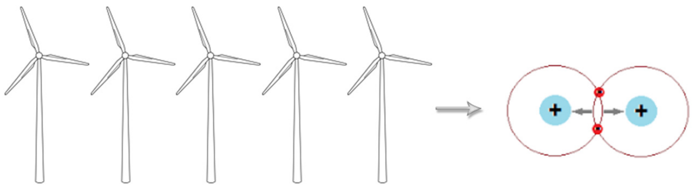
Power2Hydrogen



WP1

Potential of hydrogen in energy systems

Preface

This report presents results of the research project Power2Hydrogen, 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 Power2Hydrogen project is to analyse the operation of a PEM water electrolysis plant situated in Hobro, Denmark. The aim is to demonstrate feasible load shifting and the possibility of using the electrolyser unit to balance the electricity system while producing green hydrogen for high value markets such as industry and transportation.

The Power2Hydrogen project is divided into a series of work packages (WP) and this is the reporting of the work in WP1 "Potential of hydrogen in energy systems".
The partners in the Power2Hydrogen project are

Air Liquide
CEMTEC
Neas Energy
EMD
Aalborg University, Department of Development and Planning
Aalborg University, Department of Energy Technology

The Power2Hydrogen project runs from 2015 to 2017.

This report was finalized April 2016

Table of Contents

Abbreviations

BRP	Balance Responsible Party
BTL	Biomass-to-liquid
CAES	Compressed air energy storage
CEEP	Critical Excess Electricity Production
CHP	Cogeneration of heat and power
COP	Coefficient of performance
CRP	Consumption Responsible Party
CCS	Carbon Capturing and Sequestration
DC	Direct Current
DEA	Danish Energy Agency
DH	District heating
DK1	Denmark 1; the spot market pricing area in Western Denmark
DME	Di-Methyl-Ether
EV	Electric vehicles
FC	Fuel cell
FC	Fuel Cell based
FLH	Full Load Hours
HP	Heat pump
LHV	Lower Heating Value
MC	Motor cycles
n/a	Not available
n.d.	No data
NG	Natural gas
P2H	Power to Hydrogen
PEM	Proton Exchange Membrane
PEMEC	PEM electrolyses cells
PEM WE	Polymer Electrolyte Membrane Water Electrolyser
PES	Primary Energy Supply
PRP	Production Responsible Party
PV	Photo Voltaic
REN	Renewable Energy
RES	Renewable Energy Source
SMR	Steam Methane Reforming
SNG	Synthetic natural gas
ST	Steam Based
TSO	Transmission System Operator
UCV	Upper Calorific Values
UHV	Upper Heating Value
WP	Work package

Executive Summary and conclusion

Production of hydrogen could be one of the import contributions to the future energy system with a much higher share of fluctuating renewable energy sources. Production of hydrogen is a flexible electricity demand and even combines the different energy sectors: Electricity, heat, gas and transportation and even with the possibility of storing large quantities of energy. This report has analysed the different electricity markets that flexible electricity demand could potentially participate in.

The trading strategy can be designed in many different ways depending on the specific plant, but based on this market review the most relevant markets for a P2H plant are the spot market and the regulating power market. The primary and secondary reserve markets are relatively small in DK1 compared to the other markets. The tertiary reserve market (regulating power market) is more interesting for flexible demand such as electrolysis. In this market, bids of just one hour can be offered and these bids can be changed until 45 minutes before operation. With this option, it is easier for a plant to participate in multiple markets and adjust the production plan according to the need for hydrogen. One strategy could be to buy the needed electricity for the coming day on the spot market and within the day of operation offer upward and downward regulation in the regulating power market to the extent that electricity is dispensable or extra electricity can be consumed. In addition to this strategy, the intraday market could also be used as a way of balancing the produced hydrogen and the demand for hydrogen.

The aim for Hydrogen Hub Hobro is to study and demonstrate which role hydrogen could play in the future interaction between energy systems, combined heat, power and transportation. The municipalities have had the foresight to allocate a dedicated area for hydrogen purposes in the industrial area and this has meant the collection of competences which form a strong basis for development of the wider Hobro area as a demonstrating site for hydrogen technologies and business models. Furthermore there is an advanced industrial company in Hobro using hydrogen in their production and a location of large salt domes in the vicinity.

Hydrogen could be a key component in the electrification of the transport sector – though not necessarily in pure form. In its pure form, hydrogen has the advantage of not requiring a source of carbon and the fuel is appropriate for fuel cells, however the volumetric density is low, and high pressure / low temperature is required to store hydrogen in its liquid phase. Thus, from a user point of view, synthetic fuels synthesising hydrogen and other elements could be preferable. From a system's perspective, optimum hydrogen-based or assisted synthetic fuel pathway depends on factors including whether RES-based power production or biomass availability is restricted, whether there is a heat demand that may be covered by any excess heat generation from the process, how particularly CO2 is sequestered as specific energy demand varies with source (sequestration from the atmosphere or sequestration from combustion processes).

The electrolysis technologies alkaline, PEM and SOEC, are all in principle capable of meeting the requirements that are necessary to operate on the investigated electricity markets in terms of dynamic operation capabilities. Still, there are distinct differences that are important to point out:

- The alkaline electrolysis technology has a lower turndown ratio than PEMEC.
- The PEMEC technology is capable of delivering hydrogen at higher pressures than both of the other technologies which is important in relation to fuelling stations
- The PEMEC has a higher turndown ratio and delivers high hydrogen purity.

It should also be stressed that this conclusion is associated with some uncertainty as limited real life experience exists in this field (mostly with PEMEC and SOEC in particular) and not much information is available in the open literature.

A number of relevant scenarios are described in order to examine the role and importance of hydrogen in the perspectives of different research and governmental institutions. This includes a general qualitative overview of the energy system as well as a quantitative description of installed capacities of different energy production or conversion technologies, the specific types of technologies included and technology characteristics where available. The assessment investigates more specifically the use of hydrogen in the scenario focusing on which end-use sectors are supplied by hydrogen, and in what constellations hydrogen is used (directly or indirectly through synthetic fuels).

In only two of the four scenarios from the Danish Energy Agency are there hydrogen production. These are the wind scenario and the hydrogen scenario. Only in the latter is there direct use of some of the hydrogen. Otherwise the hydrogen is used for hydrogenation, production of biokerosene and biodiesel and for upgrading of biogas.

The CEESA-2050 scenario from 2011 considers two conversion technologies, which include hydrogen: Co-electrolysis and bioenergy hydrogenation which are primarily used within the transport sector.

Hydrogen covers around 4% of the total energy demand in the IDA-2050 scenario. It is either used in fuel cells for heat and electricity or for transport. In the latter sector, it is assumed that 20 % of all passenger cars and 25 % of trucks and busses are plug-in hybrid vehicles running on hydrogen or DME. In general, all power and CHP plants are based on fuel cells. Electricity demand for hydrogen production equals 15% of total electricity consumption in the IDA-2050 scenario.

Most of the studies do not mention details regarding electricity market integration or grid-balancing function of hydrogen. None of the studies mentions the use of hydrogen production in other than the spot market. In scenarios with hydrogen, hydrogen will primarily play a role in the transportation sector.

Use of hydrogen in the energy system is given little attention in the reviewed European studies. In the studies reviewed here, hydrogen is only mentioned in connection with the transport sector.

In the Roadmap2050 scenario, hydrogen is considered a part of the solution in transportation, however electrolysis is only one in three identified production technologies. Others are based on fossils and/or biomass sources. In Power Choices and eHighway, hydrogen is identified as a potential energy carrier but its potential usage is not quantified.

The last part of the study is a modelling of the energy systems in EnergyPLAN, a tool developed by Aalborg University. EnergyPLAN simulates the electricity, heating, cooling, industry, and transport sectors of an energy system. EnergyPLAN is purposely designed to be able to identify and utilise synergies across the sectors in the energy system. Different scenarios were created based on the energy systems in 2013 and 2035. The purpose is to identify what role electrolysers can play and how electrolysers can contribute to balancing these systems, in particular when the wind power share increases.

Modelling a high renewable energy year 2035 scenario from the Danish Energy Agency investigates the system effects of adding electrolysers to the system. In this scenario, the use of hydrogen is limited and thus impacts of electrolysers on the system were also limited. Adding more wind to the scenario increases the importance of the flexible electricity consumption by enabling the system to integrate wind power better. Increasing the hydrogen demand and increasing electrolyser capacity also enables better integration of wind power.

1 Introduction

This report is prepared as part of Work Package 1 in the Power2Hydrogen project with the general purpose to estimate the potential use of hydrogen in the energy sector, the potential use of electricity for hydrogen production for balancing the electricity system, and as well as to set the general frame for the rest of the project.

1.1 Structure of the report

The report is structured in four chapters:

Chapter 1 serves as introduction to the report. In this chapter different aspects of hydrogen solutions are introduced.

The first section describes the setup in Hobro where a 1.25 MWe Power2Hydrogen plant will be situated in 2017 as a part of the HyBalance project. The plant is introduced as well as the synergies related to the location of the plant in Hobro. Section 1.2 describes the different electricity markets in Western Denmark with a view to identifying which markets such a plant may operate within. Section 1.3 provides a technical overview of different commercial and pre-commercial electrolysis technologies and their grid balancing potential. Finally, in section 1.4 different hydrogen solutions for the transportation sector are described as a basis for the use of electricity in the energy systems in Denmark. Hydrogen may be used for several purposes and we introduce different energy conversion systems that directly use hydrogen or use hydrogen in the production of synthetic fuels. This section gives an understanding of the different possible solutions that could be used in the scenarios later in the report.

The introduction acts as the scope for the remaining analyses in the report.

Chapter 2 provides an overview of different relevant energy scenarios of the Danish energy system and Chapter 3 provides the same at a European level. The aim is on the one hand to establish an overview of various external energy actors views on the role of hydrogen in the future Danish and European energy systems, and on the other hand to provide a basis for the scenario analysis in chapter 4 and the rest of the project.

Chapter 4 provides an analysis of the future need for balancing in the Danish electricity system. The modelling tool EnergyPlan developed by Aalborg University for energy system, simulation and analysis is used for this purpose. The analysis is based on an estimation of the composition of the future energy systems including electricity, heating and transportation.

1.2 Hydrogen in Hobro

Hobro, with approximately 12,000 inhabitants, is a town in northern part of Denmark (see Figure 1). The town and surrounding area is highly focused on hydrogen as a part of the future energy system in Denmark and abroad.

The interest in investigating the development of technologies and business cases based on hydrogen in the Hobro area follows several pathways:

Hydrogen Valley Knowledge and Business Center

For more than a decade Hydrogen Valley Knowledge and Business Center (formerly Center for Energy and Materials Technology, CEMTEC) has successfully facilitated, networked and raised funds in partnerships with private companies, public authorities, universities and other research institutions. The overall aim has been to create jobs and development in the hydrogen and fuel cell sector, as well as to form a nexus between the different partners with hydrogen activities in the area.

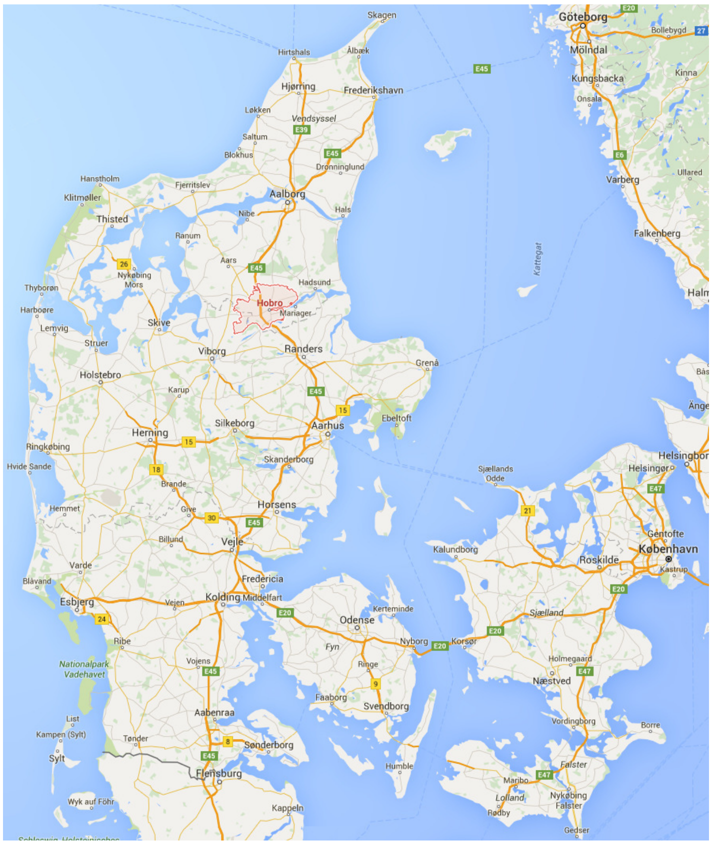


Figure 1: Hobro in Northern Denmark: Image from maps.google.com

Sintex

The company Sintex – a 100 % owned subsidiary of Grundfos – has been developing and manufacturing stainless steel sinter metal parts processed in hydrogen ovens since the establishing of the company in 1997. Today the consumption of high quality hydrogen is approx. 400,000 Nm^3/y but is expected to increase substantially due to the success of the company's technology. Today the hydrogen for the sinter ovens is partly supplied by a small and outdated alkaline electrolyser and partly from hydrogen cylinders imported from an SMR (Steam Methane Reforming) facility in Hamburg. The company seeks a greener profile and is expected to be an important customer for green, locally produced high quality hydrogen from the new PEM electrolysis plant in Hobro. Furthermore, experience and know-how on handling of hydrogen in an industrial scale, including safety issues, are locally present in the company as well as at the local authorities.

Salt domes

The unique presence of salt domes in the underground nearby Hobro with the potential of making caverns for large-scale storing of different gasses including Compressed air energy storage (CAES), methane (natural gas/bio-methane) and hydrogen. Since the beginning of the sixties AkzoNobel has produced vacuum salt from the Hvornum dome 5 km west of Hobro and for decades Energinet.dk Gaslager (The Danish TSO) has operated a large natural gas buffer and strategic storage facility, consisting of seven caverns, in the Lille Torup dome 20 km west of Hobro.

Hydrogen Valley Knowledge and Business Center is facilitating a feasibility study between AkzoNobel and Energinet.dk Gaslager with the aim to create a unique sustainable way of producing and operating largescale gas storage facilities to be used in the future Danish or European self-sufficient and carbon neutral energy system. By disposal of the salt brine for salt production and the managed handling of the waste (heavy metals etc.), the production of the caverns for gas storage can take place in an environmentally and economically much more optimal way than if the brine was just led out to the sensitive water environment.

Hydrogen transport

In addition to the above-mentioned natural presence of the salt domes and the historic build-up of know-how and competence around hydrogen and fuel cells in the wider Hobro area, there is a strong wish in Europe, Denmark and Region North Denmark to establish a transport infrastructure independent of imported fossil fuels. There are specific plans to establish a hydrogen bus project in Region North Denmark with busses in operation in Aalborg (60 km north of Hobro) and Hobro and between the cities. Furthermore there are plans to establish a service centre for the busses in partnership with Dantherm Power, who already manages the service of the fuel cells in the busses running in Europe from the Belgian bus producer Van Hool.

Further development of hydrogen activities in the Hobro area

The location of a dynamically operated 1.25 MW_e PEM electrolyser in Hobro Business Area South will furthermore contribute to the development of hydrogen activities in Hobro. To increase the overall energy efficiency of the electrolyser, the cooling heat will be sought integrated in the planned establishing of a district heating grid in Hobro South. Currently, only the Northern part of Hobro has district heating while the southern part relies on individual solutions

Furthermore, the experience from the operation of the PEM electrolyser both technically and economically will serve as input for the construction and operation of a methanation plant using the capturedCO_2 from a planned biogas upgrading plant in Hobro North as source for the production of synthetic methane.

All in all these facilities and the competences form a strong basis for further plans for development of the wider Hobro area as a demonstrating site for hydrogen technologies and business models and the role hydrogen will play in the future interaction between energy systems, combined heat, power and transportation: Hydrogen Hub Hobro.

1.3 Electricity market structure

This section describes the electricity markets in Western Denmark (DK1). These markets constitute the potential platforms on which electricity to be consumed by a PEM electrolyser situated in Hobro, could be traded. A PEM electrolyser in DK1 can potentially trade electricity on the following six different platforms:

Wholesale trading

- Day-ahead market (Spot market)
- Intraday market (Elbas)
- Bilateral contracts

Ancillary services[1]

- Replacement reserves (tertiary reserves)
  - Manual reserves (availability market)
  - Regulating power market
- Primary reserve market (frequency containment reserves)

[1] Ancillary services also includes Short-circuit power, reactive reserves and voltage control, but these services will not be included here since they are not relevant for the electrolyzer as there are not real markets for these services

- Secondary reserve market (frequency restoration reserves)

All of the above, except bilateral contracts, are market-based trading platforms. Each has different deadlines for when bids must be submitted, which is related to the purpose of each market.

The overall purpose of the electricity markets is to ensure a balance between produced and consumed electricity. By far the most of the electricity is traded in the day-ahead Spot market and most of the balance between supply and demand is secured in this market. However, incidents like outages of power plants, transmission system components or major consumers may take place between the deadline in the Spot market and the hour of delivery the next day. To make up for such incidents, buyers and sellers can trade electricity in the Elbas market down to one hour before delivery.

In case of incidents after the closure of Elbas, the reserves offered in the reserve markets will be activated in order to bring balance between the supply and demand. This could for instance be caused by a quick drop in wind power production. If this happens, the frequency in the grid will begin to decrease and the primary reserves will be activated to stop this decrease. Next the secondary reserves will be activated to bring back the frequency to 50 Hz and finally the tertiary reserves will replace the primary and secondary reserves as can be seen in Figure 2.

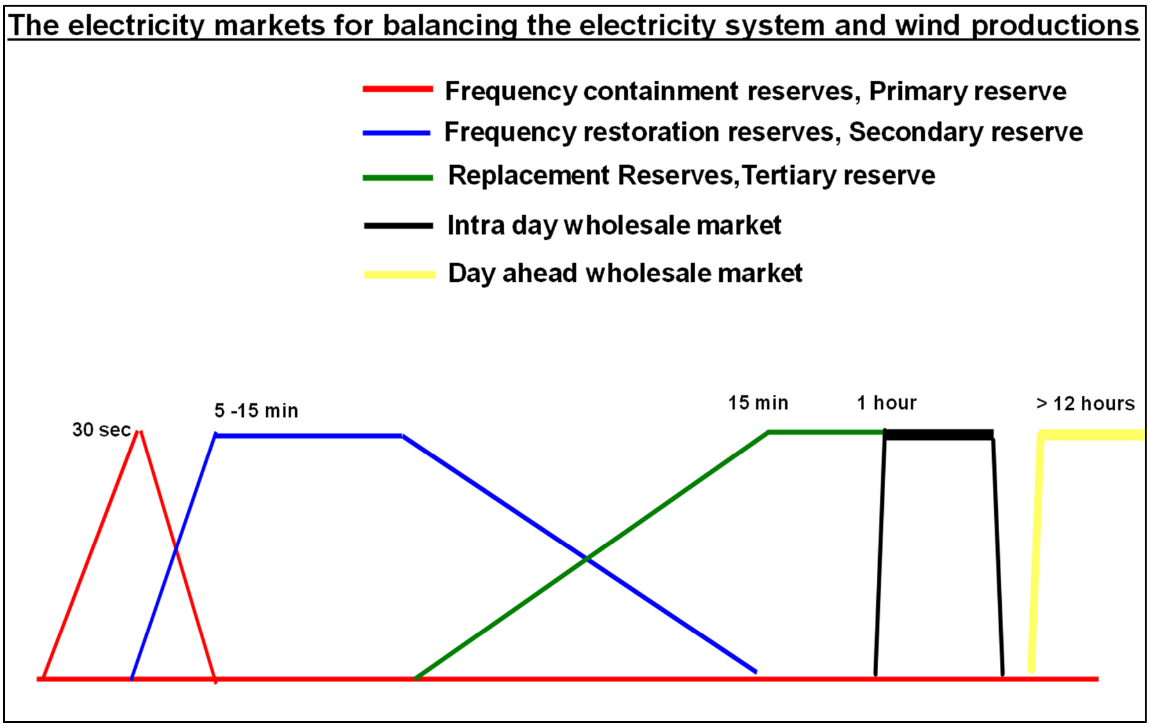


Figure 2. The five main electricity markets in DK1

Besides replacing the primary and secondary reserves, the tertiary reserves are also used by the transmission system operator (TSO) to take pre-emptive action and avoid the situation arising.

1.3.1 Main stakeholders

Prior to a more thorough description of the different trading platforms, the main stakeholders in the Danish electricity markets are briefly presented:

Transmission system operator (Energinet.dk)

The transmission system operator is responsible for maintaining the overall grid stability by balancing production and consumption of electricity. In case of discrepancies between the production and consumption of electricity, the TSO can use different balancing mechanisms to ensure that production and consumption are in line.

Balance Responsible Party

A balance responsible party (BRP) are responsible for balancing their own portfolio. The balance responsibility is distinguished between consumption, production and trade and a BRP may be responsible for one, two or all three areas. Neas Energy, for instance, are all three. Only BRPs can trade at the markets and deliver balancing services to the TSO.

Production responsible parties (PRP) trade electricity in the different electricity markets on behalf of electricity producers. If the production does not match the amount of electricity sold, the PRP is said to be in imbalance. The PRP is held financially liable for the cost which the TSO has for removing any potential imbalance caused by the producer. The cost of balancing the system is typically passed on to the stakeholders creating the imbalance.

Consumption responsible parties (CRP) trade electricity in the different electricity markets on behalf of electricity consumers. If the consumed electricity does not match the amount bought, the CRP is said to be in imbalance. The CRP is held financially liable for the cost which the TSO has for removing the potential imbalance.

Electricity suppliers

The electricity suppliers – or trading companies – sell electricity to the end-consumers. Electricity suppliers buy the electricity through a CRP. In this project Neas Energy is the electricity supplier for the P2H plant.

Electricity producer

Electricity producers produce and sell electricity on the above-mentioned platforms through a production responsible party (PRP). Producers cannot directly trade electricity in these markets unless they are an authorized PRP – approved by the TSO.

