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Modelling the grid integration of power to gas: A case study of Denmark

Master of Science Thesis in Sustainable Energy Systems

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ABSTRACT

Ambitious climate targets call for smart strategies and innovative technologies to not only decarbonize the electricity generation, but also the transport and heat supply sector during the upcoming decades. Power to gas (PtG) conversion systems can help to foster this switch from fossil fuels by providing the possibility to store surplus energy from intermittent sources in the form of hydrogen or synthetic natural gas. Next to the option of re-electrification in times of high demand, PtG also allows for the utilization of this green gas as a fuel in other areas of a sustainable energy system.

In this thesis a model has been developed to investigate the effects of power to gas on the electricity generation system in Denmark. With the objective of total cost minimization different placements for PtG in the transmission system have been simulated, followed by an analysis on changes in system operation costs, generation dispatch, prices and power flow.

It could be shown that the implementation of PtG reduces total system costs as well as the need to curtail wind power in the modelled representation of the Danish system. While average market prices slightly increase with the utilization of PtG, the line loading and times where congestion occurs at the system's bottleneck has been reduced. Distributing power to gas over three locations in the system decreases the necessary wind curtailment even further.

Keywords: Power to gas, Danish energy system, intermittent electricity generation, storage systems, GAMS, DC optimal power flow modelling

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ABBREVIATIONS

CH_4 – Methane
CHP – Combined heat and power
CO_2 – Carbon dioxide
DH – District Heating
H_2 - Hydrogen
GtP – Gas to power
LMP – Locational marginal price
O_2 - Oxygen
PtG – Power to gas
SNG – Synthetic natural gas
TSO – Transmission system operator

1. INTRODUCTION

This first chapter presents the initial situation in the Danish energy system together with the motivation to investigate on the implementation of PtG, gives the purpose and objectives of this thesis work and presents how the following parts will be structured.

1.1. *BACKGROUND ON THE DANISH ENERGY SYSTEM AND MOTIVATION FOR THIS WORK*

The transition towards a more sustainable energy system in Denmark can positively be influenced by power to gas technologies that offer possibilities to use surplus electricity to produce hydrogen or synthetic natural gas (SNG) for a subsequent re-electrification or utilization as fuel in other energy sectors.

1.1.1. Electricity generation in Denmark

In the year 2012 almost half of the electricity production in Denmark was generated by large scale, CHP or power only units. Around 17.5 % originated from small scale generation, while roughly 33 % of the total electricity was produced by wind power [1].

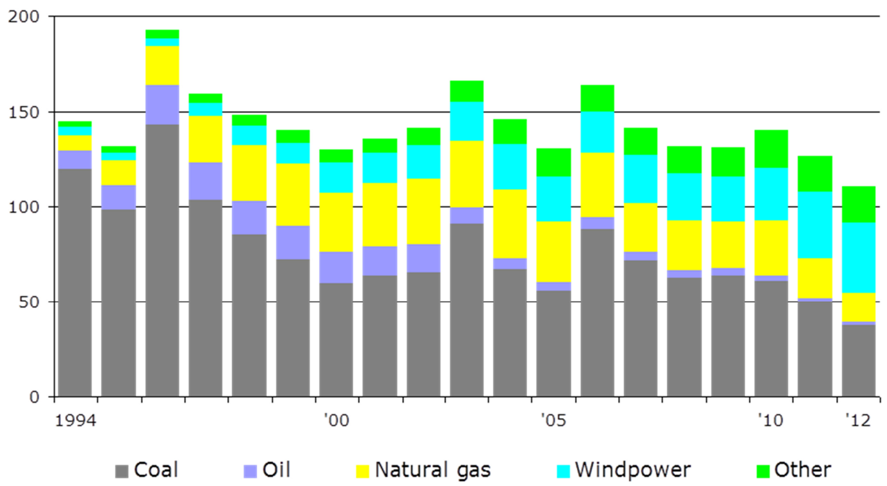

Figure 1: Electricity production by fuel in Denmark, 2012 [1]

Figure 1 reveals that also almost half of the fuel input for Danish electricity in the year 2012 came from fossil sources, coal, natural gas and oil. Wind power gives the largest share of renewable energy in Denmark with roughly a third of total production, while biomass accounts for around 13 % of the total energy. The drop in total electricity production in the figure can be explained by higher net electricity imports in 2012 compared to 2011 combined with an increasing share of domestic electricity supply.

Recently the Danish government decided on the target of a fossil fuel free energy system (that includes electricity, heat, industry and transport) until the year 2050. Several policy milestones like half of the electricity consumption covered by wind power in 2020, phase out of coal in Danish power plants until 2030 or electricity and heat covered by renewable sources until 2035 have been defined [2], [3], [4].

Plans to increase wind power capacity in Denmark up to around 7000 MW during the next 15 years [5] will increase the variability in power generation and thereby the demand on the electricity system to balance this intermittency. Energy storage technologies utilizing surplus electricity in hours when supply exceeds demand and providing electricity in hours with low generation but high loads are a promising option to tackle this challenge.

1.1.2. Advantages of power to gas in a future system

Power to gas as a long term storage option is not only able to offer balancing in this temporal dimension, but also additionally in the spatial dimension [6]. Transporting renewable gas produced from this surplus electricity instead of electricity itself can bring many advantages for bridging geographical distances between renewable generation and load centers.

When [7] writes about future possibilities of integrating the energy system, by closely linking electricity generation, heat production, gas transmission and the transport sector, it is argued that capacities for gas flow in the gas system are generally much greater than the electricity capacity in the power grid. It is also suggested to consider power to gas technologies not only for electricity storage purposes but additionally for producing fossil-free fuels in a coherent energy system.

The fact that the Danish natural gas production from the North Sea is expected to drastically decline between 2018 and 2042, will make green gases (produced from surplus electricity through power to gas, but also gasification of biomass) a valuable source for various gas consumers and is able to avoid a strong dependencies on gas import from Germany [7], [8].

Therefore also the development plan of the Danish TSO energinet.dk mentions green gas as an important fuel for industry, heat, peak load electricity generation and the transport sector until and after 2050 [9]. The role of the gas system in Denmark for this future integrated energy system will change from transmitting natural gas from the North Sea to consumers towards transporting renewable fuel for peak load electricity, heat production and transport purposes [7].

1.2. *AIM AND OBJECTIVE OF THE MASTER THESIS*

The aim of this thesis is to develop an energy system model representing electricity generation, demand and network constraints as well as power to gas conversion units and consecutively test the model on the Danish electricity system in order to draw conclusions on the effects of power to gas on the system costs, generation dispatch, locational marginal price (LMP) and the possibility to avoid wind power curtailment.

The EERA energy storage roadmap [10] suggests that business cases for re-electrification only will be hard to realize for power to gas technologies in the upcoming years. Therefore an important aspect in the model developed is the consideration of the value the synthetic gas produced by PtG has, when e.g. sold on the natural gas market. The main focus of this work was the influence of PtG on the electricity generation system, which is why the economics of different possibilities like producing hydrogen instead of synthetic natural gas to or selling waste heat produced during the process have been neglected in this analysis.

The main research questions to be answered with this work include:

Q1: What effect does power to gas implemented at different locations in the Danish power grid have on the system costs and based on this analysis which location can be recommended?

Q2: Can the application of power to gas reduce the necessity to curtail wind power in Denmark?

Q3: How does power to gas affect other system parameters like locational marginal price, generation dispatch and power flow?

Q4: Is there a difference in the impact of power to gas in a current system and future scenario for the year 2030?

Several tasks have been carried out during the process of the analysis in order to answer the stated research questions:

- First a literature review on power to gas storage systems, their application in the energy system and important characteristics has been performed.
- Furthermore a mathematical model has been developed and implemented in GAMS (General Algebraic Modeling System [11]) to analyze optimal dispatch of generation and storage units and the related system costs, taking into account the network constraints.
- Data on the Danish system have been taken from the Danish TSO combined with publically available information from the Nord Pool Spot Market, characteristics of the power to gas technology have been investigate in literature.
- Different suitable locations for a power to gas plant have been choses, based on information on the Danish electricity and gas transmission grid and several scenarios for different PtG alternatives as well as a current system for the year 2014 and a future system for the year 2030 have been formulated.
- Several simulations have been run in order to analyze and conclude on the effect of PtG at different locations on the Danish power grid.

1.3. *STRUCTURE OF THIS REPORT*

The report is structured into 6 chapters:

- Chapter 2 first presents the PtG technology and the important aspects for a system integration, followed by a literature review on similar models and analyses and some examples of demonstration projects in Europe.
- Chapter 3 explains the methodology in more detail.
- Chapter 4 describes the mathematical model and important equations as well as the acquisition of the input data utilized and a summary of the different scenarios investigated.
- Chapter 5 gives results on different aspects from this analysis and names important points for discussion.
- Chapter 6 sums up conclusions and gives some recommendation for further analyses.

2. THECHNOLOGY REVIEW AND SYSTEM INTEGRATION OF PTG

The state of the PtG technology as well as the advantages of a system integration, the comparison to other storage technologies and the challenges for an implementation have been investigated and are presented in the following parts. Also similar modelling work on PtG and demonstration projects are briefly described in this chapter.

2.1. *THE PTG TECHNOLOGY*

Power to gas describes the process of converting electricity into hydrogen via electrolysis and an optional further conversion step into synthetic natural gas via methanation, as seen in Figure 2.

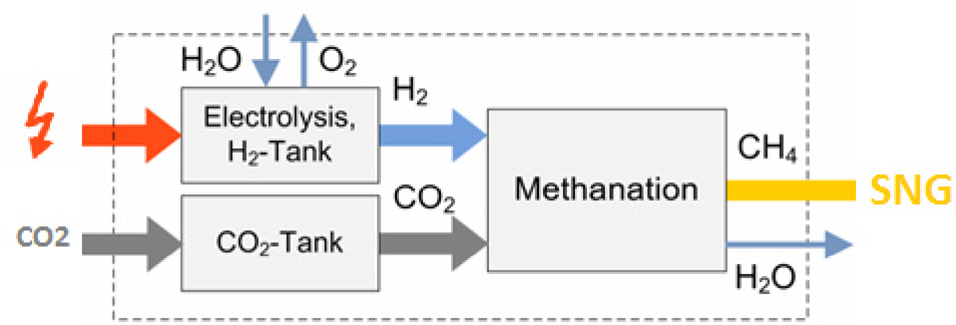

Figure 2: Conversion steps in the power to gas process (based on [12], *reproduced with permission***)**

Electricity, CO_2 and water are needed as input, while O_2, water and SNG in the form of CH_4 (methane) are produced. Also a certain amount of heat is generated during the process, what has not been shown in the figure.

2.1.1. Electrolysis

Electrolysis uses direct electric current to drive the chemical reaction that splits water into hydrogen and oxygen with an efficiency of 62 % up to 93 %, dependent on the type of technology used [13].

Alkaline electrolysis is a mature technology and commercially available. Also polymer electrolyte membrane (PEM) electrolysis is currently discussed and described to be in the pre-commercial state. While alkaline electrolysis is already used in large-scale operations and shows advantages like long durability and low costs, it also has lower flexibility with a minimum load requirement of 20 % to 40 %. These characteristics could lead to problems with fast start-up requirements for power to gas applications. However, improvements in start-up and ramp characteristics can be expected [12], [13], [14].

PEM electrolysis shows slightly higher efficiencies and faster reaction time with a load range of 5 % to 100 % and is currently quickly developing. Disadvantages are named to be expensive materials and uncertainties regarding the lifetime. Solid oxide electrolysis (SOE) is currently in the research phase but very little information available yet [13].

2.1.2. Methanation

The methanation process based on the Sabatier reaction is used to convert carbon dioxide and hydrogen to methane gas and water. Atmospheric CO_2 can be utilized as well as captured CO_2 from conventional power plants, with the latter alternative leading to higher efficiencies. Different sources name efficiencies from around 70 % to 90 % depending on the technology used [12], [13], [14].

Chemical methanation that makes use of a catalyst, often nickel, is a mature technology and is already commercially available. The process of biological methanation that uses bacteria and archae to carry out the reaction necessary to produce SNG, is currently developing from research stage. A promising advantage is the faster response time of biological methanation [13].

2.1.3. System integration of power to gas

The drivers to implement power to gas energy storage technologies in the system range from power-supply-driven, which describe approaches to solve power balance issues caused by variations in power generation, to demand-driven approaches that describe the production of low-carbon fuel, as further explained in [15].

Figure 3 describes how PtG can serve as a link between different energy sectors. The fluctuating character of renewable sources will create hours of low electricity prices, in which electrolysis can be utilized to produce oxygen and hydrogen. As described in Chapter 2.1.1, also water is needed as input for this process, which is not shown in the figure. The oxygen has high purity and can therefore be sold for industrial processes [16].

The hydrogen supplied can either be sold directly to industrial consumers or for the transport sector, stored in a hydrogen storage facility, fed into the gas transmission infrastructure or converted back to electricity in a second conversion step, with the help of a fuel cell to provide electricity in peak load hours, when electricity prices are high, as can also be seen from the figure. H_2 can also be further converted to CH_4, methane gas with similar characteristics as natural gas that can, alongside with other renewable gas from biogas production and gasification processes, be injected into the gas distribution system for use of private consumers, CHP plants that also supply district heating or power generation companies in order to convert it back to electricity again by using gas turbines. CO_2 needed for this conversion step could be provided by biogas plants, sewage companies or breweries. Also other green synthetic fuels for the transport sector can be produced from the products available in those processes.

Compared to electricity those gaseous and liquid fuels can be stored easier over longer periods and even be transported to distant consumers. Other technologies like batteries or supercapacitors, also seen in the figure, can serve as electricity storages and thereby provide power-supply-driven services, but are not able to produce another form of energy like heat or renewable fuel for transport for the end user.

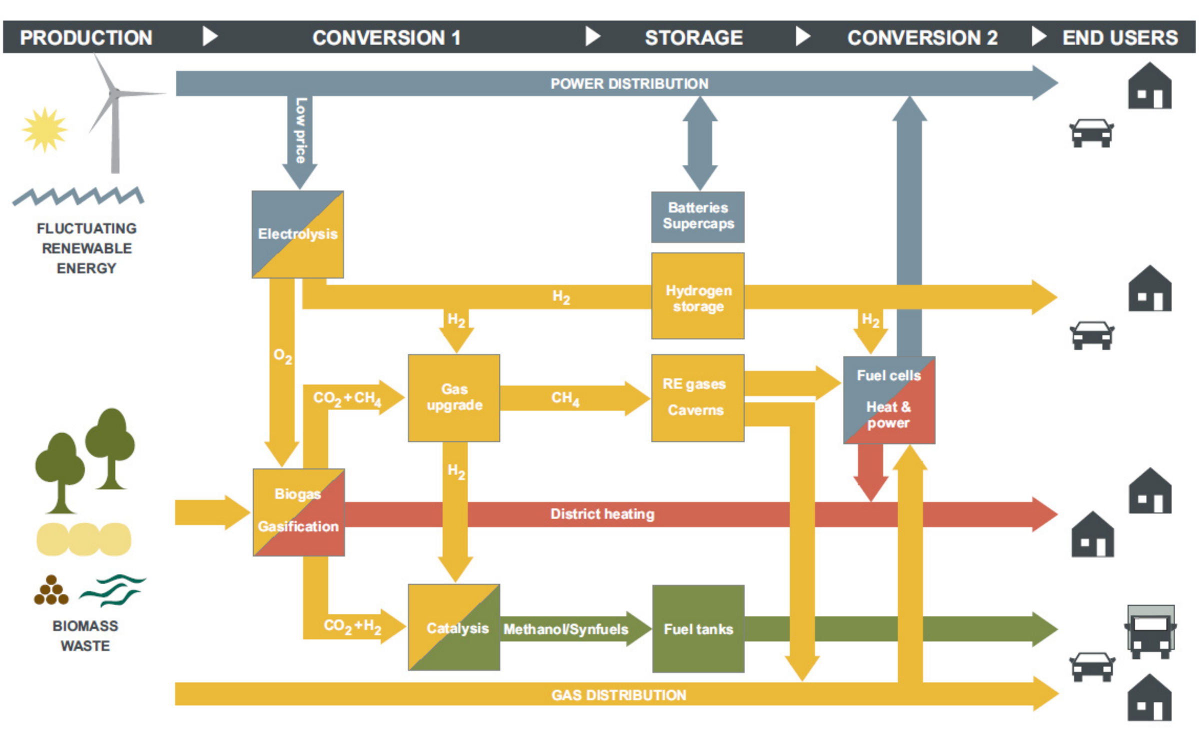

Figure 3: power to gas in an integrated energy system [17] *(reproduced with permission)*

Different benefits and limitations of PtG technologies need to be considered from a system and operator perspective:

Gas system

Power to gas technologies can supply fuel to the international gas system. Profits for PtG operators would then come from this cross-commodity trade, when the spread between buying electricity on the spot market and the price for selling on the gas market is high enough [14].

