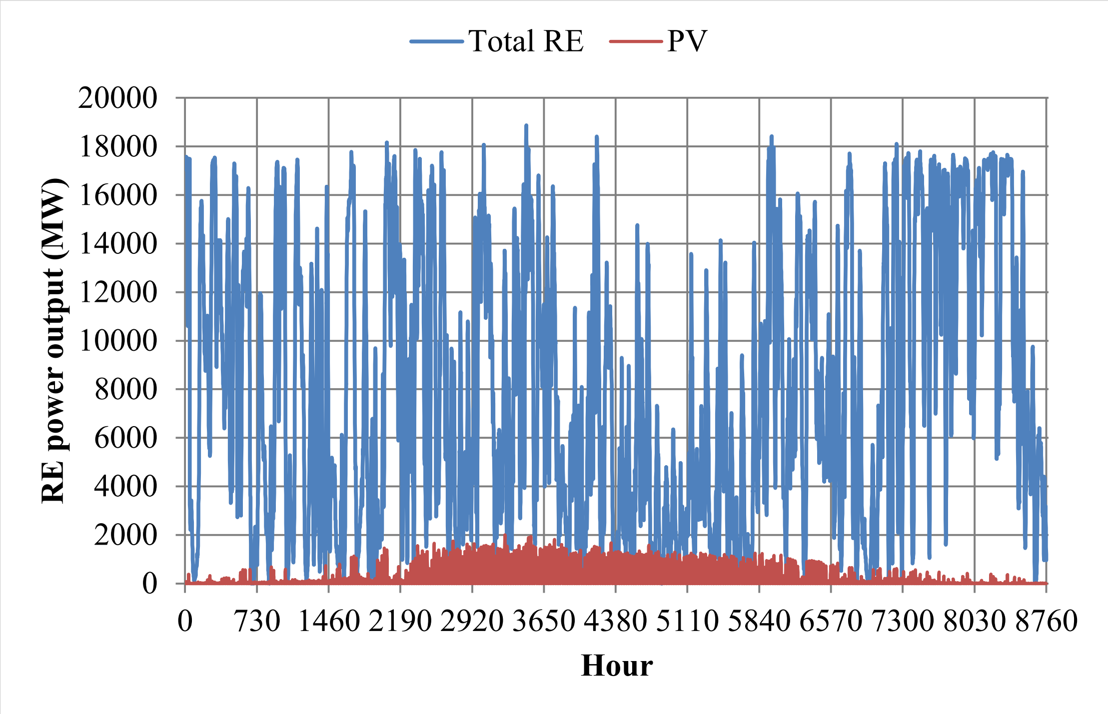


Figure 9: Hourly fluctuations of PV and total renewably energy production in 2050.

The production patterns are equal to the 2035 scenarios. However, the maximum peak is 18,875 MW and the minimum power capacity is 0 MW, which results in significant annual variations in 2050.

3.9.3 Electricity market prices in 2050

The Danish Energy Association does only estimate prices until 2035 and therefore, the same electricity price profile is applied as input for the 2050 scenarios as well. However, the output prices will be different because of the different energy system.

Currently, the price generation at the spot market is based on a marginal cost system. In a future energy system, the majority of the electricity production will come from renewable energy sources that have low marginal costs. This will result in many hours with very low electricity prices if the bidding strategy or the market system is not changed. Figure 10 illustrates the sorted market price from the 2050 scenarios.

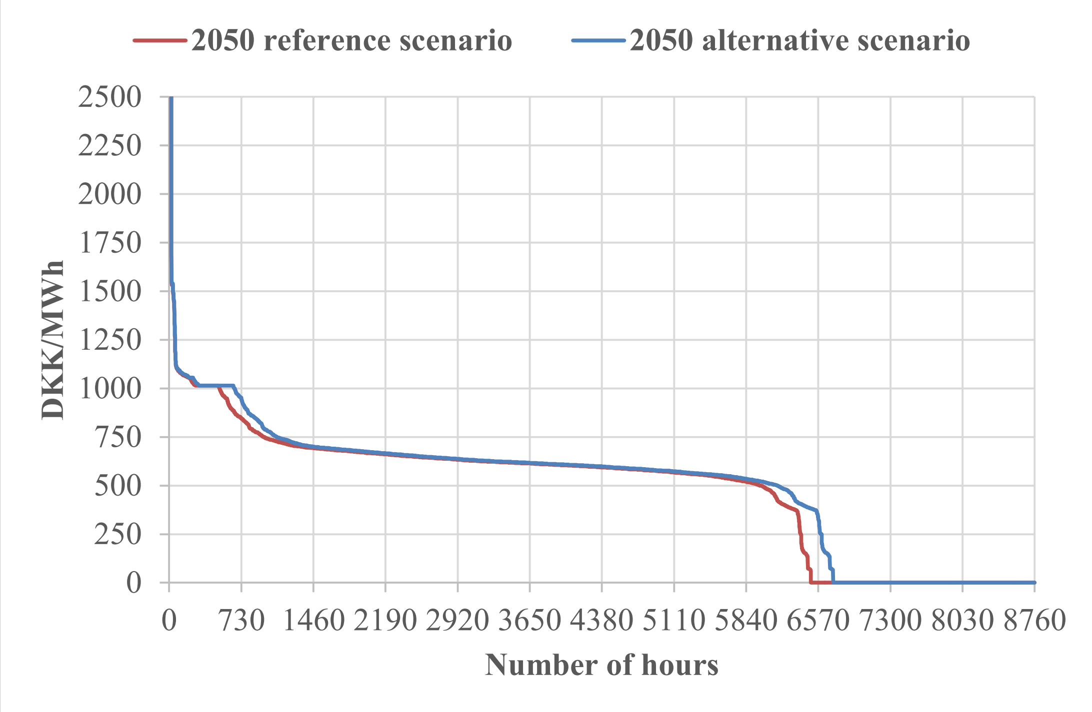


Figure 10: Hourly spot prices from the 2050 scenarios sorted from maximum to minimum.

In both scenarios, there are few hours with extremely high prices, which also was the case for the 2035 scenarios. However, it is worth to notice that there are more than 2,000 hours with a price of 0 DKK/MWh, which is caused by the large electricity production from especially wind power plants and the limited amount of export capacity on the grid connections.

In the 2050 alternative scenario, there are fewer hours with a price of 0 DKK/MWh than in the 2050 reference scenario. The higher electricity consumption from H_2 production increases the electricity price in some hours. Table 12 illustrates statistical figures from the two 2050 scenarios.

	2050 reference scenario (DKK/MWh)	2050 alternative scenario (DKK/MWh)
Minimum	0	0
Maximum	22,350	22,350
Average	530	550
Standard deviation	1,060	1,063

Table 12: Statistical price figures from the two 2050 scenarios.

The average price is significant lower in the 2050 scenarios compared to the 2035 scenarios, which is explained by the higher production from renewable energy.

3.9.4 Balancing needs in 2050

The import and export capacity is 6000 MW. CEEP indicates a technical balancing problem with too much power in the system and no possibility of using or exporting. Table 13 and 14 illustrates the main balancing figures from the two 2050 scenarios.

	Import	Export	CEEP
Total (annual)	11.87 TWh	20.56 TWh	5.49 TWh
Minimum (hourly)	0 MW	0 MW	0 MW
Maximum (hourly)	6000 MW	6000 MW	4437 MW
Average	1351 MW	2341 MW	-

Table 13: Import and export figures from 2050 wind scenario.

It has to be mentioned that wind curtailment is not included as a strategy in the model. In 2050, it will be possible to shut down all wind power turbines and it is likely to assume that wind power will be shut in order to avoid CEEP. However, from point of view of energy efficiency, it is more efficient to consume the entire production from the wind turbines compared to shut down the turbines. Furthermore, it is more environmental friendly to use the wind power i.e. for hydrogen fuel production thus decreasing the CO_2 emissions in the transport sector. Therefore, wind curtailment is not included in the model to illustrate the need for flexible capacity to avoid shutting down wind turbines.

In the 2050 reference scenario, the electricity system is highly dependent on foreign interconnectors. The entire import and export capacity is fully exploited several times during the year. In 148 hours of the year, 6,000 MW is imported to supply the need for electricity and in 2,208 hours of the year the export capacity is exceeded resulting in CEEP. There is no import problem even though the maximum import capacity is utilized for 148 hours. This indicates that it is cheaper to import electricity compared to produce electricity on distributed CHP plants that operates on SNG.

	Import	Export	CEEP
Total (annual)	13.71 TWh	19.33 TWh	4.36 TWh
Minimum (hourly)	0 MW	0 MW	0 MW
Maximum (hourly)	6000 MW	6000 MW	3941 MW
Average	1561 MW	2698 MW	-

Table 14: Import and export figures from 2050 FCEV wind scenario.

In the 2050 alternative scenario, the import and export capacity are also fully exploited for several hours during the year. The total import is higher in the alternative scenario and the import is 6,000 MW in 293 hours of the year. The higher import is required due to the higher electricity demand in the system. The total export is reduced in the alternative scenario as well as the total CEEP and the number of hours that CEEP occurs, which is 1,972 hours. The introduction of FCEV to the transport sector increases the total electricity demand in the system without causing any import problem. On the other hand, it contributes to reducing CEEP compared to the system without FCEV. The total CEEP is reduced by more than 1 TWh and the maximum CEEP is reduced almost 500 MW. From a system perspective, this is a positive development.

3.10 Discussion of results

The report findings may be different in case another base case scenario is used for the analyses conducted in the MegaBalance report. In the "biomass" and "bio+" scenarios, the energy system is to a higher degree combustion based and the wind capacity is lower than in the wind scenario. The export and CEEP are likely to be lower in an energy system with lower fluctuating production capacity such as wind turbines. The import may also be reduced if the flexible production capacity is higher. In the analyses, the need for positive balancing energy is determined as a percentage of import and the need for negative balancing energy is determined as a percentage of the export or the entire CEEP. A scenario with lower wind turbine capacity may therefore reduce the need for manual balancing energy compared to the findings in MegaBalance report.

A different energy system will also influence the electricity prices in the analyses. Off course there are several things that influence the electricity price and it is difficult to predict how the prices will be different. However, wind turbines has a price reducing effect and a lower wind turbine capacity may cause higher electricity prices if the biomass or bio+ scenario is used as base case scenario. Higher electricity prices will off course increase the H2 production cost and it will require higher income from balancing services to reach the same overall H2 production cost as calculated in the MegeBalance report. This in unlikely as the balancing need is expected to be lower. The total H2 production cost is therefore expected to be higher if the analyses is made with the biomass or bio+ as base case scenario. However, a scenario with more biomass might have other disadvantages for the system such as dependency on foreign biomass and a substantial risk because of the likelihood of rising biomass prices with higher demand.

4. Technical assessment of HRS balancing services

4.1 Technical concept and operation strategies for balancing services

This chapter includes a comprehensive description of the technical concept required to provide balancing services in the power market within the modelling framework of this analysis.

As depicted in Figure 11 the major component of the selected system is represented by the onsite electrolysis located directly at the refueling station. The electricity required to produce hydrogen comes either directly from renewable plants or from the grid. However, the power plant for electricity generation itself is not included in the system. Hydrogen is then compressed and can be either stored as CGH_2 (compressed gaseous hydrogen) in a corresponding storage device or it can be directly processed to the mobility sector.

Although the dispenser and other refueling station facilities (e.g. building, car wash etc.) are required to satisfy the demand created by the hydrogen cars these components of the refueling station are not considered within the analysis. The system includes also a fuel cell as a re-electrification unit to convert hydrogen from the storage back to electricity for the feed-in into the local electricity grid. In this way the fuel cell can provide up-regulation in the regulating power market (positive balancing services).

In addition, a heat pump is used to increase the temperature of the waste heat from the electrolysis and fuel cell for sales to the local district heating operator. Otherwise the temperature from electrolysis and fuel cell is expected to be too low (approx. 60 °C) for injection into the district heating network.