Electricity consumer

Electricity consumers buy electricity though electricity suppliers. Consumers cannot directly trade electricity in these markets unless they are an authorized CRP – approved by the TSO. A power to hydrogen (P2H) plant is in this regard an electricity consumer.

1.3.2 Day-ahead wholesale market (spot market)

The day-ahead wholesale market is operated by NordPoolSpot and is the primary market for trade of electricity in Denmark and the other NordPool countries. The day-ahead market is a 24-hour power exchange where electricity is traded for a period of 24 hours the coming calendar day (operation day) based on bids and offers from the consumers and producers. On behalf of the producers, the PRP send their offers to Nord Pool Spot containing the quantity of electricity they wish to sell (in MWh) in specific hours, as well as the price. Similarly, the CRP will send bids to Nord Pool Spot on behalf of consumers containing the quantity of electricity they wish to purchase (in MWh) in specific hours as well as the price per MWh.

Bids and offers can be submitted the following ways:

- Hourly orders: Specific volume and price for a given hour
- Block orders: Specific volume and average price for a minimum of three consecutive hours
- Flexible hourly orders: Single hour sales order where the hour is not specified

Hourly orders can be made as either *price dependent* orders or *price independent* orders. Price dependent orders are bids/offers that are only traded if the electricity price reaches a certain level while price independent orders are bids/offers that accept the best possible price, meaning that all orders will win the trade.

The day-ahead system price is determined by the intersection between the aggregated supply and demand curves, as illustrated in Figure 3. All bids and offers left of the intersection will be accepted and all to the right will be rejected.

The exchange is based on a marginal pricing system meaning that all accepted orders are settled at the same price (as opposed to pay-as-bid markets).

These are the main principles in the calculation of the spot price, but due to grid bottlenecks between price areas, the process is slightly more complex and the spot price will not always be the same in all price areas.

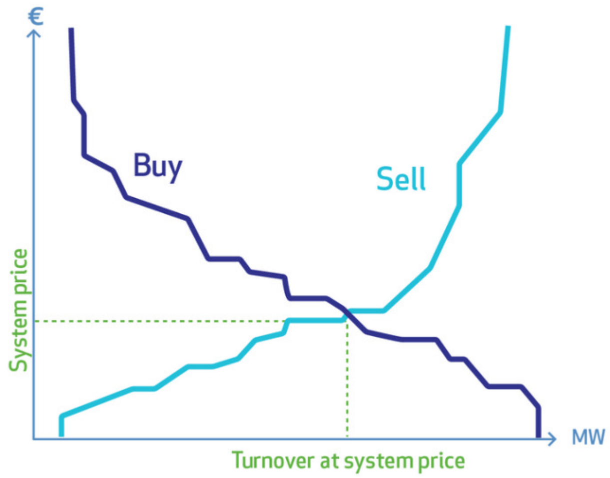


Figure 3. Calculation of the system spot price (NordPoolSpot).

Procedure for participating in the spot market:

- The bids and offers of electricity for the coming day must be sent to Nord Pool Spot no later than 12.00
- At 12.30 Nord Pool Spot notifies the TSO and the BRPs about the traded orders.
- At 15.00, the BRPs must send a notification containing the scheduled production and consumption for the coming day to the TSO. The notification can be updated until 45 minutes before the hour of operation and is used by the TSO to estimate the need for regulating power and subsequently handle potential imbalances.

A P2H plant participating in the day-ahead wholesale market

A P2H plant can either make price dependent or independent hourly orders, block orders and flexible hourly orders. Assuming that the plant operator wants to purchase 1.25 MWh electricity at a bidding price of 50 EUR/MWh in a given hour, the P2H plant then sends an hourly order for the specific hour to the CRP, which will pool the bid with other orders and send it to Nord Pool Spot. If the spot price in that hour is higher than 50 EUR/MWh the bid is not traded. On the other hand, if the spot price was instead e.g. 30 EUR/MWh, the P2H plant wins trade and must pay 1.25 MWh*30 EUR = 37.5 EUR to Nord Pool Spot.

Current and historical spot prices for DK1 can be found at: (Energinet.dk 2015).

1.3.3 Intraday wholesale market (Elbas)

The intraday wholesale market, which is also operated by Nord Pool Spot, opens after the closure of the day-ahead spot market. The purpose of the intraday market is to provide a platform for the market participants where electricity can be traded after the day-ahead market has closed, so that foreseen differences between scheduled operation and actual operation do not lead to imbalances. In this way, Elbas functions as a balancing market for the day-ahead market.

If for instance the expectations to how much a wind turbine will produce change after the Spot market has closed, it is possible for the BRP to trade "into balance" on Elbas, in order to adjust the traded volume with the expected production.

The intraday market opens at 14.00 the day before and closes one hour before the hour of operation. The price is settled by "pay-as-bid", meaning that all matched offers will receive the price offered.

Orders on Elbas are sent the following ways:

- Hourly orders: Bids/offers in a specific hour
- Block orders: Bids/offers on 1-32 consecutive hours

A P2H plant participating in the intraday wholesale market.

There are two ways for the P2H plant to participate in the Elbas market. If the power is not purchased in the spot market for the hour in question it is possible to submit a purchase bid for a particular volume at the Elbas market for the hour in question. If a counterpart is willing to sell that volume at the asked price, the trade is made and the P2H plant is activated in the hour in question.

On the other hand it is possible to sell back power bought in the spot market. A sell bid can be placed on the Elbas market in the hours where power is bought in the spot market. If a counterpart is willing to buy the specific volume at the asked price the trade is made. This is executed by not consuming electricity for the hour in question.

Current and historical Elbas prices for DK1 are found here: (Energinet.dk 2015).

Bilateral contracts

A bilateral contract is an agreement on trade of electricity between two players in the market outside the power exchange. These players must be BRPs, since it is only balance responsible parties that are allowed to make notifications.

It is not possible to make a bilateral trade between two different price areas because Nord Pool Spot allocate all the transmission capacity between the Nordic price areas. For a plant situated in DK1, it is therefore only possible to make a bilateral trade with stakeholders within this same area.

1.3.4 Replacement reserves (tertiary reserve/manual regulating power market)

The replacement reserves are mostly referred to as manual reserves or regulating power, which are actually two parts of the same market – the availability market (reserve market) and the activation market (regulating power market).

The physical purpose of regulating power is for the TSO Energinet.dk to replace the activated primary and secondary reserves with manual regulating power and thereby ensure that as much primary and secondary reserve capacity as possible is available for stabilising the grid frequency. Furthermore, the TSO also use regulating power proactively by forecasting imbalances and taking pre-emptive action to avoid imbalances. This is done by activating downward or upward regulation. The TSO will procure upward regulation in hours where less electricity is produced than is consumed, and conversely the TSO will procure downward regulation when more electricity is produced than consumed.

Procedure for participating in the auction for manual reserves

- At 9.00, Energinet.dk publishes the need for reserve capacity for the next day.

- Before 9.30, the actors can make offers for the capacity auction. The offers must contain both a price and a capacity of a size between 10-50 MW.
- At 10.00, the actors will be informed about whether their bids are accepted or not.
- At 11.00, Energinet.dk publishes the purchased volumes and prices.
- When a reserve agreement is made with Energinet.dk regulating power offers of minimum ±10 MW must be submitted before 17.00 for every hour where availability payment (reserve payment) has been won.

Reserve agreements are made in order to ensure that there are always sufficient bids on the manual regulating power market for the TSO to call upon. The manual reserve market is a marginal price market, where the last bid accepted sets the price.

If a reserve agreement is not made, the actors can still submit regulating power offers, but this is not required. Offers can be made and adjusted until 45 minutes before the hour of operation. Also in this market the price is determined by the marginal pricing system, meaning that the most/least expensive unit sets the price for all accepted bids, depending on whether it is up or down regulation.

In order to be able to participate in this market, the unit must be able to ramp up to the quantity offered within 15 minutes after activation. Once activated the unit is guaranteed a minimum operation of 30 minutes.

The minimum bid size of 10 MW applies for the bids given by the BRP, but these can consist of several smaller aggregated bids. This means that also units with a capacity below 10 MW can participate in this market if the BRP is able to pool several units to a combined capacity of more than 10 MW.

A P2H plant participating in the replacement reserve market

Given that a P2H plant is able to ramp up/down its consumption within 15 minutes, it is possible for the plant to operate at this market. If the capacity of the plant is less than 10 MW, it must be pooled with other consumers by the BRP and a collective regulation bid can be made.

Since a P2H plant is a consumption unit, it can offer downward regulation when it is not operating, upward regulation when it is in operation – or both if operated at partial load.

1.3.5 Frequency containment reserves (primary reserves)

The purpose of the frequency containment reserves (also referred to as the primary reserve market) is to stabilize the frequency when it changes due to discrepancies between produced and consumed electricity in the grid. The primary reserve only provides power until the secondary and manual reserves take over.

The primary reserves can be either production or consumption units, being able to detect variations in the grid frequency and automatically react to these variations within 15-30 seconds by turning up or down its production or consumption. To be able to offer this service a unit must have special equipment installed that can detect changes in the grid frequency. Due to these requirements, it is only units that have been preapproved by the TSO that can participate in this market.

The TSO purchases primary reserve capacity on daily auctions where units can offer either positive or negative bids of 4-hour blocks for the following day. All accepted bids receive an availability payment corresponding to the auction's marginal cost, i.e. the price of the most expensive accepted bids for positive and negative reserves.

Procedure for participating in the auction for primary reserves:

- Before 15.00, Energinet.dk must receive bids for the following day.
- At 15.30, Energinet.dk announces the accepted volumes and prices.

A P2H plant participating as frequency containment (primary) reserve

A P2H plant can participate in the primary reserve market if it is able to ramp up or down its consumption within 30 seconds. If this is possible, it will be paid an availability payment for being available, but its operation is restricted to what is needed by the system.

Historical availability payments can be seen here (in Danish): (Energinet.dk 2015) or at EMD's website (EMD 2015).

1.3.6 Frequency restoration reserves (secondary reserves)

The purpose of the frequency restoration reserve (secondary reserve) is to bring back the frequency to a level of 50 Hz once the primary reserve has stabilized the frequency at a level close to 50 Hz. Furthermore, the secondary reserves compensates for system imbalances that are too small for activation of regulating power.

Units participating as secondary reserve must be able to activate within 15 minutes and have a control system in place, which can respond to a signal from Energinet.dk. Bids in the secondary reserve market must be *symmetrical* meaning that bids have to be both positive and negative reserves of equal sizes.

As for the primary reserves, availability payments are won on auctions, but in this market, it is settled after the pay-as-bid principle. All participating units will however, receive the same payment for the energy delivered. The price, paid by the TSO for positive reserve is equal to the spot price + 100 DKK/MWh, but never less than the upward regulation price in the manual regulating market. The price, paid to the TSO for negative reserve is equal to the spot price - 100 DKK/MWh, but never more than the downward regulation price in the manual regulating market.

Energinet.dk and the Norwegian TSO, Statnett, have made a five-year agreement of 100 MW of secondary reserve capacity via the 700 MW DC Skagerrak 4 interconnector between DK1 and Norway. With this agreement, which runs from January 6, 2015, Energinet.dk will not buy secondary reserve in DK1 unless the interconnector has a failure.

A P2H plant participating as frequency restoration reserve

A P2H plants participating as secondary reserve receives first an availability payment for being available and an activation payment in cases of activation.

1.3.7 Settlement of imbalances

After the hour of operation, discrepancies between market participants' scheduled and actual operation are settled following a set of rules defined by Energinet.dk. This process is often referred to as the Balancing market, although it should not be considered as a market or even a trading platform, but rather as a procedure, where the cost of system imbalances is made up.

The cost of balancing production and consumption is reflected in the manual regulating power market. If for instance a power producer has produced differently from notified, the cost of covering this shortfall is determined in the regulating power market as an upward regulation price or a downward regulation price, depending on whether the system is in deficit or surplus of power.

In principle, the previously mentioned markets handle the physical balancing of the grid and the balancing market handles the costs paid for this balancing. The way the cost associated with activating reserve capacity is passed on to the player creating an imbalance, is done following two different pricing systems – the *one-price model* and the *two-price model*. The one-price model is used for settlement of balancing power in relation to consumption and trade, and the two-price model is used for settlement of production imbalances.

The two-price model:

1. *“Imbalances in the same direction as the system’s total imbalance and which consequently contribute to further imbalance are settled at the area's regulating power price.”*
2. *“Imbalances in the opposite direction of the system’s total imbalance and which consequently 'helps' the imbalance are settled at the area's electricity spot price.”(* Energinet.dk 2008)

The one-price model:

1. *“Imbalances, irrespective of direction, are settled at the area's regulating power price.”* ***Fejl! Bogmærke er ikke defineret.***

Since a P2H plant is a consumption unit, its imbalances are settled after the one-price model.

1.3.8 Evaluation of the electricity markets and recommendations

The above description of the electricity markets in West Denmark outlines the P2H plant’s potential role and interaction with the electricity markets. Of these markets, some are considered more relevant than others.

The primary and secondary reserve markets are relatively small in DK1 compared to the other markets. This is partly because the need of these reserves (in term of energy) is not as extensive as the need for tertiary reserves, but also because a large share of the needed reserve capacity is purchased via the Skagerak 4 interconnections to Norway. All of the secondary reserve capacity (100 MW) and 10 MW out of 23 MW of the primary reserve capacity are bought through in Norway, and only a small part of the reserves is bought in DK1. Futhermore, a P2H plant participating in these reserve market, would be paid for being available for the TSO, and it would therefore be operated regardless of the need for hydrogen.

The tertiary reserve market (regulating power market) on the other hand offers more flexibility. In this market, bids of just one hour can be offered and these bids can be changed until 45 minutes before operation. With this option, it is easier for a plant to participate in multiple markets and adjust the production plan according to the need for hydrogen. One strategy could be to buy the needed electricity for the coming day on the Spot market and within the day of operation offer upward and downward regulation in the regulating power market to the extent that electricity is dispensable or extra electricity can be consumed. In addition to this strategy, the Intraday market could also be used as a way of balancing the produced hydrogen and the demand for hydrogen.

The trading strategy can be designed in many different ways depending on the specific plant, but based on this market review the most relevant markets for a P2H plant are the Spot market and the regulating power market.

In a separate report of Work Package 2 of the Power2Hydrogen project, the business case of different electricity markets for production of hydrogen will be estimated.

1.4 Electrolysis, background and state-of-the-art

This section briefly summarizes the technical background of the three most established water electrolysis technologies; alkaline, proton exchange membrane, and solid oxide. The main purpose is to give a short overview of the capabilities of the technologies to provide grid balancing services. Key features are summarized in Table 1.

Advantages and disadvantages of alkaline, PEM and SOEC electrolysis.		
Alkaline electrolysis	**PEM electrolysis**	**SOEC electrolysis**
	Advantages	
- Well-established technology **- Non-noble catalysts** **- Long-term stability** **- Relative low cost** **- Stacks in the MW range** **- Cost effective**	- High current densities - High voltage efficiency - Good partial-load range - Rapid system response - Compact system design - High gas purity - Dynamic operation	- Efficiency up to 100%; (thermoneutral efficiency >100% w/hot steam) - Non-noble catalysts - High pressure operation
	Disadvantages	
- Low current densities **- Crossover of gases (degree of purity)** **- Low partial load range** **- Low dynamics** **- Low operational pressures** **- Corrosive liquid electrolyte**	- High cost of components - Acidic corrosive environment - Possibly low durability - Commercialization - Stacks below MW range	- Laboratory stage - Bulky system design - Durability (brittle ceramics) - No dependable cost information

Table 1: Key features of alkaline, proton exchange membrane and solid oxide electrolysis (Carmo et al. 2013).

Alkaline electrolysis

Alkaline electrolysis is a matured hydrogen production technology up to the megawatt range, and constitutes the most extended electrolysis technology at a commercial scale worldwide. Three major technical issues are normally associated with alkaline electrolyzers: low partial load range, limited current density and low operating pressure (Carmo et al. 2013). First, the diaphragm does not completely prevent the product gases from cross-diffusing through it which reduces the efficiency. There is also a potential safety risk associated with the mixing of hydrogen with oxygen at the anode particularly at a low load (<40%) where the oxygen production rate decreases, thus drastically increasing the hydrogen concentration to unwanted and dangerous levels (lower explosion limit >4 mol% H_2). The second downside to alkaline electrolysers is the low maximum achievable current density, due to the high ohmic losses across the liquid electrolyte and diaphragm. The third problem, also attributed to the liquid electrolyte, is the inability to operate at high pressure, which makes for a bulky stack design configuration.

Hydrogenics reports field experience with their HySTAT electrolyser that provided frequency regulation by responding to real-time frequency regulation signals from the IESO (Independent Electricity System Operator) on a second-by-second basis (Cargnelli and Evers, 2013). They also report that no significant degradation was seen after 10,000 On/Off cycles. The dynamic responsiveness of systems is stated to be 40-100% load (Cargnelli and Evers, 2013).

Proton exchange membrane electrolysis (PEM)

PEM electrolysers can operate at much higher current densities than alkaline, capable of achieving values above 2 A/cm^2, this reduces the operational costs and potentially the overall cost of electrolysis. The low gas crossover rate of the polymer electrolyte membrane (yielding hydrogen with high purity), allows for the PEM electrolyser to work under a wide range of power input (economical aspect). This is due to the fact that the proton transport across the membrane responds quickly to the power input, not delayed by inertia as in liquid electrolytes. A solid electrolyte allows for a compact system design with strong/resistant structural properties, in which high operational pressures (equal or differential across the electrolyte) are achievable. Some commercial models have claimed to reach pressures up to 350 bars.

The high pressure operation of an electrolyser brings the advantage of delivering hydrogen at a high pressure (sometimes called electrochemical compression) for the end user, thus requiring less energy to further compress and store the hydrogen. In a differential pressure configuration, only the cathode (hydrogen) side is under pressure, this can eliminate the hazards related to handling pressurized oxygen and the possibility of self-ignition of the titanium (Ti) based diffusion layer in oxygen.

Problems related to higher operational pressures in PEM electrolysis are also present, such as cross-permeation which increases with pressure. Pressures above 100 bar will require the use of thicker membranes to maintain the critical concentrations (mostly H_2 in O_2) under the safety threshold. The corrosive acidic environment provided by the proton exchange membrane requires the use of distinct materials. These materials must not only resist the harsh corrosive low pH condition (pH ~ 2), but also sustain the high applied over-voltage (~2 V), especially at high current densities. Corrosion resistance applies not only for the catalysts used, but also current collectors and separator plates. Only a few materials are durable in this harsh environment. This will demand the use of scarce, expensive materials and components such as noble catalysts (platinum group metals (PGM) e.g. platinum (Pt), iridium (Ir) and ruthenium (Ru)), titanium-based current collectors, and separator plates.

At single cell level **Hydrogenics** reports continuous operation for 25,000 hours at 2 A/cm^2 and 2000 h at 4 A/cm^2 with very little degradation (Cargnelli and Evers, 2013). They also achieved 5400 On/Off cycles (5 min On/5 min Off) at 2 A/cm^2 and 7 barg. Hydrogenics conducted a study of a PEM electrolyser responding to the load profile of a PV (photo voltaic) duty cycle. A total of 400 PV cycles (24 hours fluctuating production emulating PV) corresponding to more than one year of accummulated operation did not lead to degradation @ 2 A/cm^2 and 7 barg. At MW-scale they conducted current modulation tests lasting about 20 hours. The main failure modes associated with On/Off and intermittent cycling were:

- Chemical and mechanical degradation due to temperature and pressure cycling
- Chemical degradation caused by uncontrolled stack polarity

At National Renewable Energy Laboratory (NREL) in Colorado, USA, tests are ongoing to study the difference in degradation between constant power and load balancing against wind power production profile (Harrison and Peters, 2014). The tests are conducted with two similar 40 kW **Proton** Onsite PEMWE (Polymer Electrolyte Membrane Water Electrolyser) stacks. Initial constant load tests showed 9,5 µV/h degradation. Results on the intermittent load could not be found and tests may still be in progress.

SIEMENS is in the process of introducing their MW-scale PEMWE technology, the SILYZER 200 (Hotellier, 2014). Little concrete information is available about results obtained from field tests; however, from the information available on their technology the following general features are described:

- High dynamic performance
- Compact design, small footprint
- Simple cold-start capability
- High pressure operation (less compression costs)
- Rapid load changes
- High stability / low degradation

They claim a load change capability of 10% per second.

ITM from the UK also supplies PEMWE in the MW-scale (ITM, 2013). They state a load change capability of 0-100% in less than 2 seconds.

For all suppliers ramping capability is closely linked to lifetime/degradation and the full understanding of this is not yet available.

Solid oxide electrolysis

SOECs have attracted a great deal of interest because they can convert electrical energy into chemical energy, producing hydrogen with high efficiency. SOEC is still in the development stage but research has grown exponentially in the last decade, companies, research centres and universities around the world have shown interest in this field. These preliminary lab-scale studies are mainly focused on the development of novel, improved, low cost, and highly durable materials for SOECs. They are also focused on the development of the inherent manufacturing processes, and the integration in an efficient and durable SOEC. Also interesting is that SOECs, due to the chemical flexibility of those devices and high temperature of operation, could be used for the electrolysis of CO_2 to CO, and also for the co-electrolysis of H_2O/CO_2 to H_2/CO (syngas). The SOEC technology has a huge potential for the future mass production of hydrogen, if the issues related to the durability of the ceramic materials at high temperature and long-term operation are solved.

FCH-JU Electrolysis Road Map

Table 2 presents the FCH-JU multi-annual work plan 2014-2020 road map for hydrogen production for energy storage and grid balancing (Hotellier, 2014). It gives an indication of the 2014 status and future trends in relation to key performance indicators (KPIs). The development targets indicate a strong focus on parameters of importance in grid balancing applications.