Methane gas can be fed into the grid without limitations, the direct feed-in of hydrogen to the gas transmission or distribution system would be technically possible, but limited. [6] gives a value of 2 to 5 vol % of hydrogen, depending on the composition of natural gas at the injection point, but expects the limits to further rise to 10 vol %. A value 0 to 25 % for different places in Europe is mentioned in [15]. The allowable fraction can be calculated by the Wobbe index, giving the thermal load of the fuel [18]. Problems can occur with a too large hydrogen portion in the fuel for industrial applications and also gas turbines can usually only run on mixture between 1 vol % to 10 vol % of hydrogen. Improvements in burner technologies could make utilization of pure hydrogen in gas turbines easier [10]. When fed into the gas system, the price of hydrogen would strongly depend on the price for natural gas on the market, benefits for selling to the industry or transport are expected to be bigger [15].

Electricity system

In the power grid storage technologies and PtG can solve power transmission bottlenecks and thereby foster the use of renewables. Curtailment of these intermittent sources during network congestions could be reduced, while also investments in transmission grid reinforcements could be avoided. Operation costs of the electricity system can be decreased by avoiding frequent shut-downs and start-ups of thermal power plants.

Operators of power to gas units can participate on the spot market for electricity using the variation in market prices to make profit, but also have the possibility to partake in reserve markets for electric power. Since reaction time of the process is suitable [14] names negative tertiary and secondary reserve with an activation time of 15 and 5 minutes as marketing opportunities for PtG operators.

District heating system

Next to the SNG that can serve as fuel input for CHP plants that then sell heat to end consumers, also the heat from the electrolyser and reactor (see Figure 4 for the product flows) can be utilized for district heating (and industrial process steam) as suggested in [16].

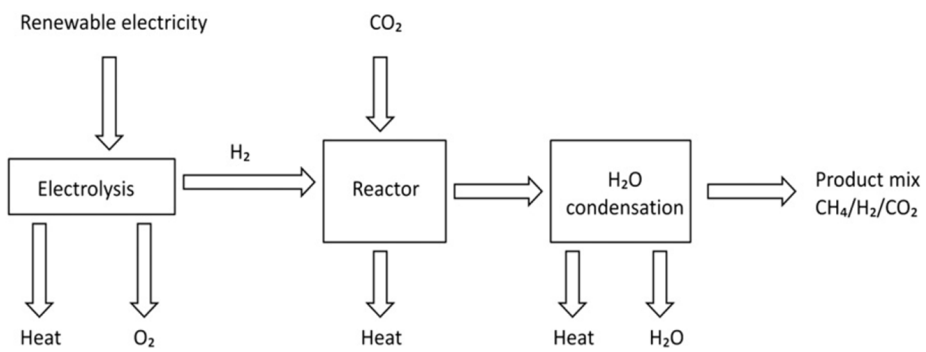

Figure 4: Production flow during electrolysis and methanation [16] *(reproduced with permission)*

As up to 62 % of Denmark is covered by the DH grid, this opportunity to sell surplus heat can be expected to add further benefit to the PtG applications [7].

2.1.4. Comparison to other storage technologies

In terms of available capacity and discharge time power to gas can best be benchmarked to pumped hydro or compressed air storages (CAES), which are considered as the most cost-efficient large scale electricity storage systems today, as shown in Figure 5 [14]. A big advantage of PtG over them is, however, the much lower dependency on geographical constraints. Compared to flywheels, supercapacitors or different forms of batteries that are suitable for short term applications, technologies like PtG, CAES or pumped hydro are best applied for mid-term or long-term storage purposes. Benefits of power to gas units over other technologies are the high energy density, fast response time and large available capacity, while improvements are needed in cost and efficiency aspects [19].

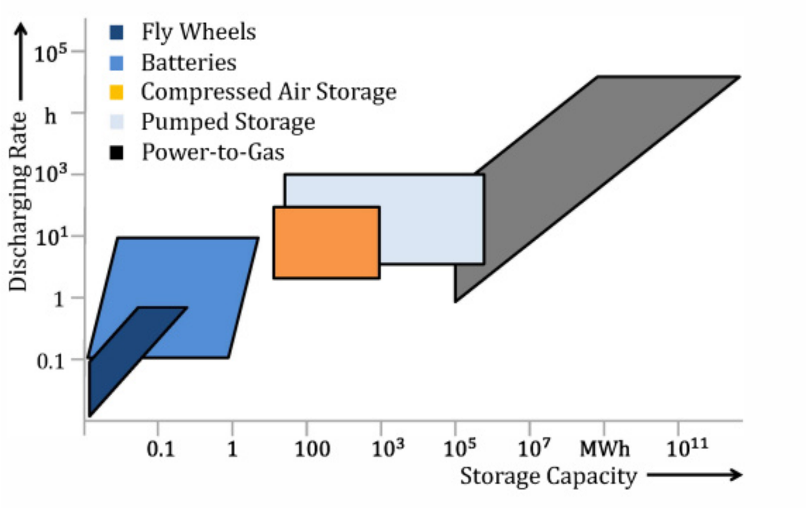

Figure 5: Capacity and discharge rate or different atorage technologies [14] *(reproduced with permission)*

A technology review for features of power to gas compared to other storage technologies and their potential for utilization in the Netherlands is presented in detail in [13].

2.1.5. Challenges for using power to gas

One main challenge for the large scale implementation of power to gas technologies will be the evaluation of relevant business cases and analysis of cross sectional benefits that come from the production of renewable fuel gas for industrial or mobility purposes. Intensive research on electrolyser and methanation technologies is expected to decrease capital costs and increase operation performance by improvements in areas like pressurized operation, temperature control, electrical integration and power electronics.

For the optimal use of PtG at larger capacities (> 10 MW) the most efficient and safe storage of hydrogen or SNG produced is another important issue to address. High pressure tanks or new storage media for hydrogen as well as the possibilities to utilize the natural gas infrastructure or geological underground storage facilities need to be further investigated.

For the conversion of hydrogen to for instance methane gas, as described in 2.1.2, also the separation of CO_2 from industrial processes or air or the process of biological methanation leaves room for further research.

To foster large scale energy storage technologies in general and power to gas in particular, regulatory framework is needed to secure use cases like providing ancillary services and reserve capacity as well as producing renewable gas. Also other factors influencing the demand for storage as the utilization of demand side management measures to shift electricity demand needs to be analyzed. [10]

2.2. *RESEARCH WORK AND DEMONSTRATION PROJECTS ON POWER TO GAS*

Several analyses to evaluate economic and technical aspects of implementing power to gas have been carried out recently.

Baumann et al. [14] investigate the economic potential for PtG operators considering different marketing strategies like arbitrage or balance power trade. A unit commitment model has been used to evaluate the dispatch of a 6 MW PtG unit and calculate the ratio between capital costs needed and possible benefit to be earned. The study concludes that current investment costs for plants are still too high and even combined trading on spot and reserve markets is not profitable under the given assumptions.

Jentsch et al. [6] use a unit commitment model of Germany in order to investigate the optimal capacity and spatial distribution of PtG plants in a German network with 85 % renewable energy. A simplified representation of the transmission system and a DC approximation approach is used to model the load flow in the system. Results show that PtG in the scenarios analyzed can contribute to the integration of renewable power sources and thereby the reduction of CO_2 emissions. The optimal economic capacity is given to be between 6 and 12 GW and should be located closer to the renewable production in order to reduce power flows and achieve the highest profit.

Another study by de Boer et al. [18] simulates the effects of using pumped hydro, compressed air and power to gas storage in the Dutch electricity network. An economically optimized system with competition among generation power plants and the objective to minimize total operating costs is modelled, similar to the approach in this thesis. Several scenarios with different storage technologies at different capacities as well as increasing wind capacity on and offshore are modelled resulting in conclusion on system costs, electricity generation and total system emissions. The conclusions show that system costs could be reduced with the implementation of storage technologies. While in cases with high wind penetration these savings come from reduction in fuel costs when utilizing more wind energy, it is important to mention that in scenarios with low wind penetration the savings mainly result from a reduction in start-up costs of thermal plants that sometimes even involve higher fuel use and thereby higher emissions and a higher environmental impact.

On behalf of the North Sea Power to Gas Platform DNV GL Oil & Gas conducted a study [15] on the macro-economic value of power to gas by investigating different PtG business cases. Four cases have been analyzed by comparing power to gas to avoid power grid reinforcements, offshore power-to-gas, distribution scale power-to-gas and direct application of power-to-gas derivatives. The authors suggest that in the short term PtG to supply fuel for the transport sector will give the best results, while good middle and long term options will also be the application of PtG on the distribution level or as alternative to power grid reinforments. High operational costs together with low retail prices for hydrogen and methane lower the profit to be made from PtG.

The focus of this thesis has been chosen, since the system of Denmark that offers no possibilities for large-scale pumped hydro storages but good suitability for storing renewable gas in the transmission infrastructure and natural gas storage facilities, will be changed significantly during the upcoming decades to switch from fossil to green fuels. In order to find the best strategy for this transition to a more sustainable energy system also the potential benefits coming from implementing power to gas technologies need to be investigated. An approach considering the changes in the operation of the power grid, but also the created value by producing renewable gas has been chosen, since literature suggests this as a promising use case.

Worldwide several power to gas pilot plants are being planned or have already been built. A review by Gahleitner published in 2012 [20] considers 41 plants with most of them being installed/planned in Germany, USA and Canada. DNV [13] gives a total of 30 demonstration projects already built or in the planning stage, most of them in Germany and Denmark based on a research from the year 2013.

The first industrial PtG plant was built by Audi AG in the German city Werlte. It is named to be the biggest operating PtG plant today with a capacity of 6.3 MW. A yearly production of around 1000 tons of synthetic methane will be use to fuel the Audi A3 Sportback g-tron [21], [22].

Another pilot plant in Germany, located in Falkenhagen, is aimed to demonstrate the processes from utilization of surplus wind energy by a 2 MW electrolyser until the feed-in of hydrogen in the local gas infrastructure. The hybrid power plant in Enertrag combines a wind power park of 3 times 2.3 MW with an electrolyser of 500 kW, a biogas production unit, hydrogen fuelling station and a combined heat and power plant in order to show flexible generation of energy for the three sectors electricity, heat and mobility [23].

In Denmark a 1 MW power to gas plant utilizing alkaline electrolysis and biological methanation is being built near the wastewater treatment plant Avedøre in Copenhagen within the BioCat project. The Danish company Electrochaea will use CO_2 from the wastewater plant to produce biogas via biological methanation to be fed into the gas infrastructure during an expected 3000 hours of operation. The technology has already been tested at smaller scale within the pre-commercial Foulum project. With the BioCat project Electrochaea expects the technology to be market ready by the year 2016 [24], [25], [26].

3. METHODOLOGY

An electricity system model has been developed representing not only power generation, flow and demand, but also power to gas units. With this model the implementation of PtG in different locations and its effects on the system have been studied in the case of the Danish energy system. Information from the Danish TSO as well as historic data from the Nord Pool Spot market have been used in a mathematical model to analyze optimal dispatch of generation and storage units and the related system costs, taking into account power flows and network constraints. Also the existing gas infrastructure and the economics of selling synthetic methane produced from PtG have been considered.

With a similar methodology as applied in [27] to determine the best placement for a biomass fuelled gas turbine in order to reduce system losses, different locations for power to gas have been analyzed and compared in this study. The method includes three main steps:

1. A base case without any implementation of PtG is run to find the initial costs and generation dispatch
2. Scenarios with different placements of PtG are selected and changes in system costs and generation dispatch are calculated.
3. Effects on costs and generation dispatch are compared and locations are ranked according to their effect on total system costs to find the most profitable placement.

Furthermore the effects of different placements of PtG on wind power curtailment, locational marginal price and line loading have been analysed and commented.

Figure 6 displays necessary steps to develop the PtG model for Denmark as well as the points to be analyzed in order to draw final conclusions.