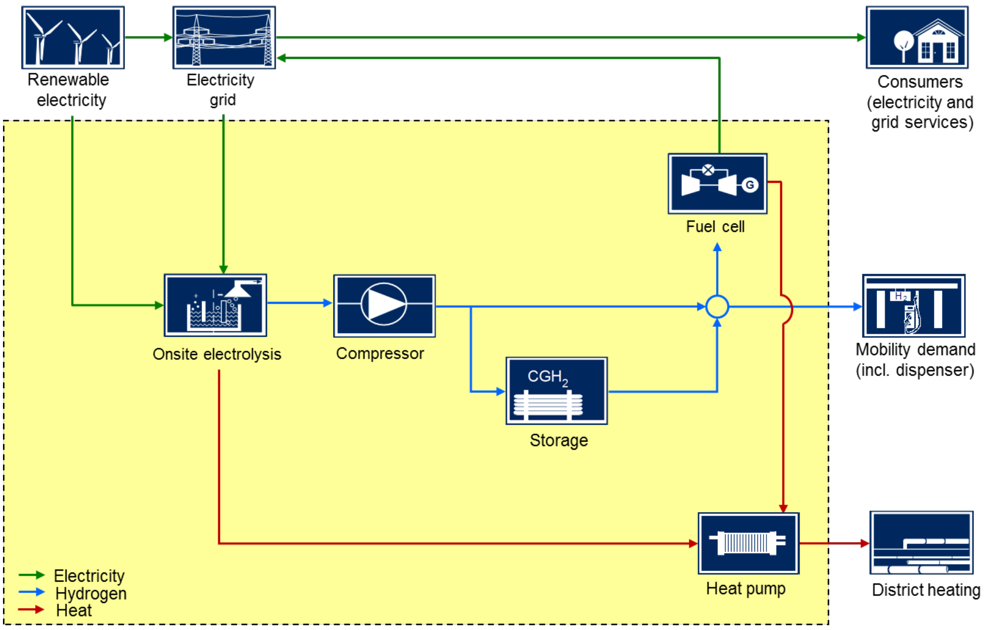


Figure 11: System boundaries.

The techno-economic data for most components of the system are summarized in table 15 to table 18. The corresponding data for the heat pump including additional explanatory remarks can be found in Appendix 2.

Parameter	Unit	2035	2050
Efficiency	%	67	67
	kWh_{el}/kg_{H2}	50	50
Stand-by consumption	% of rated power	2	2
Specific investment outlays	€/kW_{el}	841	645
	€/$kW_{H2,LHV}$	1,262	968
	€/(Nm³/h)	3,785	2,904
Fixed costs	% of investment	7	7
Other variable costs (water)	€/$MWh_{H2,LHV}$	0.41	0.41
Lifetime	a	30	30

Table 15: Techno-economic data on onsite electrolysis.

Parameter	Unit	2035	2050
Electricity consumption	kWh_{el}/kWh_{H2}	0.0088	0.0088
Specific investment outlays	€/kW_{H2}	31	31
Fixed costs	% of investment	4	4
Other variable costs	€/MWh_{H2}	0.00	0.00
Lifetime	a	15	15

Table 16: Techno-economic data on compressor unit.

Parameter	Unit	2035	2050
Specific investment outlays	€/$MWh_{H2,LHV}$	7,921	7,921
Fixed costs	% of investment	0	0
Lifetime	a	30	30

Table 17: Techno-economic data on storage device.

Parameter	Unit	2035	2050
Electrical efficiency	%	50	60
Thermal efficiency	%	45	35
Specific investment outlays	€/$kW_{el,out}$	400	400
Fixed costs	% of investment	2	2
Other variable costs	€/MWh_{H2}	0	0
Lifetime	a	25	25

Table 18: Techno-economic data on fuel cell.

The specific investment costs for the electrolysis decreasing from 841 €/kW$_{el}$ in 2035 to 645 €/kW$_{el}$ in 2050 are rather conservative values and consider not only the costs of the pure stack but also of the entire balance of plant including power electronics, transformer and other components of the electrolysis system. The electrical efficiency (lower heating value) is expected to remain at the same level of ca. 50 kWh$_{el}$/kg$_{H2}$ (or ca. 67%) in both time steps being again a conservative assumption. On the one hand the expected lifetime of 30 years is rather high but on the other hand the fixed costs of 7% of the initial investment include not only actual maintenance costs but also the exchange of the stack within the predefined lifetime. Electricity consumption for the warm stand-by accounts for 2% of rated power. The variable costs include water costs based on water consumption of 9 kg$_{H2O}$/kg$_{H2}$ and water price of 0.0015 €/kg$_{H2O}$. According to the operating temperature of ca. 60 °C the corresponding heat production is ca. 0.3 kWh$_{Th}$/kWh$_{H2}$ if all waste heat can be utilized.

The compressor unit and CGH_2 storage device are considered as state-of-the-art technologies without any specific changes of the techno-economic parameters between 2035 and 2050. The electricity consumption and specific investment outlays of the compressor unit needed to increase the hydrogen pressure from 3 MPa to 5 MPa are rather low at 31 €/kWH2 and 0.009 kWh$_{el}$/kWh$_{H2}$, respectively. However, the corresponding lifetime of 15 years is comparatively short and maintenance costs of 4% of the initial investment rather high. The investment outlays of the adequate storage device are less than 8,000 €/MWh$_{H2}$ without the need for additional maintenance (i.e. there are no maintenance costs) and the life time is 30 years.

In contrast to the electrolysis, the investment outlays for the fuel cell are expected to remain unchanged between 2035 and 2050 at 400 €/kW$_{el}$ whereas the electrical efficiency increases from 50% in 2035 to 60% in 2050. As the major purpose of the fuel cell is to provide electricity to the system, the corresponding thermal efficiency falls from 45% in 2035 to 35% in 2050. The fixed costs and the lifetime of the fuel cell are 2% of the initial investment and 25 years, respectively.

In general, balancing services in the power sector can be provided by the electrolysis and fuel cell as both devices are connected to the local grid. In case of an event in the electrical network electrolysis can be used to increase or decrease hydrogen production in order to provide negative or positive balancing services, respectively. For example as illustrated in Figure 11a, if the price for negative balancing service is low enough then the electrolysis might be incentivized to deviate from the original operation plan (i.e. not running the electrolysis and satisfying the demand from the mobility sector by discharging the hydrogen storage) and to produce hydrogen up to the overall demand level for the negative balancing services (e.g. CEEP level as specified in chapter 3).[10] In this case the costs for electricity from the balancing market must be lower than the value of hydrogen in the storage which can be utilized in later periods.

[10] Note that in reality also other market participants are likely to provide balancing services. Therefore onsite electrolysis does not have to satisfy the full demand for balancing services necessarily.

The opposite is true for positive balancing services (see Figure 12b for an example). In this case high price for positive balancing services incentives the electrolysis to decrease the hydrogen production. Then the electrolysis can either satisfy the demand in the mobility sector from the storage (if otherwise hydrogen provided by the electrolysis would be sold directly to hydrogen cars) or to postpone filling of the storage to later periods (if hydrogen demand from the mobility sector is lower than electrolysis capacity and electricity price on the spot market is low enough). Under such circumstances the electrolysis earns revenues from the balancing market but pays for the electricity which has been contracted on the spot market.

Similarly, high price for positive balancing services might provide incentives for the fuel cell to provide up regulation to the maximal demand on the balancing market (see Figure 12c for an example). In this case it is more profitable to use hydrogen from the storage and convert it into electricity since the value of hydrogen which can be used in later periods is lower than the additional revenues from the sales to the balancing market. For negative balancing service the fuel cell shut off planned electricity production. In detail, the fuel cell plans its operation on the spot market the day before and then it can deliver down regulation by not producing the power on the day this service is needed. Here the revenue is generated from the difference between spot price and the down regulation price.

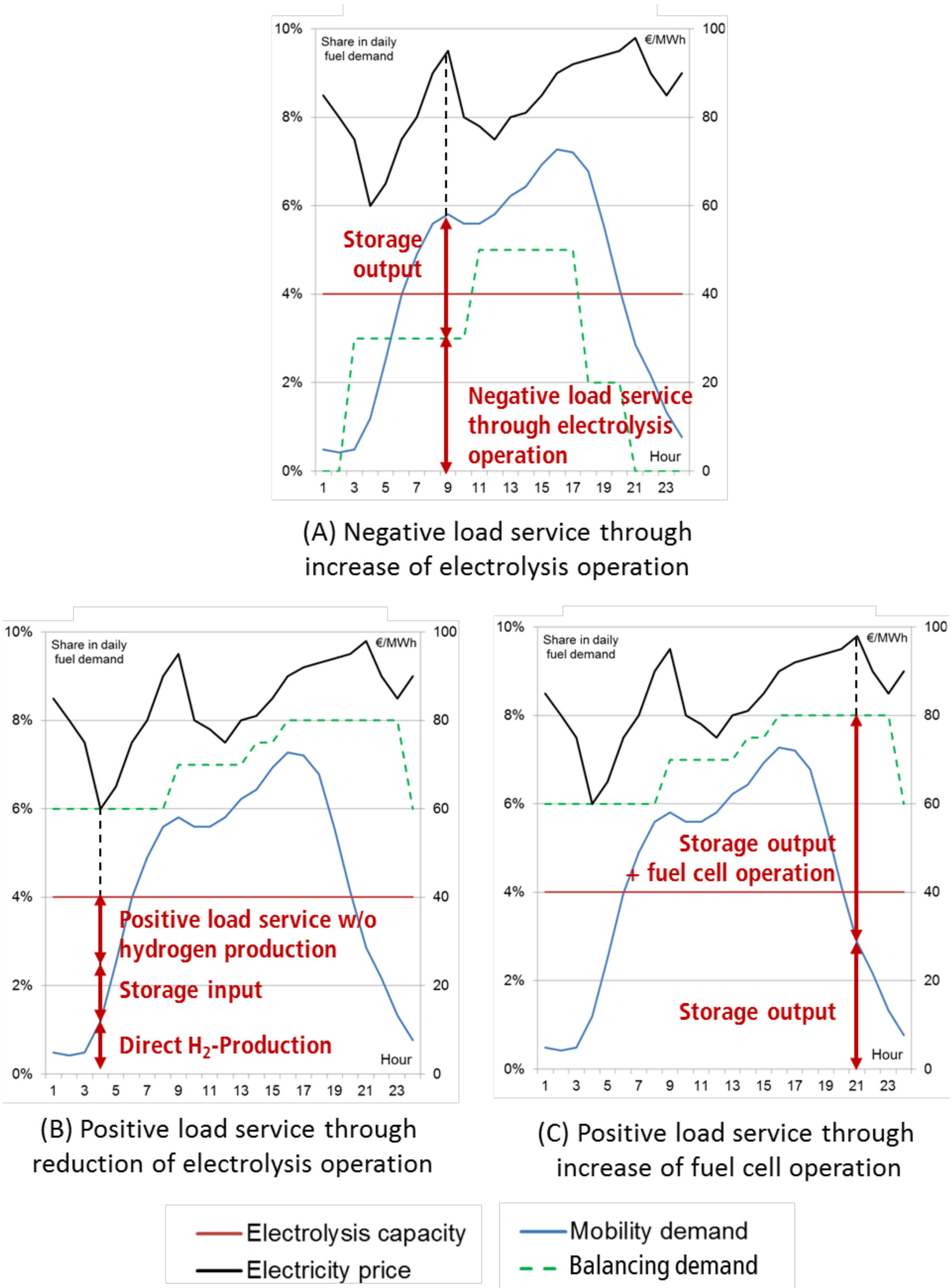


Figure 12: Exemplary operation strategy of the HRS

4.2 General model assumptions and selected scenarios

The demand for balancing services is derived from the power market analysis in chapter 3.[11] The need for negative balancing services in 2050 is represented by the CEEP within the Danish electricity system. As the analysis does not provide CEEP values for 2035 the need for negative balancing services in this time step is calculated by multiplying the electricity exports in 2035 as specified in chapter 3 with the average ratio between historical electricity exports and balancing needs from 2014.

The same approach is also applied to the demand for positive balancing services in both time steps based on imports from chapter 3 and corresponding historical import-to-balancing-ratio. As shown in Figure 13 the highest peak demand of ca. 4 GW is achieved by negative balancing in 2050. This type of balancing need occurs in almost 2,000 hours of the year accounting for more than 4.3 TWh of excess electricity.

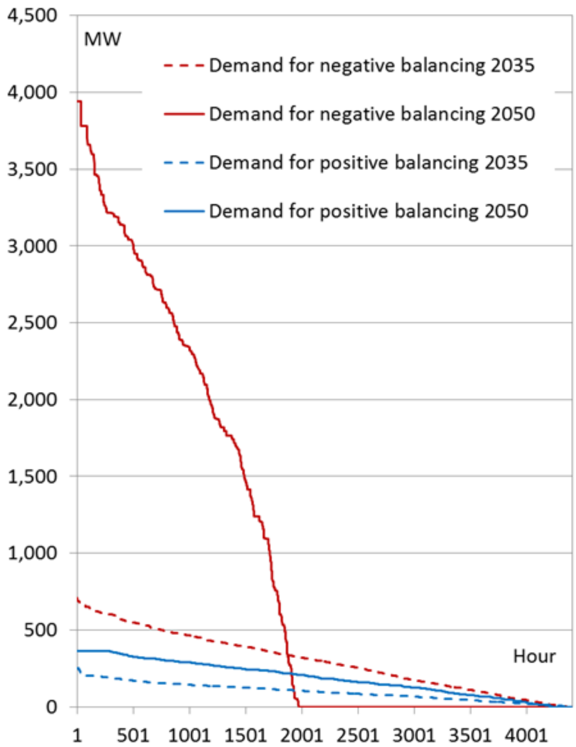


Figure 13: Expected demand for negative and positive balancing services in Denmark in 2035 and 2050.