		2014	2017	2020	2023
KPI 1	Energy consumption (kWh/kg) @ rated power	57-60 @ 100 kg/day	55@500 kg/day	52@1000+ kg/day	50@1000+ kg/day
KPI 2	CAPEX @ rated power including ancillary equipment and commissioning	8.0 MEUR/(t/d)	3.7 MEUR/(t/d)	2.0 MEUR/(t/d)	1.5 MEUR/(t/d)
KPI 3	Efficiency degradation @ rated power considering 8000 h operation per year	2-4% per year	2% per year	1.5% per year	<1% per year
KPI 4	Flexibility with a degradation <2% year (refer to KPI 3)	5%-100% of nominal power	5%-150% of nominal power	0%-200% of nominal power	0%-300% of nominal power
KPI 5	Hot start from min to max power (refer to KPI 4)	1 minute	10 sec	2 sec	< 1 sec
KPI 6	Cold start	5 minutes	2 minutes	30 sec	10 sec

Table 2: Roadmap for electrolysis development under the FCH-JU platform.

Conclusion

All three electrolysis technologies included in this section, alkaline, PEM and SOEC, are in principle capable of meeting the requirements that are necessary to operate on the investigated markets in terms of dynamic operation capabilities. Still, there are distinct differences that are important to point out:

- The alkaline electrolysis technology has a lower turndown ratio than PEMEC
- The PEMEC technology is capable of delivering hydrogen at higher pressures than both of the other technologies which is important in relation to fuelling stations
- The PEMEC has a higher turndown ratio and delivers high hydrogen purity.

It should also be stressed that this conclusion is associated with some uncertainty as limited real life experience exist in this field (mostly with PEMEC and SOEC in particular) and not much information is available in the open literature.

1.5 Energy conversion technologies integrating hydrogen into the transport sector

In future energy systems, the transportation sector needs to convert to renewable energy. With restricted biomass availability, electricity as a source of primary energy becomes increasingly important. Different options exist for transforming the transportation sector into using electricity for motion. These are

a) Transportation means operating through direct electricity use such as in trains, light-rail, trams, trolley buses
b) Transportation means operating through electricity storage such as battery electric vehicles (BEVs) , electric mopeds and battery-operated ships
c) Transportation based on fuel cell technologies using hydrogen directly or
d) Synthetic fuels produced on the basis of electricity and potentially a carbon source.

Some changes will require model shifts (personal car to light rail for instance), some changes will require large changes to the means of transportation while yet some fuels might be included using technologies resembling today's (synthetic liquid fuels in personal vehicles).

The different options have different characteristics in terms of connection requirement, efficiency, transportation range and refuelling speed thus future transportation systems will most likely include a range of different technologies.

Focusing on the production of synthetic fuels using electricity – also denoted electro-fuels – a number of options exists where hydrogen and possible other components are used. Based on Connolly et al[2], four alternatives are relevant in future renewable energy-based energy systems. These are

a) Hydrogen for direct use
b) Bioenergy hydrogenation
c) CO_2 hydrogenation
d) Co-electrolysis

Hydrogen for direct use is hydrogen produced in electrolysis, compressed, and delivered to end-users where it may be used in fuel cells to power an electric engine or in internal combustion engines producing mechanical power directly.

Bioenergy hydrogenation gasifies biomass into a carbon-rich gas which combined with hydrogen may synthesize ethanol or DME which in either case is a liquid that may be used in fuel cells or internal combustion engines. The process may also produce methane which needs compression before being delivered to end-users at which point in can be used in fuel cells or internal combustion engines adapted for a gaseous fuel.

CO_2 hydrogenation is similar to bioenergy hydrogenation only the carbon source is CO_2 from combustion processes thus involving sequestration. Potential fuels are the same as for bioenergy hydrogenation.

Co-electrolysis occurs when carbon dioxide and water forms hydrogen and carbon monoxide in a single electrolyser, which subsequently are synthesized to methanol. Again, this requires carbon dioxide sequestration. Potential fuels are the same as for bioenergy hydrogenation.

The different alternatives differ with respect to carbon source, efficiency and output fuel. Comparing them in term of stoichiometric efficiency (i.e. heating value of inputs to outputs) gives the results shown in Table 3.

[2] A comparison between renewable transport fuels that can supplement or replace biofuels in a 100% renewable energy system (Connolly et al., 2014).

	Inputs	Outputs	Stoichiometric efficiency
Hydrogen for direct use	-	-	-
Bioenergy hydrogenation	Biomass + hydrogen	Methanol	2823 kJ + 1452 kJ -> 3778 kJ; η=88.4%
Bioenergy hydrogenation	Biomass + hydrogen	Methane	2823 kJ + 2904 kJ -> 4800 kJ; η=83.8%
CO_2 hydrogenation	Carbon dioxide + hydrogen	Methanol	0 kJ + 726 kJ -> 630 kJ; η=86.8%
CO_2 hydrogenation	Carbon dioxide + hydrogen	Methane	0 kJ + 968 kJ -> 800 kJ; η=82.6%
Co-electrolysis	Carbon dioxide + water	Methanol and oxygen (via Carbon monoxide, hydrogen and oxygen)	726 kJ +786 kJ -> 1259 kJ; η=83.3% (inputs calculated in stage 2)
Co-electrolysis	Carbon dioxide + water	Methane, water and oxygen (via Carbon monoxide, hydrogen and oxygen)	726 kJ + 393 kJ -> 800 kJ; η=71.5% (inputs calculated in stage 2)

Table 3: Stoichiometric efficiency for a range of synthetic fuel production pathways. Based on (Connolly et al., 2014).

The efficiencies in Table 3 do not fully capture the required inputs, the practically attainable conversion efficiencies or energy inputs required to supply all input constituents such as carbon dioxide. Table 4 gives indicative inputs for supplying 100 PJ of fuel applying different pathways. In addition to the inputs and outputs indicated, all pathways also have the possibility of supplying excess heat, however the relevance of this varies with geographic location compared to potential heat demands, access to district heating grids, the evolution of the heat demand – and naturally seasonally varying heat demands.

	Inputs	Outputs	Comments
Hydrogen for direct use	137 PJ electricity	100 PJ hydrogen	The only option not dependent on biomass or carbon dioxide Produces a gaseous fuel
Bioenergy hydrogenation	53.4 PJ electricity 83 PJ biomass	100 PJ Methanol/DME	Requires biomass availability Produces a liquid fuel
Bioenergy hydrogenation	77.2 PJ electricity 58.6 PJ biomass	100 PJ Methane	Requires biomass availability Produces a gaseous fuel
CO_2 hydrogenation	155.3 PJ electricity 77 PJ biomass (for CHP for CO_2 generation)	100 PJ Methanol/DME + Power and heat from biomass CHP	There are potentially other carbon dioxide sources. Energy demand for carbon dioxide sequestration varies with source Produces a liquid fuel
CO_2 hydrogenation	156.9 PJ electricity 55 PJ biomass	100 PJ Methane + Power and heat from biomass CHP	There are potentially other carbon dioxide sources. Energy demand for carbon dioxide sequestration varies with source

			Produces a gaseous fuel
Co-electrolysis	155.3 PJ electricity 77 PJ biomass	100 PJ Methanol + Power and heat from biomass CHP	There are potentially other carbon dioxide sources. Energy demand for carbon dioxide sequestration varies with source Produces a liquid fuel
Co-electrolysis	156.1 PJ electricity	100 PJ Methane + Power and heat from biomass CHP	There are potentially other carbon dioxide sources. Energy demand for carbon dioxide sequestration varies with source Produces a gaseous fuel

Table 4: Inputs required to produce 100 PJ of synthetic fuel for various pathways. Inputs include process heat demands, electricity for carbon sequestration and more. Based on (Connolly et al., 2014)

Optimum hydrogen-based or assisted synthetic fuel pathway depends on various factors including

- whether RES-based power production or biomass availability is restricted,
- whether there is a heat demand that may be covered by any excess heat generation from the process,
- how particularly CO_2 is sequestered as specific energy demand varies with source (sequestration from the atmosphere or sequestration from combustion processes), and
- the type of vehicle applied.

Methanol/DME has the advantage over hydrogen and methane that it is liquid at relevant ambient temperatures making handling and storage both convenient and similar to alternative existing motor fuels

	UCV per volume Standard conditions	UCV per volume All in liquid phase	UCV per mass
Hydrogen	12.8 MJ/m^3	10.1 GJ/m^3	142.5 MJ/kg
Methane	40.1 MJ/m^3	23.7 GJ/m^3	56.0 MJ/kg
Methanol	18.2 GJ/m^3	18.2 GJ/m^3	22.9 MJ/kg
DME	21.1 GJ/m^3	21.1 GJ/m^3	31.7 MJ/kg
Ethanol	23.6 GJ/m^3	23.6 GJ/m^3	29.8 MJ/kg
Petrol	33.2 GJ/m^3	33.2 GJ/m^3	46.0 MJ/kg
Diesel	39.0 GJ/m^3	39.0 GJ/m^3	44.8 MJ/kg
Fuel oil	38.1 GJ/m^3	38.1 GJ/m^3	44.8 MJ/kg

Table 5: Upper calorific values (UCV) for hydrogen, hydrogen-derived fuels and alternatives for comparison.

Observing Table 5 it is furthermore clear that the potential energy contents of a tank in any form of vehicle is heavily influenced by the choice of fuel. While methane and hydrogen have very high energy contents per mass, they are relatively low per volume even in liquid phase. Additionally, liquid phase is neither practically feasible with hydrogen or methane in personal vehicles so the liquid-phase UHV should not be seen as practically attainable targets but rather upper boundaries. Methanol and DME both have lower UHV per volume than the fossil alternatives diesel and petrol. Comparing to diesel, methanol and DME have per-volume UHVs of 46.6 and 54.0 % making these options more practical in terms of obtaining a reasonable driving range. Against them is the circumstance that they require a carbon sources. Either a limited biomass availability or a potentially energy-intensive sequestration from either flue gasses or from atmospheric carbon dioxide.

In conclusion, hydrogen is a key component in the electrification of the transport sector – though not necessarily in pure form. In its pure form, hydrogen has the advantage of not requiring a source of carbon and the fuel is appropriate for fuel cells, however the volumetric density is low, and high pressure / low temperature is required to store hydrogen in its liquid phase.

For applications where volume is less important, other options are therefore favourable: Synthetic fuels combining hydrogen and carbon are closer to today's fossil fuels in volumetric and mass energy density.

Of course, compared to electricity storage, hydrogen and other fuels surpass flow-batteries and other storages technologies by far both in terms on volumetric and mass energy density. For comparison, flow-batteries have volumetric energy densities in the 300-800 MJ/m^3-range, thus hydrogen and synthetic fuels enable further driving range for installations of comparable sizes.

2 Danish scenarios

In this section we assess a number of relevant energy systems scenarios for Denmark with a focus on determining the role and importance of hydrogen in the perspectives of different research and governmental bodies. The reason for this is twofold: Firstly to give an overview of the different scenarios and their use of hydrogen and secondly to choose one of the scenarios for the analysis in this and later work packages of the project.

2.1 Scenario assessment framework

In our assessment, we address

1. *General characteristics and purpose of the scenario* including who developed it and with what ambition. Main results including primary energy supply and economic effects of the scenario are assessed.
2. *Energy system structure*. This includes a general qualitative overview of the energy system as well as a quantitative description of installed capacities of different energy production or conversion technologies, the specific types of technologies included and technology characteristics where available.
3. *Hydrogen usage in scenario*. The assessment investigates more specifically the use of hydrogen in the scenario focusing on which end-use sectors are supplied by hydrogen, and in what constellations hydrogen is used (directly or indirectly through synthetic fuels) referencing the topologies in Section 1.3.
4. *Market integration and balancing using hydrogen in the scenario* assesses whether hydrogen is used for covering balancing demands though the dispatch of electrolytic converters and/or fuel cells as well as the markets hydrogen technologies operate on, referencing Section 1.3

2.2 The Danish Energy Agency's scenario analyses

In May 2014 the Danish Energy Agency (DEA) published a report (DEA 2014a) describing four scenarios for the future energy system onwards 2050, which meets the political targets. The scenarios are called wind, biomass, bio+ and hydrogen scenario. All four scenarios are based on high energy savings and an import/export capacity to Norway and Sweden of approximately 4000 MW. The energy systems are designed as narrow systems meaning that electricity production capacities barely secure security of supply. In the hourly simulations the aggregated capacity of CHP, condensing power and import from Norway and Sweden are designed to cover the maximum consumption. Finally, the scenarios are designed in a way that no net electricity import occurs. In a parallel Monte Carlo simulation of the security of supply, additional 2000 MW import/export capacity to Germany is included. Below, the four scenarios are described.

2.2.1 Wind scenario

In the wind scenario, the energy system is highly electrified to keep down the biomass consumption that is maintained at a level of 250 PJ corresponding to the Danish potential for biomass including waste. In 2050, the installed wind capacity is 17.5 GW, which will require an extensive wind capacity development corresponding to a 400 MW offshore wind park every year in the period 2020-2050. The wind scenario has a gross energy consumption of 575 PJ and a self-sufficient degree of 104% compared to domestic resources. The scenario is anticipated to have an annual cost of approximately 140 billion DKK.

Energy system structure in the wind scenario

The wind turbines are the main electricity supplier but PV and CHP contributes to the production as well, while gas turbines are installed as back-up capacity to ensure security of supply. There are no central power plants in the system. The transport and heat sectors are highly electrified to integrate the high electricity production from the wind turbines. A large share of the car fleet is supplied by electricity but also biofuels are used to fuel the transport sector.

Electrolyser plants produce hydrogen to increase the energy output of the biofuels and the waste heat from the biofuel plants is supplied to the district heating grid. The district heating demand is mainly based on CHP, excess heat from biofuel plants and heat pumps. Solar thermal plants, geothermal plants, industrial waste heat and backup biomass boilers contribute with a smaller share of the heat production. Biomass fuelled CHP units, gas boilers, electric boilers and heat pumps supply the low, medium and high temperature heat demand in industry. In 2050, the gas consumption is less than half of the gas consumption today and the gas is therefore targeting specific applications namely transport, industry, distributed CHP and gas turbines. Residual heat demand is mainly covered via heat pumps but also from solar thermal installations and biomass boilers.

Table 6 illustrates installed production and consumption capacities or annual production figures for the different units in the system in 2050 in DEA's wind scenario.

	Technology	Installed capacity	Annual Production	Characteristics
Power	Onshore wind power	3500 MW_e	10.77 TWh	Annual FLH* 3076
	Off-shore wind power	14000 MW_e	57.62 TWh	Annual FLH 4116
	Solar power	2000 MW_e	1.70 TWh	Annual FLH 849
	Wave power	n.d MW_e		Annual FLH n.d
	Condensing mode power stations	4600 MW_e		η_e= n.d.
Power and heat	Micro CHP	n.d. MW_e		η_e= n.d. & η_{th}= n.d.
	Small-scale CHP	684 MW_e		η_e= n.d. & η_{th}= n.d.
	Large-scale CHP	0 MW_e		η_e= n.d. & η_{th}= n.d.
	Waste incineration plants	366 MW_e		η_e= n.d. & η_{th}= n.d.
	Industry CHP	305 MW_e		η_e= n.d. & η_{th}= n.d.
Heat – central DH	Solar DH	n.d.	0.56 TWh	
	HPs	78 MW_e		COP = 3.2
	Geothermal	100 MJ/s		
	Large-scale CHP	0 MJ/s		
	Boilers	2300 MJ/s		
	Electric boilers	n.d.		
	Waste incineration plants	1000 MJ/s		
	Waste heat industry	n.d.	0.89 TWh	
	Waste heat biofuel plants	1210 MJ/s		
Heat – distributed DH	Solar DH	n.d	1.39 TWh	
	HPs	250 MW_e		COP = 3.2
	Geothermal	100 MJ/s		
	Small-scale CHP	600 MJ/s		
	Boilers	1800 MJ/s		
	Electric boilers	n.d.		
	Waste incineration plants	0 MJ/s		
	Waste heat industry	n.d.	0.42 TWh	
	Waste heat biofuel plants	308 MJ/s		
Transport	Hydrogen production	4138 MW_e		For synthetic fuel production
	Synthetic fuel production	n.d. MJ/s	17.53 TWh	Biodiesel, biokerosene
	Electric vehicles*	1230 MW_e		Charging capacity: n.d.
Gas	Biogas production	n/a	11.67 TWh	
	Hydrogen production	1226 MW_e		
	SNG	n/a	17.97 TWh	
Storage	Electricity storage	0 GWh	n/a	
	Hydrogen storage	n.d.		
	Synthetic fuel storage	n.d.		

	Heat storage (DH)	n.d.		
Individual	Individual biomass boilers	3500 MJ/s	1.39 TWh	
	Individual solar	n.d. MJ/s		
	Individual HPs	806 MW_e		COP = 4.25 (average air and ground source HPs)
	Individual oil boilers	n.d. MJ/s		
	Individual NG boilers	n.d. MJ/s		

*Table 6: Production and consumption capacities in MW and MJ/s divided on different energy sectors, in 2050, in the DEA's wind scenario.*Includes EVs, trucks, busses and MCs.*

Table 7 illustrates energy demands in 2050 in DEA's wind scenario.

	Category	Demand	Characteristics
Electricity	Electricity – Classic*	25.33 TWh	4968 MW, annual FLH 5100
	Electricity for hydrogen	n.d.	Annual FLH n.d.
	Electricity for DH HP	1.55 TWh	Annual FLH 2959 (central), 5263 (distributed)
	Electricity for DH boilers	n.d.	
	Electricity for individual HP	3.65 TWh	Annual FLH 1099 (Air), 6073 (Ground source)
	Electricity for Co-electrolysis	n.d.	
Heat	Heat demand for DH – central	15.83 TWh	
	Heat demand for DH - distributed	10.59 TWh	
	Heat demand for individual dwellings	n.d.	
Fuel	Transport demand – electricity	12.5 TWh	
	Transport demand – hydrogen	0 TWh	Direct use
	Transport demand – Synthetic	17.53 TWh	Biokerosene, biodiesel
	Transport demand – Fossil	6.9 TWh	Patrol
	Industrial fuel demand	n.d.	
	Total Primary energy Supply	163.06 TWh	

*Table 7: Energy demands in DEA's wind scenario in 2050. Electricity demands are calculated based on annual FLH. *Classic electricity consumption includes all consumption except "new" electricity consumption i.e. EVs, HPs, electric boilers, hydrogen plants etc.*

Hydrogen usage

In the wind scenario, there is no direct use of hydrogen. The car fleet is mainly supplied by electricity because this technology is expected to be the most cost-effective when it comes to individual transportation. Furthermore, there is no direct injection of hydrogen to the natural gas grid but the hydrogen produced is used to increase the energy output of specific bioenergy sources, via bioenergy hydrogenation, to extend the limited biomass resource that is available in the wind scenario.

The hydrogen is produced by electrolyser plants, which are connected to the electricity grid and thereby used as a mean to integrate the high power production from the wind turbines. The capacity of the electrolyser plants are 4138 MW_e for synthetic fuel production and 1226 MW_e for synthetic natural gas (SNG) production.

The biofuels produced from hydrogenation are biokerosene, used for air traffic, and biodiesel, used for fuelling trucks and ships. The production of biokerosene and biodiesel amount to 37.6 PJ and 25.5 PJ, respectively. In 2050, the biogas production of 42 PJ is upgraded to SNG increasing the energy output to 64.7 PJ. This amount composes the entire gas in the system in 2050 and is therefore, as mentioned, targeted specific applications namely distributed CHP, backup gas turbines, industry and transport. In the transport sector, SNG is used as fuel for trucks, busses and ships whereas gas is used for producing medium and high temperature heat in industry.

Market integration and balancing using hydrogen

The hydrogen is produced by electrolysis, which is modelled as interruptible consumption thereby contributing to balancing of electricity system. However, there is no detailed description of the use of the electrolyser plants in relation to any of the regulation markets described in section 1.4. The DEA model does only include the spot market.

2.2.2 Biomass scenario

The biomass scenario is designed to have an annual bioenergy consumption of 450 PJ resulting in a net biomass import of approximately 250 PJ (normal year). The development of the wind capacity corresponds to an additional 400 MW off-shore wind park every third year, from 2020 to 2050, resulting in 8.5 GW installed wind capacity by 2050. The biomass scenario has a gross energy consumption of 590 PJ and a degree of self-sufficiency of 79% of the domestic resources. The anticipated annual cost is approximately 136 billion DKK, which is the lowest of the four scenarios developed by the DEA. The large biomass import makes the scenario sensitive to changes in biomass fuel prices.

Energy system structure in the biomass scenario

Besides wind turbines, electricity is produced from PV installations and CHP in industry and district heating sector. Gas turbines are installed as backup capacity but less than in the wind scenario. Contrary to the wind scenario, there are central biomass-fired CHP plants that decrease the need for backup gas turbines. District heating is mainly supplied from CHP units, heat pumps and waste heat from biofuel plants, while biomass boilers are included for peak load hours. The heat pumps are the main producer in the distributed district heating area whereas the production is very low in the central areas. Additional heat sources are solar thermal, geothermal and industrial waste heat.

The transport sector is supplied by biofuels and electricity. As in the wind scenario, the car fleet is mainly supplied by electricity to keep down bioenergy consumption. Hydrogen is not used at biofuel plants nor to upgrade biogas. The biogas is still upgraded to SNG but without using hydrogen. The process heat for industry is produced at biomass fuelled CHP units and biomass boilers. The residual heat demand is mainly covered from heat pumps but also from solar thermal and biomass boilers.

Table 8 illustrates installed production and consumption capacities and/or annual production figures for the different units in the system in 2050 in DEA's biomass scenario.