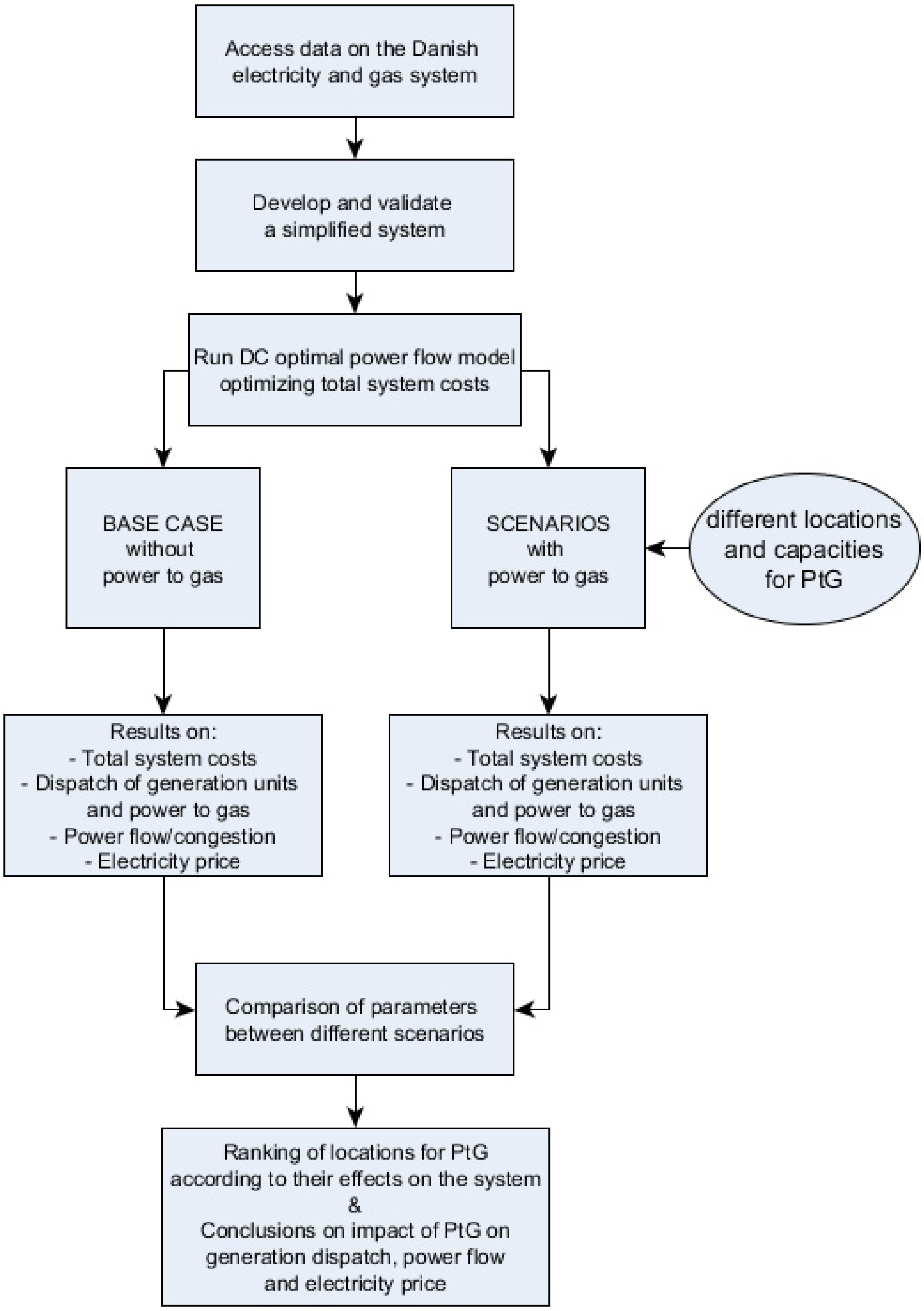

Figure 6: Method to find best location for PtG

The method has been applied for a base case representing one year from April 2014 to April 2015 as well as a future scenario in the year 2030. Both cases have been compared in order to draw conclusions on the profitability of PtG now and in the future.

4. THE PTG MODEL

A mixed integer problem has been developed in GAMS (General Algebraic Modeling System [11]*) to analyze power to gas in the Danish system. The following chapters describe the equations and data applied in the model.*

4.1. *MODEL DESCRIPTION*

The optimal dispatch of generation units and power to gas plants with the objective to minimize the total system costs over the period of a year has been investigated with a DC optimal power flow model of the Danish transmission grid. Only active power flows have been considered, reactive power and voltage variations at the buses have been neglected. Equations and constraints for DC optimal power flow modelling and unit commitment modelling have been used from [28] and when necessary adapted for the modelling of PtG. The simulation is run from April 2014 to April 2015 in the base case and from April 2030 to April 2031 for a future scenario. A time resolution of 2 hours has been chosen since simulation time of the model could thereby be significantly reduced and a sufficient level of detail still allows for final conclusions.

4.1.1. Nomenclature

The indices i and j in the nomenclature refer to buses, while index t indicates the time step.

Sets in the PtG model:

N	Total number of buses
NG	Number of buses with generation units
$NGas$	Number of buses with gas CHP units that can be utilized for GtP
$NPtGG$	Number of buses with PtG units
T	Total simulation time

Variables used in the PtG model:

$Cost$	Total system costs in €
$PG_{i,t}$	Active power generation at bus i at time t in p.u., pos. variable
$PPtG_{i,t}$	Scheduled amount of electricity converted to SNG at bus i at time step t in p.u. , pos. variable
$PGtP_{i,t}$	Scheduled amount of electricity produced from SNG at bus i at time step t in pu. , pos. variable
$PWind_{i,t}$	Active wind power generation at bus at time step t i in p.u., positive variable
$F_{i,j,t}$	Active power flow between buses i and j per time step t
$\delta_{i,t}$	Voltage angle at bus i at time step t in radians
$W_{i,t}$	Unit state at time step t (1 running, 0 not running)
$UST_{i,t}$	Start-up state at time step t (1 start-up, 0 no start-up)
Gst_t	Amount of SNG stored in the system at time step t in m^3, pos. variable

$SNG_{sold\ t}$	Amount of the SNG produced in m^3 that is sold per time step, pos. variable

Parameters used in the PtG model:

$PD_{i,t}$	Active power demand at bus i at time step t in p.u.
P_i^{min}	Lower real power generation limit at bus i in p.u.
P_i^{max}	Upper real power generation limit at bus i in p.u.
$PWind_{i,t}^{max}$	Available wind energy per bus for each time step t in p.u.
$PPtG_i^{min}$	Lower capacity limit for power to gas at bus i in p.u.
$PPtG_i^{max}$	Upper capacity limit for power to gas at bus i in p.u.
$F_{i,j}^{max}$	Maximum limit on power flow between buses i and j
$B_{i,j}$	Susceptance B over line i, j in Siemens
C_i	Generation costs per bus i in €/MWh
ST_i	Start-up costs at bus i in €
MDT	Minimum down time in number of time steps
Gst^{max}	Maximum possible storage capacity in the system in m^3
HVGas	Heating value of methane in MWh/m^3
μPtG	Efficiency of converting electricity to SNG
μGtP	Efficiency of converting SNG to electricity
pr_{SNG}	Average selling price for SNG in €/m^3
$SNG_{Max\ t}$	Maximum amount of SNG to be sold per time step t in m^3

Output parameters calculated from the PtG model:

$Curtailm_{i,t}$	Wind curtailment per time step at each bus in p.u.
$LL_{i,j,t}$	Line loading in % per time step

4.1.2. Objective function

The objective of the model, given in Eq. (1), is to minimize total system costs, consisting of the costs for power generation minus the profit to be made from selling the portion of gas produced from power to gas, which is not used to be converted back to electricity. Additionally a decision variable is introduced to account for the power plant start-up costs, while shut-down costs have been neglected.

$$Cost = \sum_{t=1}^{T} \sum_{i=1}^{NG} (C_i * PG_{i,t} + UST_{i,t} * ST_i) - pr_{SNG} * SNG_{sold\ t} \quad (1)$$

The operating costs of the power to gas unit are not included in the objective functions, as explained in Chapter 4.1.5.

4.1.3. Network constraints

The nodal power balance in Eq. (2) includes all generation at bus i, the power flow from the node, but also power consumed by PtG or produced by GtP at the respective bus equal to the demand at each time step t.

$$PD_{i,t} = PG_{i,t} - \sum_{j}^{N} B_{i,j} * \delta_{i,t} - PPtG_{i,t} + PGtP_{i,t} \qquad \forall\, \mathrm{i,j} = 1, \dots, \mathrm{N} \tag{2}$$

The active power flow between buses i and j is given in Eq. (3).

$$F_{i,j,t} = (\delta_{i,t} - \delta_{j,t}) * B_{i,j} \qquad \forall\, \mathrm{i,j} = 1, \dots, \mathrm{N} \tag{3}$$

The power flow over the transmission lines is limited by the maximum power flow limit, as given in Eq. (4).

$$F_{i,j,t} \le F_{i,j}^{max} \qquad \forall\, \mathrm{Y\, i,j} \neq 0 \tag{4}$$

4.1.4. Power generation

Several thermal and wind power plants are included in the model, which are explained in more detail in Chapter 4.3.2.

Eq. (5)and Eq. (6) give the upper and lower power generation limits on each bus.

$$PG_{i,t} \le P_{i}^{max} * W_{i,t} \qquad \forall\, \mathrm{i} \in \mathrm{NG} \tag{5}$$

$$PG_{i,t} \ge P_{i}^{min} * W_{i,t} \qquad \forall\, \mathrm{i} \in \mathrm{NG} \tag{6}$$

A binary variable is used to determine the start-up state of each unit, as described in Eq. (7). [1]

$$UST_{i,t} = W_{i,t} - W_{i,t-1} \qquad \forall\, \mathrm{t} > 1 \tag{7}$$

Additionally a minimum down time, given in Eq. (8), is defined for coal, woodchips and gas CHP plants.

$$\sum_{m=1}^{MDT} UST_{i,t-m+1} \le 1 \qquad \forall\, \mathrm{t} \ge \mathrm{MDT} \tag{8}$$

Ramp-up and ramp-down constraints for the generation units have been neglected, because of the two hour resolution of the model. No must-run constraints are added for CHP plants, as they are assumed to produce heat only in times of low electricity demand.

4.1.5. PtG and GtP

The power to gas unit is defined by a specific capacity and location that will be varied for different scenarios in the analysis and its efficiency.

[1] Since no minimum capacity is considered for the peak power plant in the Danish model, this method does not represent the start-up state of this peak generation. This simplification has been chosen to avoid a non-linear mixed integer problem.

SNG produced by power to gas

In Eq. (9)the amount of SNG that is stored is described by adding up the stored gas from the previous time step and the amount produced in the PtG process and subtracting the gas consumed by GtP and the amount that is sold on the gas marked for an average gas price.

$$\begin{aligned} Gst_t = Gst_{t-1} &+ \sum_{i}^{NPtG} \left(PPtG_{i,t} * \frac{\mu PtG}{HVGas} \right) * Base \\ &- \sum_{i}^{NGas} \left(PGtP_{i,t} * \frac{1}{\mu GtP * HVGas} \right) * Base \qquad \forall\, t > 1 \\ &- SNG_{sold\ t} \end{aligned} \tag{9}$$

The amount of stored gas is limited by a gas storage maximum, given in Eq. (10).

$$Gst_t \leq Gst^{max} \tag{10}$$

Eq. (11) describes the amount of gas available for the GtP process to be lower or equal the amount SNG stored in the system.

$$\sum_{i}^{NGas} PGtP_{i,t} * \frac{1}{\mu GtP * HVGas} * Base \leq Gst_t \tag{11}$$

Another constraint, given in Eq. (12) limits the amount of SNG that can be sold per time step to be lower or equal the amount stored in the previous time step.

$$SNG_{sold\ t} \leq Gst_{t-1} \qquad \forall\, t > 1 \tag{12}$$

Conversion limits

In Eq. (13) the power used by PtG each time step is defined with an upper and lower limit.

$$PPtG_i^{min} \leq PPtG_{i,t} \leq PPtG_i^{max} \qquad \forall\, i \in NPtG \tag{13}$$

The process of GtP is restricted by the maximum capacity of the already existing gas power plants that are used to convert SNG to electricity and their generation independent from GtP, as shown in Eq. (14).

$$GtPLimUp_{i,t} \leq PG_{Gas\ t}^{max} - PG_{Gas\ i,t} \qquad \forall\, i \in NGas \tag{14}$$

Lower limit for GtP is set to be zero, by defining PGtP as positive variable.

Electricity costs to run PtG

The costs for electricity to run the power to gas process and the costs to convert the produced SNG to electricity in a gas plant are assumed to be zero in the objective function for total system costs. Costs for producing the electricity for the power to gas plant have already been taken into account as fuel input costs for the thermal generation units and therefore also the fuel for the GtP process produced from this electricity has already been considered.

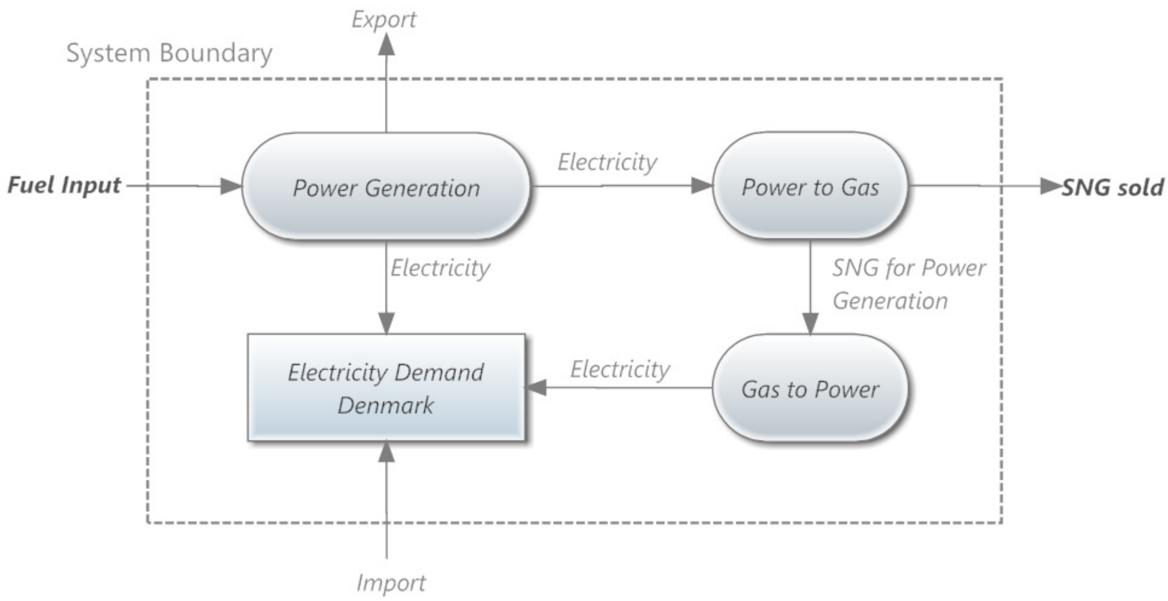

Figure 7: System boundaries for the Power to Gas Model

As can be seen in Figure 7, for the analysis of the total system costs the system boundaries are set around the generation and power to gas units. If in that case one more MWh of power to gas would be used, this additional MWh would need to be produced by the cheapest available generation unit and the additional costs will therefore be considered in the model as fuel input costs for this additional generation. The same approach to avoid accounting for the electricity costs twice has been used in the energy storage model in [29].

Limit of SNG sold per time step

Since the variations in the natural gas market are not modelled, the SNG in the simulation can be sold at any time step for the average selling price assumed without changing the total system costs. To spread the selling of SNG more equally over the time period a value is chose for a theoretical limit to sell per time step. Eq. (15) states that the actual amount of SNG sold per time step has be below this given limit.

$$SNG_{sold\,t} \leq SNG_{Max\,t} \qquad \forall\, t > 1 \tag{15}$$

Efficiency and ramp rates

Based on the technology review in Chapter 2.1 and assumptions given in the descriptions of similar models (efficiencies of 62 % [6], 63% [12], 60 % [14]) an efficiency of 62 % for the conversion of electricity to SNG has been chosen. The efficiency of converting SNG back to electricity has already been accounted for in the model, since the already existing gas CHP plants and if needed the peaking gas turbine (see Chapter 4.1.4) are utilized for the gas to power process.

In [18] ramp rate constraints for power to hydrogen and power to methane processes are discussed, but since all of them are given to be considerably smaller than the two hour resolution of this model, they will not be considered here.

4.1.6. Calculation of other output parameters

Further parameters needed for the analysis of the results are calculated from the results on power generation and scheduling of power to gas after the simulation is run, as described below.

Wind curtailment

The wind curtailment, meaning the amount of available wind energy that could not be utilized due to network constraints or otherwise losses in total system costs by the need to shut down and pay for starting up thermal power plants again is given in Eq. (16).

$$Curtailm_{i,t} = PWind_{i,t}^{max} - PWind_{i,t} \tag{16}$$

Line loading

The percentage of the available line capacity that is actually used per time step, the line loading is calculated by Eq. (17).

$$LL_{i,j,t} = \frac{F_{i,j}^{max}}{F_{i,j,t}} * 100 \qquad \forall F_{i,j}^{max} > 0 \tag{17}$$

Locational marginal price (LMP)

The locational marginal price that gives the price of one additional unit produced at a network bus is acquired by taking the marginal value of the nodal balance equation in Chapter 4.1.3.