The peak demand for negative balancing services in 2035 and for positive balancing services in both time steps is comparatively moderate (ca. 0.25-0.7 GW), however, applying to 4,200-4,400 hours of the year. The excess electricity (negative balancing demand) in 2035 is 1.3 TWh and the need for positive balancing is between ca. 0.4 TWh in 2035 and 0.8 TWh in 2050.

The hydrogen demand in the mobility sector is based on the extrapolation of the corresponding assumption of the HyTEC project (see also chapter 3.5). The FCEV fleet

[11] Based on the wind scenarios including FCEVs.

is expected to growth from more than 825,000 vehicles in 2035 up to almost 1.5 million cars in 2050. In this way FCEVs would account for more than 33% of all vehicles on the road in Denmark and for 50% in 2050. Under the assumption of an average annual mileage of ca. 16,000 km and energy consumption of a FCEV of 0.277 kWh_{H2}/km the total energy demand from the mobility sector accounts for 111 kt H_2 (or 3.7 TWh_{H2}) in 2035 and 196 kt H_2 (or 6.5 TWh_{H2}) in 2050.

The hourly demand profiles are based on the daily patterns provided by H2Logic for a typical HRS in Denmark as well as on weekly and seasonal patterns from the HyUnder project (HyUnder 2014).[12] For the sake of transparency, all HRS available in Denmark are considered for balancing services in the power market. In reality the actual balancing capability of a refueling station depends on its actual position within the transmission network. In Denmark the power system can be considered as “copper plate” without any transmission constraints. In this study only the regulating power market is considered.

Regarding the economic assessment in chapter 5 the build-up of the onsite electrolysis is considered to occur in 0.5 MW_{el} steps (i.e. this value corresponds to the incremental investment in electrolysis capacities at each HRS). The interest rate is 8%, the detailed planning horizon 10 years and the exchange rate 7.446 DKK/€ (exchange rate from 06.03.2015).

The heat price is considered to remain unchanged at ca. 40 €/MWh (or 300 DKK/MWh) in both time steps. The total grid tariffs of 22.54 €/MWh or ca. 168 DKK/MWh used for the sensitivity analysis include the current payments to the transmission system operator (TSO) of 9.54 €/MWh or ca. 71 DKK/MWh (so-called TSO tariffs) as well as payments to the distributions system operator (DSO) of 13 €/MWh or ca. 97 DKK/MWh (so-called DSO tariff). Other additional payments such as the public service obligation (PSO) or energy taxes are not taken into account for this analysis. The electricity price corresponds to the results from chapter 3 on the wind scenario including FCEVs.

In order to analyze the role of HRS within the market for balancing services following scenarios are defined for both technical assessment in this chapter as well as economic assessment in chapter 5:

- **Reference scenario:** Onsite hydrogen production for mobility only without any balancing services.
- **Scenario A:** Negative load services (down-regulation) by increasing hydrogen production through electrolysis.

[12] HyUnder was a project co-funded by the European Union on the assessment of the potential, the actors and relevant business cases for large scale and seasonal storage of renewable electricity by hydrogen underground storage in Europe. See HyUnder 2014.

- **Scenario B:** Positive load services (up-regulation) by reducing hydrogen production through electrolysis.

- **Scenario C:** Positive load services (up-regulation) by providing electricity from fuel cells.

Note that for the sake of clarity each scenario includes only one type of balancing service. In reality the system might provide the services to different balancing markets such that the overall additional revenues might be aggregated from different markets. Hence, this is a rather conservative approach from the perspective of the onsite electrolysis. Additional analysis provides a range of technically available waste heat from electrolysis and fuel cell operation as well as potential reduction of hydrogen costs in all scenarios.

4.3 Technical needs for HRS balancing services

Figure 14 depicts the optimal sizing and operation of the onsite electrolysis for the predefined scenarios to fully satisfy the demand for hydrogen fuel as well as for the balancing services. The comparison of the electrolysis capacity between both time steps (2035 and 2050) reveals a typical trade-off between the capital expenditures (CAPEX) mainly represented by specific investment outlays for the electrolysis and operational expenditures (OPEX) mainly represented by the electricity costs. In order to satisfy a predefined demand in the mobility sector falling electrolysis costs and rising price volatility typically lead to larger capacities which are operated in fewer hours thus lowering the corresponding electricity costs. Therefore the installed electrolysis capacity in 2035 ranges between 0.7 - 1 GW and is considerably lower than in 2050 between 1.8 - 3.9 GW. However, the utilization of the facility decreases from 7,100-7,800 (ca. 81%-90%) in 2035 to 2,500-5,700 (ca. 29%-65%) in 2050.

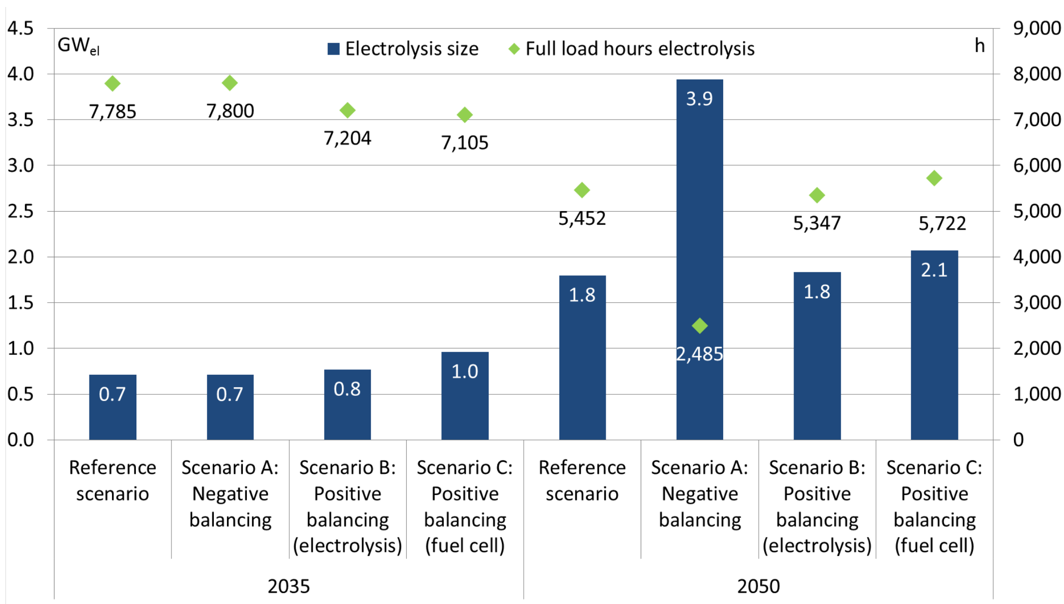
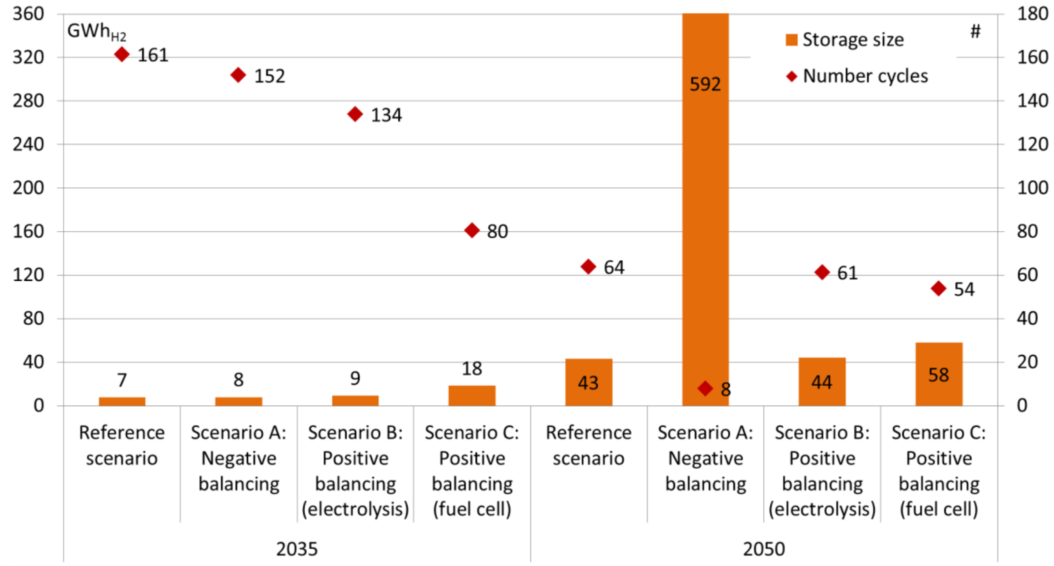


Figure 14: Required electrolysis size for balancing services.

In 2035 the optimal electrolysis size needed for the mobility sector (ca. 0.7 GW) is sufficient to satisfy the demand for negative balancing in scenario A. Due to additional hydrogen production the overall utilization of the facility increases slightly by ca. 15 full load hours in this case. Providing positive balancing services in 2035 requires additional investments in electrolysis capacity leading to a slightly lower utilization. In scenario B the overall capacity increases only by 8% due to the fact that in some hours the electrolysis is not operated under the positive balancing regime whereas in scenario C the capacity rises substantially by ca. 35% due to the low roundtrip efficiency of the electrolysis fuel cell system. It is worth mentioning that in scenario C the fuel cell capacity of 0.25 GW corresponds to the peak demand for positive balancing services.

In 2050 the largest electrolysis capacity is required for negative balancing services in scenario A (ca. 4 GW) being higher than in the reference scenario by a factor of 2. This is also the reason for a very low utilization of the electrolysis of less than 2,500 hours (or less than 30%). This is due to the very high peak demand for the negative balancing in this time step. Similarly to 2035 positive balancing requires only small additional investments (ca. 2% in scenario B and 15% in scenario C)[13]. The fuel cell in scenario C in 2050 has an installed capacity of 0.35 GW being again responsible for the larger electrolysis in comparison to scenario B.

In general, the dimensioning of the subsequent facility components including the compressor and storage device follows the sizing of the electrolysis. As shown in Figure 15 the storage size in 2035 is comparatively low ranging between 7 GWh_{H2} and 18 GWh_{H2} and being utilized on 2-5 days basis (i.e. 64-161 full cycle equivalents[14]).



[13] Note that the relative share of the balancing demand on the overall energy consumption including the electrolytic hydrogen production for the mobility sector is much lower in 2050 than in 2035 due to substantial increase of demand in the mobility sector as a corresponding basis.

[14] A full cycle equivalent corresponds to full charging and discharging of the storage. Days of storage are calculated by dividing the total number of days in a year (365) by the number of full cycle equivalent. This value indicates the average storage duration of hydrogen.

Figure 15: Required storage size for balancing services.

In 2050 the optimal storage size in the reference scenario as well as in scenarios B and C is between 43-58 GWh_{H2} being operated at ca. 54-64 full cycle equivalents (6-7 days). For the negative balancing services in scenario A the facility requires a very large device of ca. 600 GWh_{H2} with a corresponding utilization of 8 full cycle equivalents (i.e. operated at 45 days basis). Again positive balancing services in general (in scenario B and C) and usage of the fuel cell in particular (in scenario C) require larger storage leading to lower device utilization.

Under the given boundary conditions waste heat production in the reference scenario as well as in scenario A and B amounts to ca. 1.2 TWh in 2035 and ca. 2.1 TWh in 2050 (see Figure 16). The difference between the two time steps is due to increasing hydrogen production for the mobility sector. Interestingly, the overall heat production remains unchanged among the abovementioned scenarios for each time step as additional balancing services impact only the optimal operational mode of the electrolysis but not the overall amount of hydrogen which is sold solely in the mobility sector. In Scenario C the heat production is higher than in other scenarios (1.8 TWh in 2035 and 3.0 TWh in 2050) due to lower roundtrip efficiency of the system and thus higher electrolytic hydrogen production as well as due to additional waste heat generation by the fuel cell (ca. 20% in both time steps).

