LOAD MANAGEMENT – STRATEGIES FOR DEALING WITH TEMPORARY OVERSUPPLY OF VARIABLE RENEWABLE ELECTRICITY

Research Report
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Supervisors, Utrecht University
Dr. Machteld van den Broek
Dr. Wilfried van Sark

Supervisors, Quintel Intelligence
Dr. Alexander Wirtz
Dr. Chael Kruip

Richard Deuchler

richard.deuchler@quintel.com / rdeuchler@gmail.com
Energy Science M.Sc. (Natural Science Variant)
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This research is undertaken in cooperation with the Copernicus Institute at Utrecht University and Quintel Intelligence. The goal of both, the Copernicus Institute and Quintel Intelligence, is to contribute to a sensible transition towards sustainable energy systems. Next to sustainability, system costs and well-coordinated decisions are key in this transition.

Abstract

The Netherlands is currently in the process of massively increasing electricity generation capacity from wind and solar energy in order to meet its target of 20% renewable final energy consumption in 2020. As a result of large installed capacities, intermittent electricity production could temporarily surpass demand. If the phenomenon of excess electricity is not addressed, free and renewable electricity will be wasted as the generation from wind turbines and solar panels will have to be curtailed. This study examines technologies that are designed to absorb temporary oversupply from volatile renewables and convert it into useful energy. Three examples of conversion technologies are investigated, each representing one of the categories power-to-power, power-to-heat and power-to-gas conversion.

A model is built that forecasts excess electricity as a function of installed volatile generation capacity. It is forecasted that The Netherlands will be confronted with 2 TWh of excess electricity in the year 2020, if the target of installing ~17 GW of wind and solar energy is reached and other options of dealing with oversupply are not available (e.g. export). Technologies that only convert excess electricity will run at a very low load factor (typically below 10%) in 2020 because excess electricity is only available for 1000 hours throughout the year. In consequence, the conversion technologies have rather high levelized cost and none of them is expected to be profitable in 2020. Nonetheless, there are considerable differences in technology performance: Power-to-heat performs well in 2020 and would cause the least expenses. Power-to-gas conversion will be too expensive in 2020, but is generally suitable to reduce curtailment. Power-to-power conversion does not seem suitable for reducing curtailment, because of high costs and a limited storage volume.

It is unlikely that curtailment will ever be avoided completely by the technologies discussed here, as the reduction of curtailment follows the Pareto principle: The first installed conversion units have a large effect, while the complete reduction of excess will call for unreasonably large conversion capacities.

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Terminology

CHP	Combined heat and power plant.
Curtailment	The practice of turning off wind and solar power generation fully or partially, because their output would cause excess electricity.
Dispatchable	Power plants with manageable output. They can be ramped up or down according to the electricity demand.
Excess electricity	Excess electricity is observed whenever the residual load curve is negative. Excess electricity cannot be integrated into the grid by definition.
Inflexible	The term refers to conventional power plants that do not adapt to the residual demand. In other words, they continue electricity production during an excess electricity event. ‘Flexible’ power producers can switch off if the residual demand drops to zero.
Integrated volatile electricity	The term refers to the amount (or share) of wind and solar power that is integrated into the grid. For example: In the 2020 scenario, wind and solar generation produces 49 TWh of electricity. However, only 47 TWh can be integrated into the grid, 2 TWh are in excess. 47 TWh of integrated volatile electricity represent 40% of total electricity demand. The term does not consider the potential conversion of excess into useful energy.
Intermittent	The word intermittent has the same meaning as non-dispatchable, but stresses the fact that the power output is not reliable.
Must-run	See inflexible.
Non-dispatchable	Power producers that cannot be managed as desired. Non-dispatchable producers can potentially be switched off but not switched on as desired.
Oversupply	See excess electricity.
P2-heat P2-gas P2-power	Abbreviations referring to power-to- heat/gas/power conversion technology.
Participant	The term participant refers to a class of electricity generation units that ‘participate’ in the model. For example, wind offshore turbines and industrial CHPs are two participants in the model.
Variable	See volatile.
Volatile	Volatile producers are also non-dispatchable, but the word underlines the fact that power output may fluctuate significantly (high peaks).

1. Introduction

One of the major challenges in providing residential and industrial consumers with electricity lies in supplying the correct quantity at the right moment in time. Since the electricity grid itself cannot store energy, electricity production always has to follow the demand. Until today, the demand is satisfied mainly by conventional power plants, which are managed in such a way that their output reflects the demand over time.

There is a strong interest to move towards a more sustainable electricity system. Therefore, it is desirable to increase the share of electricity from renewable sources, especially, wind and solar energy. Next to many benefits, higher shares of renewable electricity make it more challenging to constantly balance supply and demand [Ummels, 2009; Tarroja et al., 2012].