	Technology	Installed capacity	Annual Production	Characteristics
Power	Onshore wind power	3500 MW_e	10.77 TWh	Annual FLH* 3076
	Off-shore wind power	5000 MW_e	20.71 TWh	Annual FLH 4141
	Solar power	2000 MW_e	1.70 TWh	Annual FLH 849
	Wave power	n.d MW_e		Annual FLH n.d
	Condensing mode power stations	1000 MW_e		ST based; η_e= n.d.
Power and heat	Micro CHP	n.d. MW_e		FC based; η_e= n.d. & η_{th}= n.d.
	Small-scale CHP	684 MW_e		FC based; η_e= n.d. & η_{th}= n.d.
	Large-scale CHP	2040 MW_e		ST based; η_e= n.d. & η_{th}= n.d.
	Waste incineration plants	366 MW_e		ST based; η_e= n.d. & η_{th}= n.d.
	Industry CHP	516 MW_e		ST based; η_e= n.d. & η_{th}= n.d.
Heat – central DH	Solar DH	n.d. MJ/s	0.56 TWh	
	HPs	78 MW_e		COP = 3.2
	Geothermal	100 MJ/s		
	Large-scale CHP	1700 MJ/s		
	Boilers	500 MJ/s		
	Electric boilers	n.d. MW_e		
	Waste incineration plants	1000 MJ/s		
	Waste heat industry	n.d. MJ/s	0.89 TWh	
	Waste heat biofuel plants	1087 MJ/s		

Heat – distributed DH	Solar DH HPs Geothermal Small-scale CHP Boilers Electric boilers Waste incineration plants Waste heat industry Waste heat biofuel plants	n.d. MJ/s 250 MW_e 100 MJ/s 600 MJ/s 1800 MJ/s n.d. 0 MJ/s n.d. 0 MJ/s	1.39 TWh 0.42 TWh	 COP = 3.2
Trans port	Hydrogen production Synthetic fuel production Electric vehicles*	0 MW_e n.d. MJ/s 960 MW_e	 17.39TWh	For synthetic fuel production Biodiesel, biokerosene Charging capacity: n.d.
Gas	Biogas production Hydrogen production SNG	n/a 0 MW_e n/a	11.67 TWh 11.67 TWh	
Storage	Electricity storage Hydrogen storage Synthetic fuel storage Heat storage (DH)	0 GWh n.d. n.d. n.d.	n/a	
Individual	Individual biomass boilers Individual solar Individual HPs Individual oil boilers Individual NG boilers	3500 MJ/s n.d. MJ/s 806 MW_e n.d. MJ/s n.d. MJ/s	 1.39 TWh	 COP = 4.3 (average air and ground source HPs)

*Table 8: Production and consumption capacities in MW and MJ/s divided on different energy sectors, in 2050, in the DEA's biomass scenario. *Includes EVs, trucks, busses and MCs.*

Table 9 illustrates energy demands in 2050 in DEA's biomass scenario.

	Category	Demand	Characteristics
Electricity	Electricity – Classic* Electricity for hydrogen Electricity for DH HP Electricity for DH boilers Electricity for individual HP Electricity for Co-electrolysis	25.33 TWh n.d. 1.73 TWh n.d. 3.65 TWh n.d.	4968 MW, annual FLH 5100 Annual FLH n.d. Annual FLH 2959 (central), 5263 (distributed) Annual FLH 1099 (Air), 6073 (Ground source)
Heat	Heat demand for DH – central Heat demand for DH - distributed Heat demand for individual dwellings	15.83 TWh 10.56 TWh n.d.	
Fuel	Transport demand – electricity Transport demand – Hydrogen Transport demand – Synthetic Transport demand – Fossil Industrial fuel demand Total Primary energy Supply	9.72 TWh 0 TWh 17.39 TWh 6.9 TWh n.d. 163.89 TWh	 Direct use Biokerosene, biodiesel Patrol

*Table 9: Energy demands in DEA's biomass scenario in 2050. Electricity demands are calculated based on annual FLH. *Classic electricity consumption includes all consumption except from "new" electricity consumption i.e. EVs, HPs, electric boilers, hydrogen plants etc.*

Hydrogen usage

There is no hydrogen production in the scenario.

Market integration and balancing using hydrogen

There is no hydrogen production and therefore no hydrogen usage for balancing purposes.

2.2.3 Bio+ scenario

The bio+ scenario is a combustion-based scenario similar to the system known today but all fossil fuels are replaced by bioenergy. It is designed to have no limitations of the biomass use. It requires a significant import of biomass and biofuels resulting in a total bioenergy consumption of 700 PJ. In 2050, the wind capacity is 6 GW, which corresponds to of 50% of the classic electricity consumption (2020 level). Both heat and transport sectors are mainly supplied by biomass and electricity. The bio+ scenario has a gross energy consumption of 672 PJ and a self-sufficiency degree of 59%. The annual cost of the system amounts to approximately DKK 160 billion, which is the highest cost of the DEA's scenarios. The cost is very sensitive to increases in fuel prices.

Energy system structure

The electricity is produced by wind turbines, central and distributed CHP units, PV and backup gas turbines. As in the biomass scenario there are central biomass fired CHP plants that consequently reduce the need for backup gas turbines. The heat for the central district heating sector is mainly produced at the biomass fired central CHP plants, waste incineration plants and biofuel plants supplying waste heat. Distributed CHP plants fuelled by SNG and biomass boilers are the main heat suppliers in distributed areas. The production from heat pumps is low in the scenario. Additional sources are solar thermal, geothermal and waste heat from industry.

The transport sector is based on biodiesel and bioethanol of which the most is imported. There are only few electric vehicles and no hydrogen fuelled vehicles. The entire biogas production is upgraded to SNG without using hydrogen that among other things is used as fuel for heavy means of transport. Biomass CHP and biomass boilers produce almost the entire heat demand in industry. In the individual heat demand, there is a significant biomass boiler capacity but also a small heat pump and solar thermal capacity.

Table 10 illustrates installed production and consumption capacities and/or annual production figures for the different units in the system in 2050 in DEA's bio+ scenario.

	Technology	Installed capacity	Annual Production	Characteristics
Power	Onshore wind power	3500 MW_e	TWh	Annual FLH* 3076
	Off-shore wind power	2500 MW_e	TWh	Annual FLH 4141
	Solar power	1000 MW_e	TWh	Annual FLH 849
	Wave power	n.d MW_e		Annual FLH n.d
	Condensing mode power stations	400 MW_e		ST based; η_e= n.d.
Power and heat	Micro CHP	n.d. MW_e		FC based; η_e= n.d. & η_{th}= n.d.
	Small-scale CHP	684MW_e		FC based; η_e= n.d. & η_{th}= n.d.
	Large-scale CHP	0MW_e		ST based; η_e= n.d. & η_{th}= n.d.
	Waste incineration plants	366MW_e		ST based; η_e= n.d. & η_{th}= n.d.
	Industry CHP	429MW_e		ST based; η_e= n.d. & η_{th}= n.d.
Heat – central DH	Solar DH	n.d. MJ/s	0.56TWh	
	HPs	MW_e		COP = 3.2
	Geothermal	100MJ/s		
	Large-scale CHP	2000MJ/s		
	Boilers	500MJ/s		
	Electric boilers	n.d. MW_e		
	Waste incineration plants	1000MJ/s		
	Waste heat industry	n.d. MJ/s	0.89 TWh	
	Waste heat biofuel plants	1173MJ/s		
He at	Solar DH	n.d MJ/s	1.39 TWh	
	HPs	63MW_e		COP = 3.2

	Geothermal Small-scale CHP Boilers Electric boilers Waste incineration plants Waste heat industry Waste heat biofuel plants	100MJ/s 600MJ/s 1600MJ/s n.d. MJ/s n.d. MJ/s	 0.42TWh	
Transport	Hydrogen production Synthetic fuel production Electric vehicles	$0MW_e$ n.d. MJ/s $36MW_e$	 17.53TWh	 Biodiesel, biokerosene Charging capacity: n.d.
Gas	Biogas production Hydrogen production SNG	n/a MW_e n/a	11.67 TWh 6.31TWh 17.97TWh	
Storage	Electricity storage Hydrogen storage Synthetic fuel storage Heat storage (DH)	GWh n.d. n.d. n.d.	n/a	
Individual	Individual biomass boilers Individual solar Individual HPs Individual oil boilers Individual NG boilers	5000MJ/s n.d. MJ/s $222MW_e$ n.d. MJ/s n.d. MJ/s	 1.39TWh	 COP = 4.3 (average air and ground source HPs)

*Table 10: Production and consumption capacities in MW and MJ/s divided on different energy sectors, in 2050, in the DEA's bio+ scenario. *Includes EVs, trucks, busses and MCs.*

Table 11 illustrates energy demands in 2050 in DEA's bio+ scenario

	Category	Demand	Characteristics
Electricity	Electricity – Classic* Electricity for hydrogen Electricity for DH HP Electricity for DH boilers Electricity for individual HP Electricity for Co-electrolysis	25.34TWh n.d. 0.43TWh n.d. 1.87TWh n.d.	4968 MW, annual FLH 5100 Annual FLH n.d. Annual FLH 2959 (central), 5263 (distributed) Annual FLH 1099 (Air), 6073 (Ground source)
Heat	Heat demand for DH – central Heat demand for DH - distributed Heat demand for individual dwellings	15.83TWh 10.56TWh n.d.	
Fuel	Transport demand – electricity Transport demand – Hydrogen Transport demand – Synthetic Transport demand – Fossil SNG Industrial fuel demand Total Primary energy Supply	12.50TWh 0TWh 18.78TWh 6.94TWh 17.97TWh n.d. 163,06TWh	 Direct use Biokerosene, biodiesel Patrol

*Table 11: Energy demands in DEA's bio+ scenario in 2050. Electricity demands are calculated based on annual FLH. *Classic electricity consumption includes all consumption except from "new" electricity consumption i.e. EVs, HPs, electric boilers, hydrogen plants etc.*

Hydrogen usage

There is no hydrogen production in the scenario.

Market integration and balancing using hydrogen

There is no hydrogen production and therefore no balancing using hydrogen.

2.2.4 Hydrogen scenario

The hydrogen scenario is designed to have a low bioenergy consumption corresponding to less than 200 PJ, which is less than the domestic potential for bioenergy in 2050. The scenario emphasises sustainability and the use of biomass outside the energy sector. Consequently, the wind turbines are the main energy contributor and the installed capacity is 21 GW in 2050. The electrification of the system requires an improvement of the electricity grid and increased production and consumption capacity. On the consumption, there is a significant hydrogen production. The total annual cost is just above DKK 140 billion of which a large share is investment costs. The self-sufficient degree is 116 %.

Energy system structure

There are no central CHP plants in the hydrogen scenario. Electricity is mainly produced with wind turbines but CHP units and PV do also contribute to the production. In the hydrogen scenario fuel cells and gas turbines are applied as back up capacity. The main heat contributors for central district heating sector are the waste incineration plants and waste heat from biofuel plants. In the distributed district heating area a large share of the heat is produced at heat pumps while the distributed CHP plants have few operation hours due to the high cost of SNG. Additional heat production comes from geothermal plants, solar thermal plants, and back up biomass boilers produces.

Biofuels, SNG, electricity and hydrogen are applied as fuels in the transport sector. Electric vehicles constitute a large share of the car fleet to keep down bioenergy consumption.

The installed electric boiler capacity is capable of covering the entire medium and high temperature heat demand in industry in hours with high production from wind turbines. Gas boiler and gas CHP capacity plus low capacity biomass boiler are also installed to produce heat in hours of low production from wind turbines. Heat pumps cover the majority of the low temperature heat. The individual heat sector is mainly based on heat pumps.

Table 12 illustrates installed production and consumption capacities and/or annual production figures for the different units in the system in 2050 in DEA's hydrogen scenario.

	Technology	Installed capacity	Annual Production	Characteristics
Power	Onshore wind power	3500 MW_e	TWh	Annual FLH* 3076
	Off-shore wind power	17500 MW_e	TWh	Annual FLH 4141
	Solar power	1000 MW_e	TWh	Annual FLH 849
	Wave power	n.d MW_e		Annual FLH n.d
	Condensing mode power stations	4600 MW_e		ST based; η_e= n.d.
Power and heat	Micro CHP	n.d. MW_e		FC based; η_e= n.d. & η_{th}= n.d.
	Small-scale CHP	684MW_e		FC based; η_e= n.d. & η_{th}= n.d.
	Large-scale CHP	0MW_e		ST based; η_e= n.d. & η_{th}= n.d.
	Waste incineration plants	366MW_e		ST based; η_e= n.d. & η_{th}= n.d.
	Industry CHP	0MW_e		ST based; η_e= n.d. & η_{th}= n.d.
Heat – central DH	Solar DH	n.d.	0.56TWh	
	HPs	156MW_e		COP = 3.2
	Geothermal	100MJ/s		
	Large-scale CHP	0MJ/s		
	Boilers	2000MJ/s		
	Electric boilers	n.d.		
	Waste incineration plants	1000MJ/s		
	Waste heat industry	n.d.	0.89 TWh	
	Waste heat biofuel plants	709MJ/s		
Heat	Solar DH	n.d	1.39 TWh	
	HPs	625MW_e		COP = 3.2

	Geothermal Small-scale CHP Boilers Electric boilers Waste incineration plants Waste heat industry Waste heat biofuel plants	100MJ/s 600MJ/s 1800MJ/s n.d. 0MJ/s n.d. 308MJ/s	0.42TWh	
Transport	Hydrogen production	$6034MW_e$		Used for synthetic fuel production
	Synthetic fuel production	n.d. MJ/s	17.53TWh	Biodiesel, biokerosene
	Electric vehicles	$1278MW_e$		Charging capacity: n.d.
Gas	Biogas production	n/a	11.67 TWh	Used for SNG production
	Hydrogen production	MW_e	6.31TWh	Used for SNG production
	SNG	n/a	17.97 TWh	Fuel for CHP, industry and transport
Storage	Electricity storage	GWh	n/a	
	Hydrogen storage	n.d.		
	Synthetic fuel storage	n.d.		
	Heat storage (DH)	n.d.		
Individual	Individual biomass boilers	3500MJ/s		
	Individual solar	n.d. MJ/s	1.39TWh	
	Individual HPs - Air	$250MW_e$		COP = 4.3 (average air and ground source HPs)
	Individual HPs – ground	$556MW_e$		
	Individual oil boilers	n.d. MJ/s		
	Individual NG boilers	n.d. MJ/s		

*Table 12: Production and consumption capacities in MW and MJ/s divided on different energy sectors, in 2050, in the DEA's hydrogen scenario. *Includes EVs, trucks, busses and MCs.*

Table 13 illustrates energy demands in 2050 in DEA's hydrogen scenario

	Category	Demand	Characteristics
Electricity	Electricity – Classic*	25.34TWh	4968 MW, annual FLH 5100
	Electricity for hydrogen	n.d.	Annual FLH n.d.
	Electricity for DH HP	2.35TWh	Annual FLH 2959 (central), 5263 (distributed)
	Electricity for DH boilers	n.d.	
	Electricity for individual HP	4.67TWh	Annual FLH 1099 (Air), 6073 (Ground source)
	Electricity for Co-electrolysis	n.d.	
Heat	Heat demand for DH – central	15.83TWh	
	Heat demand for DH - distributed	10.56TWh	
	Heat demand for individual dwellings	n.d.	
Fuel	Transport demand – electricity	12.50TWh	
	Transport demand – Hydrogen	TWh	Direct use
	Transport demand – Synthetic	13.78TWh	Biokerosene, biodiesel
	Transport demand – Fossil	6.94TWh	Patrol
	SNG	17.97TWh	
	Industrial fuel demand	n.d.	
	Total Primary energy Supply	163.06TWh	

*Table 13: Energy demands in DEA's hydrogen scenario in 2050. Electricity demands are calculated based on annual FLH. *Classic electricity consumption includes all consumption except from "new" electricity consumption i.e. EVs, HPs, electric boilers, hydrogen plants etc.*

Hydrogen usage

In the hydrogen scenario there is direct use of hydrogen for transportation namely for fuelling trucks. There is no direct hydrogen injection to the gas grid but the remaining hydrogen is applied for bioenergy hydrogenation to increase the energy output of the scarce biomass resource. Furthermore, electrolyser plants are used as a mean to integrate the high production from wind turbines.

Hydrogen is used for production of biokerosene used for jet fuel, biodiesel used as fuel for ships and a small share of the trucks. Furthermore, the entire biogas production is upgraded to SNG, of which some is used as fuel for ships and busses.

The capacity of the electrolyser plants, producing hydrogen for the biofuel plants, is 6034 MW_e. the production of biofuels is 12 PJ biodiesel and 37.6 PJ biokerosene. The electrolyser plant capacity is 1236 MW_e producing hydrogen for the biogas hydrogenation process, which increases energy content in the biogas from 42 PJ to 64.7 PJ (SNG). In 2050 the entire gas in the system is limited as fuel for distributed CHP, backup gas turbines, gas boilers in industry and transport as described above.

Market integration and balancing using hydrogen.

The electrolyser plants, producing hydrogen, are modelled as interruptible consumption as a mean to integrate the high power production from wind turbines. Thereby, the plants contribute to balancing the system. It is not described if and/or how the plants are operated in relation to electricity markets.

2.3 The CEESA study analysis

In late 2011, a group of seven different research institutions, among others Aalborg University, Technical University of Denmark and Pöyry Energy Consulting, published the report of the Coherent Energy and Environmental System Analysis (CEESA) project. This interdisciplinary project focuses on the integration of existing tools and methodologies into a more comprehensible tool to analyse design and implementation of future sustainable energy systems. It comprises three different, self-sufficient 100% renewable energy scenarios in 2050 to reflect dependency on the availability of technologies: a conservative, an ideal and a recommendable scenario. Primary energy supply in all scenarios is around 500 PJ/a. The annual socio-economic costs vary slightly above 150 billion DKK/year.

CEESA-2050 scenario

For the purpose of this report, the recommended scenario "CEESA-2050" is chosen. Here, energy savings and direct electricity consumption have a high priority. In particular, primary energy supply is assumed to decrease in the next 35 years by app. 350 PJ. A smart energy system is integrated, which implies the use of heat storages, CHP for district heating, large heat pumps, electric vehicles for storage and electrolysers. Transport demand is adjusted to a medium increase scenario, taking into account the limits of the Danish biomass potential.

Energy system structure in the CEESA-2050 scenario

In the CEESA 2050 scenario primary energy consumption has decreased to 479 PJ. It is split up into 135 PJ for transport, 97 PJ for electricity and 247 PJ for heating. Wind and biomass are the two main resources to satisfy this demand. Biomass accounts for app. 50%, while wind is slightly below 40%. Overall wind power capacity is designed to 14,150 MW, though there is no specification regarding onshore and offshore. PV, solar thermal, geothermal and wave power cover the remaining demand. A large share of the biomass is gasified for transport and CHP.

Residual heat demand is mainly covered via district heating from CHP and heat pumps, but also from excess industrial heat. To a major extent, electricity demand is supplied by wind, but also CHP contributes to it. A minor share is supplied by PV and wave power. It may be noted that electricity demand for electrolysis and co-electrolysis represents the biggest share among the different consumers (57%). The rest is comprised of classic electricity demand, direct consumption for transport and heat pumps. Transport demand equals 135 PJ and is satisfied by bio-fuel (44%), syn-fuel (34%) and direct electricity (22%).

Table 14 illustrates installed production and consumption capacities or annual production figures for the different units in the system in 2050 in the CEESA-2050 scenario.

	Technology	Installed capacity	Annual Production	Characteristics
Power	Onshore wind power	n.d. MW_e	n.d. TWh	Annual FLH n.d.
	Off-shore wind power	n.d. MW_e	n.d. TWh	Annual FLH n.d.
	Solar power	5000 MW_e	6.5 TWh	Annual FLH n.d.
	Wave power	300 MW_e	0.8 TWh	Annual FLH n.d
	Condensing mode power stations	n.d. MW_e		ST based; η_e= n.d.
Power and heat	Micro CHP	n.d. MW_e		FC based; η_e= n.d. & η_{th}= n.d.
	Small-scale CHP	n.d. MW_e		FC based; η_e= n.d. & η_{th}= n.d.
	Large-scale CHP	n.d. MW_e		ST based; η_e= n.d. & η_{th}= n.d.
	Waste incineration plants	n.d. MW_e		ST based; η_e= n.d. & η_{th}= n.d.
	Industry CHP	n.d. MW_e		ST based; η_e= n.d. & η_{th}= n.d.
Heat – central DH	Solar DH	n.d.		
	HPs	n.d. MW_e		
	Geothermal	n.d. MJ/s	3.4 TWh	
	Large-scale CHP	n.d. MJ/s		
	Boilers	n.d. MJ/s		
	Electric boilers	n.d.		
	Waste incineration plants	n.d. MJ/s		
	Waste heat industry	n.d.	21.1 TWh	
	Waste heat biofuel plants	n.d. MJ/s		
Heat – distributed DH	Solar DH	n.d		
	HPs	n.d. MW_e		
	Geothermal	n.d. MJ/s		
	Small-scale CHP	n.d. MJ/s		
	Boilers	n.d. MJ/s		
	Electric boilers	n.d.		
	Waste incineration plants	n.d. MJ/s		
	Waste heat industry	n.d.		
	Waste heat biofuel plants	n.d. MJ/s		
Transport	Hydrogen production	n.d. MW_e	6.3 TWh	Used for biofuels (transport)
	Synthetic fuel production	n.d. MJ/s	12.7 TWh	Synfuel for Transport only
	Electric vehicles	n.d. MW_e		
Gas	Biogas production	n.d.	7.9 TWh	Injected into Gas grid
	Hydrogen production	n.d. MW_e	2 TWh	Used for CHP and PP
	SNG	n.d.	13.2 TWh	Used for CHP and PP
Storage	Electricity storage	n.d. GWh		
	Hydrogen storage	n.d.		
	Synthetic fuel storage	n.d.		
	Heat storage (DH)	n.d.		
Individual	Individual biomass boilers	n.d. MJ/s	0.9 TWh	
	Individual solar	n.d. MJ/s	2.2 TWh	
	Individual HPs	n.d. MW_e	1.7 TWh	COP = 3.6
	Individual oil boilers	n.d. MJ/s		
	Individual NG boilers	n.d. MJ/s		

Table 14: Production and consumption capacities in MW and MJ/s divided on different energy sectors, in 2050, in the CEESA's recommended scenario.

Table 15 illustrates energy demands in CEESA's 2050 scenario.

	Category	Demand	Characteristics
Elect.	Electricity – Classic*	26.9 TWh	
	Electricity for hydrogen	12.4 TWh	

	Electricity for DH HP	n.d.	
	Electricity for DH boilers	n.d.	
	Electricity for individual HP	1.7 TWh	
	Electricity for Co-electrolysis	21.4 TWh	For Synfuel production
Heat	Heat demand for DH – central	n.d.	
	Heat demand for DH - distributed	n.d.	
	Heat demand for individual dwellings	n.d.	
Fuel	Transport demand – electricity	8.2 TWh	
	Transport demand – Hydrogen	0 TWh	Used with biomass for biofuel
	Transport demand – Synthetic	12.7 TWh	
	Transport demand – Bio	16.6 TWh	
	Transport demand – Fossil	n.d.	
	Industrial fuel demand	n.d.	
	Total Primary energy Supply	135.8 TWh	

*Table 15: Energy demands in CEESA-2050 scenario. Electricity demands are according to the Sankey diagram of the study *Classic electricity consumption includes all consumption except from "new" electricity consumption i.e. EVs, HPs, electric boilers, hydrogen plants etc.*

Hydrogen usage in CEESA-2050

In the CEESA-2050 scenario hydrogen is primarily used within the transport sector and only to a smaller share to cover heat demand. It is stressed that hydrogen can have a positive effect on reducing biomass consumption for energy. Since transport demand is assumed to increase in the long-term and biomass resources are limited anyway, solutions which are based on electricity and which can substitute oil-derived fuels for transport become important. Further, hydrogen generation through electrolysis can also promote wind power integration while it offers ancillary services for grid stability.