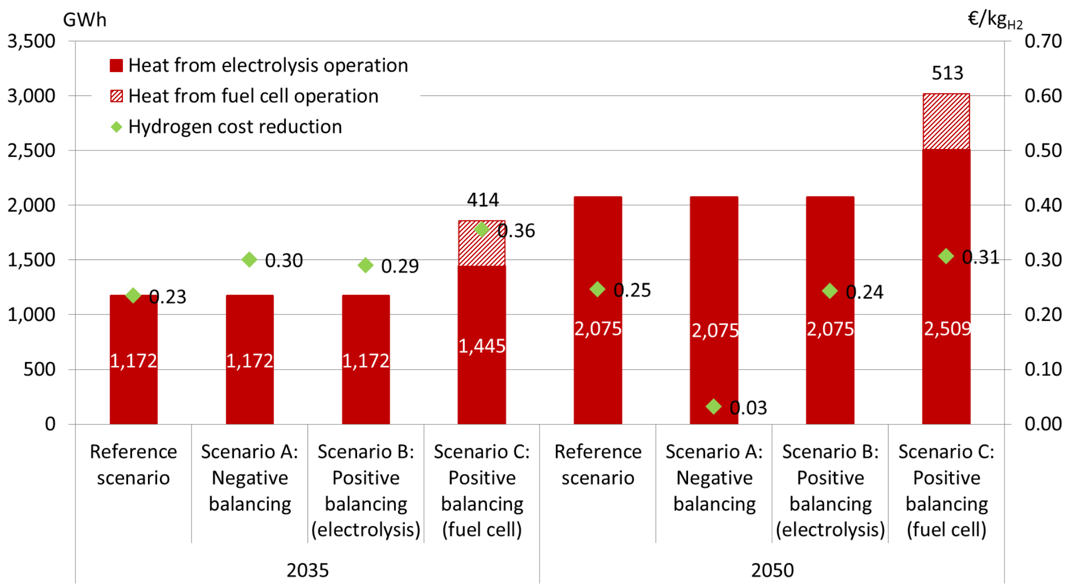


Figure 16: Waste heat production and hydrogen costs reduction.

On the one hand the facility earns additional revenues from the sales to the heat market but on the other hand the additional investment outlays and electricity costs for the heat pump reduce the potential benefits of using waste heat. Based on the assumptions on the heat pump as specified in Appendix 2 and average electricity costs of 71-80 €/MWh in 2035 and 41-54 €/MWh in 2050 the specific hydrogen costs can be reduced by ca. 0.20-0.30 €/kg_{H2} in most scenarios. Only in scenario A in 2050 the benefit of waste heat is limited to ca. 0.03 €/ kg_{H2}. This is mainly due to large investment in heat pump capacity which follows the electrolysis dimensioning.

5. Economic assessment of HRS balancing services

The assessment in this chapter focuses on the boundary conditions under which the provision of balancing services in the power market becomes a valuable option for a hydrogen refueling station from the economic perspective. The first step of the analysis estimates the expected build-up of the HRS network in Denmark until 2050. The actual economic assessment on the "willingness to pay" for balancing services is then conducted in the subsequent step under the assumption that all refueling stations are aggregated into one entity in one node of the electricity grid.[15]

5.1 Hydrogen refueling station build-up in Denmark until 2050

Figure 17 illustrates the expected spatial development of the HRS network in 2035 and 2050. The refueling stations are mainly sited in urban areas characterized by high population and thus vehicle density such as Copenhagen, Aarhus, Odense or Aalborg as well as along major roads between such areas. In addition, some stations are also located in the countryside with a lower vehicle density to ensure full network coverage. In total, 400 hydrogen refueling stations are expected in 2035. According to the increasing number of FCEVs and thus the demand in the mobility sector (see also chapter 4.2) the number of stations goes up to 700 in 2050. This corresponds to an average ratio of ca. 2,000 FCEVs per HRS in both time steps.

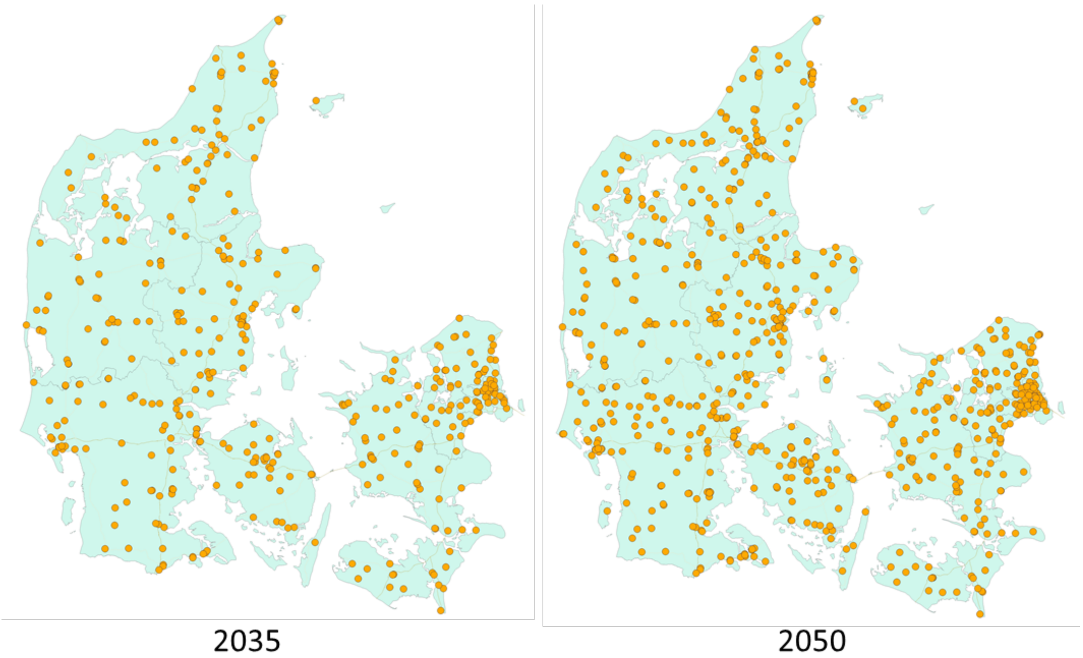


Figure 17: Spatial development of the HRS network in 2035 and 2050.

According to the development of the hydrogen demand from the mobility sector the build-up of the HRS until 2020 focuses on comparatively small stations with daily sales of up to 200 kg_{H2} per day (Type A with maximal 50 kg_{H2} per day and Type B

[15] This is line with the assumption of the electricity system as a "copper plate" without any transmission constraints.

with maximal 200 kg_{H2} per day). From 2020 the demand for hydrogen fuel increases rapidly such that existing stations have to be upgraded in capacity and new stations have a capacity of more than 200 kg_{H2} per day (see Figure 18). Both in 2035 and 2050 ca. 55% - 60% of the HRS in Denmark have an expected capacity of 1,000 kg_{H2} per day (Type D), ca. 20% - 25% a capacity of maximal 500 kg_{H2} per day (Type C) and 20% of the locations can be considered as a very large HRS with a capacity of more than 1,000 kg_{H2} per day (Type D+).

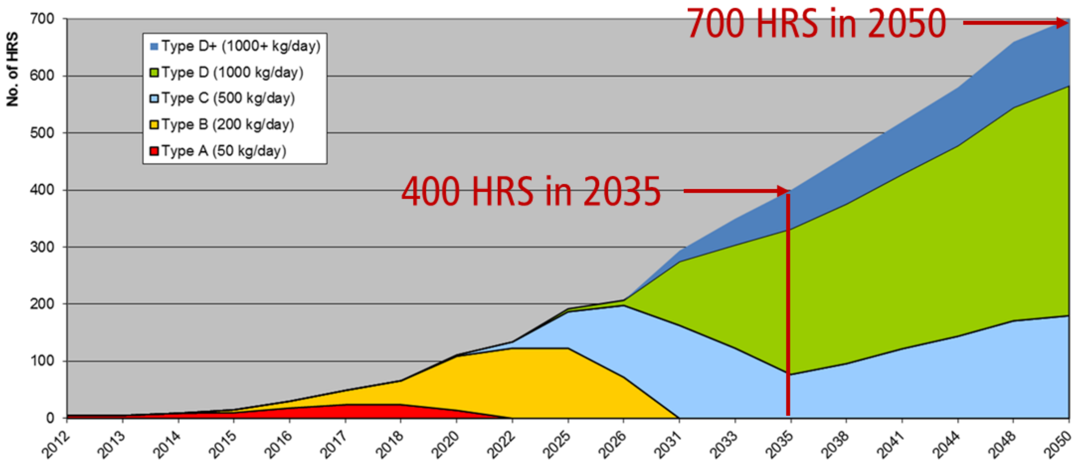


Figure 18: Expected HRS netwrok development over time until 2050.

Based on the expected build-up of the HRS network and optimal operation mode of the onsite electrolysis in the reference scenario (see chapter 4.3) the overall installed electrolysis capacity at all HRS amounts to more than 0.8 GW_{el} in 2035 and to almost 2 GW_{el} in 2050. In this way the electrolysis needed for hydrogen production in the mobility sector is able to satisfy the peak demand for all balancing services in 2035. For 2050 the electrolysis capacity is larger than the peak demand for positive balancing services but it accounts only for less than 70% of the peak demand for negative balancing.

Note that the calculated electrolysis capacity in this chapter is higher than the results on the optimal electrolysis sizing in chapter 4.3. This is due to the fact that the actual build-up of hydrogen supply infrastructure in this chapter is conducted in discrete 0.5 MW steps. The results from this analysis are considered as initial capacity and thus as input values for the modelling of balancing services in the subsequent chapter.

5.2 Economic feasibility of HRS balancing services

5.2.1 Reference scenario

Based on the economic assessment of hydrogen production for the mobility sector in the reference scenario (hydrogen production only for the mobility sector without any balancing services) the specific hydrogen costs without grid fees amount to almost 4.80 €/kg_{H2} in 2035 (see Figure 19). The electricity costs of less than 3.60 €/kg_{H2} account for the major share of the overall hydrogen costs (ca. 75%). The optimal electrolysis utilization is ca. 6,800 hours (ca. 78%) and is lower than its utilization based on the technical assessment in chapter 4.

Similarly, the storage size is slightly higher (ca. 9 GWh H_2) and its utilization lower (140 full cycle equivalents or ca. 2.5 days) than the corresponding results from chapter 4. This is again due to the fact that the actual build-up of the onsite electrolysis is conducted in discrete steps of 0.5 MW as described in the previous chapter. Capital expenditures represented by the annuity for the investments in all facility components play a less important role (more than 0.70 €/kg_{H2} or 15% of total costs). Fixed costs for maintenance amount to ca. 0.40 €/kg_{H2} (or 9% of total costs) whereas other variable costs (mainly water costs) are negligible. Overall hydrogen costs increase by more than 24% or 1 €/kg_{H2} up to almost 6 €/kg_{H2} if grid fees are taken into account.

Due to falling electrolysis costs and rising electricity price volatility in 2050 the specific hydrogen costs without grid fees in this time step decrease substantially by 20% to less than 4 €/kg_{H2}. The electricity costs still account for a major share of the overall costs (ca. 2.42 €/kg_{H2} or ca. 64%) but they are less important in comparison to 2035. In this case the electrolysis is operated in almost 5,000 hours per year with a utilization rate of 57% (vs. almost 5,500 hours according to the technical assessment). Adequately, the storage is again larger (49 GWh_{H2}) and its utilization lower (58 full cycle equivalent or more than 6 days) than the expected values from the technical analysis in chapter 4. In contrast to electricity costs, the CAPEX and fixed costs increase to 0.90 €/kg_{H2} (or 24% of total costs) and 0.46 €/kg_{H2} (or 12%), respectively. Other variable costs are again negligible. As the same tariffs are assumed for both time steps the impact of grid fees is similar to the results for 2035 rising the total costs by 1.15 €/kg_{H2} (or 30%) to almost 5€/kg_{H2}.

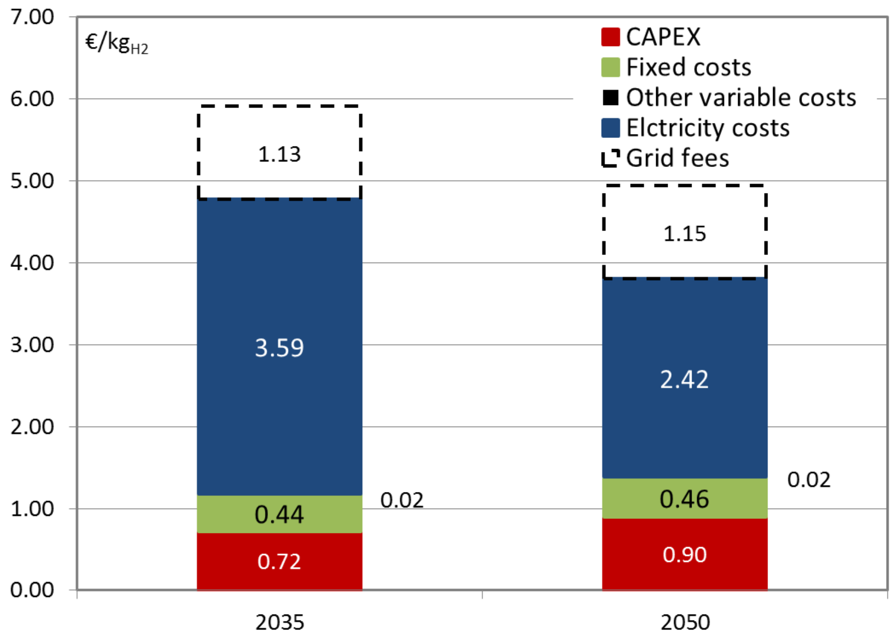


Figure 19: Specific hydrogen costs in the reference scenario.