4.2. *REPRESENTATION OF THE DANISH POWER TRANSMISSION SYSTEM*

The Danish transmission grid, operated at 400 kV, connects to neighboring countries Norway, Sweden and Germany. The regional transmission grid operates at 132 kV in the Eastern part of Denmark and 150 kV in the West. Both are owned by energinet.dk, the lower voltage distribution grid by local grid companies. In total there are about 4900 km overhead lines and 1900 km cables [30]. Figure 8 and Figure 9 show these existing lines and cables on different voltage levels. DK1 is the Nord Pool Spot bidding area for Western Denmark, while DK2 describes the bidding area for Eastern Denmark. The areas DK1 and DK2 are connected with a HVDC cable.

To reduce the number of network nodes and thereby calculation time a simplified model of the transmission grid is applied in this thesis. Only the 400 kV buses in DK1 and DK2 are represented in GAMS, lower voltage loads and generation units have been aggregated to the geographically closest 400 kV node. Transmission lines to neighboring countries have not been modelled (see Chapter 4.3.2 for details), focus of the simulation instead is the Danish network. The single line diagram in Figure 10 shows the final system consisting of 9 buses for DK1 and 9 buses for DK2.

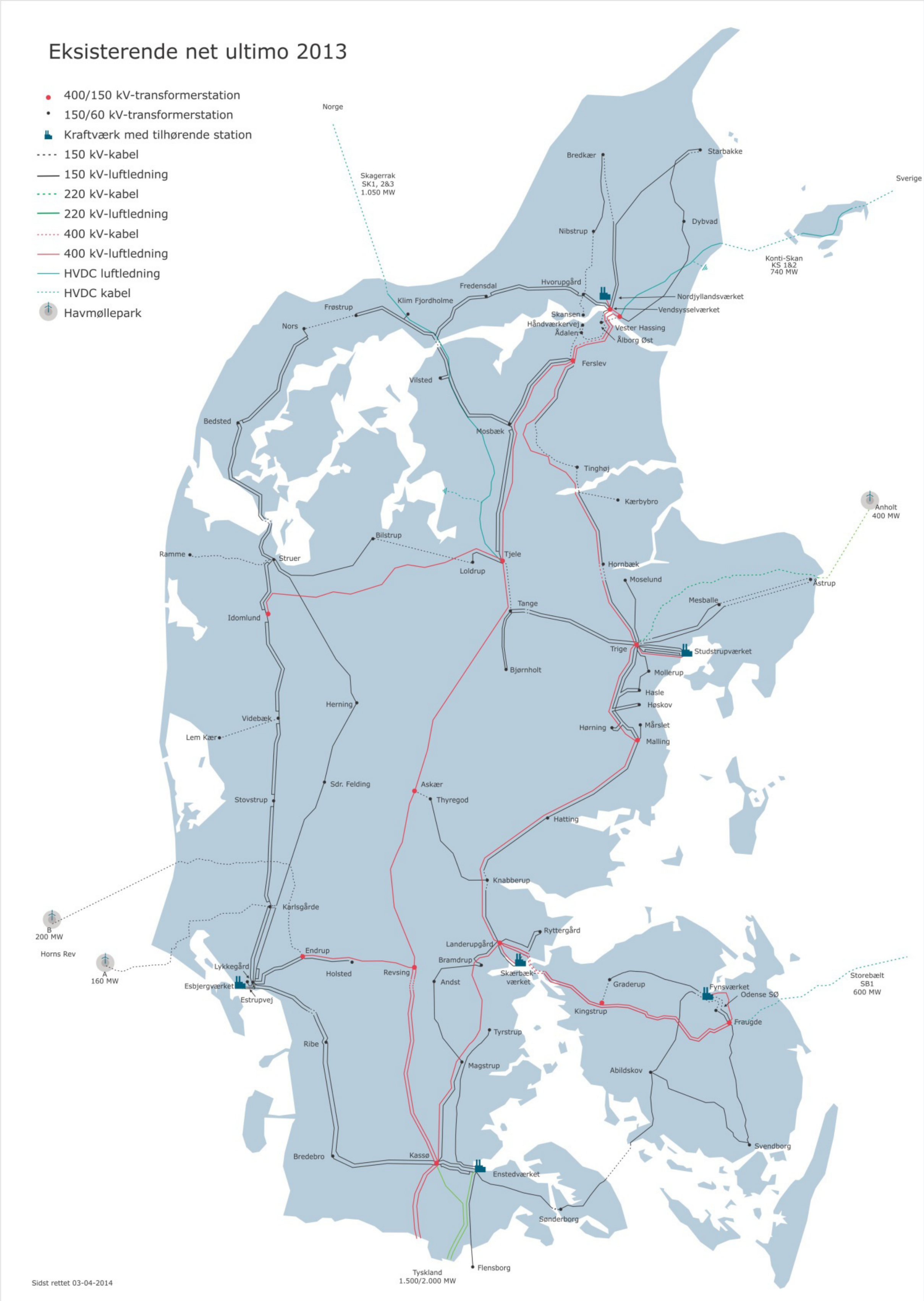

Figure 8: Electricity System DK1 [31] *(reproduced with permission)*

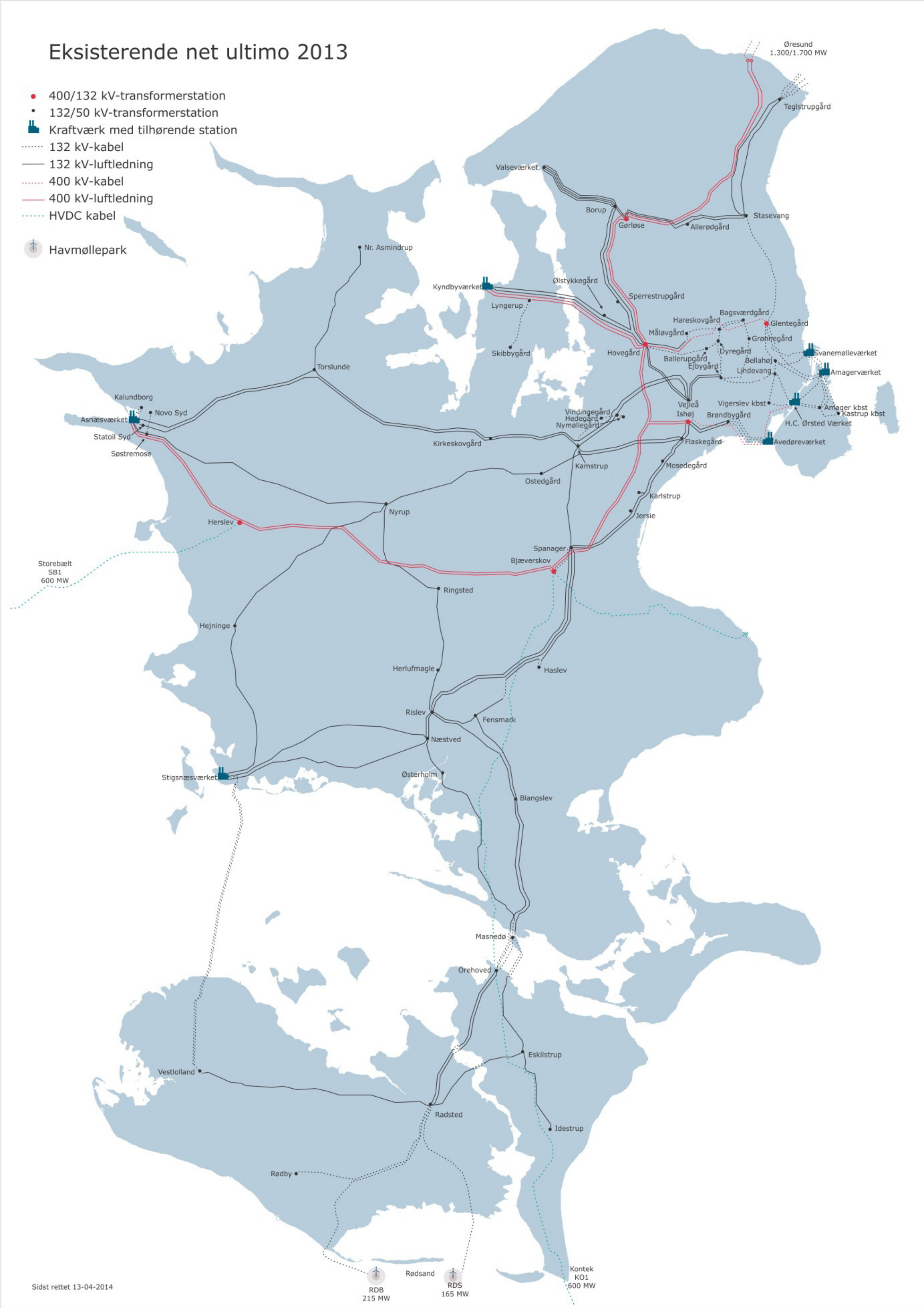

Figure 9: Electricity System DK2 [31] *(reproduced with permission)*

A validation of the simplified system by comparing the power flow over the HVDC line between DK1 and DK2 to the real values that can be acquired from Nord Pool Spot, has only been possible in a very limited way due to two reasons. In the simplified system the only connection from the two market areas is the HVDC line, whereas in the real system also import and export to neighboring countries in times of price differences between market areas is possible. Furthermore, the same operational costs have been considered in the model for all units with the same fuel input type, whereas in reality different running costs for various plants might lead to another generation dispatch and thereby different power flow over the HVDC line from DK1 to DK2.

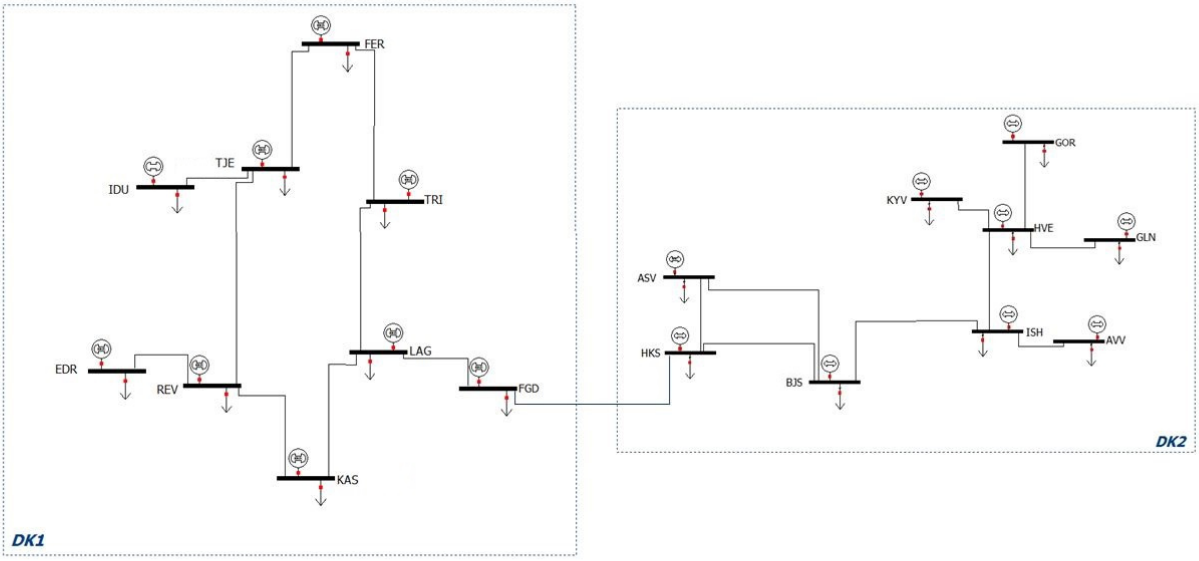

Figure 10: Single line diagram of the simplified transmission system

Table 1 shows the abbreviation of the buses in the single-line diagram, which have also been utilized in the simulation, together with the name of the location that can be read in the map.

Table 1: Bus name and location (400 kV transmission grid)

Market Area	Bus name	Bus name
DK1	KAS	Kassø
DK1	FGD	Fraugde
DK1	FER	Ferslev
DK1	LAG	Landerupgård
DK1	TRI	Trige
DK1	EDR	Endrup
DK1	TJE	Tjele
DK1	IDU	Idomlund
DK1	REV	Revsing
DK2	GLN	Glentegård
DK2	ASV	Asnæsværket
DK2	AVV	Avedøreværket
DK2	KYV	Kyndbyværket

DK2	BJS	Bjæverskov
DK2	HKS	Herslev
DK2	ISH	Ishøj
DK2	HVE	Hovegård
DK2	GOR	Gørløse

4.3. *DATA INPUT AND ASSUMPTIONS*

The GAMS model is based on the Danish electricity and gas grid in the year 2014 and a literature study on power to gas technologies. Input data used and necessary assumptions are described below.

4.3.1. Time resolution

As parameters like the load scale factor or the capacity factor of wind energy acquired from Nord Pool [32] are given in hourly resolution but the time step in this simulation has been chosen to be two hours, leading to 12 different values per day and 4380 entries for a whole year, the original data had to be slightly modified. For every two hours therefor an average value has been calculated that then has been applied in the model. In order to utilize the latest available data from Nord Pool the model starts with hour 1 at the first of April, ending at hour 4380 at the 31st of March. The first time step of each month is given in Table 2.

Table 2: First time step of each month in the model

	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb	March
Time step	1	361	733	1093	1465	1837	2197	2569	2929	3301	3673	4009

For the simulation of one year, two separate models, one for the summer months, one for the winter months had to be run, to reduce calculation time of the model. All information has been put together to compare the whole year in the results section of this report.

4.3.2. Electricity system

Parameters needed for the simulation of the Danish power grid could be acquired from available public data and analysis assumptions used by the Danish TSO.

Demand data

The peak load assumptions for 2014 per station for all transmission nodes could be acquired from energinet.dk and, as explained in Chapter 4.2, have been aggregated to the geographically closest 400 kV node [31]. Table 3 shows these peak values for each bus in the system.

Table 3: Peak demand per bus in DK1 and DK2 in MW

Market area	Bus	Peak load 2014 [MW]
DK1	FER	658.0
DK1	TJE	213.4
DK1	IDU	516.1
DK1	TRI	686.8
DK1	LAG	575.9
DK1	REV	44.3
DK1	EDR	299.8
DK1	KAS	310.1
DK1	FGD	540.6
DK2	ASV	230.4
DK2	HKS	52.2
DK2	BJS	527.5
DK2	ISH	180.5
DK2	HVE	380.5
DK2	KYV	24.7
DK2	GOR	432.0
DK2	GLN	714.7
DK2	AVV	167.8

To represent the load variation over time Nord Pool demand data from the previous year [32] has been used to calculate a load scale factor by dividing the actual demand in MW per hour of the day by the maximum load in MW of the whole year. Considering the two hour time resolution of this model that has already been explained, multiplying this load scale factor by the maximum demand assumption used by energinet.dk gives load per 400 kV bus for each time step in the model. Figure 11 display these variations in the system load over a whole year. Beginning from around time 2700 the increase in demand in the winter months can be seen, while also the difference between weekdays and weekend for all the weeks throughout the year are visible.