The CEESA-2050 scenario considers two conversion technologies, which include hydrogen: Co-electrolysis and bioenergy hydrogenation, resulting in synthetic, respectively biogenic Di-Methyl-Ether (DME). Regarding biomass scarcity in Denmark, syn-DME is a promising technology to lower biomass consumption for energy. Though, there is a high uncertainty regarding the availability of co-electrolysis for syn-DME production in 2050. It is highlighted that at the time of the study it was not even known how syn-jetfuel could be produced. Therefore, it might be unlikely that syn-DME will be the dominant energy supplier for the transport sector. The study assumes that the initial technology for fossil fuel substitution is bio-DME. After 2030 electrolysis for hydrogen production shall increase gradually to replace larger amounts of liquid fuels for transport. When syn-DME is technologically and economically available it can also contribute to the replacement process. In 2050, 60 PJ of bio-DME and 46 PJ of syn-DME are consumed in the transport sector. Direct usage of hydrogen only makes up a marginal share. It is considered for small and large scale fuel cell CHP and power plants.

Market integration and balancing using hydrogen in CEESA-2050

The study does not mention specific details regarding the market integration or the grid-balancing function of hydrogen. It is only stated that hydrogen production will promote the integration of wind power in the ancillary services of maintaining voltage and frequency in the electricity system.

2.4 The IDA Climate Plan 2050 study analysis

In August 2009, the Danish Society of Engineers (IDA) published the IDA Climate Plan 2050. It is part of a bigger collaboration to present national solutions to reduce greenhouse gas (GHG) emissions for climate change mitigation. It is stated that Denmark can reduce its GHG emissions by 90% between the year 2000 and 2050. At the same time it presents a self-sufficient, 100% renewable energy system with total energy consumption reduced to 442 PJ. This would save up to 500 PJ compared to the reference scenario of the Danish Energy Agency. The IDA-2050 scenario is a closed energy system, and biomass consumption is supplied by domestic production alone. From a socio-economic viewpoint this leads to annual savings of around 25 billion DKK, while simultaneously having positive effects on employment. Investments in new technologies and infrastructure are the main costs in the IDA-2050 scenario, contrasting to the reference scenario, where fuel costs are dominating.

Energy system structure in the IDA-2050 scenario

In the IDA-2050 scenario offshore capacity is set to 4,615 MW and onshore capacity to 4,554 MW. Thus, wind power can cover around 60% of the electricity production. This requires a flexible energy system with a variable consumption. Therefore fuel cell CHP, heat pumps and a large fleet of electric cars are necessary to provide flexibility and storage potential. 2 million electric vehicles with a total capacity of 36 GW are installed. After 2030, also electrolysis plants are supposed to be a considerable part of a flexible demand management. Further, emphasis is put on the implementation of smart energy meters, the development of district heating and energy savings in the housing sector. In particular, the electricity consumption in households is reduced by 50 % between 2008 and 2050. It also requires significant electricity savings in the industry and service sector, which is equal to a reduction of 65 % between 2008 and 2050. Further, energy consumption for transport has also decreased by 44 % in relation to 2008.

Biomass covers app. 65 % of the primary energy supply. It is primarily used for CHP and power plants, industry and biofuels, e.g. the industrial fuel demand is solely covered by biomass. More than two thirds of the biomass is consumed in CHP, power plants and industry, which later on covers the main share of Denmark’s heat demand (app. 90 %). Wind power supplies 26 % of primary energy consumption and the rest comes from PV, wave power and solar thermal. The demand side splits up into 254 PJ for heating, 123 PJ for transport and 68 PJ for electricity.

Table 16 illustrates installed production and consumption capacities or annual production figures for the different units in the system in 2050 in the IDA-2050 scenario.

	Technology	Installed capacity	Annual Production	Characteristics
Power	Onshore wind power	4,454 MW_e	12.6 TWh	Annual FLH* 2829
	Off-shore wind power	4,625 MW_e	18.9 TWh	Annual FLH 4086
	Solar power	3,400 MW_e	4.5 TWh	Annual FLH 1314
	Wave power	700 MW_e	2.61 TWh	Annual FLH 3723
	Condensing mode power stations	n.d. MW_e		ST based; η_e= n.d.
Power and heat	Micro CHP	n.d. MW_e		η_e= n.d. & η_{th}= n.d.
	Small-scale CHP	1,950 MW_e		Fuel Cell based; η_e= 66% & η_{th}= 24%
	Large-scale CHP	10,300 MW_e		Fuel Cell based; η_e= 56% & η_{th}= 34%
	Waste incineration plants	n.d. MW_e	3.3 TWh El.	ST based; η_e= 27% & η_{th}= 77%
	Industry CHP	n.d. MW_e	1.01 TWh El. 2.45 TWh Heat	ST based; η_e= n.d. & η_{th}= n.d.
Heat – central DH	Solar DH	n.d.	0.61 TWh	
	HPs	450 MW_e	10.2 TWh	
	Geothermal	478 MJ/s	4.1 TWh	
	Large-scale CHP	3,745 MJ/s	3.67 TWh	
	Boilers	n.d. MJ/s		
	Electric boilers	n.d.		
	Waste incineration plants	n.d. MJ/s	6.2 TWh	
	Waste heat industry	n.d.	2.7 TWh	Assumed to be only central DH
	Waste heat biofuel plants	n.d. MJ/s		
Heat – distributed DH	Solar DH	n.d	2.72 TWh	Incl. DH areas without CHP
	HPs	n.d. MW_e		
	Geothermal	n.d. MJ/s		
	Small-scale CHP	1,184 MJ/s		
	Boilers	n.d. MJ/s		
	Electric boilers	n.d.		
	Waste incineration plants	n.d. MJ/s	3.33 TWh	
	Waste heat industry	n.d.		
	Waste heat biofuel plants	n.d. MJ/s		
Transport	Hydrogen production	564 MW_e	3.29 TWh	
	Synthetic fuel production	n.d. MJ/s	1.25 TWh	
	Electric vehicles	36,000 MW_e		
Gas	Biogas production	n.d.	11.1 TWh	
	Hydrogen production	600 MW_e	1.81 TWh	
	SNG	n.d.	TWh	
Storage	Electricity storage	n.d.		
	Hydrogen storage	164 GWh		101 GWh for CHP and 63 GWh for transport
	Synthetic fuel storage	n.d.		
	Heat storage (DH)	88 GWh		For solar thermal
Individual	Individual biomass boilers	n.d. MJ/s	0.87 TWh	
	Individual solar	n.d. MJ/s	2.04 TWh	
	Individual HPs	n.d. MW_e	6.01 TWh	COP = 3.85
	Individual oil boilers	n.d. MJ/s	0 TWh	
	Individual NG boilers	n.d. MJ/s	0 TWh	

*Table 16: *Includes electric vehicles, commercial vehicles, trucks, busses and motor cycles.*

Table 17 illustrates energy demands in 2050 in IDA's Climate Plan.

	Category	Demand	Characteristics
Electricity	Electricity – Classic*	19.3 TWh	
	Electricity for hydrogen	7.5 TWh	
	Electricity for DH HP	9.5 TWh	Including Industrial HP
	Electricity for DH boilers	n.d.	
	Electricity for individual HP	1.6 TWh	
	Electricity for Co-electrolysis	n.d.	
Heat	Heat demand for DH – central	23.23 TWh	
	Heat demand for DH - distributed	14.05 TWh	Incl. boilers in DH areas
	Heat demand for individual dwellings	10.42 TWh	
Fuel	Transport demand – electricity	12.1 TWh	Roads/Busses/Rail
	Transport demand – Hydrogen	1.94 TWh	
	Transport demand – Synthetic	1.25 TWh	DME
	Transport demand – Bio	20.83 TWh	
	Transport demand – Fossil	0 TWh	
	Industrial fuel demand	23.6 TWh	i.e. only biomass
	Total Primary energy Supply	122.78 TWh	

*Table 17: Energy demands in the IDA-2050 scenario. *Classic electricity consumption includes all consumption except from "new" electricity consumption i.e. EVs, HPs, electric boilers, hydrogen plants etc.*

Hydrogen usage in IDA-2050

Hydrogen covers around 4% of the total energy demand in the IDA-2050 scenario. This corresponds to a total hydrogen production of 5.1 TWh in 2050. It is either used in fuel cells for heat and electricity (1.81 TWh) or for transport (3.29 TWh). In the latter sector, it is assumed that 20 % of all passenger cars and 25 % of trucks and busses are plug-in hybrid vehicles running on hydrogen or DME. Their hydrogen/DME consumption represents approximately 10 % of the overall transport fuel consumption. The majority is supplied by electricity and biofuels. The transport sector in the IDA-2050 scenario requires 564 MW_e capacity for electrolysis facilities in connection with a storage size of 63 GWh. The storage size can cover app. one week average consumption.

In 2050 high-temperature electrolysis with an efficiency of 69% (including storage losses) will be available. Hydrogen storage and electrolysis are supposed to reduce the consumption of scarce biomass resources, although the investment costs for these technologies are a major challenge. In the present scenario an electrolysis capacity of 600 MW_e is installed. 400 MW_e are allocated at central CHP and 200 MW_e at decentral CHP plants. In general, all power and CHP plants are based on fuel cells. Further, a storage capacity of 101 GWh is installed. This allows the electrolysis facilities to run on full capacity for a whole week. Electricity demand for hydrogen production equals 7.5 TWh, i.e. 15% of total electricity consumption in the IDA-2050 scenario.

Market integration and balancing using hydrogen in IDA-2050

The study does not mention specific details regarding the market integration or grid-balancing function of hydrogen. Though, it is mentioned that fuel cell CHP plants can potentially be up and downward regulated much faster than current steam turbines and therefore they can contribute to regulation and grid stability.

2.5 Energikoncept 2030 (Energinet.dk)

This study from April 2015 is the first of a number of studies called "Energy of the Future" planned by Energinet.dk. The purpose is to give input to the long term system planning of the electricity and gas systems in Denmark. The approach is scenarios for 2035 and 2050. Energikoncept 2030 introduces the concept of "System robustness" which is an assessment of the energy system's collective ability to supply energy services at competitive costs at any wind and solar production, varying fuel and CO_2 prices, new technologies etc. A part of Energikoncept 2030 is to identify new system-related initiatives and concepts specifically targeted to make wind / REN scenarios competitive and more robust than a fossil reference towards 2035.

The modelling uses as a point of departure the wind scenario from the DEA described earlier because this scenario is assessed by DEA to have the highest security of supply.

DEA has estimated the wind scenario to have a 8 % higher cost than a fossil reference scenario. However, based on a number of system initiatives Energinet.dk estimates that the wind scenario can be much more cost effective and have a long term cost competitiveness with the reference scenario.

One of the initiatives is an effective integration between the different energy systems. This will result in a reduction of the total requirement for wind power and this could be the more expensive off shore wind power.

A system integration between the electricity, the gas and the heating systems can ensure that the wind power could be balanced within the Danish borders. However, according to the analysis this would not be desirable when considering cost assessments and energy efficiency and it would also call for additional fixed asset investments.

A key issue is the analysis of other countries power supply in situations where wind power dominated Denmark has weeks with extremely low or high production from wind and solar. The result is that it is possible that sufficient interconnectors can strengthen the Danish power supply, and that Denmark is relatively robust towards changing in foreign framework conditions.

Spike power capacity will be one of the issues that has to be assessed. Most of the central power stations in Denmark will be outdated within 10 to 20 years from now (2015) and have to be either closed or heavily renovated. The analysis shows that especially the Nordic countries but also UK can contribute cost-effective to spike power capacity in Denmark.

There are two suggestions for greatly reducing the cost for back-up capacity for peak load: Flexible demand and international market integration.

The role of the electricity system and the conversion of electricity will greatly increase along with the need for balancing. There will be substantially more wind in the future energy system and the electricity consumption will be considerably higher – 30 % more in 2030 and 100 % more in 2050. However, the assessment is that the utilization of the grid can be greatly enhanced. The study shows that flexible consumption can cover the need for balancing in the five minutes intervals that are part of the study.

The analysis is based on the wind scenario from the Danish Energy Agency, described earlier in this chapter. The wind scenario is assessed by the DEA to be 5 – 10 % more expensive than the fossil reference scenario. However, with the different measures suggested in Energikoncept 2030 the wind scenario has a cost level equal to the fossil reference and thus is not more expensive.

2.6 Use of hydrogen in national Danish scenarios

In the scenarios we have screened in this chapter, hydrogen plays no role in the biomass and bio+ scenarios of the Danish Energy Agency, in the Wind scenario (and thus also the Energikoncept 2030 scenario) and the CEESA 2050 scenario, hydrogen is almost exclusively used indirectly – i.e. through the production of synthetic fuels. Only the Hydrogen scenario and the IDA scenario have significant direct use of hydrogen.

The only scenarios without hydrogen – the biomass scenarios – are highly dependent on biomass and also in quantities beyond what is domestically available in Denmark, thus realistically, hydrogen will play a role, however there is no consensus on whether the use will be direct or indirect.

In scenarios with hydrogen, hydrogen will primarily play a role in the transportation sector.

In the next chapter three European studies will be described.

3 European scenarios

In this chapter, three scenarios for the European energy system are reviewed in order to establish an overview of the expected future use of hydrogen in the perspectives of different research and governmental bodies.

Many of the available European studies mention hydrogen as a potential energy carrier in the future energy system, but few studies evaluate the scope and scale of this potential. This Chapter focus on three different studies where the use of hydrogen is briefly discussed. The studies included here, are the following:

- **Roadmap 2050** by the European Climate Foundation
- **eHighway2050** by the pan-European cooperation between transmission system operators, companies, universities, research institutions, energy associations.
- **Power Choices** by EURELECTRIC

3.1 Roadmap 2050

In April 2010, the European Climate Foundation (ECF) published the report, *Roadmap 2050: a practical guide to a prosperous, low-carbon Europe*. The report provides an analysis of three different pathways to achieve the political objective of reducing greenhouse gas (GHG) emissions by at least 80% below 1990 levels by 2050 – an objective that was announced by the leaders of the European Union at the G8 summit in July 2009. The study investigates both the technical and economic feasibility of achieving this political objective.

The three pathways investigated differ in their mix of supply technologies, but are otherwise, based on the same assumptions. The technologies used in the pathways are fossil fuel plus CCS, nuclear energy and a mix of renewable technologies.

Since the report is based on a desirable outcome, it should not be considered as a forecast, but rather as derived plausible pathways from today in achieving the 2050 goal. This approach is also known as "back-casting".

General assumptions in the pathways

Realizing an 80% reduction in GHG emissions below 1990 levels by 2050, requires fundamental changes to the energy system including energy efficiency measures, a nearly full decarbonisation of the power sector and an extensive fuel shift in the transport and building sectors.

European power supply

The decarbonisation of the power sector is one of the cornerstones in reaching the 80% GHG reduction target and the study shows that it will need to decarbonize at least 95%. One of the challenges for the power sector is to incorporate large shares of intermittent renewables, but in all of the modelled pathways, it is technically achievable. It does require, however, significant increased transmission capacity, additional backup generation capacity and more demand response.

In the study, the European power demand is expected to increase almost 40% from 3,450 TWh/year in 2005 to 4,800 TWh/year in 2050.

As can be seen in Figure 4, the three pathways cover a share of renewable energy between 40% and 80%, a share of nuclear energy between 10% and 30% and a share of fossil fuels plus Carbon Capturing and Sequestration (CCS) plants between 10% and 30%. The three pathways are compared to a baseline scenario, which is based on external forecasts, e.g. IEA and Oxford Economics projections.

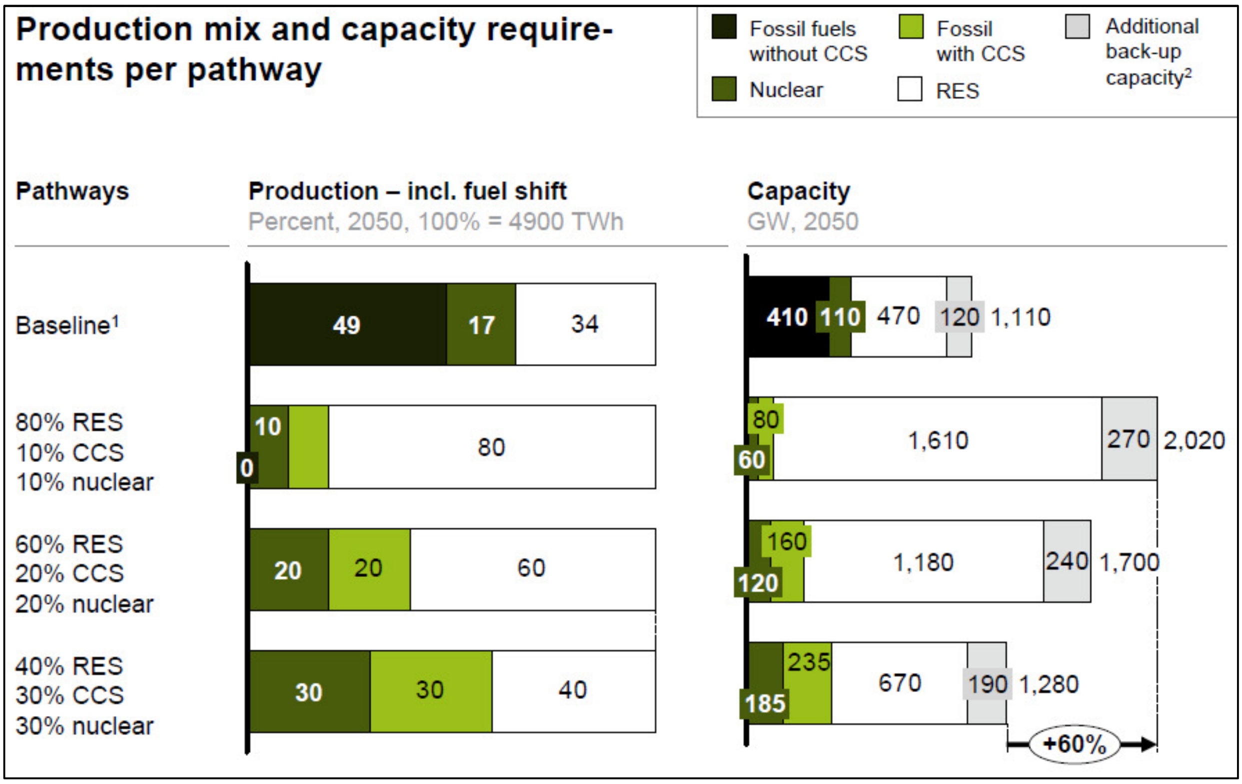


Figure 4. The production and capacity mix in the power sector in 2050 for the three scenarios compared to the baseline (Roadmap2050).

Due to the fact that many renewable energy sources (RES) rarely produce at full load, the generation capacity needed to meet the demand increases with the increasing RES penetration. For instance, a wind turbine will only produce at partial load during most hours of the year. The effects of this is a 60% higher generation capacity for the pathway with 80% RES compared to the pathway with 40% RES.

All technologies applied in the pathways are commercially available at large scale, except CCS, which is considered to be in a late stage development.

Energy efficiency

Energy efficiency measures in buildings and industries are assumed implemented linearly up to 2050, reducing the electricity demand. However, the shift in road transport to electric vehicles accelerates after 2020 causing an overall increase in the demand.

Use of biomass across sectors

The use of biomass in the pathways is limited to 5,000 TWh in primary energy supply (12 billion tonnes per year). The study assumes that 40% of the biomass will be used for road transport, 20% for air and sea transport and 40% for power generation. Furthermore, it is assumed that the biomass used for power generation is required in small isolated plants across Europe where CCS is either not possible or too costly. If however, CCS can be applied in 25% of the biomass fired power plants it will bring an additional 5% of decarbonisation to the power sector.

European transport and building sector

A decarbonisation of the transport sector requires an extensive use of electric vehicles and some hydrogen fuel cell vehicles and/or biofuels and a few vehicles still running on conventional diesel. The transition of the transport sector is illustrated in Figure 5.