The energy in both time steps is used in a comparable way (see Figure 20). The major share of total energy consumed by the facility is utilized to produce hydrogen which is then directly sold to the market (2.4 TWh or 43% in 2035 and 3.7 TWh or 37% in 2050). The overall energy processed through the storage increases slightly from 23% (or 1.3 TWh) in 2035 to 29% (or 2.9 TWh) in 2050. The energy losses of the electrolysis and other electricity consumption (such as energy provision for hydrogen compression or electrolysis stand-by) are proportional to the overall energy demand and efficiency of the electrolysis amounting to ca. 34% in both time steps (1.9 TWh in 2035 and 3.4 TWh in 2050).

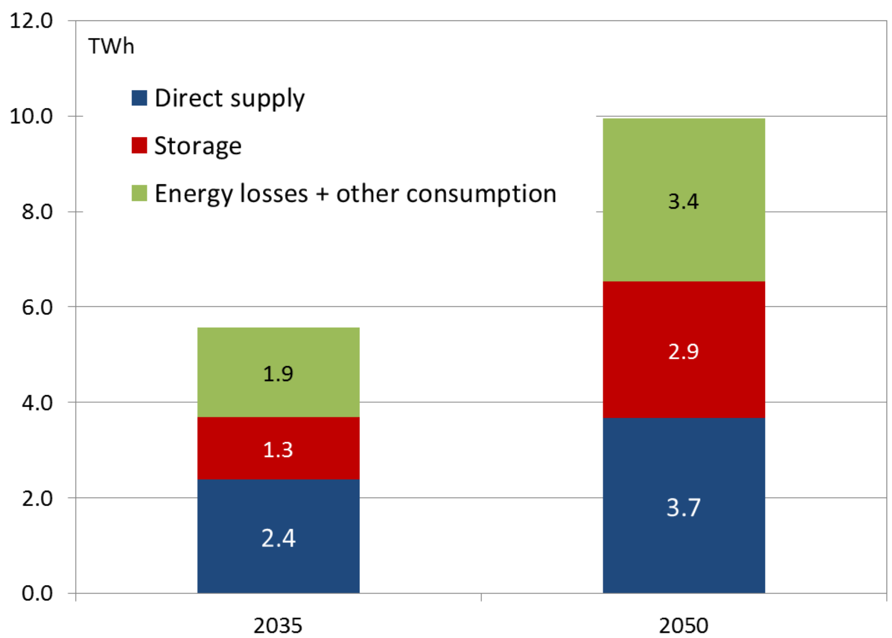


Figure 20: Energy use in the reference scenario

5.2.2 Negative balancing services in scenario A

In general, there is an adverse relationship between the price for negative balancing and the overall amount of the corresponding service provided to the market (i.e. the lower the price the higher the corresponding supply). This is mainly due to the optimization regime of the facility as low prices for balancing services allow for cheaper electricity purchases in the balancing market in comparison to the spot market.

Based on the assumption of this analysis the demand for negative balancing is fully satisfied only if the corresponding average price is as low as 0 €/MWh, i.e. if the excess electricity in the system can be used for free (see Figure 21). In reality such average price for electricity could hardly occur as it would be an effective price signal for other consumers with a flexible load to enter the balancing market. In the consequence the increasing supply would raise the market price until an equilibrium has been reached. However, if the price for electricity in the balancing market is lower than 50 €/MWh, i.e. lower by 40% in comparison to the average spot market price of ca. 84 €/MWh, then HRS can satisfy more than 80% of the overall balancing demand. In fact as depicted in Figure 21 the supply of negative balancing services is rather sensitive to the corresponding market price in the range between 50 €/MWh and 80 €/MWh.

As mentioned in chapter 4.3 the electrolysis size initially installed for the mobility sector is sufficient to satisfy the demand in the balancing market and no additional investment are needed. Although the utilization of the electrolysis remains unchanged (ca. 6,800 hours) additional storage with a lower number of full cycle equivalents is required to compensate the discrepancies between hydrogen production and demand in the mobility sector. The supply of negative balancing services might decrease the overall specific hydrogen costs by ca. 0.70 €/kg$_{H2}$ (ca. 15%) to 4 €/kg$_{H2}$ if the balancing is low enough and all demand in this market is satisfied by the HRS.

In general, the grid fees have an analogues impact on the behavior of the facility. As the grid fees apply to all hours of the year in the same way the only difference is represented by the shift of the supply curve by ca. 20 €/MWh to the right.[16] This means that 70 €/MWh (ca. 15% less than the average electricity spot market price) are sufficient to incentivize a supply rate of more than 80% whereas the balancing demand is fully satisfied already at 20 €/MWh. Specific hydrogen costs are higher by ca. 1 €/kg$_{H2}$ for a given balancing price in comparison to the results without the tariffs. In addition, grid fees have no impact on the sizing and operation of the electrolysis and storage.

[16] Note that time varying grid fees are also possible in the future.

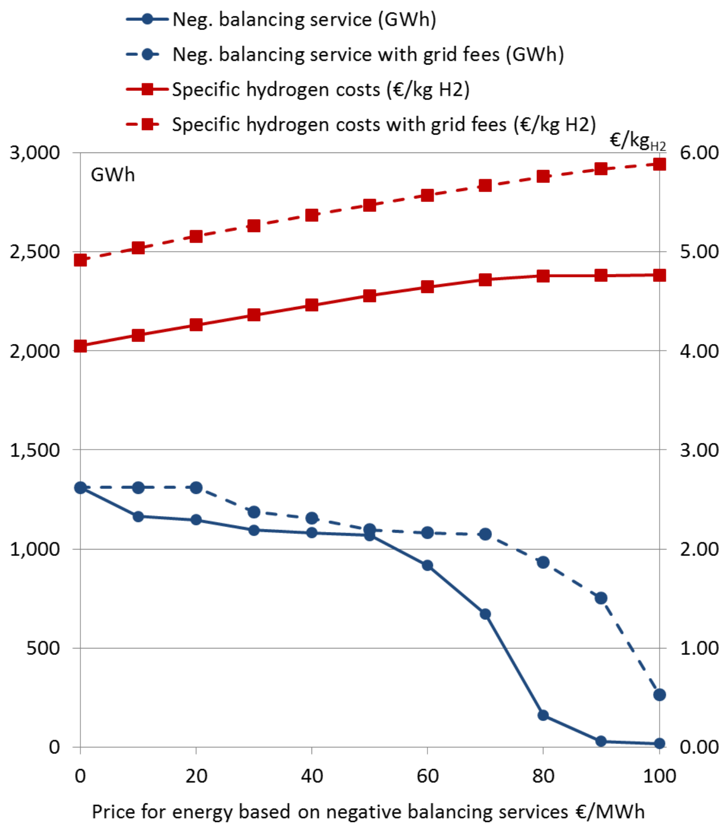


Figure 21: Results scenario A in 2035.[17]

As mentioned in chapter 4.3 satisfying the demand for negative balancing services in 2050 requires additional investments in both electrolysis and storage capacities. Therefore the balancing price must be negative in order to incentivize the HRS to provide balancing services to the market. This means that the facility expects to be paid for consuming the excess electricity which otherwise would cause supply security problems to the whole energy system. In this context the balancing price must fall below -200 €/MWh in order to satisfy more than 80% and below -500 €/MWh to satisfy 100% of the demand for negative balancing (see Figure 22). As expected, the electrolysis and storage size go up while the corresponding utilizations go down according to falling price in the balancing market.

Similarly to 2035, the behavior of the HRS on the balancing market is again very sensitive within a limited range between 0 €/MWh and 50 € MWh. Negative balancing prices have a strong lowering effect on the specific hydrogen costs as in this case the payments for electricity consumption can be viewed as an additional stream of revenues. Interestingly, grid fees have only limited impact on the actual behavior of the facility as well as on the specific costs as soon as balancing services are provided (ca. 0.80 €/kg_{H2}). This is due to the fact that a large amount of electricity is obtained from the balancing market without the grid fees.

[17] Note that the prices for balancing prices in this and all other forthcoming figures represent average price for all hours of the year.

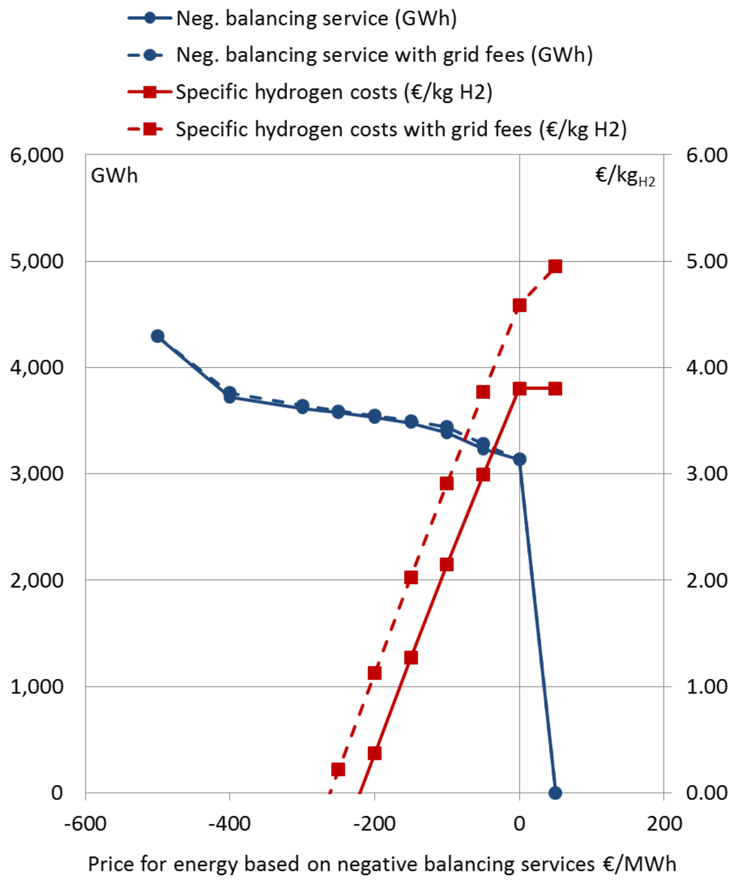


Figure 22: Results scenario A in 2050.

5.2.3 Positive balancing services in scenario B (electrolysis)

In contrast to the findings in the previous chapter rising prices for positive balancing also increase the amount of the corresponding service provided to the market by the electrolysis, i.e. the higher the price the higher the overall balancing amount. This is due to the fact that in some hours the electrolysis is paid for not consuming the electricity which represents an additional stream of revenues.

In 2035 the average balancing price must rise above 120 €/MWh in order to satisfy more than 80% and above 150 €/MWh to satisfy almost 100% of the demand (see Figure 23). Both prices are clearly higher than the average electricity spot market price of 84 €/MWh in 2035 as according to the modelling framework the facility is still obliged to pay the spot market prices when providing positive balancing service. The largest sensitivity in respect to balancing prices can be observed between 50 €/MWh (almost no grid services) and 150 €/MWh (full supply).

Similarly to scenario A the electrolysis capacity and the corresponding full load hours remain unchanged whereas the rising balancing prices lead to larger storage sizing combined with a lower number of full cycle equivalents. Positive balancing services are able to decrease the specific hydrogen costs by more than 0.50 €/kg$_{H2}$ (or ca. 12%) down to ca. 4.20 €/kg$_{H2}$. On the one hand the additional grid fees increase the average balancing prices required to supply a given amount of balancing service (shift of the supply curve to the right by more than 20 €/MWh) but on the other hand the tariffs have no impact on the sizing and operational mode of the facility.