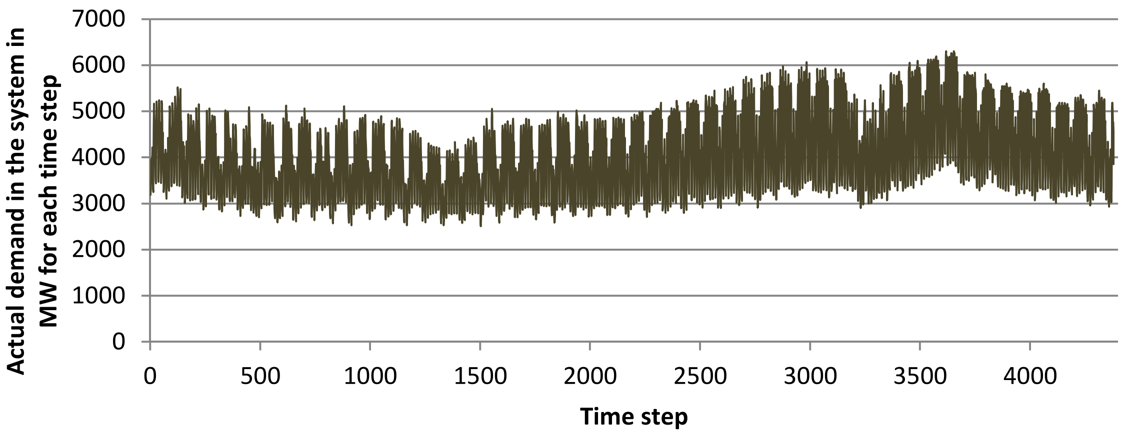

Figure 11: Variation in system demand over a year in MW for each time step

Generation data

Energinet.dk publish their assumptions for 2013 until 2035 used in their analyses, models and forecasts [5]. Their comments on thermal power plants together with information from Dong Energy [33] has been used for assumptions on maximum load, location and fuel input for all generation units in the simulation. The prevailing fuel type has been chosen for each plant and local CHP plants in East and West have been allocated to all buses equally. A summary of the power generation units parameters can be found in Table 5.

Table 4: Data of the thermal power generation units considered in the model

Market area	Bus name	Plant name	Pmin [MW]	Pmax [MW]	Start-up costs [€/StUp]	Fuel type
DK1	KAS	Ensted Power Station	294.2	840.7	54428.2	coal
DK1	FGD	Fyn Power Station	288.2	823.4	53308.2	coal
DK1	FER	Nordjylland Power Station	277.3	792.4	51301.2	coal
DK1	LAG	Skærbæk Power Station	124.1	620.7	30742.6	gas
DK1	TRI	Studstrup Power Station	394.9	1128.4	73054.4	coal
DK1	EDR	Esbjerg Power Station	207.4	592.7	38372.3	coal
DK1	REV	Herning Power Station	55.9	279.7	17893.5	woodchips
DK2	GLN	Amager Power Station	136.2	389	25198.1	coal
DK2	GLN	Svanemølle Power Station	27.2	136	6746.4	gas
DK2	ASV	Asnæs Power Station	403.0	1151	74538.0	coal
DK2	AVV	Avedøre Power Station	304.2	869.2	56274.1	coal
DK2	AVV	H.C. Ørsted Power Station	869.2	207	10268.1	gas
DK2	HKS	Stigsnæs Power Station	165.6	473	30636.4	coal

The variable running costs for plants displayed in Table 5, consist of fuel costs, taken from Energinet.dk's analysis assumptions [5] but also operation and maintenance costs given in the IEA report on projected costs of generating electricity [34].

Table 5: Generation cost in €/MWh and minimum down time (MDT) in hours for each fuel type

	Coal	Gas CHP plant	Wind power	Woodchips	Peak power plant
GenCosts	30.8	41.3	0	30.5	60
MDT	6	6	0	6	0

Additionally a start-up time of six hours for coal, gas and woodchip power plants and minimum power of 35 % for thermal and 20 % for gas power plants has been added, as suggested in [35]. The start-up costs also given in Table 4 then have been calculated by minimum power generation over the start-up time multiplied with the running costs. No start-up costs have been considered for the peak power plant. The three gas CHP plants in the system are assumed to run only for district heating in times where electricity demand in Denmark can be supplied by cheaper generation units.

Wind capacity and its detailed location until April 2014 could be downloaded from [36]. With the same method as for the load data, the wind capacity has been aggregated based on their geographical distribution to the 400 kV buses used in the model. The maximum capacity on each bus is given in Table 6.

Table 6: Maximum wind capacity per bus in MW

Market area	Bus name	Max. wind capacity [MW]
DK1	KAS	296.8
DK1	FGD	213.2
DK1	FER	556.2
DK1	LAG	167.7
DK1	TRI	666.2
DK1	EDR	501.8
DK1	TJE	287.6
DK1	IDU	947
DK1	REV	154.6
DK2	GLN	25.8
DK2	ASV	75.8
DK2	AVV	38.5
DK2	KYV	0
DK2	BJS	405
DK2	HKS	452.6
DK2	ISH	8.4
DK2	HVE	3.1
DK2	GOR	11.6

Nord Pool Spot [32] gives information on wind power production per hour during the last year in DK1 and DK2. Dividing this value by the maximum capacity in East and West respectively gives a capacity factor that can be used to calculate the wind generation in each node and each hour in the GAMS model.

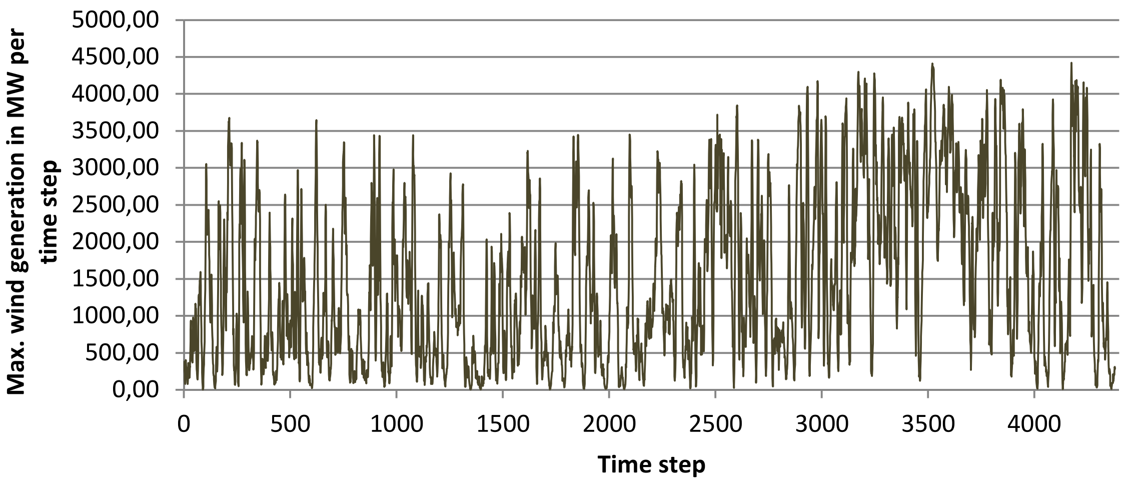

Figure 12: Variations in wind generation over a year in MW per time step

Figure 13 displays the variation in total available wind power over all time steps with maximum of 4424 MW available for wind generation, reached in the middle of March.

Line data

A network model and the lengths of the transmission lines have been used from energinet.dk [31]. Standard values for thermal power limits and reactance per km line have been taken from [37], the HVDC connection has been modelled like the other lines with the respective value for the max. power flow. All necessary data for the transmission lines have been summarized in Table 7.

Table 7: Power line data

Market area	From bus	To bus	Reactance [p.u.][2]	Length [km]	Max. flow [MWh/h]
HVDC DK1 DK2	FGD	HKS	0.00848	41.13	590
HVDC DK1 DK2	HKS	FGD	0.00848	41.13	600
DK1	FER	TJE	0.01270	61.57	1380
DK1	IDU	TJE	0.01497	72.60	1380
DK1	FER	TRI	0.01900	92.14	1380
DK1	TJE	REV	0.02473	119.90	1380
DK1	EDR	REV	0.00621	30.13	1380
DK1	TRI	LAG	0.02237	108.48	1380
DK1	LAG	KAS	0.01394	67.59	1380
DK1	REV	KAS	0.00564	2*0.01 [3]	2760
DK1	LAG	FGD	0.00770	2*0.02 [3]	2760
DK2	ASV	BJS	0.01408	68.28	1380
DK2	ASV	HKS	0.00454	22.00	1380
DK2	HKS	BJS	0.00955	46.28	1380
DK2	BJS	ISH	0.00664	32.17	1380
DK2	ISH	AVV	0.00249	12.05	1380
DK2	ISH	HVE	0.00350	16.98	1380
DK2	BJS	HVE	0.00769	37.30	1380
DK2	HVE	KYV	0.00259	2*0.01 [3]	2760
DK2	HVE	GLN	0.00389	18.88	1380
DK2	HVE	GOR	0.00214	2*20.77 [3]	2760

Connection to neighboring countries

Import and export to and from Denmark have not been considered for this study, however, the connection to neighboring countries could be included in this or similar models based on the values of the previous year. Power flow on the transmission lines to Norway, Sweden and Germany can be

[2] A base of 100 MVA has been used to calculate the p.u. values for the reactance.
[3] Two parallel lines between the same nodes have been modelled as one line with the equivalent reactance.

obtained from Nord Pool Spot [32] and then be added as generation or demand parameter on the respective connection node in the Danish model.

4.3.3. Gas system

Also the gas transmission system, shown in Figure 13, is owned by energinet.dk. Connections exist to Germany and Sweden. The Danish natural gas supply is located in the North Sea, entering the onshore gas grid at Nybro, but as explained in Chapter 1.1, the supply is declining and additional sources for gas production or import from Germany will become increasingly important in the upcoming decades [8].

Figure 13: Gas system Denmark [38] *(reproduced with permission)*

Figure 13 also displays the two storage sites in the Danish gas infrastructure, a salt cavity at Lille Torp in Northern Jutland and an aquifer storage facility at Stenlille on Sealand. Most of the storage volume is used by commercial players to be filled up during summer months, April to September, when gas supply exceeds consumption in order to supplement the production in winter time, November to March, when gas demand increases. Also the TSO energinet.dk reserves some capacity for emergency supply [8].

Both the gas storage providers, Dong Energy [39] and energinet.dk Gaslager [40] sell gas storage capacity on a yearly basis. Discussion with both companies [41] on the availabiliy of storage capacity for PtG in the future, revealed that presently there is no sign, that any future demand of capacity caused by PtG could not be met. The Danish gas system is connected to the rest of Europe via Germany and Sweden, where huge storage capacities can not be used at the moment. In [14] for example a total of 220 TWh storage capacity available in the German gas system is estimated. Furthermore, if demand for gas storage capacity increases, prices to sell capacity might increase and therefore new incentives to invest in building new storage sites will appear.

For these reasons no limit for the total maximum available storage capacity has been set in the GAMS model. Details on prices for buying gas storage capacity can be found online, but have been neglected in the cost function for this model.

When comparing Figure 8, Figure 9 and Figure 13 it can be found that electricity and gas transmission grids are located very close to each other, what supports a lot of different possible location for power to gas units with a connection to both of the systems. This factor has been considered for the choice of PtG locations analyzed as described in Chapter 4.3.4..

The wholesale market for natural gas in Denmark is called Gaspoint Nordic. Producers, retailers, energy companies, trading representatives and large consumers are allowed to partake in the trading system with a daily settlement [42]. Using an average over their historic market data from the previous year results in a selling price for SNG in Denmark, which is slightly higher than the value suggested by [15] in their study on the Netherlands.

Synthetic natural gas produced from PtG can also be sold on the fuel market as explained for the case of Sweden in [16]. The paper gives higher prices for this case since SNG competes with petrol and other fossil fuels instead of natural gas on the gas market, what consequently could result in higher benefits from PtG. Denmark is investigating on the decarbonisation of the transport sector for upcoming decades, what makes power to gas an interesting option.

4.3.4. Power to gas

The different locations for PtG units investigated in this study have been chosen to be geographically close to both, the electricity as well as the gas transmission grid. Three locations spread over the whole country, one in the North, in the South West and one in the East, have been selected, as seen in Figure 14. To compare the effects on total costs, also splitting the total capacity to equal parts on each location has been investigated. Based on analyses in literature and the size of demonstration projects mentioned in Chapter 2.2 a capacity of 10 MW has been chosen to be used in this case study. All locations and sizes are summarized in Table 8.

Table 8: Location and capacity of power to gas units chosen

	2014 and 2030			2030 only	
Bus(es)	ISH	EDR	FER	ISH; EDR; FER	ISH; EDR; FER
Capacity [MW]	10	10	10	10/3 each	10 each

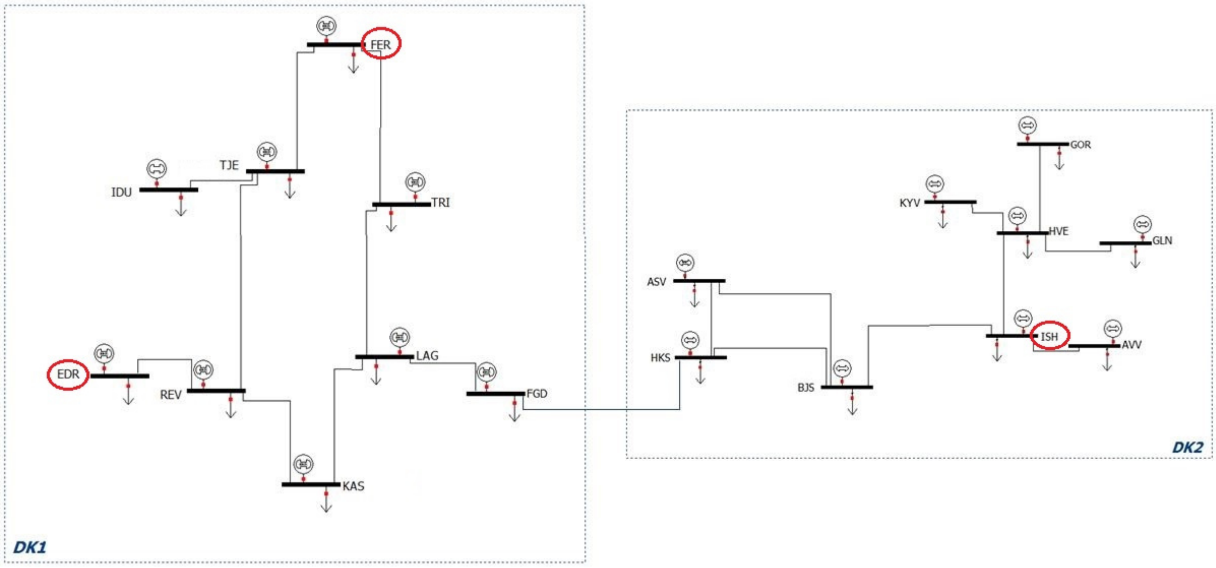

Figure 14: Single line diagram with locations of PtG

The efficiency of 62 %, as already mentioned in Chapter 4.1.5, has been chosen based on different values in literature [6], [12], [14]. As also explained in detail in Chapter 4.1.5, for this analysis from a system perspective the electricity costs, as a major part of the PtG running costs, do not need to be considered separately. Literature as [6], [15] or [16] give further details on operational and investment costs of power to gas plants or other factors as compression and storage of the product gas. Aspects interesting for a further, more detailed analysis on the economics of implementing PtG are the costs and availability of CO_2 and water needed as input, as well as the benefits that could be gained from selling surplus produced throughout the process.