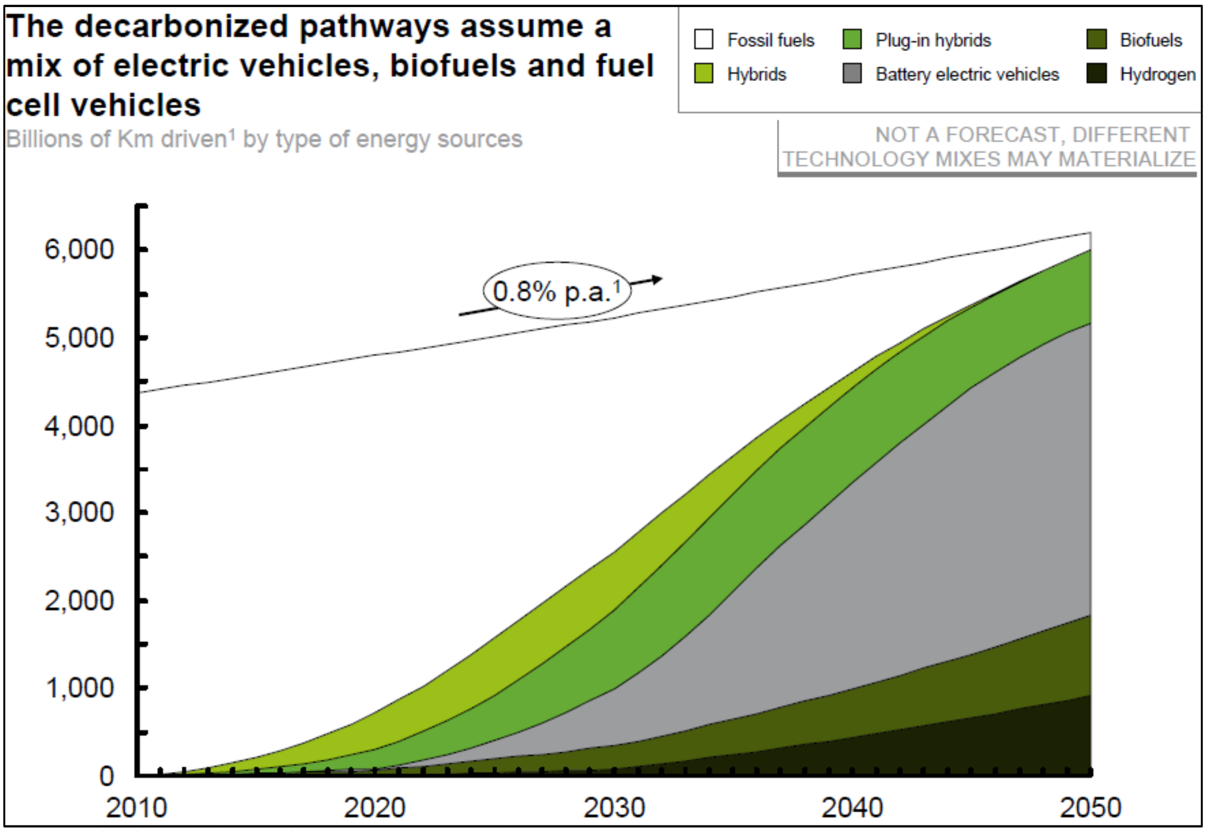


Figure 5. The shift in fuel use in the transport sector (Roadmap2050)

In order for this transition to be economically feasible, a significant improvement in performance and cost is needed for the applied technologies.

Use of hydrogen

The use of hydrogen in the pathways is limited to the transport sector, but here it constitutes a significant proportion. The hydrogen used for transportation is assumed to be produced via processes such as Integrated Gasification Combined Cycle (IGCC) plants with pre-combustion CCS, Steam Methane Reforming (SMR) or electrolysis.

It is important to note of course, that the two former technologies rely on fossil fuels or biomass for the hydrogen production, and only electrolysis is feasible in fossil-free, low biomass scenarios.

3.2 eHighway2050

The eHighway2050 project is an ongoing study of developing and applying a methodology for the long-term development of the pan-European transmission network. Planning of the transmission network will assume a crucial role when it comes to implementation and realisation of the European single electricity market and the decarbonisation process over the next 40 years. The findings presented here are the preliminary results, as the project is not finalised until the end of 2015.

Members of the project are transmission system operators from Belgium, the Czech Republic, France, Germany, Italy, Portugal, Switzerland, Poland and ENTSO-E, university and research institutions together with companies and associations of technology manufacturers and energy and consulting associations.

The e-Highway2050 scenarios nor is one scenario more preferred than another. The scenarios should be considered as a possible futures for the European Electricity Highways.

The development of possible scenarios is based on the available options that decision makers have, which are in line with the 2050 policy orientations.

eHighway2050 scenarios

From initially 30 potential energy scenarios, a final set of five scenarios have been identified Find more details about the scenarios at: (GridInnovation)

Large scale RES deployment

The strategy focuses on the deployment of large-scale RES technologies, e.g. large scale offshore wind parks in the North Sea and Baltic Seas as well as solar projects in North Africa (large-scale PV power for instance). A lower priority is given to the deployment of decentralized RES (including CHP and biomass) solutions. A high priority is given to centralized storage solutions (such as pumped hydro storage and compressed air energy storage) accompanying large-scale RES deployment.

1. *High GDP growth and market-based energy policies*
   Common agreements/rules have been set for transnational initiatives regarding the functioning of an internal EU market, EU wide security of supply and coordinated use of interconnectors for cross-border flows exchanges in EU. Yet, there is a special interest about large-scale decentralized solutions for RES deployment and storage. CCS technology is assumed mature while electrification of transport (for instance Integration of EVs), heating and industry is considered to occur mainly at centralized (large-scale) level.

2. *Large fossil fuel deployment with CCS and nuclear electricity*
   Electrification of transport, heating and industry is considered to occur mainly at centralized (large-scale) level. No further flexibility is needed since variable generation from PV and wind is low. Public acceptance towards deployment of RES technologies is indifferent in the EU.

3. *100% RES electricity*
   In this scenario, Europe's electricity system becomes 100% based on renewable energy. To reach this target, both large scale and small-scale options are used: offshore wind parks in the North Sea and Baltic Seas and projects in North Africa, combined with EU-wide deployment of de-centralized RES (including CHP and biomass) solutions. Neither nuclear nor fossil fuels with CCS are used. Thus, both large-scale storage technologies and small-scale storage technologies are needed to balance the variability in renewable generation.

4. *Small and local*
   Common agreements/rules for transnational initiatives regarding the functioning of an internal EU market, EU wide security of supply and coordinated use of interconnectors for transnational energy exchanges have not been reached. The focus is on local solutions dealing with de-centralized generation and storage and smart grid solutions mainly at distribution level. Due to a somehow heterogeneous European landscape of energy strategies, some member states still rely on energy imports from outside the EU.

Use of hydrogen in scenarios

Very little attention is given to the use of hydrogen in the above scenarios. Hydrogen is only briefly mentioned as a potential fuel for passenger vehicles in the decarbonisation of the transport sector. It could for instance be used to power fuel cells vehicles, but the scale of the potential use of hydrogen is not assessed in this study.

3.3 Power Choices – Pathways to Carbon-Neutral Electricity in Europe by 2050

November 2009, EURELECTRIC published the report, *Power Choices - Pathways to Carbon-Neutral Electricity in Europe by 2050*. EURELECTRIC is the Union of the Electricity Industry representing the electricity industry at pan-European level. According to EURELECTRIC, *Power Choices* should be seen as a compass indicating the way to carbon-neutral electricity in Europe by 2050.

The report presents a scenario, *Power Choices*, which if accomplished will reduce CO_2 emissions by 75% compared to 2005 levels. The scenario also meets the targets included in the so-called 20-20-20 Climate and Energy policy package[3]. The *Power Choices* scenario is compared with a *Baseline 2009* scenario, which throughout the projection period is based on policies implemented in 2009.

Power Choices scenario

The main challenges in reaching the objective of a 75% reduction in GHG for EU by 2050 compared to 2005 levels are in this study identified as:

1. Increasing the overall energy efficiency
2. Electrification of the transport sector.
3. Electricity generation with a high share of carbon-free energy sources.

Energy efficiency

A reduction in the overall energy use in the *Power Choice* scenario is achieved through investments in more energy efficient equipment, direct energy savings, increased use of heat pumps and an electrification and optimisation of the energy use in the transport sector. The final energy use by sector in the two scenarios, *Power Choices* and *Baseline 2009* can be seen in Figure 6.

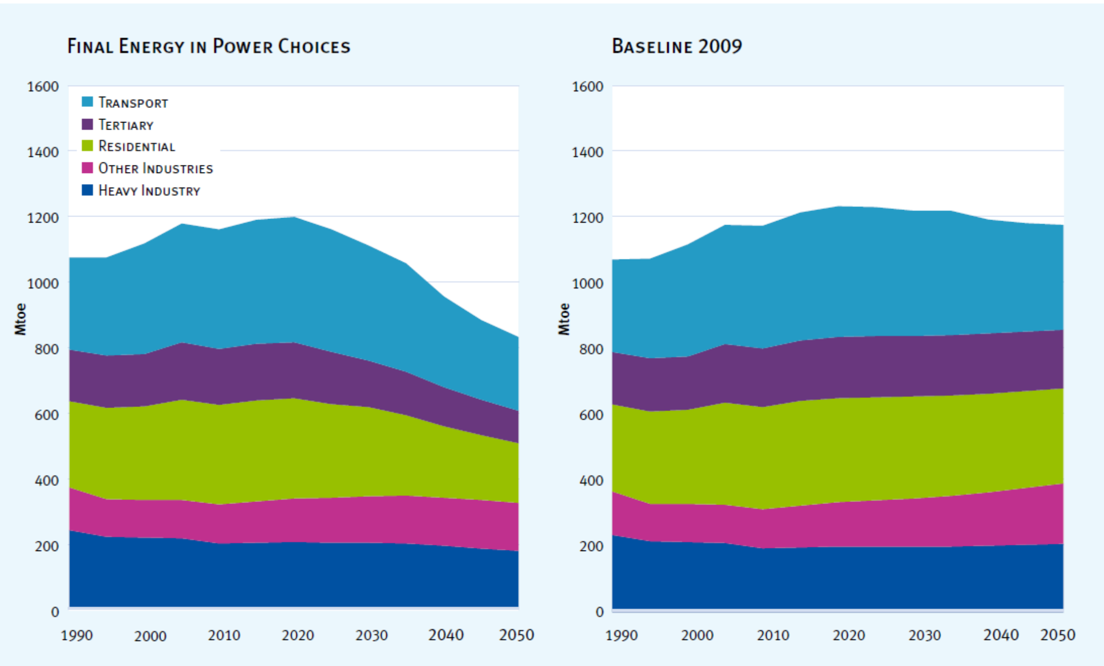


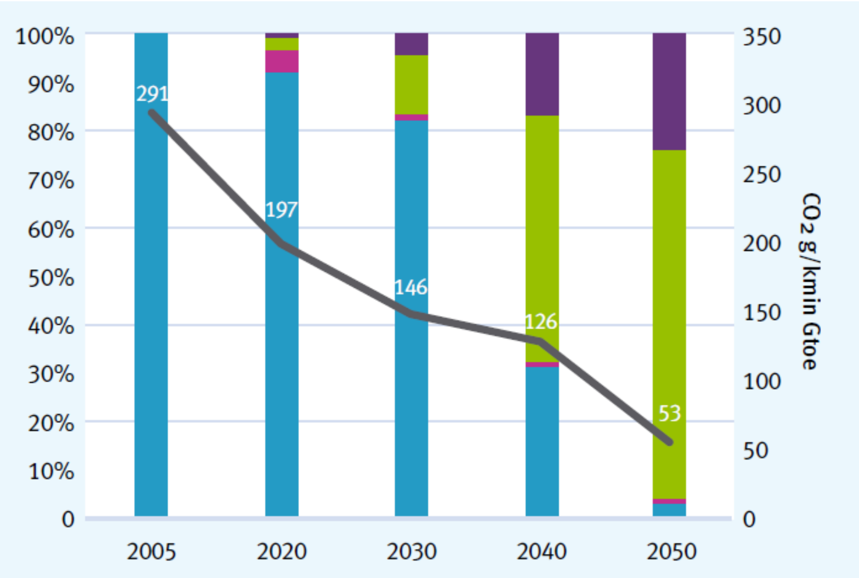
Figure 6. Final energy use by sector in the scenarios, Power Choices and Baseline 2009 (PowerChoices, 2009)

[3] 20% cut in greenhouse gas emissions (from 1990 levels) by 2020; 20% of EU energy from renewables by 2020; 20% improvement in energy efficiency by 2020

Electrification of the transport sector

In order to achieve emission reductions in the transport sector it is necessary to shift the fuel use to a carbon-free energy carrier. In this study, the identified candidates for this shift are biofuels, hydrogen and electricity, provided that their production have a low carbon footprint.

For this reason, the study expects a transition from conventional cars to electric and hybrid cars, which operate with a large electricity share. This can be seen in Figure 7.



Fuel Mix Cars	2030	2050
Oil	76%	7.5%
Biofuels	12.2%	2.1%
Electricity	11.1%	90.3%
Natural Gas	0.7%	0.1%

Figure 7. Fuel mix in cars in the scenario, Power Choices (PowerChoices, 2009)

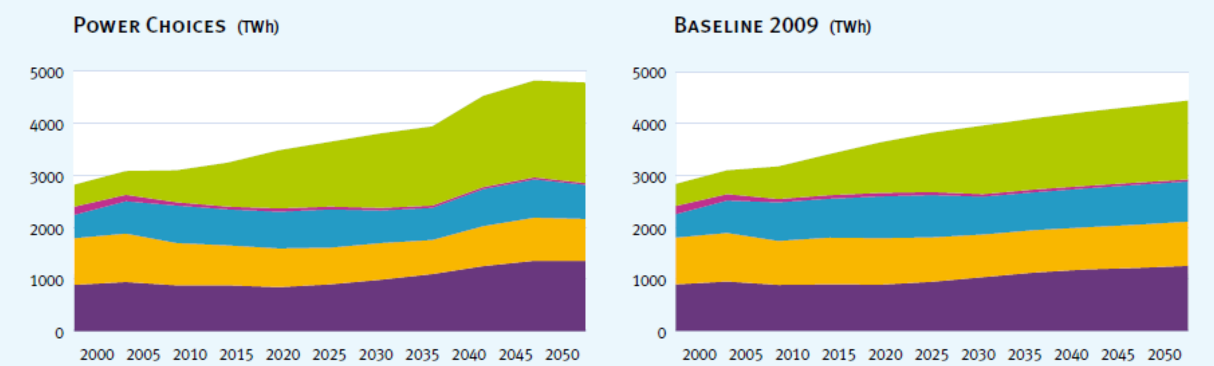
Electricity generation mix

In the decarbonisation of the electricity sector it is assumed that the RES technologies, which are commercially available today, have a considerable potential for improving their technical and economic performance. As a result, the electricity production cost for the technologies is decreasing towards 2050.

Other important assumptions are:

- Electricity becomes a major transport fuel as hybrid and electric cars develop
- Nuclear power remains an option for power production in countries that has nuclear today
- CCS technology is commercial available from 2025
- After 2020 all major emitting sectors pay for their emissions

As a result, the total power production mix will develop as shown in Figure 8.



%	2005	Power Choices 2020	Power Choices 2030	Power Choices 2050	Baseline 2009 2020	Baseline 2009 2030	Baseline 2009 2050
RES	14.8	32.0	37.7	40.4	26.7	33.3	34.2
Oil	5.6	1.8	1.2	0.7	1.9	1.2	0.9
Gas	16.0	20.3	16.5	13.6	22.2	18.5	17.3
Solids	31.9	21.4	18.5	16.9	24.7	20.8	19.3
Nuclear	31.7	24.5	26.1	28.4	24.5	26.2	28.3

Figure 8. The power production mix in the scenarios, Power Choices and Baseline 2009 (PowerChoices, 2009)

Use of hydrogen

Hydrogen is only mentioned in the Power Choices scenario as a potential energy carrier in the transport sector. It will however require a new transportation and distribution infrastructure, which will involve significant capital investments and several technical problems. The most important limitation is the high cost of fuel cells, which are required to decrease by a factor of 10 from today's levels in order to become competitive with other systems.

3.4 Use of hydrogen in European studies

In general, use of hydrogen in the energy system is given little attention in European studies. In the studies reviewed here, hydrogen is only mentioned in connection with the transport sector.

In the Roadmap2050 scenario, hydrogen is considered a part of the solution in the transition from the use of fossil fuels in transportation, however electrolysis is only one in three identified production technologies. Others are based on fossils and/or biomass sources.. In Power Choices and eHighway, hydrogen is identified as a potential energy carrier but its potential usage is not quantified.

4 Future need for balancing and the use of hydrogen - EnergyPLAN analysis (Energy system analysis of electrolysers in energy systems)

The purpose of the modelling of electrolysers in the current and a future high-renewable Danish energy system is to identify what role electrolysers can play and what the impacts could be of integrating these. Another aspect is to analyse how electrolysers can contribute to balancing these systems, in particular when the wind power share increases and more fluctuating electricity will be produced.

Energy system modelling can identify some key trends that are not intuitively evident in the energy sector and the modelling is often required to see this due to the synergies being exploited. By simulating different alternatives in an energy modelling tool such as EnergyPLAN, it is possible to quantify the impact of different choices for the energy system (Lund 2010).

4.1 Modelling approach

The modelling analysis is performed by developing an energy system of 2013 and a future 2035 high-renewable energy system based on the scenarios developed by the Danish Energy Agency (DEA, 2014). In these scenarios different factors are changed to analyse if they have an impact, more specifically these factors are the electrolyser types, the capacities and the wind power capacity. Based on previous research hydrogen should be produced via electrolysers for creation of liquid and gaseous fuels rather than for direct hydrogen usage in e.g. the transport sector – see section 1.5 and (Ridjan et al., 2013; Ridjan et al., 2012).

The modelling is carried out applying the energy system analysis tool EnergyPLAN, which is described in further details below.

EnergyPLAN simulates the electricity, heating, cooling, industry, and transport sectors of an energy system. It simulates each sector on an hourly basis over a one-year time horizon and it is typically used to analyse national energy systems. EnergyPLAN is typically referred to as a simulation tool since it optimises how a mix of pre-defined technologies operate over its one-year time horizon (Collolly et al. 2010). The EnergyPLAN user can define a wide range of inputs before the simulation begins, such as technology capacities, efficiencies, and costs, which EnergyPLAN then uses to identify how this energy system will perform under either a technical or economic simulation.

An economic simulation strategy is utilised here for the 2035 models to operate the energy systems during each hour in EnergyPLAN. EnergyPLAN is purposely designed to be able to identify and utilise synergies across the sectors in the energy system, especially when accommodating large penetrations of intermittent renewable energy such as wind and solar. It has been developed for approximately 15 years at Aalborg University based on the Smart Energy System concept (Mathiesen, 2015).

In this study, EnergyPLAN is used to quantify the impact of installing electrolysers in today's energy system and a 2035 system with higher shares of renewable energy. Previous research that investigated electrolysers for fuel production purposes indicated potential of using electrolysers for wind integration (Connolly et al., 2014; Ridjan et al., 2014; Ridjan, 2015; Mathiesen et al., 2008; Mathiesen et al., 2015; Ridjan et al., 2015a). To begin a model of today's energy system is constructed based on actual empirical data, so EnergyPLAN can be validated to ensure it is modelling the country correctly. During the process of developing the EnergyPLAN tool a cost database was also established, which forms the basis for all cost assumptions in the analyses conducted (AAU, 2015).

The costs applied in this study are from a socio-economic perspective meaning that no taxes or tariffs are included in the calculations.

4.2 Scenario development and calibration

Two different scenarios are developed replicating the Danish energy system as of 2013 and a high-renewable energy system in 2035 based on the Danish Energy Agency's wind scenario (DEA, 2014a).

A more detailed description of the technical characteristics is outlined below as these have a large impact on the further analysis.

The 2013 reference system is based on the annual energy statistics from the Danish Energy Agency in order to create an energy system similar to the existing. This scenario will later be used for analysing whether electrolysers also have a role to play in an energy system similar to the existing system. This 2013 system is based on the renewable production as of 2013 and the energy demands reported for this year and the transport sector is therefore almost solely based on fossil fuels.

As mentioned in chapter 2 the 2035 wind scenario developed by the Danish Energy Agency's (DEA) scenario has a high share of renewable energy, but is not carbon neutral due to fossil fuel consumption in the transport sector. In this 2035 wind scenario large energy savings have been implemented leading to reduced demands in order to stay within domestic renewable resources. In particular, the biomass resources are scarce and under pressure as this is the only fuel that can directly replace a large share of the fossil fuels in today's system. In the 2035 wind scenario biomass is only consumed equal to what is domestically available in Denmark (around 250 PJ compared to a total primary energy demand of around 840 PJ). In order to stay within these biomass potentials electrification is carried out in transport, industry and district heating while hydrogen produced is used for upgrading gasified biomass and biogas for production of fuels for transport sector. These fuels could potentially be used also for heat and power sectors. The scenario has a high reliance on wind power and the expected wind expansion is equal to around 400 MW offshore wind turbines every year between 2020 and 2050 as well as replacing existing turbines with new models (DEA, 2014a). In addition to wind power, electricity is produced from photovoltaics (PV) and thermal plants.

In the transport sector the fuel demands are met by a large share of fossil fuels, electricity and a smaller share of synthetic natural gas (SNG) or further called methane, produced from biogas methanation. Electricity is used directly in a share of the cars while the methane is used for heavy transportation (trucks and ships).

In the heating sector district heating delivers a large share of the heating while individual heat pumps and biomass boiler is used for heating outside of district heating areas.

The 2013 reference and the 2035 wind scenario have been replicated in EnergyPLAN in order to be able to analyse the impacts of carrying out changes in the systems. These models have been calibrated and validated against the published data from DEA to create a model that replicates them as best as possible (DEA, 2014a; DEA, 2013). Below in Figure 9 and Figure 10 comparisons are made of the primary energy demand for the 2013 and 2035 EnergyPLAN models and the DEA 2013 and 2035 data.

The primary energy demands are rather similar between the EnergyPLAN 2013 reference and the DEA 2013 models with differences less than 5% for all fuel types. This model is therefore sufficiently accurate to provide further information when carrying out additional analysis.

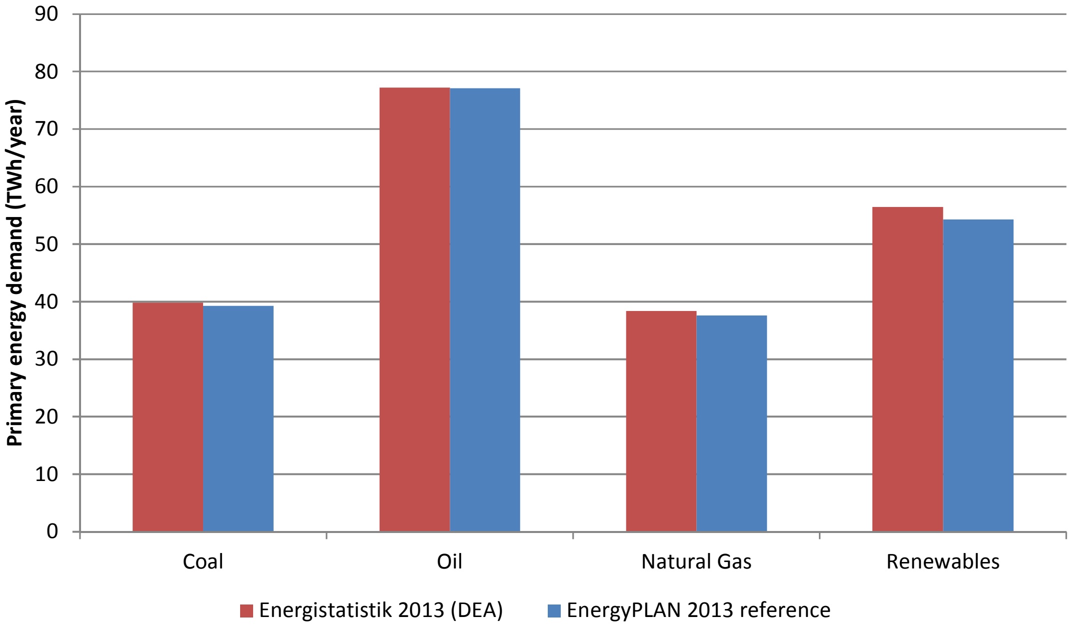


Figure 9: Comparison between the primary energy demand in the EnergyPLAN 2013 reference model and the DEA annual energy statistics (DEA, 2013).