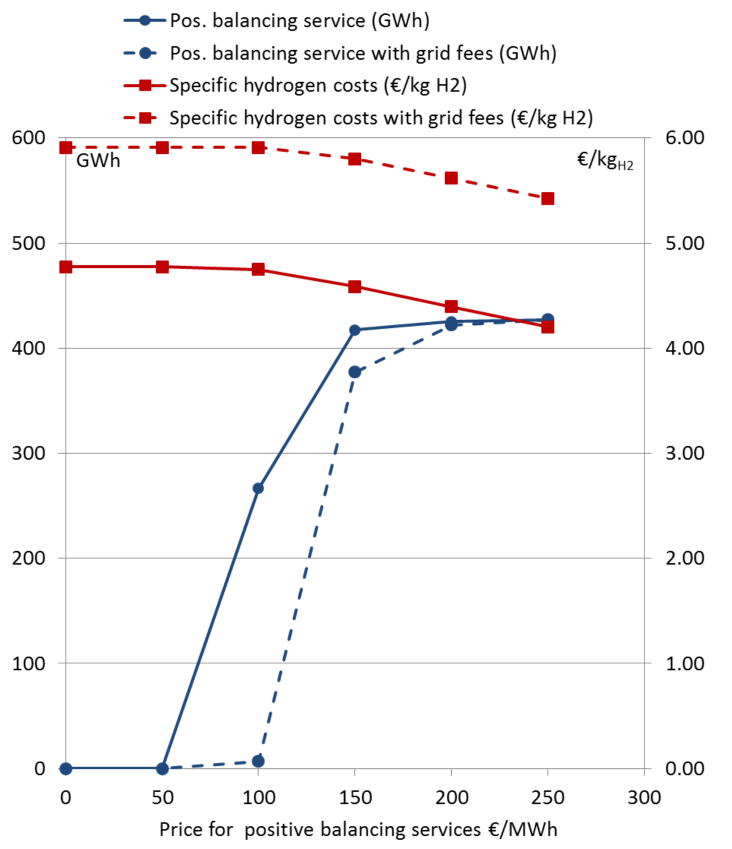


Figure 23: Results scenario B in 2035

As the average electricity price in 2050 of 74 €/MWh is comparable to the corresponding values in 2035 the results on the positive balancing services in both time steps are similar. The most sensitive range in respect to balancing prices is again between 50 €/MWh and 150 €/MWh (with 120 €/MWh for at least 80% of the balancing needs and more than 150 €/MWh to fully satisfy the demand) and there is the same impact on the sizing and operation of the storage and electrolysis. Specific hydrogen cost can decrease by 17% (or by 0.60 €/kg$_{H2}$) if full demand for positive balancing services is taken into account. The grid fees have the same influence on the facility and its costs as in the previous time step.

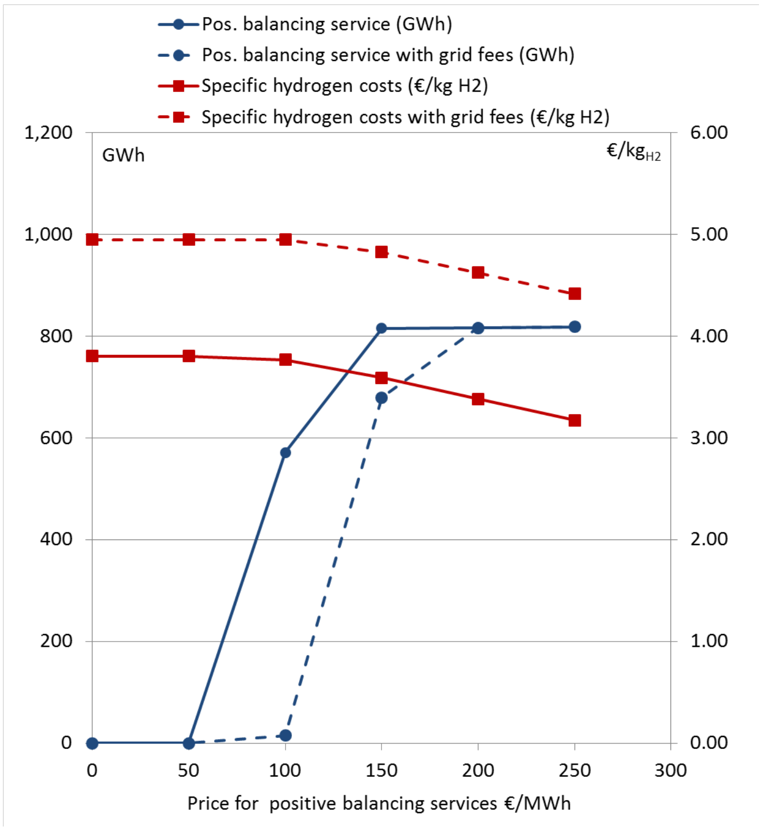


Figure 24: Results scenario B in 2050.

5.2.4 Positive balancing services in scenario C (fuel cell)

Similar results as in scenario B can be also observed in scenario C where positive balancing services are provided by an additional fuel cell as a re-electrifctation unit. However, since such facility layout requires investments in costly fuel cell and electrolysis capacities the average balancing prices must be higher than in scenario B in order to incentivize the supply of balancing services by the HRS. As shown in Figure 25 the adequate average balancing price to satisfy more than 80% of the balancing needs in 2035 is estimated at ca. 400 €/MWh (a threefold increase in comparison to scenario B) with a very sensitive range between 300 €/MWh and 400 €/MWh. From the economic perspective the whole demand for the balancing service can be provided by a fuel cell only if the balancing price is larger than 800 €/MWh being higher than the average spot market price by a factor of almost 10.

As revealed by the technical assessment the electrolysis and storage capacity slightly increase (in combination with a higher utilization of the electrolysis but lower utilization of the storage in comparison to scenario B) with rising balancing prices due to additional hydrogen production and low roundtrip efficiency along the electrolysis-fuel-cell pathway. The additional revenues from the positive balancing can potentially reduce the specific hydrogen costs in 2035 by more than 28% (or almost 1.40 €/kg_{H2}) to 3.40 €/kg_{H2}. Interestingly, the grid fees have a disproportional impact on the balancing prices required to satisfy the corresponding demand. However, the specific hydrogen costs increase only by 1.10-1.50 €/kg_{H2} due to grid fees.

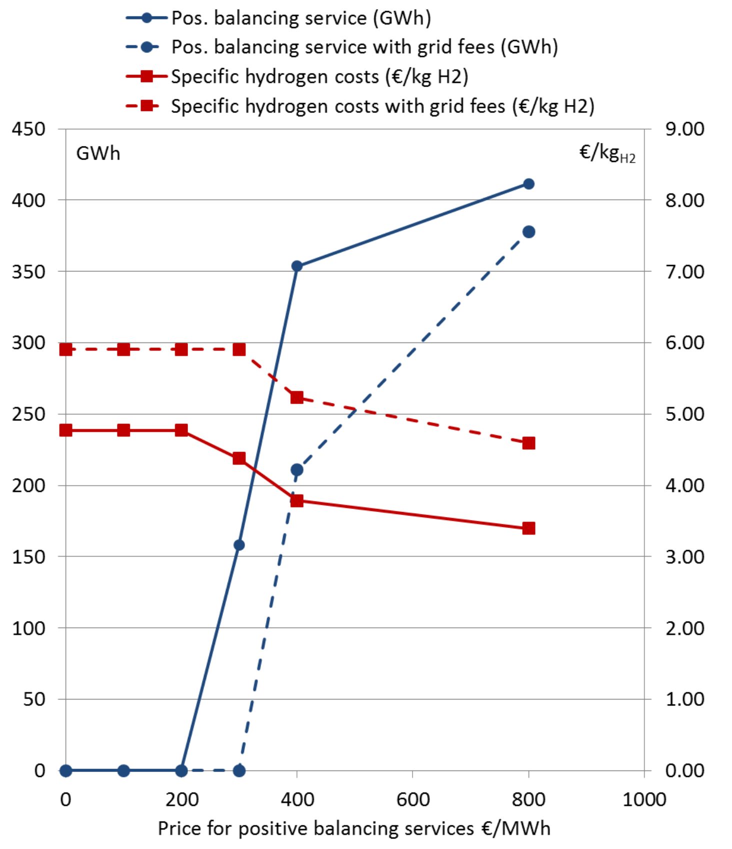


Figure 25: Results scenario C in 2050.

As depicted in Figure 26 the corresponding average prices required to achieve the same effect on balancing services are lower in 2050 in comparison to 2035 (more than 280 €/MWh for at least 80% and more than 400 €/MWh for 100% of the balancing demand) due to two effects. On the hand the higher efficiency of the fuel cell lowers the overall hydrogen production costs and on the other hand the average spot market price is lower in 2050 in comparison to 2035. Therefore the most sensitive range in respect to balancing prices can be observed between 200 €/MWh and 300 €/MWh. The impact of balancing services in 2050 on facility dimensioning and optimal operation are comparable to the results from 2035. The specific hydrogen cost can be reduced substantially by almost 40% (ca. 1.50 €/kg$_{H2}$) to less than 2.30 €/ kg$_{H2}$. The observations regarding the grid fees in 2050 are again analogous to the results for 2035.

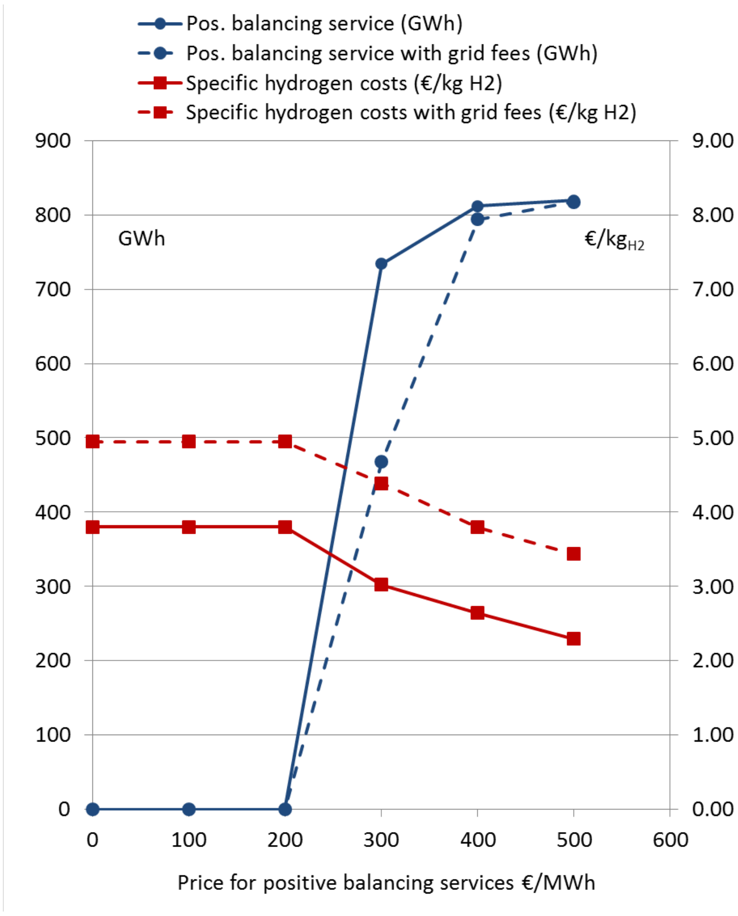


Figure 26: Results scenario C in 2050.

Surprisingly, the impact of the investment outlays for the fuel cell has only a limited impact on the amount of balancing services supplied to the market (in 2035 more than 350 €/MWh for 80% and almost 800 €/MWh for 100% of the demand; in 2050 more than 250 €/MWh for 80% and more than 350 €/MWh for 100% of the demand). Consequently in contrast to the electrolysis and storage unit, the fuel cell cannot be viewed as a critical component of the facility in regard to the positive balancing services.

6. Conclusion

In general, the analysis in this study reveals that the onsite electrolysis in combination with a storage unit at HRS is capable of providing a significant amount of negative and positive balancing services in Denmark until 2050. In the context of this study, on the one hand negative balancing services can be obtained by increasing hydrogen production through electrolysis. On the other hand positive balancing services can be provided either by reducing the electrolytic hydrogen production or by increasing electricity production through a fuel cell as a re-electrification unit.

6.1 Conclusions on power market projections

The purpose has been to develop scenarios for the future energy system to estimate volumes and variations of fluctuating electricity production, electricity market prices and balancing needs. The scenarios take their point of departure in the “Wind” scenario made by the Danish Energy Agency. The report describes the energy system in 2035 and 2050 in detail. Heat and electricity production and consumption capacities and annual consumptions figures from both years are identified and implemented in the EnergyPLAN model. These two scenarios serve as reference scenarios, which are compared to two other scenarios in which the development in the transport sector is different i.e. includes FCEV.

The fluctuating renewables consist of wind power and PV where the wind power is the main contributor to the production of electricity. In 2035, the total installed capacity is 9,500 MW, of which 8,500 MW is wind turbine capacity. In 2050, the total installed capacity is 19,500 MW, of which 17,500 MW is wind turbine capacity.