4.3.5. Changes in a future system in 2030

The analysis assumptions of energinet.dk [5] include estimations on changes in Denmark until the year 2036. In order to simulate the transmission and generation system in the year 2030 peak demand, wind capacity as well as fuel type for generation units have been adapted according to the assumptions. Transmission line parameters, generation capacities and general assumptions regarding the gas infrastructure remain the same as described for the year 2014.

Increased demand

The peak demand in DK1 and DK2 is given to rise from 2014 to 2030 as depicted in Table 9. A factor is calculated for East and West Denmark in order to increase the load per bus that has been used in the base case.

Table 9: Increased demand in the year 2030

	DK1	DK2	Total
2014	3 845	2 710	6 555
2030	4 042	2 861	6 902
Scale factor	1.05102	1.05561	1.05292

Increased wind capacity

The wind capacity installed in Denmark is expected to increase from 4.8 GW in the year 2014, the base case of this simulation, up to 7.1 GW in 2030. Table 10 shows that the biggest part of this rise in capacity comes from offshore wind farms. The wind park in Horns Rev 1 and 2 is going to be increased to 1.2 GW while new wind power plants are going to be operated in Kriegers Flak in 2019, in Ringkøbing in 2030 and in Jammerbugt in the year 2026. Also the near-shore based wind turbines will increase in capacity, while the decommissioning of old plants will slightly decrease the onshore capacity until the year 2030 [5].

Table 10: Increased wind capacity in the year 2030

	2014	2030	added to bus
Offshore:			
Rødsand	373	373	**BJS**
Horns Rev	369	1 169	**EDR**
Anholt	400	400	**GLN**
Kriegers Flak		600	**ISH**
Ringkøbing		200	**IDU**
Jammerbugt		400	**FER**
Near-shore:			
Eastern Denmark	56	306	**all DK2**
Western Denmark	74	324	**all DK1**
Onshore:			
Eastern Denmark	668	602	**all DK2**
Western Denmark	2 789	2 682	**all DK1**
Sum MW	**4 729**	**7 055**	

The capacities of the offshore plants are added to the nearest 400 kV bus in the transmission system, while then near-shore and onshore increase is evenly spread over all nine buses in each area, by multiplying with the factor 1.0499 in DK1 and 1.2541 in DK2. This results in a total of 7483 MW for the year 2030, which is slightly different from the number above, as the initial values for 2014 in the base case from [31] (given in more detail for each bus, instead of the values from [5] given only for DK1 and DK2) were adapted with the calculated factor to acquire the model input for the future scenario.

Switch of fuel type for power generation plants

To account for the change in operation costs of the generation units that comes with a fuel switch based on information from energinet.dk [5] and Dong Energy [33] four of the plants initially run on coal in bus FGD, FER, GLN and AVV have been assumed to operate on woodchips in the year 2030.

4.4. *SCENARIOS*

The input data given in Chapter 4.3 have been utilized to run the model of the Danish system with different conditions. Table 11 summarizes the scenarios for the base case in the year 2014 and for a future scenario in the year 2030. For each of the scenarios two models, one for the summer months and one for the winter months has been run, for the analysis all information has been put together to compare the whole years in 2014 and 2030.

Table 11: Summary of the scenarios analyzed for a base case 2014 and a future scenario 2030

	Scenario:					
2014	No PtG	EDR 10 MW	FER 10 MW	ISH 10 MW		
2030	No PtG	EDR 10 MW	FER 10 MW	ISH 10 MW	10/3 MW each	10 MW each

5. RESULTS AND DISCUSSION

This section presents and interprets the results from the various scenarios that have been modelled and described in Chapter 4.4. First the total system costs are analyzed in order to determine the best location for a PtG unit from the alternatives simulated. Then various parameters like wind power curtailment, generation dispatch and necessary plant start-ups, the locational marginal price and dispatch of PtG units as well as the re-electrification of the SNG produced are investigated for the different cases. For all these points the difference in the effects of implementing PtG in a present or a future system are compared. Finally it is discussed how results could be affected by a change in assumptions used during the development of the model.

5.1. *EVALUATION OF THE BEST PLACEMENT FOR PTG BY COMPARISON OF TOTAL COSTS*

The total system costs to be minimized in the simulation consist of the fuel input costs of generation, the biggest portion, as well as the costs for start-ups of generation plants, but can be reduced in the scenarios including PtG by the benefit coming from selling the produced synthetic natural gas.

Figure 15 shows these parts for the different scenarios in 2014. Fuel costs given in million € can be seen to be reduced from 402.4 million € in the base case without PtG to between 386 and 387 million € in the different scenarios with PtG. The detailed generation dispatch that leads to this reduction is given in more detail in Chapter 5.3 about effects of PtG on the generation system.

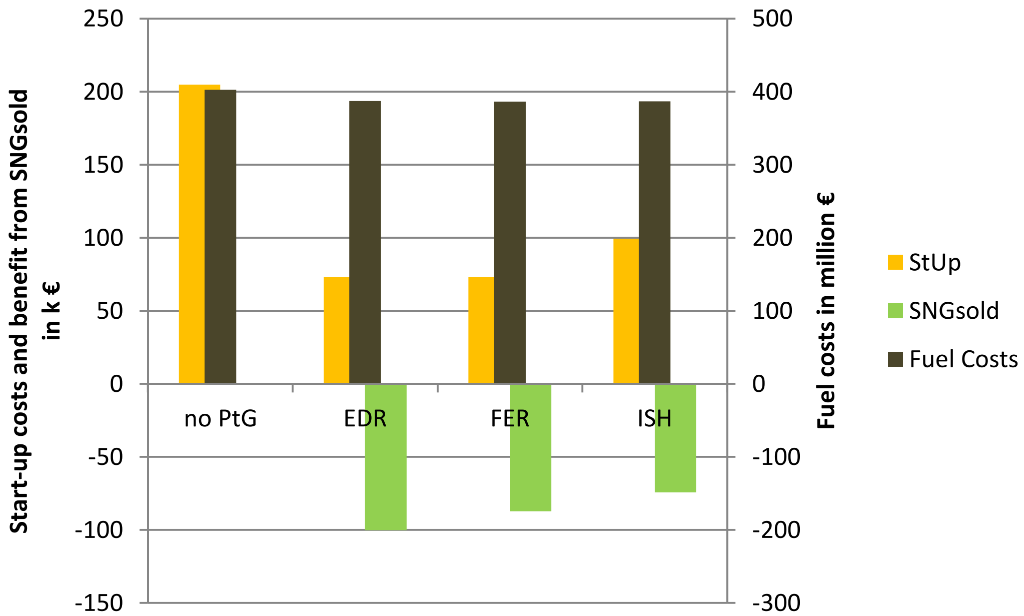

Figure 15: Comparison of total cost fractions in the 2014 scenarios

The start-up costs in the year 2014 can be reduced too in the cases with PtG, as also the number of necessary start-ups decreased compared to the number in the base case without PtG (see also Chapter 5.3). The benefits from selling SNG vary within the different scenarios as also the total amount of SNG sold differs. The lowest amount of SNG in the year 2014 is sold when a PtG unit is installed at bus ISH. More information on dispatch of PtG and production of SNG are given in Chapter 5.2.

In comparison to the year 2014, the fuel costs in the year 2030, as can been seen in Figure 16, are slightly higher, which can be explained by the switch of coal to the more expensive fuel biomass in a portion of the base load plants and the fact that total demand and thereby total generation increased. Still those costs can be reduced from a total of 416.5 million € in the case without PtG to values between 412 and 416 million € when applying power to gas. The start-up costs in difference to the present year 2014 can only be reduced by a small amount, while in the FER scenario they even increased together with the total number of start-ups. In 2030 in all three simulations with PtG a lower amount of SNG as in the 2014 cases is sold, which consequently leads to a lower benefit.

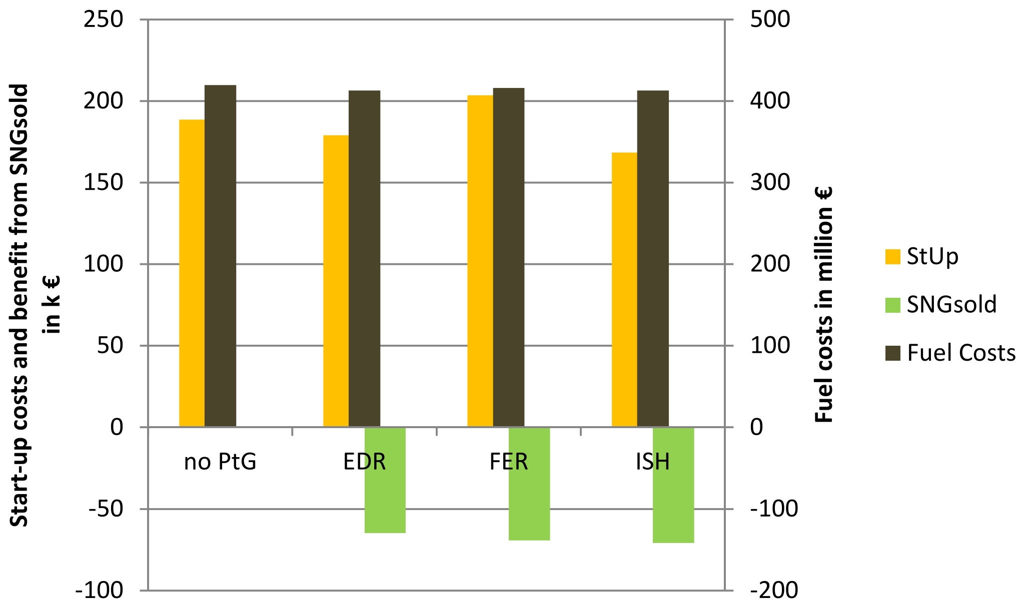

Figure 16: Comparison of total cost fractions in the 2030 scenarios

When summing up all the differences in fuel costs, start-up costs and benefits from selling SNG, the total savings when utilizing PtG at various locations can be calculated, resulting in the numbers given in Table 12. The much higher savings in % in the present year 2014 can be explained by the fact that start-up costs do not decrease when using PtG in 2030 to the same extent as this happens in 2014 together with the lower amount of SNG sold in the future scenario.

Table 12: Total savings in % for PtG in different locations compared to the base case without PtG

	2014 %	2030 %	2014 million €	2030 million € (discounted)
no PtG	0	0	0	0
EDR	3.85	1.64	15.50	3.16
FER	4.12	0.87	16.58	1.68
ISH	3.85	1.69	15.50	3.24

Table 12 also gives the actual savings in million € (DS), calculated with Eq. (18), where ΔC gives the difference in total costs between the scenario with PtG compared to the one without PtG over the 16 years between 2014 and 2030 with a discount rate (r) of 5 %.

$$DS = \frac{\Delta C}{(1+r)^{16}} \quad (18)$$

Figure 17 displays the total system costs in million € for the different scenarios with and without power to gas in 2014 and 2030 and allows for a quick comparison of the different locations.

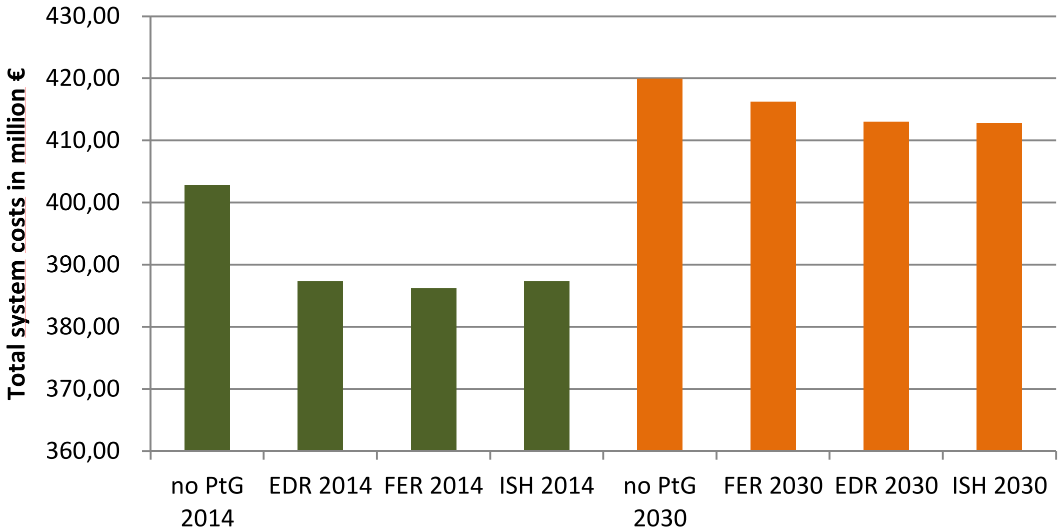

Figure 17: Total system costs in comparison for 2014 and 2030

When applying the method suggested in Chapter 3, the best placement with the biggest savings for the year 2014 clearly is bus FER, followed by almost equal savings in total system costs at each of the buses EDR and ISH. In the year 2030 a power to gas unit at node ISH brings higher savings, the best location in the year 2014, bus FER, in this future scenario shows the lowest savings. A different location can therefore be recommended for a 10 MW power to gas unit in the year 2014 and 2030. While in a present scenario FER would reach the highest system savings, in a future scenario bus ISH would be the more suitable location. Further analyses on the upcoming years until 2030 therefore are recommended to get a clearer picture of the impact of PtG on the system costs in the future.

5.2. *DISPATCH OF PTG AND GTP*

The dispatch of power to gas as well as gas to power plants varies over different scenarios. Table 13 shows the total energy utilized for the production of SNG in the power to gas process in MWh over the whole year for all three different alternatives, as well as the number of times steps this PtG units are running in the year 2014 and 2030. It can be found that in the case 2014 all PtG plants are run for a similar amount of time utilizing almost the same amount of electricity. In the year 2030 a PtG unit at location EDR runs the most time steps, sometimes only at a portion of the total capacity of 10 MW since it uses almost the same amount of electricity as the second alternative at FER. The differences in number of time steps PtG is utilized could partly be explained by the variations of the marginal electricity price that determines the costs of producing the additional up to 10 MWh consumed by PtG.

Table 13: Total amount in MWh and number of times PtG is used over a year for 2014 and 2030

2014			**2030**	
	PtG total in MWh	**Times used**	**PtG total in MWh**	**Times used**
EDR	22384,64	1113	22903,7	1688
FER	22544,14	1122	22898,28	1156
ISH	22435,6	1117	20326,66	1010

Gas to power is used most often in the scenario with a PtG plant implemented at node FER in the year 2014, while used only a very limited number of times in the 2030 FER and ISH scenarios.

The utilization of PtG mainly depends on the questions whether additional wind power is available in the system that can be transmitted to the PtG units, while the main purpose of operating GtP is avoiding unnecessary start-ups of thermal plants.

Table 14: Total amount in MWh and number of times GtP is used over a year for 2014 and 2030

2014			**2030**	
	GtP Total in MWh	**Times used**	**GtP Total in MWh**	**Times used**
EDR	4311,38	15	5127,64	23
FER	4890,4	31	22,32	1
ISH	827,1	6	182,6	2

The fact that more gas to power is utilized in 2014 compared to 2030 at a very similar dispatch of the PtG units, explains why in the previous chapter more benefit from selling the surplus SNG could be observed in 2014.