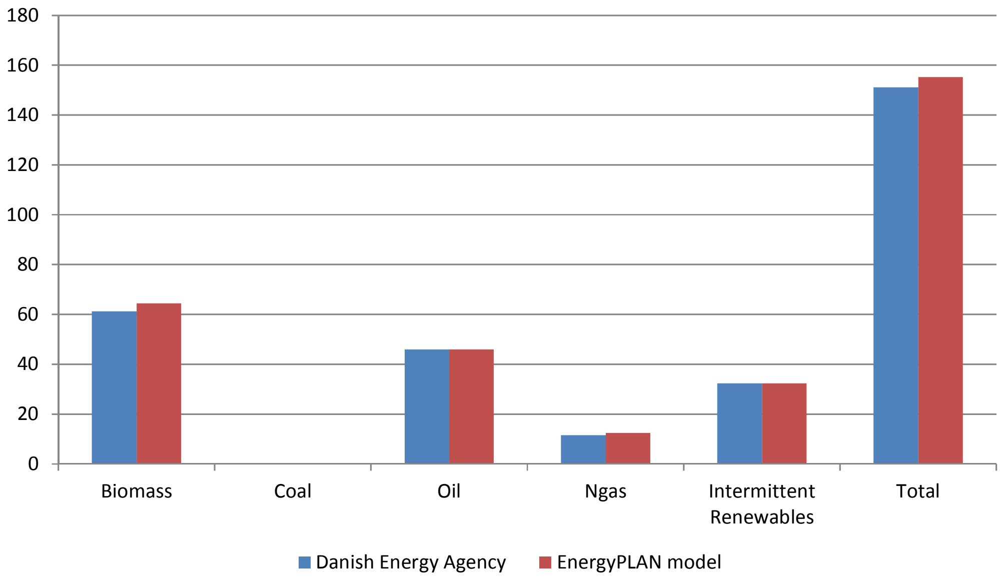


Figure 10: Comparison between the primary energy demand in the EnergyPLAN wind 2035 and the DEA wind 2035(DEA, 2014a).

The primary energy demand when comparing the 2035 EnergyPLAN and DEA models is somewhat different for biomass, natural gas and the total demand. The reason for this can be seen in Figure 11 where the different demand types are outlined. Here, it can be seen that there is a difference in the net electricity exchange with a difference of 1.5 TWh/year. This is because no market data has been available for international electricity exchange and hence in the EnergyPLAN model the electricity demand is met by domestic power plant production consuming fuels thereby increasing the demand for biomass and natural gas. In the DEA models the electricity import is higher and hence this electricity is “produced” without any fuel consumption. When assuming that the 1.5 TWh/year would have to be produced with a typical power plant efficiency of 46% the additional fuel consumption would be 3.5 TWh/year. This amounts to the difference in the total primary energy demand between the two models.

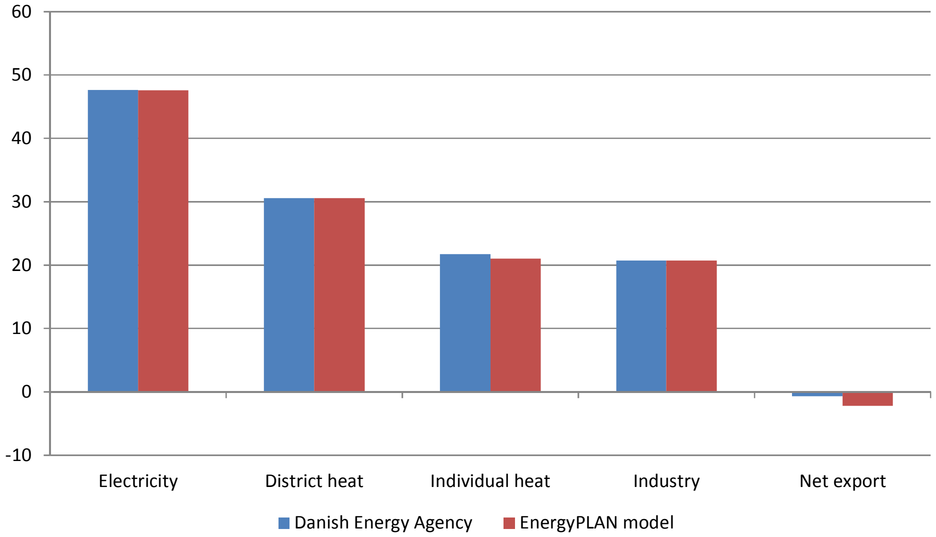


Figure 11: Energy demands in the EnergyPLAN wind 2035 and the DEA wind 2035 models

In general, small differences in primary energy demands are expected between the DEA model and the EnergyPLAN model because these models are based on different methodologies. However, the differences outlined in the figures are deemed as acceptable and the EnergyPLAN models can therefore be used for further analysis.

Some of the key data applied to construct the 2013 reference and the 2035 wind scenario are outlined in

Sector	Technology	Unit	2013 reference	2035 wind
Electricity	Electricity production	TWh/year	34.4	47.1
	Electrolyser electricity demand	TWh/year	0	4.3
	Power plant efficiency	%	39	44
	Wind production	TWh/year	11.1	31.5
	PV production	TWh/year	0.4	0.9
Heating	Heating Demand	TWh/year	49.9	45.5
	CHP efficiencies - centralised	% (electricity/heat)	34/56	38/52
	CHP efficiencies - decentralised	% (electricity/heat)	36/48	49/43
	Large HP capacity	MW-e	0	216
Transport	Fuel demand	TWh/year	60.2	49.7
	Electricity demand	TWh/year	0.38	3.41
Carbon Dioxide	CO_2-Emissions	Mt/year	43.1	14.8

Table 18.

Sector	Technology	Unit	2013 reference	2035 wind
Electricity	Electricity production	TWh/year	34.4	47.1
	Electrolyser electricity demand	TWh/year	0	4.3
	Power plant efficiency	%	39	44
	Wind production	TWh/year	11.1	31.5
	PV production	TWh/year	0.4	0.9
Heating	Heating Demand	TWh/year	49.9	45.5
	CHP efficiencies - centralised	% (electricity/heat)	34/56	38/52
	CHP efficiencies - decentralised	% (electricity/heat)	36/48	49/43

	Large HP capacity	MW-e	0	216
Transport	Fuel demand	TWh/year	60.2	49.7
	Electricity demand	TWh/year	0.38	3.41
Carbon Dioxide	CO_2-Emissions	Mt/year	43.1	14.8

Table 18: Key data about the 2013 reference and 2035 wind scenario

4.3 Scenario simulations and analysis

In these two EnergyPLAN models the impact of altering the electrolyser capacity, the wind capacity, the hydrogen storage capacity as well as the types of electrolysers will be analysed. Concretely, the following models are built for analysing the impacts of the changed assumptions.

- 2013 reference
    - 2013 – Electrolyser for transport
    - 2013 – Electrolyser for CHP
- 2035 wind scenario
    - 2035 - Different types of electrolyser technologies
    - 2035 – Changed electrolyser capacities
    - 2035 – Changed wind capacities

To assess the impact of electrolysers a number of metrics will be used including the impact on exchange of electricity with the surrounding world and thereby the balancing capabilities with different electrolyser capacities. Furthermore, the operation hours of the electrolysers are analysed when changing the capacities and finally, the impacts on the system costs and primary energy demand are assessed.

The assumed electrolyser efficiencies and costs are outlined in

Electrolyser specifications		Investments	Lifetime	Operation and maintenance	Efficiency-$_{LHV}$
	Unit	M€/MW	years	% of investment	%
2013	SOEC	0.93	15	3	73
	Alkaline	1.07	25	4	47.5
	PEM	2.55	10	4	51.3
2035	SOEC	0.35	15	3	73
	Alkaline	0.87	27.5	4	63.7
	PEM	1.27	30	4	66.5

Table 19 (Mathiesen et al. 2013).

Electrolyser specifications		Investments	Lifetime	Operation and maintenance	Efficiency-$_{LHV}$
	Unit	M€/MW	years	% of investment	%
2013	SOEC	0.93	15	3	73
	Alkaline	1.07	25	4	47.5
	PEM	2.55	10	4	51.3
2035	SOEC	0.35	15	3	73
	Alkaline	0.87	27.5	4	63.7
	PEM	1.27	30	4	66.5

Table 19: Electrolyser specifications assumed in the analysis for 2013 and 2035 (Mathiesen et al. 2013).

4.4 Results

The results are described in this section for the 2013 and the 2035 models.

4.4.1 2013 models

After creating the reference 2013 model based on DEA data it was investigated whether electrolysers and the production of hydrogen can have a role to play in an energy system similar to the existing system when installed in two different sectors; respectively hydrogen for the transport sector and for CHP production.

The first part concerning the transport sector was analysed assuming that 20% of the transport fuels are produced by advanced BTL (biomass-to-liquid) technology with hydrogen addition. A total of 13.1 TWh of syngas is produced and converted to jetfuel, petrol or diesel of which diesel represents half of the production. For the production of these fuels 11.05 TWh of biomass and 5 TWh of hydrogen are required.

The second part of the analysis assumed that the same gas production takes place (13.05 TWh), but instead of converting this to transport fuels this gas is used for CHP production of electricity and heat.

For both parts of the analysis three different types of electrolysers were analysed: PEM, alkaline and SOEC technologies with technology specifications according to (Mathiesen et al. 2013).

In Figure 12 the primary energy demand for the different models show that the energy demand increases when installing electrolysers in the existing energy system. This is because the share of renewable intermittent energy is at a level where the energy system of today is already able to integrate this without installing additional flexible technologies such as electrolysers. Hence, the electrolysers only add more electricity demand that has to be produced from thermal plants consuming coal and biomass and also adds biomass demand for the gasification that is required to produce the electrofuels[4]. Therefore, in the scenarios where electrolysers are used in the transport sector the oil demand decreases while the coal and biomass demand grows for electricity production. In the scenarios where the syngas is used for CHP production the natural gas share decreases wile more biomass and coal is consumed. Some of the increasing coal and biomass demands for electricity production could potentially be replaced by electricity from renewable sources.

[4] Electrofuels are defined as a means for electricity storage in the form of liquid fuels (Ridjan et al. 2015b). In this context electrofuels refers to fuel production through the combination of either methane by biogas upgrade with hydrogen or biomass gasification with further upgrade with hydrogen to desired fuels CO_2 and hydrogen.

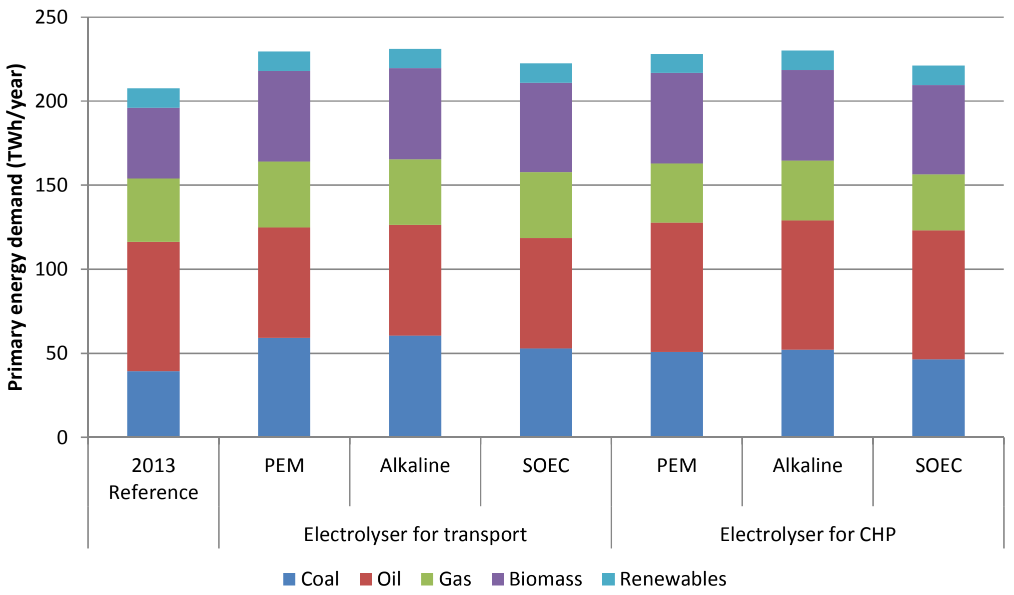


Figure 12: Primary energy demand in the 2013 models when implementing different types of electrolysers for transport and CHP

The growing fuel demands also have an impact on the socio-economic costs of the models as can be seen in Figure 13. When installing the electrolysers the fuel costs therefore increase, and so do the investments and operation & maintenance costs. The energy systems therefore have higher costs when installing electrolysers in a system similar to the existing.

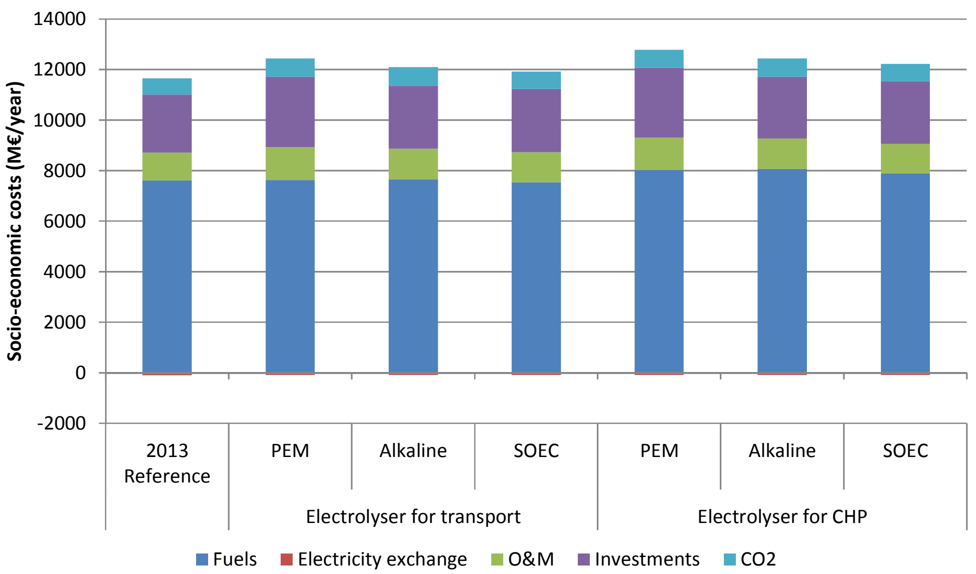


Figure 13: Socio-economic costs for the models divided by fuels, electricity exchange, operation & maintenance and CO2

The electricity export is reduced when the electrolysers are installed, because the electricity demand of the system increases for hydrogen production and because the electrolysers can utilize the wind power in the hours where there is an excess of renewable electricity production. The exchange of electricity is however limited when comparing to the overall electricity demand, i.e. the electricity exchange in the 2013 electrolyser for transport PEM scenario is around 0.2 TWh/year out of a total electricity demand of 44.3 TWh/year (0.5% of total demand).

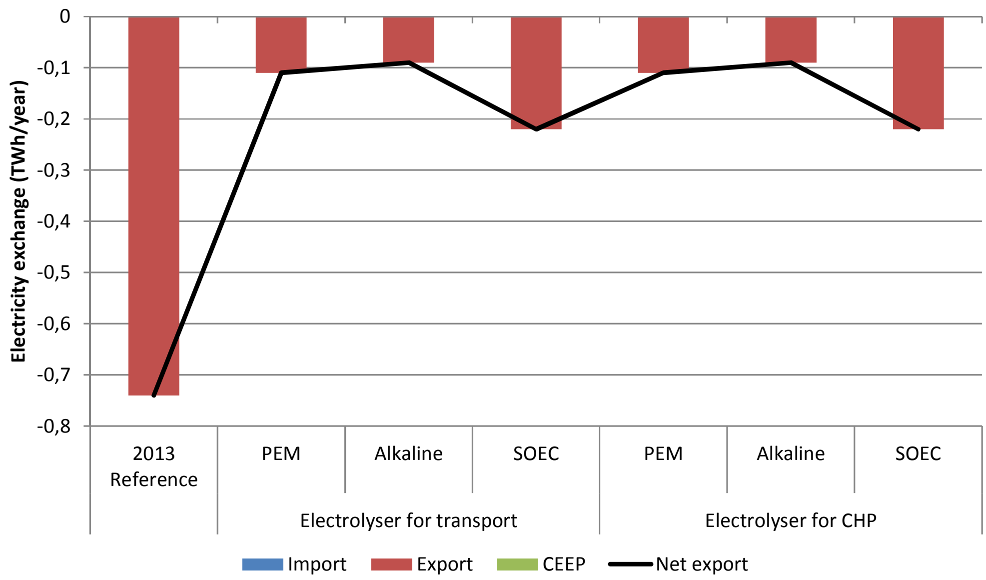


Figure 14: Electricity exchange when implementing electrolysers for transport and CHP in the 2013 energy system

When comparing the different electrolyser technologies investigated the SOEC technology has a significantly higher efficiency than the other technologies and therefore experience lower fuel demands and system costs.

It should be noted that the electrolyser capacities are the same between the different technologies analysed for comparison reasons, but the electrolyser capacities for PEM and SOEC could be reduced while still producing sufficient electrofuels. This would lower the investment and operation & maintenance costs of the systems. The capacity is the same for the three types of electrolysers and due to their different efficiencies, the utilization of the electrolyser technologies differs. For the alkaline electrolysers the utilization of the capacity throughout the year is 91% while it is 86% for PEM and 60% for SOEC. The difference in electrolyser utilization is because the fuel demand is constant, but since the SOEC technology is more efficient than the other types it has to operate in fewer hours and the utilization is thereby reduced on an annual scale. With a higher utilization rate the production is more constant, which could possibly hinder the potential for integration of wind in peak periods.

4.5 2035 models

The 2035 analyses are all based on the 2035 wind scenario developed by the DEA. It is investigated 1) what impact different types of electrolysers have in the 2035 wind scenario and 2) what the impacts are of changing the electrolyser capacity as well as 3) the wind capacity in the system with two electrolyser capacities.

The models all use an EnergyPLAN CEEP[5] regulation strategy 2,3[6] while the annual average electricity spot price applied for the 2035 models are assumed according to the DEA projections of 77 €/MWh (573 DKK/MWh) (DEA, 2014b).

[5] CEEP or Critical Excess Electricity Production, is defined as the electricity that production which exceeds the exportable electricity production due to transmission limitations. In reality, this would often be curtailed or hindered in other ways and is therefore not beneficial to the system.

The 2035 wind scenario has a capacity of 600 MW alkaline electrolysers installed for production of hydrogen that is used for the fuel production processes, both BTL to diesel, petrol and jetfuel and for methanation of biogas but also for the use in CHP plants. The total synthetic gas production is 9 TWh, with 2 TWh from methanation of biogas and the remainder from BTL which is further converted to long-chained alkanes by Fischer-Tropsch synthesis. The first analysis investigates what the impacts are of installing other types of electrolysers in the same system.

4.5.1 Electrolyser technologies

In Figure 15 below the socio-economic costs for the entire energy system are depicted. The differences when installing different types of electrolysers are small on an energy system scale with differences less than 1%, which is also the case for primary energy demands. The impact of installing different types of electrolysers is therefore limited based on these analyses. It can however not be concluded if this is also the case in more local systems or when the share of hydrogen production increases.

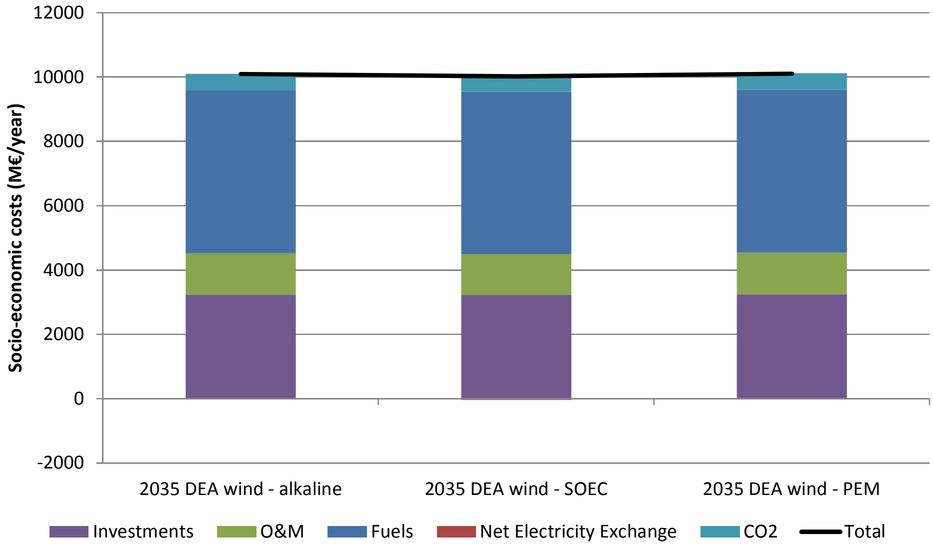


Figure 15: Socio-economic costs when installing different types of electrolysers in the 2035 wind scenario.