EnergyPLAN is a deterministic model that generates the same outputs from the same inputs. The production of electricity from fluctuating renewables are therefore the same in the two 2035 scenario and the two 2050 scenarios. In 2035, the peak power capacity from wind and solar is 9,077 MW whereas it is 18,875 MW in 2050. The minimum capacity is 0 MW, so there are large deviations on annual basis.

The model generates an hourly electricity price based on an input price profile. The output electricity profiles from the four scenarios are illustrated in figure 27.

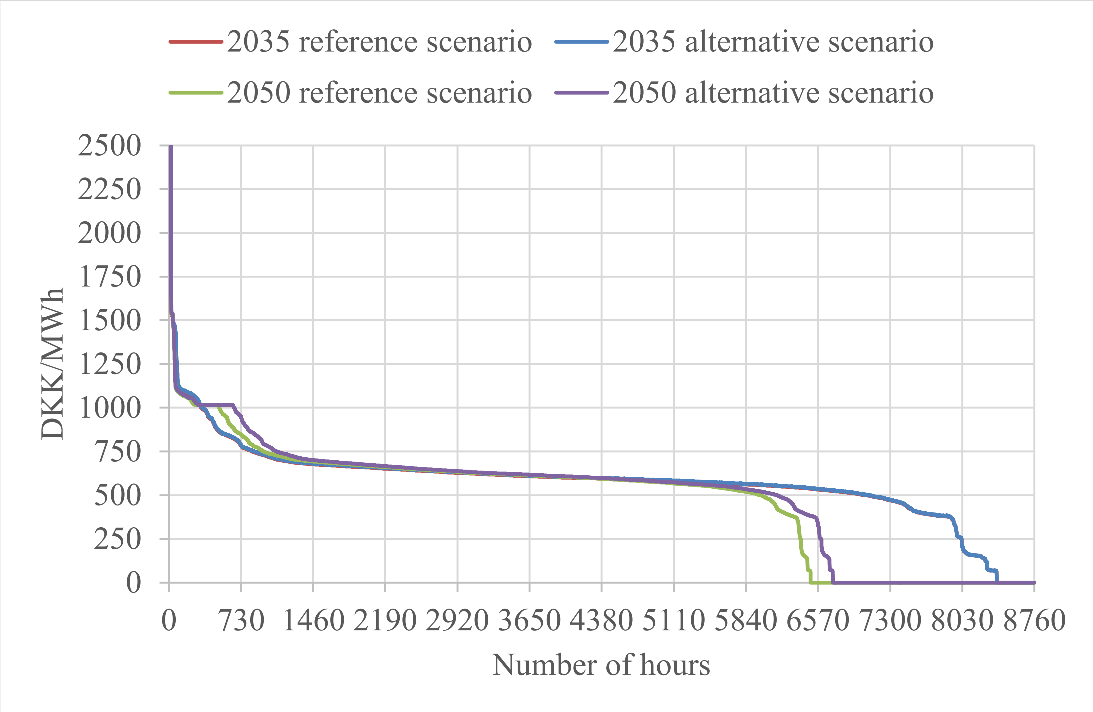


Figure 27: Hourly electricity prices in the four scenarios sorted from maximum to minimum.

In all four scenarios there are few hours of extreme high prices. The maximum price limit of 3,000 €/MWh is reached in all scenarios.

There is insignificant price deviation between the two 2035 scenarios. The majority of the prices are in the range of 500-750 DKK/MWh but the price reaches 0 DKK/MWh in approximately 400 hours/year.

In the two 2050 scenarios there are more than 2,000 hours where the price is 0 DKK/MWh, which is a substantial increase compared to the 2035 scenarios. The difference is caused by the higher production from wind power and limited export capacity, which is 6,000 MW in all scenarios. It should also be noticed that there is a difference between the two 2050 scenarios. Higher electricity demand in the FCEV scenario increases the electricity price and reduces the number of hours with a price of 0 DKK/MWh.

In the analysis, the critical need for balancing energy is estimated. Critical balancing needs is defined as CEEP and import problems. In such situation the full import or export capacity is fully exploited without the system is in balance. As mentioned, the import and export capacity is 6,000 MW in all scenarios. In the 2035 scenarios, there is no CEEP nor import problems, which indicates that there is no critical balancing problem in the systems. This is not the same as there is no need for balancing energy in the system. The actual need for balancing energy is estimated as a part of the technical and economic assessment for the HRS capability of providing balancing services. Higher electricity consumption in the FCEV scenario decreases the maximum need of export and increases the maximum need of import compared to the original 2035 scenario.

In the 2050 scenarios, the large production from wind power causes a critical need for balancing energy. There is no critical import problem but CEEP occurs for a significant amount of hours in both scenarios. Higher electricity consumption in the FCEV scenario reduces the total annual CEEP by approximately 1 TWh and reduces the maximum hourly CEEP by 500 MWh. The analyses indicates that the implementation of electrolyzers can contribute to better utilization of electricity production from fluctuation renewables and thereby contribute to balancing the grid in 2050.

6.2 Conclusions on technical and economic assessment of HRS balancing

From the technical perspective, additional balancing service supply requires higher electrolysis and storage capacities lowering the corresponding utilization of both devices. However, large additional investments are needed only to fully satisfy the demand for negative balancing by the electrolysis in 2050 whereas in all other scenarios the change in capacity is rather small. This is mainly due to the high peak demand for negative balancing in 2050. Based on the technical assessment of balancing services the overall electrolysis size in 2035 ranges between 0.7 GW_{el} in the reference (with a utilization of 7,800 hours) and 1 GW_{el} (7,100 hours) in the scenario with positive balancing through the fuel cell. The corresponding storage size is between 7 GWh_{H2} (as a 3 days storage) and 18 GWh_{H2} (as a 5 days storage).

Due to a trade-off between CAPEX and OPEX the capacities for electrolysis and storage are higher and the corresponding utilization lower in 2050 in comparison to 2035.

The electrolysis size in 2050 ranges between 1.8 GW_{el} (utilization of 5,500 hours) in the reference scenario and 3.9 GW_{el} (utilization of 2,500 hours) in scenario A where negative balancing is provided by the electrolysis. In addition, the storage dimensioning in 2050 ranges between 43 GWh_{H2} (as a 6 days storage) and 592 GWh_{H2} (as a 46 days storage). Due to its low temperature the waste heat from electrolysis and fuel cell can be also utilized for sales in the local heat market if a heat pump is included within the facility. The additional revenues from the sales of the heat of 1.2-1.8 TWh in 2035 and 2.1-3.0 TWh in 2050 can reduce the overall hydrogen costs by up to 0.36 €/kg_{H2} in 2035 and 0.31 €/kg_{H2} in 2050.

From the economic perspective, the specific hydrogen costs in the reference scenario (i.e. in the case without balancing services) range between 4 €/kg_{H2} in 2050 and 5 €/kg_{H2} in 2035. Major costs in both time steps are due to the electricity costs from electricity purchases in the spot market. CAPEX represented by the annuity of the investments in all HRS components have a smaller impact on the overall hydrogen costs. Balancing service supply is rather sensitive to the corresponding balancing prices in a limited range. As long as no additional electrolysis capacities are needed only the price difference between the spot and balancing markets is crucial.

The price for negative balancing must be substantially lower (below 50 €/MWh in 2035 and even negative in 2050) than the spot market price in the same hour in order to incentivize the supply of a large amount of the adequate service. For positive balancing comparatively high prices of 120-400 €/MWh in 2035 and 120-280 €/MWh in 2050 are needed to satisfy more than 80% of the total demand. Supply of positive balancing service is cheaper with electrolysis rather than with the fuel cell lower prices due to low roundtrip efficiency along the electrolysis-fuel-cell pathway and thus additional hydrogen production and costly investments in fuel cell and electrolysis capacities. Balancing services have the potential to decrease specific hydrogen costs by 0.5 €/kg_{H2} to 1.5 €/kg_{H2}.

Future research on the balancing services at HRS could include an explicit optimization of operation and sizing of an electrolysis-storage facility directly included within the electricity system simulation. In this way the actual impact of the electrolysis on the market prices can be analyzed. Moreover explicit modelling of the spatial dimension for different HRS locations based on the local hydrogen demand, availability of renewable energy and district heating would provide more detailed insights into the actual potential of the HRS for electricity grid balancing. Finally a simultaneous simulation of the electrolysis and energy system based on spatial distribution of balancing needs and hydrogen demand (i.e. neglecting the copper plate assumption) could be used to analyze the technical and economic differences between the hydrogen infrastructure and electrical grid.

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Appendix 1 – Grid requirements for hydrogen production and fueling

The technical requirements for HRS grid interface can be divided in two parts, requirements regarding feeding power to the electricity grid and requirements regarding using power from the grid.

The requirements regarding using power from the grid to produce hydrogen are not comprehensive as they only deal with how the electric consumption unit is connected to the grid and how this can affect the grid in terms of "polluting" the power quality. Regarding the electric production the requirements are much more severe as these not only contain demands regarding power quality but also contain requirements regarding topics as fault-ride-trough, islanding, regulating power quality aspects, measurements and communications and protection of the production unit.

Electricity production unit

The technical requirements for grid connection of production units to the Danish electricity grid is specified by Energinet.dk. The requirements for CHP are divided in two groups, plant with electric power between 11 kW and 1.5MW and plant with electric power above 1.5MW. We have focused on the smaller power group as this is the most relevant in this project as larger systems will require more development. However, if more systems with a combined electric power above 1.5MW the latter regulations is to be used.

The requirements for smaller power group can be found in "Teknisk forskift 3.2.4 – Termiske kraftværker større end 11 kW og mindre end 1,5 MW". It could be argued that a power plant consisting of a fuel cell generator should be made under the regulation "Retningslinjer for elproducerende anlæg med en mærkestrøm på over 16 A pr. fase". However, in our opinion this regulation is too simple to use with large HRS, because it is based on PV plants, that are normally smaller and consisting of a number of inverters. We therefore argue using the regulation for CHP's instead as this makes it possible for the grid company to regulate the production unit and thereby support the stability of the power grid.

The main purpose of the regulation is to ensure the technical quality and balance of the collective power grid and thereby ensure that the electricity production is continuously adapted to the consumption and that the voltage is maintained. The regulation is based on traditional coal or wood burning CHP's that procedure electricity using turbines and synchronous generators, which is why some of the requirements in the regulation is not applicable when installing a fuel cell generator. Requirements will therefore also be taken from other regulations.
Firstly, the requirement states that all production units with a rated power above 11 kW has to be built as 3-fased units to feed the power symmetrically to the grid.

Tolerance to voltage and frequency

The requirements also state that the production unit has to tolerate variations in frequency and voltage. The requirements are shown in figure 28 based on the assumption that the production unit is connected to the grid with a rated voltage of 10 kV.

As seen in the figure Ultra high frequency UHF (Upper voltage at rated load) and Ultra low frequency ULF (Lower voltage at rated load) are based on the typical voltage. As the typical voltage varies in different places in the country this is determined by the grid company in the area where the production unit is connected. The precise value will be determined according to the connection point in the power grid.

The figure below shows that the production unit is required to produce as close to its maximum power although the voltage or frequency falls out of the normal operation area. The requirements are shown as timeframes of how long the production should be maintained under specific circumstances and how much the maximum power can be reduced in these situations. The grid interface of the HRS has to be built according to these requirements.