5.3. *IMPACT OF PTG ON POWER GENERATION*

With the implementation of a power to gas unit that represents an additional electricity consumer at the respective bus also the power generation in the system is altered.

Figure 18 displays how the generation from wind can be increased when utilizing PtG at different locations, which is also explained in more detail in the part on wind curtailment in Chapter 5.4. In scenario FER no woodchips are utilized in the summer months what consequently results in higher generation from the peak power plants in certain time steps as less capacity is available for ramp-up and ramp-down instead. The production from gas CHP is reduced when PtG is implemented, since not all available plants are started-up and GtP is utilized in some time steps instead to avoid those start-up costs. In the scenario without PtG the lowest generation from the expensive peak power plant is required, since more gas CHP plants are utilized at the same time. This offers more options for ramp-up and ramp-down, while still avoiding start-up costs.

When comparing the generation from these five fuel types it is important to consider that they do not sum up to the same total generation in all scenarios, since the additional demand from PtG as well as the additional generation from GtP has an influence too.

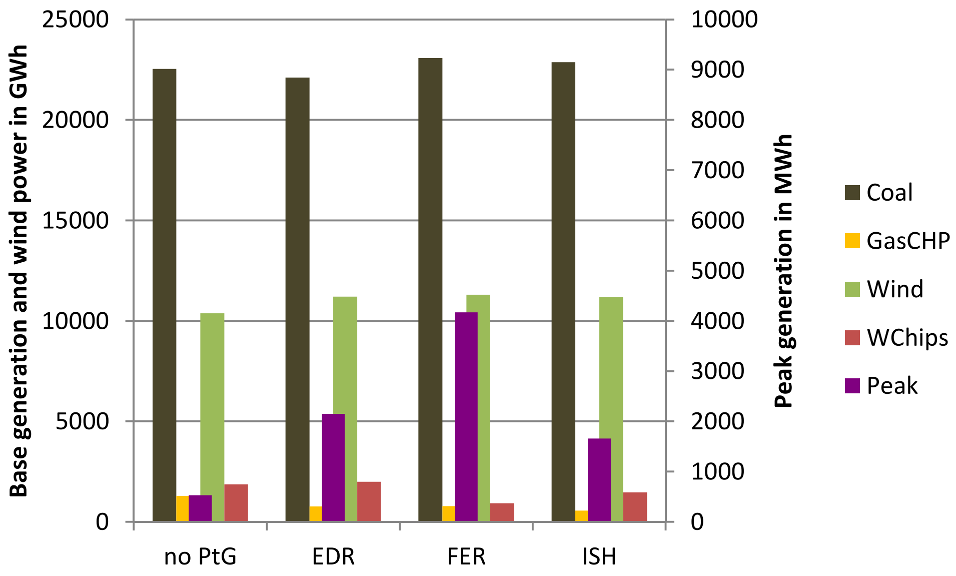

Figure 18: Total generation from different fuel types over a year in 2014

The scenarios for 2030 in Figure 19 show a much higher generation from wood chips, resulting from the fuel switch from the fossil fuel coal to biomass in some of the base load plants. The total amount of generation from wind power increased for all four scenarios, since the total wind capacity rises until the year 2030. As in the 2014 case, the generation from gas CHP has been reduced to avoid unnecessary start-up costs and also in this future scenario the case without PtG utilized more CHP plants and therefore has lower demand for peak load generation.

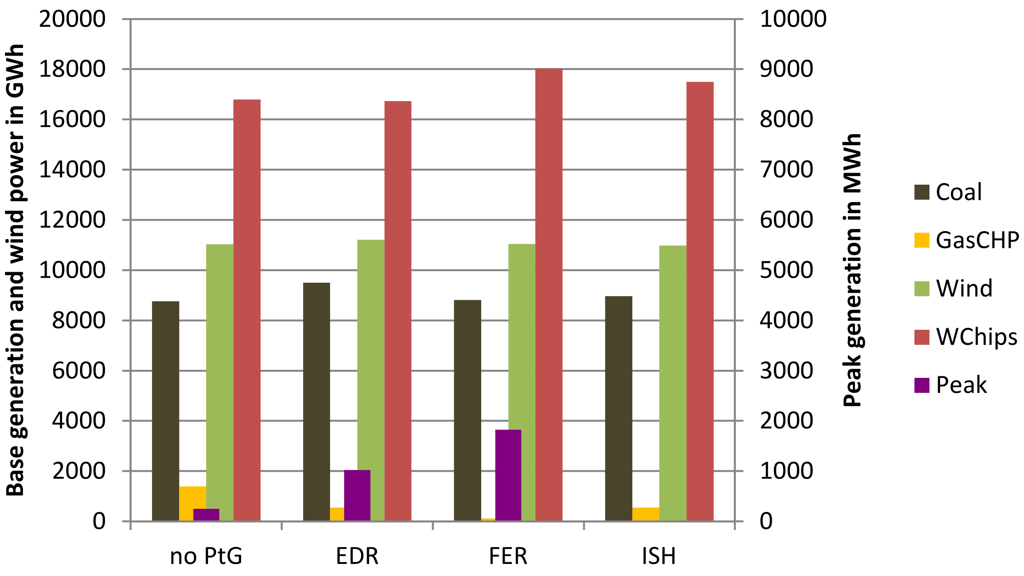

Figure 19: Total generation from different fuel types over a year in 2030

Table 15 gives the number of start-ups necessary for each fuel type. In the year 2014 those can clearly be reduced from the scenario without PtG compared to the three alternatives with PtG at different locations, what explains the clear difference in start-up costs shown in Chapter 5.1. The clear increase in the number of start-ups for the 2030 cases could be explained by the reason that thermal generation capacity has been kept constant compared to the year 2014, while the wind capacity has been increased. This leads to a higher portion of fluctuating production and since this intermittent wind power is the cheapest source available and will therefore be used as much as possible, the higher number of start-ups can be a consequence of that.

Table 15: Number of start-ups for different scenarios for 2014 and 2030

2014				2030		
	Coal	**WoodChips**	**GasCHP**	**Coal**	**WoodChips**	**GasCHP**
no PtG	4	1	1	2		2
EDR	1			1	4	
FER	1			2	2	1
ISH	2	1		2	2	

In the scenarios utilizing PtG the start-ups of gas CHP plants could be reduced or avoided, since, when not restricted by power flow limits on the lines, the GAMS model has the option to utilize gas to power in the same plants for a couple of time steps and thereby avoid start-up costs.

5.4. *IMPACT OF PTG ON WIND POWER CURTAILMENT*

The amount of wind curtailment per time step is varying over the whole year, with some periods where all available wind can be utilized and other time steps where power has to be "wasted" on one or more nodes. Figure 20 shows that the percent of curtailment over the whole year can be reduced when PtG is applied, with one exception in the FER scenario in 2030, where a lot of wind curtailment occurs in the winter. Since a higher capacity of wind power is applied in the 2030 scenario a further investigation with a higher PtG capacity is recommended.

It can also be read from the figure that the best location in the year 2014 at bus FER, which gives the highest possible system savings, also reduces curtailment the most. Also in the year 2030, node ISH with the highest system savings gives the lowest wind curtailment.

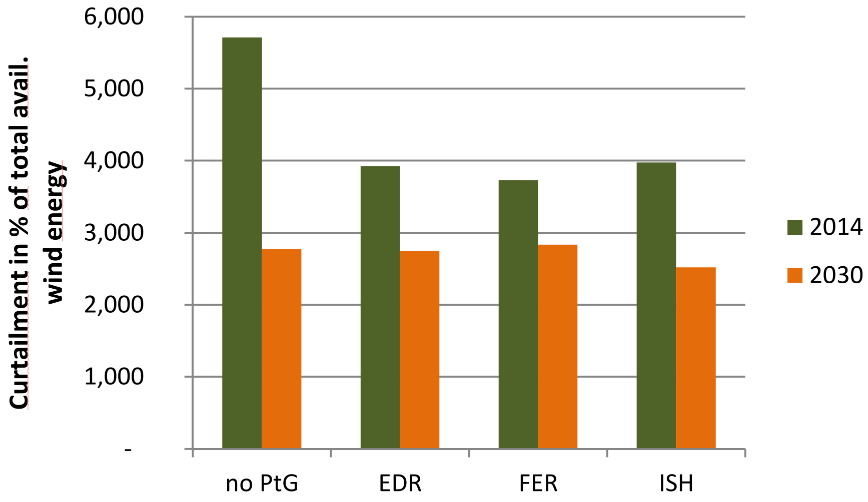

Figure 20: Total curtailment in % of total available energy from wind over a whole year for different scenarios

Wind curtailment can be affected by congestion on the power lines. The only bottleneck in the system analyzed, where the power flow limit is actually reached is the HVDC line between DK1 and DK2. Surplus generation from wind on either of the sides that cannot be transmitted to load buses where it is needed has to be curtailed. The second factor influencing the need for curtailment is the slow reaction of thermal power plants that need several time steps to start up again after being shut down. Considering the costs that occur for those start-ups, curtailing some wind power can be the cheaper solution when optimizing total system costs. As already explained, in the less flexible 2030 case with a higher share of intermittent generation sources the remaining thermal plants might be slower to react on these variations.

5.5. *IMPACT OF PTG ON ELECTRICITY PRICE*

The locational marginal price (LMP) gives the generation costs of another unit at each node in the system. Since the only bottleneck for the power flow in the system analyzed is the connection between DK1 and DK2, both areas always have the same LMP for all of their buses. However, there are periods, where East and West Denmark have different prices, which are those, where the HVDC connection is congested.

Table 16 displays how many of the total time steps analyzed lie within a certain LMP range. They sum up to 8760 in total, as one price for DK1 and one price for DK2 is considered. In 2014 as well as in 2030 the number of periods with zero on the margin has been reduced when applying power to gas compared to the case without this technology. PtG in these cases uses the additional electricity that can be generated from wind power at zero operational costs to produce SNG that can later on be utilized for re-electrification or sold at the average gas price, thereby decreasing total costs. As the events with zero marginal costs decrease when using PtG, those time steps between 0,1 and 59 € increase in number for the 2014 as well as the 2030 cases.

Table 16: Number of time steps with different LMP in €

2014				**Average price**		
	0	**0,1> <59**	**>59**	**Total DK**	**DK1**	**DK2**
no PtG	2596	6154	10	21.90	21.78	22.01
EDR	2132	6598	30	23.62	23.42	23.83
FER	2257	6501	2	26.43	22.53	22.92
ISH	2142	6601	17	23.48	23.25	23.70
2030				**Average price**		
	0	**0,1> <59**	**>59**	**Total DK**	**DK1**	**DK2**
no PtG	2322	6432	6	22.64	22.31	22.97
EDR	2199	6525	36	23.08	23.02	23.14
FER	2257	6501	2	22.72	22.53	22.92
ISH	2059	6689	12	23.48	23.05	23.90

DK2, East Denmark, on average has higher locational marginal prices than West Denmark, as can also be read from the table, what can to a certain extent be explained by the fact that West Denmark holds a higher wind capacity in total, which is the cheapest source in the system and thereby helps reducing the LMP in this area. As the HVDC connection between DK1 and DK2 reaches its capacity limits under certain periods energy from the cheapest generation cannot always be transmitted over the whole system. Average prices over a whole year increase with the utilization of PtG compared to the cases without power to gas. This can partly be explained by the fact that the PtG units represent an additional demand in the system which leads to increased generation, where energy in some time steps of the year also has to come from more expensive sources, what thereby increases the average LMP over the whole year.

Figure 21 shows the duration curve for the average locational marginal prices in DK1 and DK2 for two examples in the year 2014, the case without PtG and one case with PtG at the recommended location at bus FER. It can be seen that very high LMPs of 40 € or higher in both cases only occur a couple of times, while the LMP of around 30 €, where coal power is on the margin, is more frequent. Time steps with wind power at zero costs on the margin appear slightly more often in the base case without power to gas, as, what has already been mentioned in Chapter 5.4, more wind power needs to be curtailed and therefore additional generation could come from this cheap wind power.

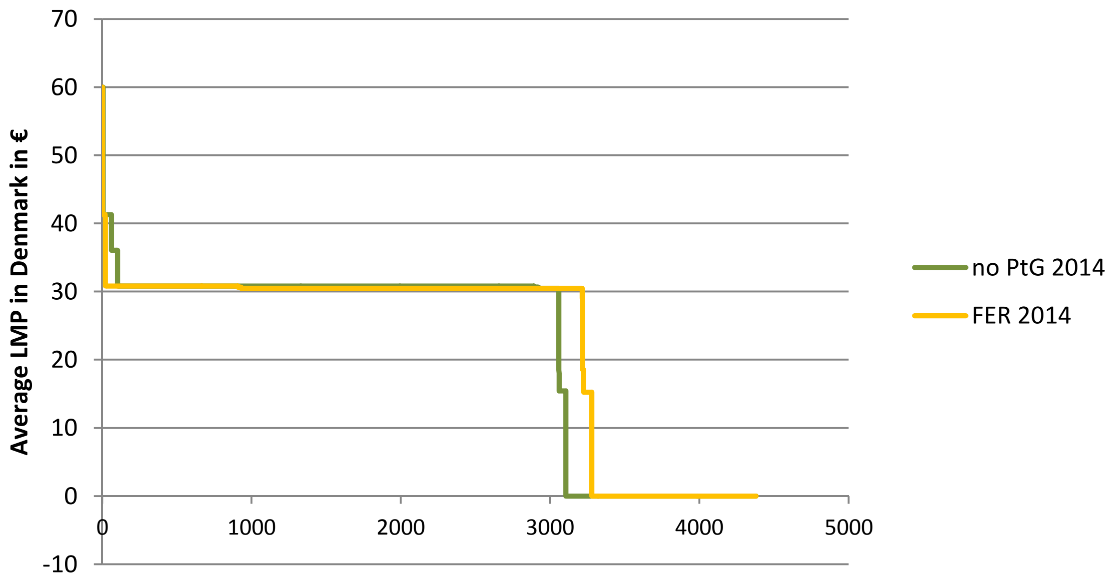

Figure 21: Duration curve of the average LMP for the 2014 case without PtG and with PtG at the best location FER

5.6. *IMPACT ON POWER FLOW*

As already mentioned in previous chapters of this analysis the bottleneck in the modelled Danish transmission system, without any connection to the neighboring countries, is the HVDC connection between DK1 and DK2. The power line loading of the other lines lies outside a critical state over the whole year.

Table 17: Number of time steps with congestion on the HVDC connection

	2014 no PtG	2014 EDR	2014 FER	2014 ISH
HKS - FGD	259	895	290	1387
FGD - HKS	1568	896	1528	276
Total	1827	1791	1818	1663
	2030 no PtG	**2030 EDR**	**2030 FER**	**2030 ISH**
HKS - FGD	94	101	65	111
FGD - HKS	922	524	635	720
Total	1016	625	700	831

Table 17 shows that the number of events with congestion on the HVDC connection clearly decreases when PtG is applied in each of the three different locations, as power can also be utilized for PtG when the limit on the connection between Denmark East and West is reached. The system for the year 2030 contains a higher share of intermittent wind power, which gives one explanation why PtG has a much higher effect in those scenarios.