4.5.2 Changed electrolyser capacities

In the second part of the analysis the electrolyser capacity is changed to analyse whether this has an impact on the system. The capacity in the 2035 wind scenario is 600 MW alkaline electrolysers, but since the focus of the project is PEM electrolysers this is also the type of electrolyser included in the further analysis. The capacity is decreased by 16% (the minimum capacity to produce the transport fuel demand) and increased up to 100% additionally. The purpose behind changing the electrolyser capacity is to investigate whether a larger capacity will allow for integration of more fluctuating renewables that would otherwise not be able to integrate in the system.

The primary energy demand does not change significantly when changing the electrolyser capacity but a slightly lower demand occurs when increasing the electrolyser capacity, see Figure 16. This is because there are no significant benefits when increasing the electrolyser capacities since the wind production can already be integrated in the system. In other systems with more wind production the electrolysers could potentially

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[6] These regulation strategies are applied to ensure a reduced CEEP. Concretely, these strategies reduce the CHP operation in both decentralized and centralised networks when the fluctuating electricity production is high and start producing heat from boilers instead to reduce the electricity production.

contribute to utilizing the wind power during peak production and convert it into fuel types that are more feasible to store than electricity.

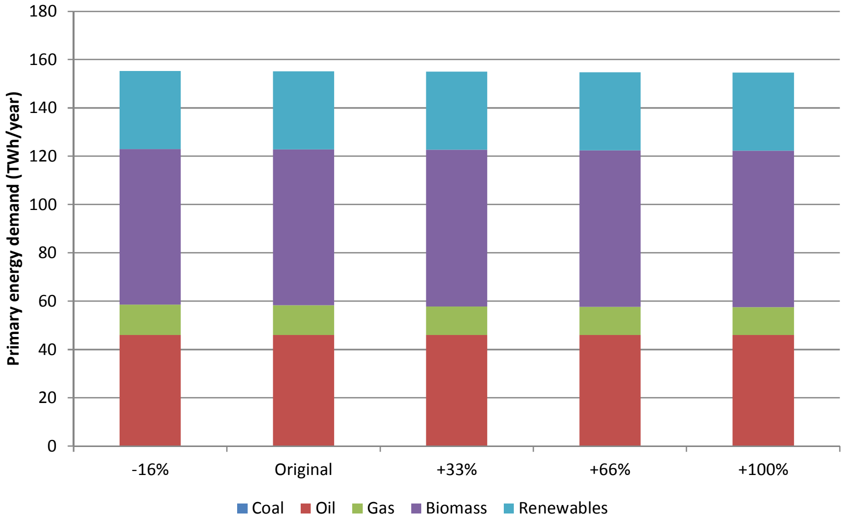

Figure 16: Primary energy demand when changing the electrolyser capacity

When investigating the socio-economic costs of the system no significant changes are apparent when altering the electrolyser capacity, but the system does become slightly more expensive (less than 0.5%) with the higher electrolyser capacity. The models are not optimised according to reserve markets, etc. The system flexibility it optimized meaning that an increased electrolyser capacity might influence the flexibility of the system and thereby reduce the fuel consumption or the excess electricity.

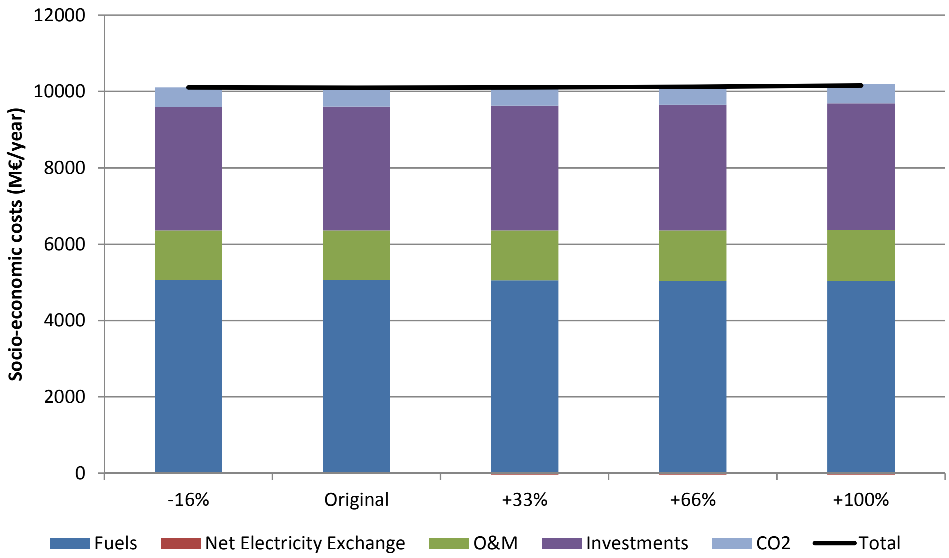

Figure 17: Socio-economic costs when changing the electrolyser capacity. Net electricity exchange costs are negligible compared to the overall system costs and can hardly be seen on the figure.

Another factor that is influenced by a change in electrolyser capacity is the electricity exchange. Once more no significant changes occur with alteration of the capacity, see Figure 18. The net exchange of electricity decreases when installing more electrolyser capacity, but still on a level that does not significantly affect the overall energy system.

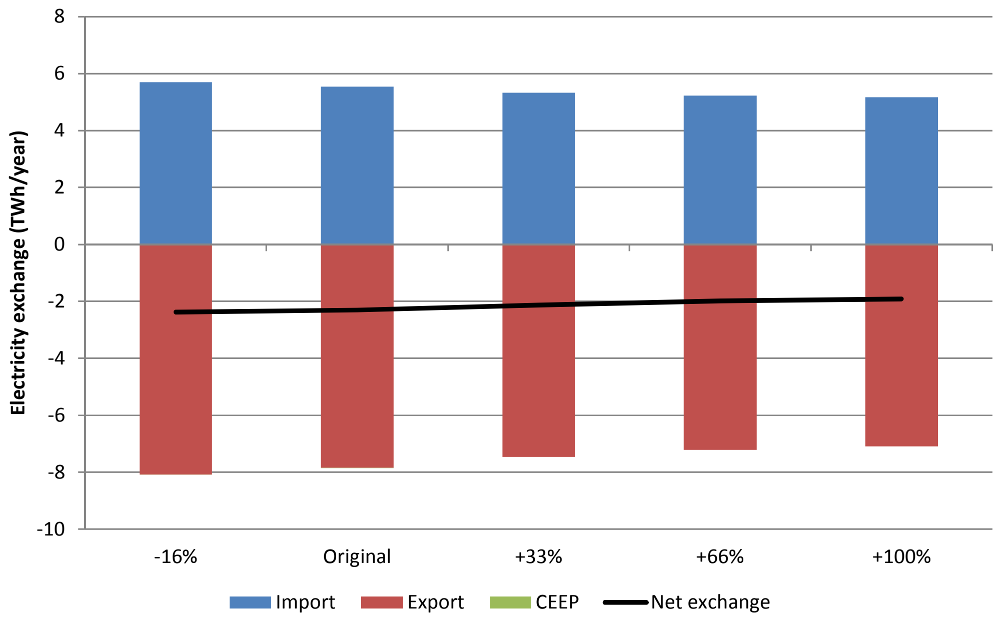

Figure 18: Electricity exchange when changing the electrolyser capacity

Finally, altering the electrolyser capacities has an impact on the operation hours and the utilization (the average production compared to the capacity) of the electrolysers. In Figure 19 the utilization rate is illustrated showing that the rate decreases significantly when increasing the capacity. This is because the transport fuel demand is constant and the hours where electrolysers need to operate to produce hydrogen for fuel production decrease with higher capacities.

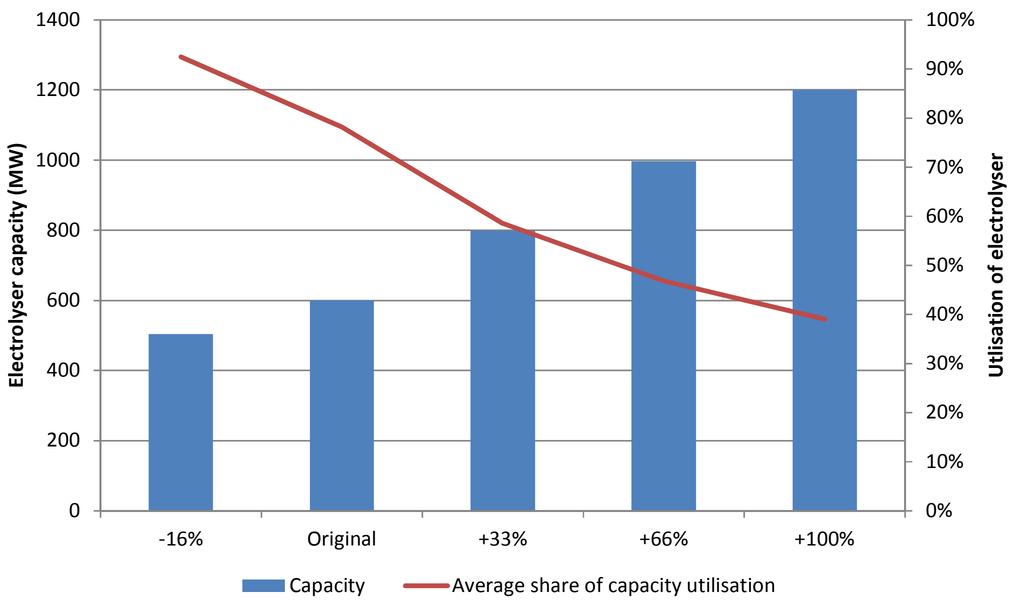

Figure 19: Electrolyser capacities and utilisation rate

These analyses show that no conclusions can be drawn regarding the electrolyser capacity due to the limited impacts on the system. This is because the hydrogen demand for fuel production is rather low in comparison to the overall fuel demand and the system impacts of changing the electrolyser capacities are affected by this.

Previous work has in line with this indicated that an increased electrolyser capacity creates larger benefits when the hydrogen demand increases (Mathiesen et al., 2015; Ridjan et al., 2015a).

Furthermore, the energy system is created as an open system where electricity can be exchanged and the benefits from flexible technologies, such as electrolysers, therefore diminish. The impacts therefore also depend on how neighbouring countries create their energy systems and how the electricity prices develop in the future.

It should be noted that the fuel mixes of the surrounding countries are not included. This means that if wind production is dominant in the energy mix and correlated between for example Denmark and Germany the interconnection might be inefficient in managing excess wind power on this interconnection. This has not been taken into account.

4.5.3 Changed wind capacity

The third part of the analysis investigates what the impacts are of changing the wind capacity in the system with two different electrolyser capacities. Different systems (with different capacities) are compared and from that the impacts of the changing capacities are identified. Hence, the systems are designed by the user as a simulation model where different technologies etc. are tested.

The onshore wind capacity in the 2035 wind scenario is 3.5 GW and 5 GW offshore wind power. In this analysis the offshore wind capacity is changed from the original with two extremes of removing all offshore wind capacity (-100%) and to a 280% increase to 14 GW (+180%), which is the wind capacity assumed in the 2050 wind scenario by the DEA. This has been run two times; one with the DEA electrolyser capacity of 600 MW and one with an electrolyser capacity of 1000 MW. Thus, in this socio-economic perspective the utilization rate of the electrolyser system with 600 MW is 78% while it in the system with 1,000 MW is 47%.

In this way it can be analysed what the impact of electrolysers are in different situations with changing wind capacities.

The results regarding the primary energy demand and the CEEP (critical excess electricity production) are shown in Figure 20. When installing a higher electrolyser capacity the point where CEEP start occurring is moved to a higher wind production level. This means that more wind can be integrated in the system and therefore the primary energy demand, excluding wind and PV, is also slightly lower with the higher electrolyser capacity. This shows the balancing capabilities of the electrolysers in a system like the 2035 wind scenario. With the higher electrolyser capacity the value of the wind is therefore increased as it does not have to be curtailed.

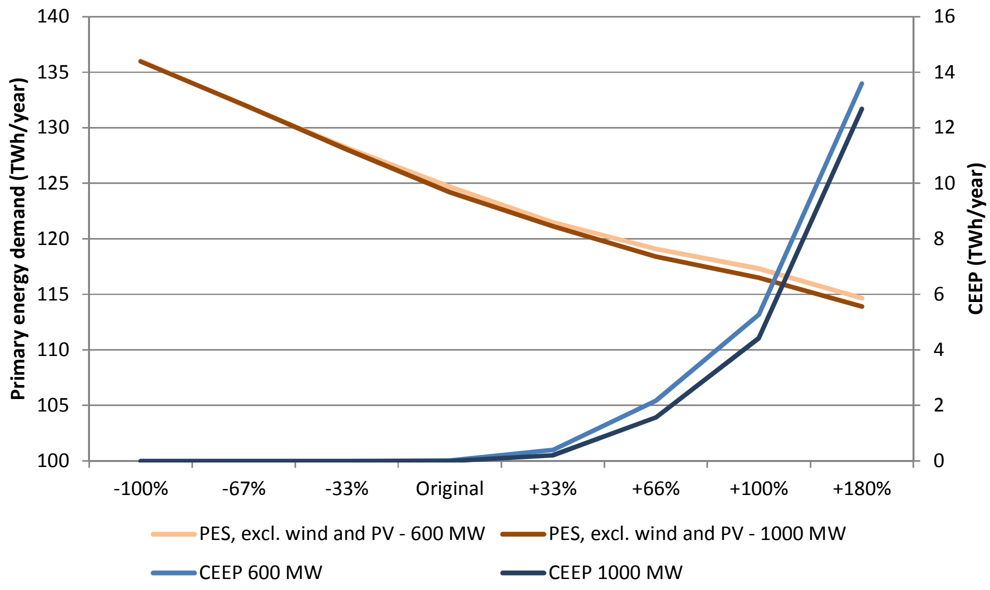

Figure 20: Primary energy demand, excluding wind and PV, and CEEP with capacities of 600 and 1,000 MW PEM electrolyser

The balancing capabilities can also be seen in Figure 21 and Figure 22 that show the electricity exchange in the systems. The differences are very small, but when the electrolyser capacity is increased to 1,000 MW more wind can be used in the system and therefore there is less export in the system. This also means that there is less demand for import from other countries.

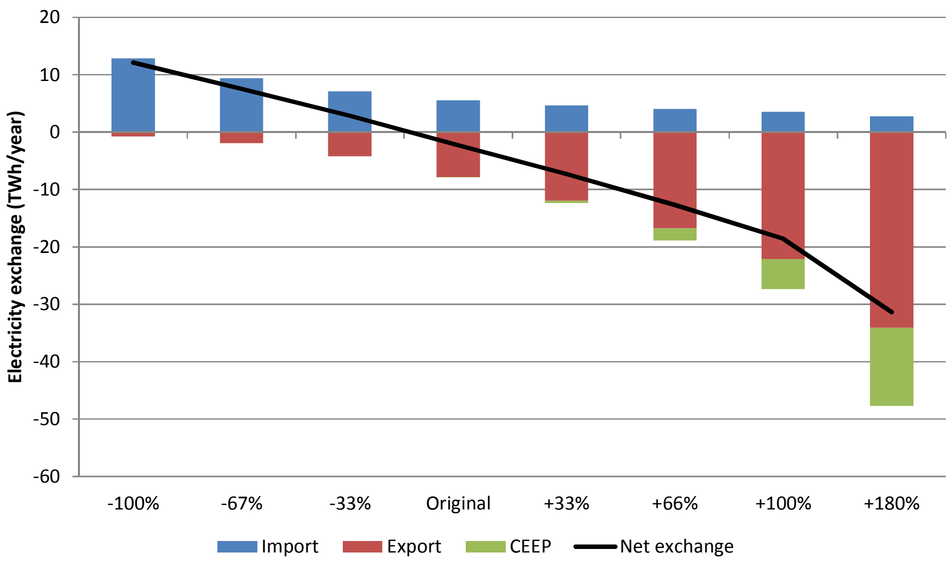

Figure 21: Electricity exchange and critical excess electricity production (CEEP) with an electrolyser capacity of 600 MW

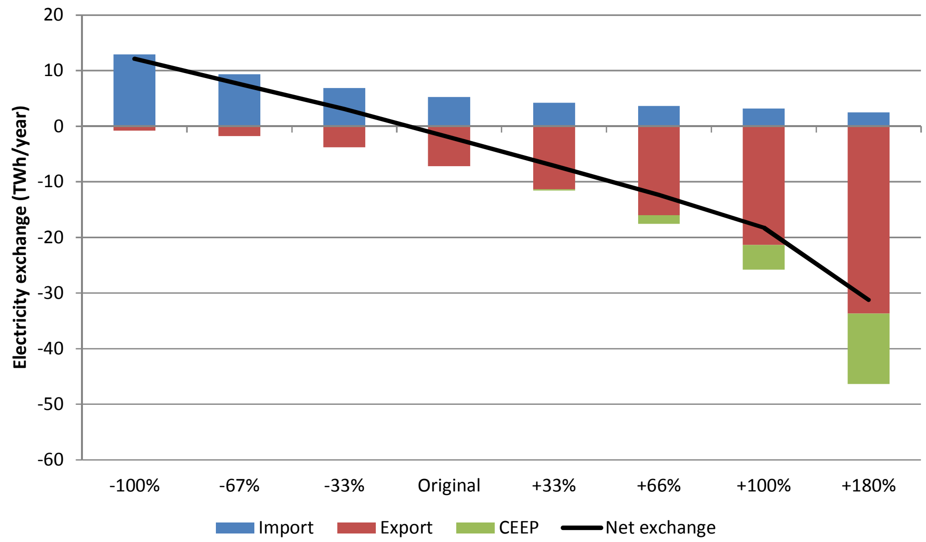

Figure 22: Electricity exchange and critical excess electricity production (CEEP) with an electrolyser capacity of 1000 MW

The increased electrolyser capacity is economically a good idea when the wind levels are high. In Figure 23 the total socio-economic costs are illustrated where the system with the lowest electrolyser capacity has the lowest costs when the wind capacity is below the original capacity. If the wind capacity is higher than the original capacity then the system with the higher electrolyser capacity will have the lowest costs.

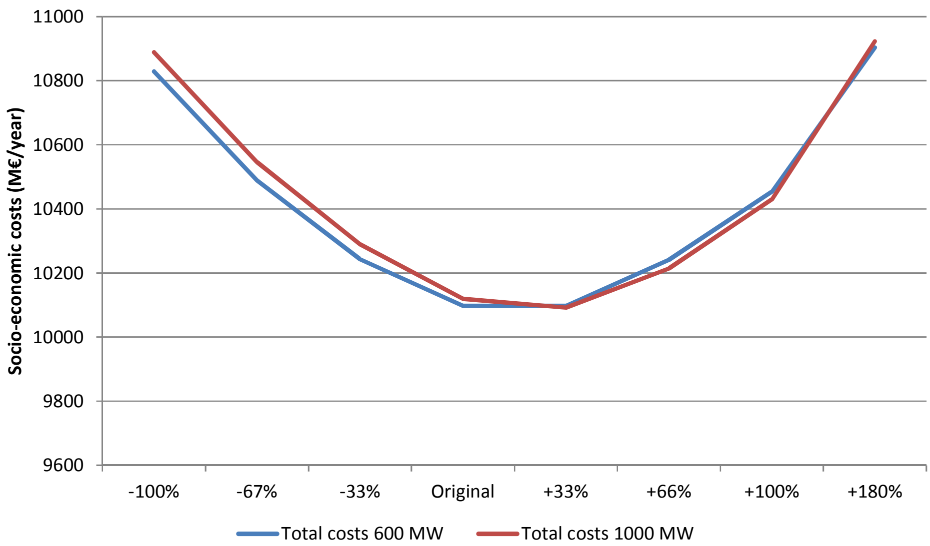

Figure 23: Total socio-economic costs for the systems with 600 MW and 1,000 MW electrolyser

The economy of increasing the electrolyser capacity therefore depends on the system design of the surrounding system. The impacts in the analyses presented are however rather limited, but this can in part be explained with the limited electrofuel demand in the 2035 DEA wind scenario (16% of the transport fuel demand is covered by electrofuels). In a system with higher electrofuel demands, as also expected by the DEA in 2050, the electrolysers will have a larger impact on the overall system.

4.6 Conclusion

The purpose of this modelling analysis of electrolysers in the current and a future high-renewable Danish energy system was to identify what role electrolysers can play and what the impacts of integrating these could be.

This was investigated by developing a 2013 Danish energy system and a 2035 high-renewable energy system based on the Danish Energy Agency models. In these models different factors where changed to analyse the impacts and a particular focus was dedicated to electrolysers.

The analyses showed that the impact of installing electrolysers in an energy system similar to the existing Danish system is counterproductive as the fuel demands and costs increased while the system flexibility only improved slightly. This is because existing system is sufficiently flexible to integrate the intermittent electricity production and no noteworthy additional benefits are created when installing the electrolysers.

In a future 2035 energy system with a higher wind production it was shown that no significant differences on the system impacts occurred when installing different types of electrolyser technologies such as PEM, alkaline or SOEC technologies with the assumptions applied. However, the specific electrolyser technology could potentially be more important in a local perspective or with higher hydrogen consumption for liquid or gaseous fuel production processes.

When changing the electrolyser capacity no significant impacts on the national energy system were identified as long as the capacity was sufficient to meet the fuel demands. When changing the installed wind capacity in the system some importance of the electrolyser capacity was found as an increased electrolyser capacity with a high wind production allowed for further wind integration. The increased electrolyser capacity in the high wind situation thereby contributed to enhancing the flexibility of the system. Electrolysers therefore have a larger role in a high-renewable energy system for balancing of electricity production and demands.

However, to a large degree the feasibility of electrolysers depends on the surrounding system design rather than the actual type and capacity of electrolysers implemented. If additional flexibility in the system is required electrolysers can potentially contribute to creating this. However, this also depends on the market conditions and the fuel and electricity prices as an alternative to creating a more flexible system is to increase the electricity exchange.

The analyses conducted are based on the 2035 wind scenario were the fuels produced by addition of hydrogen from electrolysers are rather low and in a different energy system (e.g. the DEA 2050 wind scenario) these fuels have a higher share of the total fuel demand and hence the impacts of electrolysers might potentially be more significant.

Electrolysers therefore play a larger role in the energy system with high wind penetrations in the system (50% of the electricity demand or higher), electrolysers should operate with a high utilization rate when the hydrogen demand is limited and with lower utilization rates (larger capacity) when the hydrogen demand is higher. In this way the electrolysers will offer greater benefits to the energy system.

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