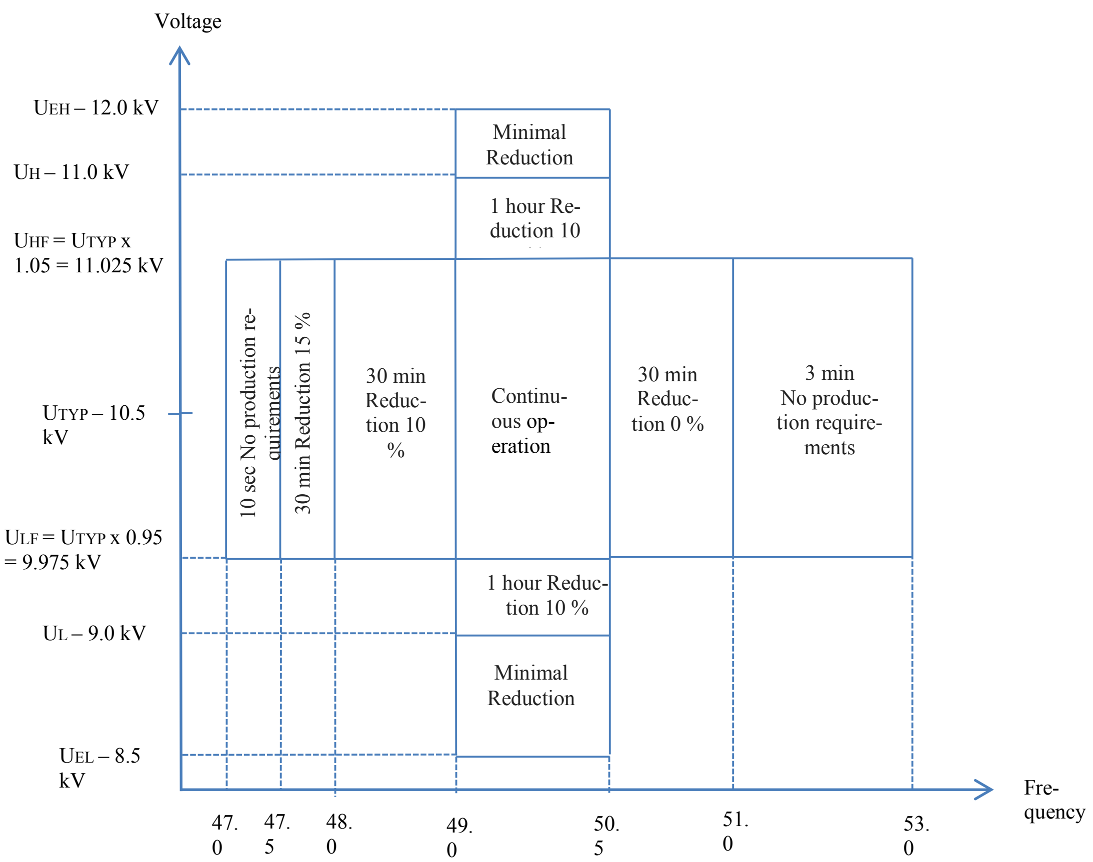

Figure 28: Tolerance to voltage and frequency

For example, when the power grid is operated when couplings are made in transformer stations this can cause voltage transients. The requirements shown in the figure will ensure that the production is not impacted by these, but the voltage transients can also damage the electronics in the production unit. Whether or not protection equipment against voltage transients should be installed can be discussed with the grid company as the amount of voltage transients caused by coupling varies according to the connection point.

The grid can also contain frequency transients when faults in the grid occur. The general requirement is that the production unit should be able to continue is production in spite of these frequency transients. As these transients are not very well known the specific requirement is that the unit have to tolerate frequency transients (df/dt) up to $\mp$ 2.5 Hz/sec in the connection point.

Tolerance to grid faults

All production units is require to work as stable as possible in the event of a grid fault, but there are specific requirements for units larger than 200 kW. These should be able to stay synchronized under specific grid faults and resume production as soon as the grid fault is over. It has to be able to tolerate a dip in the voltage of 50 % of nominal voltage on all 3 phases for 1 second and a dip in the voltage to 0 % in one phase for 1 second. In this situation the production cannot fall for more than 10 %.

Start and switching

The production unit is of course required to be able to start when the frequency and voltage is in the normal operating area but this should also be possible when the voltage is as low as U_L (9.0 kV with grid voltage of 10 kV). The unit has to be constructed so that the startup time is as low as possible but taken economy into account.

The production unit must be equipped with a synchronization unit which can switch in the production unit safely and stably to the grid, when within the normal operating area of the voltage and frequency, and to voltages as low as U_L. The production unit is not allowed to feed inrush currents so big that it can cause disruptive, passing voltage changes.

The production unit must be built in a way that insures that it cannot switch to the power grid when the power grid is not energized.

Active power production and frequency regulation

If the production unit has a nominal power above 200 kW it is required to be equipped with a fast reacting power/frequency regulator which can control the net power and perform power/frequency regulation safely and stably. The net power must be controlled via set points and must be controlled from as external signal. It must be able to regulate of the net power between minimum and maximum power but taking into account natural restriction caused by the productions units working process.

The power/frequency regulator must be equipped with droop that can set between 2%-8% with a resolution of 1 % or less.

Reactive power production and voltage regulation

Production units with a nominal power above 200 kW is required to be able to control and regulate voltage and power factors. As the requirements mentioned in "Teknisk forskift 3.2.4" are only applicable for synchronous and a synchronous generators it states that the requirements should be discussed with the grid company. However, requirements more usable can be found in "Teknisk forskrift 3.2.5" that contains the requirements for wind turbines.

In this it is stated that the production unit must have Q-regulation which is a regulation of the reactive power independently from the active power. This regulation must be done by set points from the grid company. When a new set point is received the unit must start the regulation within 2 sec and complete it within 30 sec. The accuracy of the regulation including accuracy of the set point must be no more than ∓ 2 % of the set point value or ∓0.5 % of nominal power, depending on which is greater. The production unit must the able to receive a set point with an accuracy of 1 kVar.

The production units must also have a power factor regulation which is a function that regulates the reactive power in proportion to the active power. The requirements are that the unit can receive a power factor set point with an accuracy of 0.001 and that timeframe and accuracy of the regulation is the same as for Q-regulation.

Regarding voltage control the production unit must be able to regulate the voltage in a voltage reference point. This regulation must have a setting range within the U_H and U_L as shown in figure 28 and have an accuracy of 0.1 kV. Regulation to a new set point must be stated within 2 sec of reception and must be done within 10 sec. The accuracy of the regulation must be no more than ∓ 2 % of the set point value or ∓0,5 % of nominal power, dependent of which is greater.

Protection

The HRS grid interface must contain function to protect itself and the grid from damage and interferences. The requirement regarding this is specialized according to the type of production unit and because the focus again is on synchronous and asynchronous generators, there are no specific requirements for this kind of production unit.

Therefore we once again look to the regulation regarding wind turbines. The general requirement is that the production unit must contain a relay with a setting that causes the production unit to disconnect from the grid when the frequency or voltage is outside certain values for a set timeframe. The values for wind turbines is not applicable for these kinds of plants as the relay setting for wind turbines will make it unable for the production unit to live up to the requirements of tolerance to frequency and voltage. These setting will therefore have to be discussed with the specific grid company is case of installation. But generally the relay must have 2 or 3 levels of over voltage and 1 level of under voltage, furthermore one level for over-frequency, and under-frequency.

Operation and maintenance

One last requirement not bound directly to the design of the grid interface but still very important in the aspect of the grid is that the production unit must undergo ongoing maintenance to ensure that the production unit is not a risk to the power grid.

Hydrogen production unit – electricity consumption

The requirements regarding grid interface for electricity consumption units can be found in the regulation "Teknisk forskift 3.4.1 – Spændingskvalitet". The purpose of this regulation is to ensure the technical quality and balance of the power grid. It specifies requirements regarding power quality, which the unit must comply with if it is connected to the power grid. The requirements are applicable in units connection point to the grid, this means that the power quality does not have to comply with the requirements in its own installation, but at the connection point they have to. In most cases though, the values in those two places will be very similar.

The first requirement is regarding balance of the voltage. The contribution of voltage unbalance from the consumption unit must not exceed the threshold of voltage unbalance by more than 1.4%. This is calculated according to the amount of power the unit can maximally draw from the grid and the amount of power the transformer station can deliver. This does not specify specific requirements for the grid interface, but shows that the place of installation and the power grid here is to be considered when choosing the place of installation.

There are also demands regarding harmonic distortion introduced to the grid. The total harmonic distortion must not exceed 3 % but there are also requirement regarding the individual harmonics. These values can be seen in the tables below. The harmonics are like the voltage unbalance, again calculated according to the power if the consumption unit and the transformer it is connected to, but more important the amount of harmonics the unit will produce. This means that the unit's grid interface must make sure that harmonics are not introduced to the grid in too high values.

Odd harmonics (not multiple by 3)					Odd harmonics (multiple by 3)			
5	7	11	13	$17 \leq h \leq 49$	3	9	15	$21 \leq h \leq 45$
2.0	2.0	1.5	1.5	$1{,}2 \times \frac{17}{h}$	2.0	1.0	0.3	0.2

Table 19: Threshold values of harmonic voltage U_h/U_n (%) for odd harmonics.

Even harmonics				
2	4	6	8	$10 \leq h \leq 50$
1.4	0.8	0.4	0.4	$0.19 \times \frac{10}{h} + 0.16$

Table 20: Threshold values of harmonic voltage Uh/Un (%) for even harmonics

Flicker is also a thing to be looked at because the consumption unit can interfere with the grid if there is too much flicker. Flicker is formed when units are switches on and off often. Please see the thresholds in the graph and table. The graph shows how many percent the voltage can chance and how many couplings can be made within a given timeframe. The table says that the intensity of flicker over short time must be no larger than 0.8 and for the long time intensity 0.6. How this is calculated can be seen in the regulation.

This means that the grid interface of the consumption unit must ensure that the unit does not feed to much flicker to the grid. In practice this unit will be switched on not often as the production will go on for some time to fill the fuel tanks, but maybe we can imagine a situation with much switching if the production is controlled by the price of the electricity. That means that there might be a situation where production is turned on and of "rapidly" due to varying price signals, so in reality there is limitations from the grid on how many startups there can be in a given period.

One last requirement is that the power factor of the consumption unit must not be smaller than cos φ of 0.95. This should not be a problem with a fuel cell generator.

Appendix 2 – Heat pump assumptions

For the cooling of the electrolysis or fuel cell we use water. From the fuel cell we get 60°C with a flow on 70,000kg/h (see figure below).

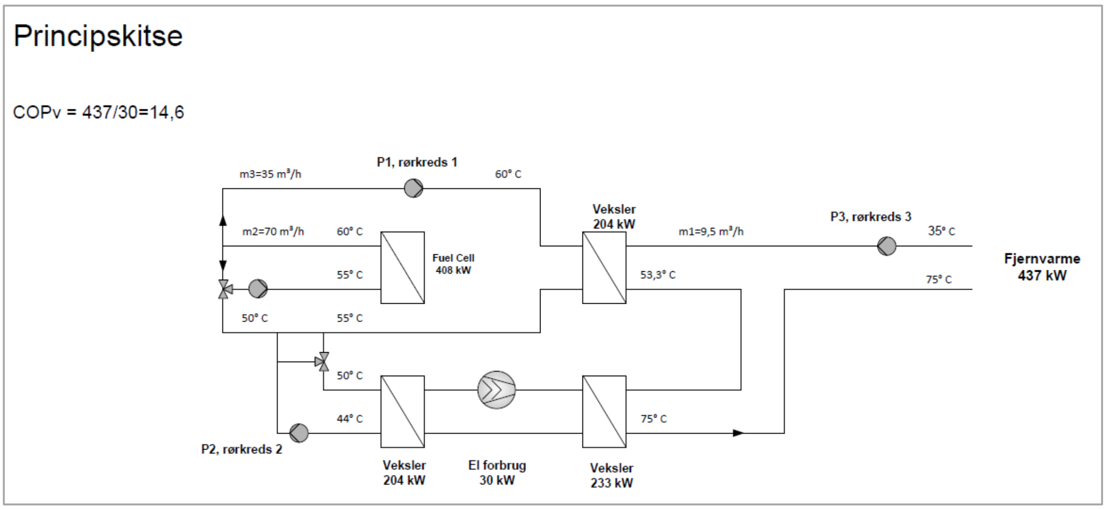

Figure 299: Heat pump assumptions

The flow can be separated in to two lines.

1. 32000kg/h goes to a district heating, heat exchanger where the temperature on the district heating can rise from 35°C to 53°C and the return temperature for the fuel cell will be 55°c
2. 38000 kg/h goes to an evaporator for a heat pump, and will here be cooled from 60°C to 55°C

The return from 1 and 2 will be merged and lead back to the electrolysis or fuel cell. The 53°C water from the district heating exchanger will be lead into a condenser from the heat pump. Here the temperature will rise from 53°C to 75°C. The district heating will be supplied to the forward line on the district heating system and when in use it can substitute about 437 kW of the district heating production. The district heating lines must be able to consume 32,000 kg/h of hot water in order to keep the system running, and also it must be guaranteed that the water from the return line never exceeds 35°C, If needed a cooling tower can be installed.

The energy needed to run this process will be 30 kW for the heat pump, and about 7 kW for the circulation pumps. A total of 37 kW electricity, to produce 437 kW heat. This is a heating COP at 437/37 = 11,8 meaning that for every kW electricity we get 9,7 kW district heating. The overall investment outlays for a such heat pump system are estimated at 1,600,000 DKK (or ca. 215,000 €). Together with an additional 5 days heat storage required to balance out heat production by the electrolysis or fuel cell and the continuous heat demand the overall system is expected to cost ca. 3,300,000 DKK (or 305,000 €). This corresponds to specific investment outlays of ca. 5,600 DKK/kWh$_{Th}$ (or 747 €/kWh$_{Th}$). The expected lifetime is 30 years.