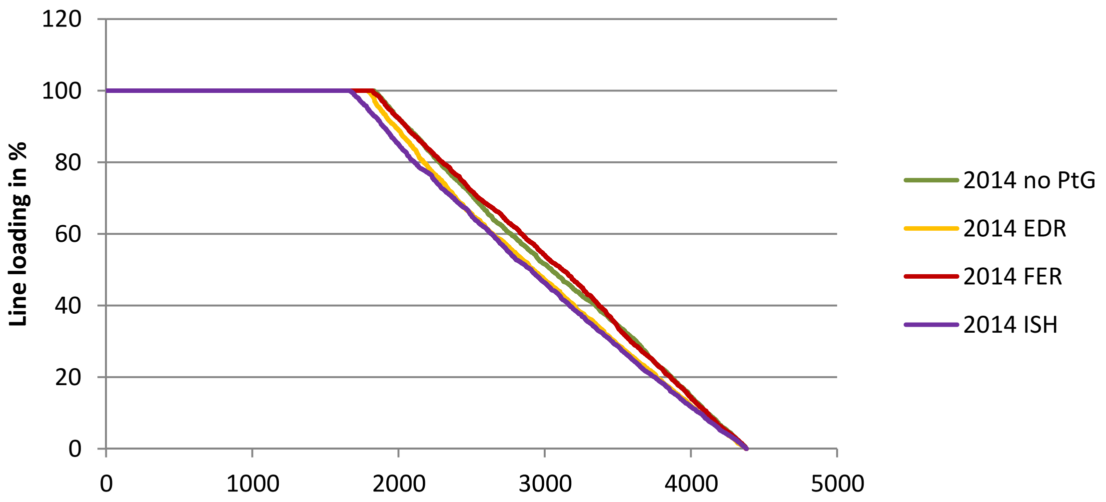

Figure 22: Duration curve for the line loading of the HVDC connection from bus HKS to bus FGD in the 2014 scenarios

Figure 22 and Figure 23 display a duration curve over the whole year for the power line loading of the HVDC connection between DK1 and DK2 for all four scenarios in the current Danish system, 2014 and the future system in 2030. As mentioned above, the number of events with congestions can be found to be higher in the case without PtG, since instead of transmitting electricity between the two market areas, it can also be utilized in the power to gas unit and can, when needed, also be re-electrified in times of high demand. Power to gas has a higher effect on congestion in the 2030 scenarios, what can be explained by the higher share of intermittent wind power.

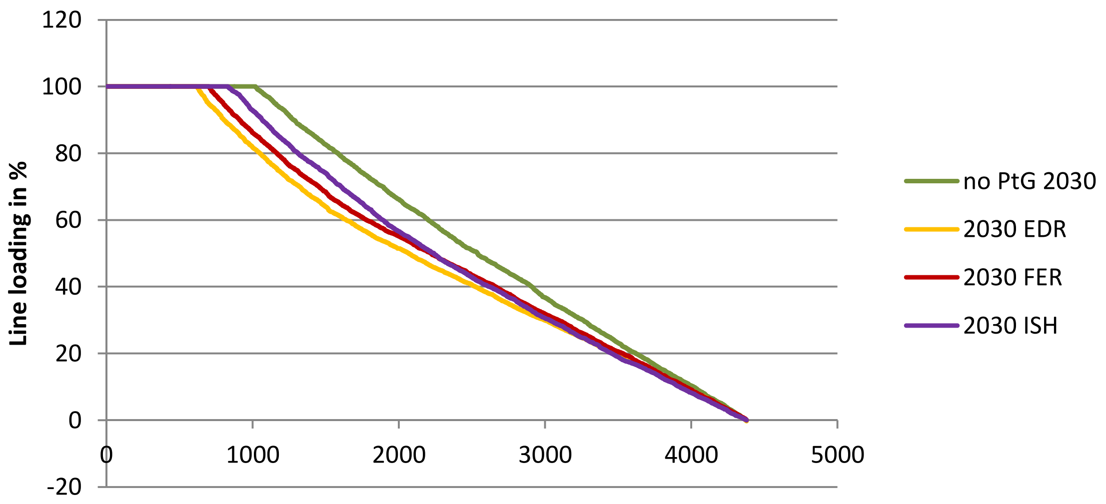

Figure 23: Duration curve for the line loading of the HVDC connection from bus HKS to bus FGD in the 2030 scenarios

5.7. *CHANGE IN IMPACT WHEN DISTRIBUTING PTG ON ALL THREE LOCATIONS*

In order to see the effect of equally spreading the PtG capacity over all three locations in the system two more scenarios have been analyzed, one with the investigated capacity of 10 MW distributed over all three buses and another one with an increased capacity of 10 MW on each of these nodes, both for the future case in the year 2030.

Table 18: Comparison of total system savings when PtG is distributed over all three location alternatives

	Total system savings in %
2030 - 10/3 MW each	1.30
2030 - 10 MW each	2.41
2030 – 10 MW ISH	1.69

When comparing the savings in total system costs, as seen in Table 18, the option with 10 MW equally distributed over all buses results in lower values than the best option for 2030 with all 10 MW implemented at bus ISH. However, it is significantly better than the worst of the three alternatives presented in Chapter 5.1. The case with an increased capacity of 10 MW PtG on each of the three buses gives higher savings than all other investigated 2030 scenario, which can only partly be compared to the other scenarios, since three times more electricity can be utilized in the PtG units.

Table 19: Comparison of total curtailment per year when PtG is distributed over all three location alternatives in 2030

	Total curtailment in MWh	Decrease compared to no PtG in %
no PtG	20046.1	0
10 MW each	14551.7	27.41
10/3 MW each	17380.2	13.30
ISH	18215.6	9.13

Table 19 compares the total curtailment in the year 2030. Distributing the 10 MW over all three nodes results in 13 percent lower curtailment than in the scenario without PtG, which is also significantly better than the best single location at bus ISH. As all of the three nodes chosen, are close to one of the main wind connection points, this result is reasonable. Additional load that becomes available when increasing the capacity to 10 MW each can thereby further foster the utilization of the full wind capacity installed, leading to a reduction of curtailment by 27.41 % compared to the case without PtG.

5.8. *DISCUSSION ON ASSUMPTIONS AND POSSIBLE IMPROVEMENTS IN THE MODEL*

In order to simulate the complex Danish energy system in GAMS several assumptions and simplifications had to be made. A change in some of these aspects could lead to a change in final outcomes as discussed in the following.

Two different models for summer and winter and time resolution

The fact that in order to model a whole year two different simulations had to be run separately will definitely affect final results for all parameters. Power generation cannot be optimized continuously over the year resulting in a different dispatch and start-up schedule. In two of the simulations run one specific fuel type has been utilized in one half of the year, but not been started up at all in the other half, what would definitely look different in a continuous simulation.

A more detailed time resolution of one hour instead of an average for each two hours would give more accurate results, while the general conclusions could be expected to be very similar.

Neglecting import and export and the effects on market price, power generation and flow

Modelling the Danish system without any connection to the neighboring countries does have a major influence on the outcomes of the simulations. In reality two connections each exist to Sweden and Germany and one more connecting to the south of Norway. Neglecting the import and export over those power lines will alter the results of market prices, generation dispatch and power flow within the Danish system.

First, the parameter of wind power curtailment as well as the dispatch of the remaining generation units will change when trade depending on the different market prices, as in reality, is possible. Import in times of high market prices in the two Danish areas and export during periods of low marginal costs will thereby also influence the power flow on the transmission lines within Denmark. More congestion within the Danish system might be the consequence as electricity from cheap generation sources will be transmitted to the lines connecting to higher priced areas in some time steps. With the option to transmit also to neighboring countries, the flow over the bottleneck in the analyzed system, the HVDC line between DK1 and DK2, will also differ. The possibility to generate additional energy in order to make profit by exporting it, will, together with a change in generation dispatch, also alter the locational marginal price. When the difference in market price to the neighboring areas is high enough, generation from more expensive sources might become profitable, leading to an increase in locational marginal prices.

Modelling a transmission line to Norway would also allow the consideration of the pumped hydro capacity in Norway as an alternative to the PtG technologies simulated in this analysis and would give further important conclusions.

The benefit from PtG could be expected to be lower when connections to neighboring countries are included in the model, since in this case surplus generation from wind power can also be exported instead of utilized for the production of SNG and PtG therefore might not be operated as many time steps as in this simulation. Further analyses on the economic effects this change may have need to be carried out in order to comment on the difference this makes to the results.

PtG operational costs simplifications and potential additional benefits

When modelling the power to gas units, only the main portion of the operational costs, the electricity consumption is considered, which is a reasonable assumption for the type of analyses carried out. However, for a more detailed investigation further cost fractions could be included. As described in Chapter 2.1 CO_2 and water are necessary as process input. In [15] costs for buying CO_2 are estimated for the analysis while in [6] and [16] the delivery of carbon dioxide is assumed without any costs. Water as well as O & M costs are estimated for the case of Sweden in [16] and could be implemented in a similar way for the analysis in Denmark. Additional revenues, much smaller than the benefits from selling SNG could also come from sales of oxygen or surplus heat produced during the process.

The consideration of benefits to the total system stemming from avoided grid reinforcements or the supply of balancing power as in [6] is not considered in this work, but could give interesting new perspectives on the conclusions on implementing power to gas.

Assumptions on selling of the product gas

In this analysis an average market price for selling the produced SNG has been assumed. In reality amounts traded on the gas market and market prices for this will change with variations in demand and supply, as is the case in the electricity market. The simplification that any amount of SNG can be sold on the market at any time might not be true when the effect of gas produced from other sources and the variations in demand are considered. In order to get a more detailed picture on the benefits possible from selling gas, the gas market would have to be incorporated into the model.

In Chapter 4.3.4 the possibilities of selling the synthetic gas to other sectors has already been mentioned. Further investigations on the potential benefits from selling SNG to the transport sector, as discussed in [16] or from producing hydrogen to sell to industry, as mentioned in [15] are required to find the best marketing strategies for the product gas and thereby analyze the dispatch of PtG units. Especially in the transport sector higher revenues when competing with car fuels together with high amounts possible to sell can be expected [16].

The average market price assumed for SNG will also have an influence on the comparability of the cases without PtG (and thereby no income from selling SNG) to the cases with different amounts of SNG sold. Considering a value for the product gas is important to create an incentive to operate PtG in the simulation and as explained in Figure 7, not only the benefit from selling SNG but also the additional generation costs from producing the necessary electricity as well as the efficiency during the conversion process are accounted for in the model.

Estimation of future generation capacity and electricity demand

For the changes in the generation system described in Chapter 4.3.5 the increase in wind capacity has been considered and the fuel switch to biomass has been simplified by modelling a portion of the coal plants as being woodchip-fuelled in the future. A more detailed representation of which plants are expected to switch to what type of biomass fuel would influence operational costs and thereby to a small extent parameters like e.g. the locational marginal price in the final results. Energinet.dk [5] include no comments on the change in total generation capacity in their assumptions, which is why this value has been kept constant in the simulation. However, also investment in new capacity next to the switch from fossil fuels could affect the design of the future generation system.

The estimations of the total demand increase from energinet.dk include considerations on the implementation of electric vehicles, the utilization of heat pumps as well as electricity efficiency measures. Still, those aspects mentioned are very hard to predict for the upcoming years, what has to be kept in mind when interpreting the results for these future scenarios.

6. CONCLUSIONS AND FUTURE WORK

After a detailed analysis of different aspects considered in the model of the Danish electricity generation system in the previous chapter, this part sums up the key findings from simulating different cases and also presents the interesting points for further research on the implementation of PtG in the Danish system.

6.1. *FINDINGS FROM THE CASE STUDY OF DENMARK*

A model has been developed capable of simulating generation dispatch, active power flow restricted by the network constraints and the implementation of power to gas units, considering also the production, storage and utilization of the synthetic natural gas produced. The model has then been tested in the case of Denmark by modelling different scenarios in the present year 2014 as well as a future system in the year 2030. The analysis of various parameters acquired from the simulation allows for several conclusions to be drawn in order to answer the research questions presented in the beginning of this report:

Q1: Impact on system costs and recommendation of the best location for PtG

- The application of power to gas reduces total system costs in all analyzed scenarios. Variable costs of power generation constitute the largest part of total system costs, while start-up costs and benefit from selling SNG on the market have a lower impact.
- The highest savings in total system costs can be achieved in the simulations when power to gas is applied at bus FER (DK West) in the year 2014 with a total reduction of 4.1 %. In the year 2030 total system costs can be reduced by 1.7 % with the recommended location being the bus ISH (DK East).

Q2: Impact on curtailment

- In the year 2014 all scenarios with PtG can decrease wind curtailment in the system, with up to 2 % more available wind energy used in the scenario with PtG at the recommended location on node FER in the year 2014.
- Distributing the total PtG capacity equally over all three buses results in lower wind curtailment than PtG on a single bus, since all of the three locations investigated are close to large wind capacities.

Q3: Impact on system parameters

- The number of time steps with a LMP of zero is reduced when PtG is applied, since this free additional generation from wind power that would have otherwise been "wasted" can create a value to the system when converted into SNG. A difference in average LMP over the whole year between DK1 and DK2 in all scenarios for 2014 and 2030 shows that congestion occurs on the HVDC line connecting East and West Denmark.

- The number of times steps with congestion on the connection between DK1 and DK2 can drastically be reduced with the application of power to gas in the future scenario and also decreases in the 2014 case.

- The main change in total generation from each fuel type between the respective cases in 2014 as well as 2030, next to the higher amount of wind that can be utilized, is the fact that without PtG a bigger number of gas CHP plants are continuously running, leaving more room for ramp-ups and ramp-downs and thereby reducing the generation from peak power plants compared to the cases with PtG. In those cases the flexibility to react on quick variations comes from GtP as well as peak generation.

Q4: Difference in the impact of PtG in 2014 and 2030 scenarios

- In the year 2030 more start-ups for all thermal plants are necessary, as compared to 2014 a higher share of intermittent generation from wind demands for more flexibility in the power generation system.

6.2. *FURTHER ANALYSES ON THE IMPLEMENTATION OF PTG IN DENMARK*

Next to the improvements to the model suggested in 5.8 also some interesting further investigations will lead to important conclusions on the implementation of power to gas in Denmark.

Detailed costs analysis

In this report total system costs and possible saving in different scenarios are compared. While this allows for conclusions on the effect different locations for PtG have on the outcome, also the comparison of necessary investment to the possible benefits is interesting. Details on investment costs for electrolyser and reactor, gas and oxygen storages, compression and necessary connections as well as parameters like lifetime or interest rate are found in literature as [6] and [16] and could be used for further analyses of the results acquired form the simulations.

Also a cost benefit analysis from the PtG operator perspective as [14] suggests could be carried out, using the results on PtG dispatch together with the market price the operator would have to pay and the amount of SNG that can be sold at a price depending on the sector it is used in, from the simulations.

Additional scenarios and sensitivity analysis

Additional scenarios, simulating e.g. the changes in results when using electrolysis only (thereby increasing the efficiency when the additional step of methanation can be avoided) and selling hydrogen as a product gas or different conditions when accounting for a more detailed representation of operational costs or benefits from selling O_2 and surplus heat, could easily be simulated with the model developed. Increasing the PtG capacity with an increased wind capacity for the 2030 scenario will also give interesting conclusion on the effect of power to gas.

Also a sensitivity analysis on the changes in technical parameters as improvements in the efficiency of electrolysis and methanation as well as economic aspects as variations in gas market price are necessary to be carried out. An optimization of the storage capacity is another interesting point for further research in order to make more detailed cost analyses.

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