The occurrence of excess electricity generation is a relatively new phenomenon, caused by the installation of volatile electricity sources. The act of discarding excess electricity, which cannot enter the grid, is called curtailment. In case of variable renewable power generation, curtailment implies that solar panels and wind turbines are turned off although they could produce electricity. Regulatory legislation is already in place in Germany, where wind farms and large-scale solar generation utilities can be switched off if required by the grid operator [Bundesnetzagentur, 2011]. The ability to curtail surplus energy is essential for guaranteeing a stable and reliable electricity system; therefore, curtailment might be an issue for every country that strives for high electricity production from volatile sources. Curtailing wind and solar electricity is a costly[1] and politically unpopular decision.

For most European countries, including The Netherlands, it is not well known how much electricity is curtailed today and projections for the future are highly uncertain if they are available at all. For Germany, the following estimations are published.

In 2004, 10 GWh of wind energy were curtailed [Bömer, 2011]. By the year 2010, the curtailment of wind energy increased to a more substantial 72 – 150 GWh (~0.3% of the integrated wind energy) [Bömer, 2011]. Although curtailment does not play a major role today, it is expected to increase significantly within the coming decade. For Germany, it is possible that up to 20% of the potentially available electricity from wind and solar will have to be curtailed by 2020 [Münch, 2012].

There is consensus in the literature that the Northwestern European electricity system is not flexible[2] enough to fully incorporate very large shares of variable renewable electricity: Denholm & Hand [2011] come to the conclusion that it is feasible to integrate shares of variable renewables (wind and solar) of up to only 30 – 35% in today's systems without

1 The investors that finance wind and solar power generation units have certain expectations towards the benefits that are gained from selling power. If electricity is curtailed, someone has to pay for it. Either the investors have to write off or the government/consumers have to reimburse the investors.

2 Grid flexibility refers to the ability of a grid to cope with fluctuations of volatile electricity production. At times of low volatile generation, conventional dispatchable plants have to make up for the lack in volatile generation. Only a couple of hours later, the volatile production might peak and call for the shut down of dispatchable plants. Flexible systems can cope better with increased ramping requirements.

adding electricity storage. Higher shares of renewables lead to extremely high curtailment rates, which cause excessive system costs [Denholm & Hand, 2011]. Another example is the research by Lund [2005], who advises that the Danish' grid flexibility should be increased as soon as wind energy delivers 20 – 25% of the total production. Bove et al. [2012] investigate the situation in several European countries (Germany, Denmark, Netherlands, United Kingdom, and Spain) and show that storage, which is a measure to increase flexibility, becomes an economically attractive option if wind energy reaches shares larger than 30% in the electricity mix.

These findings underline that variable renewables do not match the electricity demand very well and that electricity grids might face frequent events of surplus or deficient volatile generation. Potential options for increasing flexibility lie in the implementation of new storage facilities and demand side management.

It is crucial to find strategies of how future curtailment can be dealt with intelligently. Does electricity have to be discarded when it cannot be integrated into the grid? And are there alternative options that can help with the reduction of curtailment?

In principle, excess electricity can be reduced in the following ways:

1. export to neighboring countries
2. demand side management of domestic electricity consumers (electricity consumption is time-shifted to periods of high volatile generation)
3. increased flexibility of combined heat and power plants
4. electricity storage (domestic)
5. convert electricity into other useful energy carriers

The obvious choice would be to export superfluous electricity. Export of electricity generally leads to financial revenues and trading with neighboring countries can help with keeping the domestic electricity grid stable. However, the option of exporting electricity might not be available at times of high volatile electricity generation, because there is a probability that neighboring countries also have an excess of electricity. The power output of wind farms may be correlated, depending on weather conditions and geography. “Typical weather patterns in Europe are only about 1500 km in extent… [Giebel, 2000]”. Especially for longer time intervals (>24h), the correlation increases noticeably [Too, 2005]. Although the literature allows for different conclusions[3], it can be said that European wind park power output is

[3] A report by Wan et al. [2003] considers two wind farms in Midwestern United States (330 MW) that are separated by 200 km. There is considerable correlation in power output during time intervals of hours and days (correlation coefficient of 0.744 on a day-to-day basis).
Work by Adams & Cadieux [2009] and Harrison [2008] further indicates that wind parks with a distance below 100 km have highly correlated power output (considering wind parks of 40 – 190 MW in Ontario, Canada).
Too [2005] examines a larger number of American wind parks and comes to less definitive results. The correlations are high for daily intervals in comparison to 5 min, 30 min and 6-hour intervals. Correlation effects are found to be less coherent in this study.
Ward & Boland [2007] investigate six locations in South Australia and conclude that these sites are not correlated in power output. (footnote continues on next page)

highly correlated over distances up to 150 km [Giebel, 2000]. For the Netherlands, this means that excessive wind power will likely occur simultaneously in all neighboring countries that are governed by similar weather patterns. For solar power, the correlation is much stronger as solar generation peaks during midday throughout Europe.

In conclusion, the export option might not be available during times of high domestic volatile electricity generation. Furthermore, nations are aiming towards securing the domestic electricity supply without relying on foreign parties. For grid analyses that consider security of supply and grid stability in scenarios of high wind and solar capacities, it is common to exclude import and export (see for example Consentec & IAEW [2011]).

In politics and public debates, excess electricity will likely be allocated to nations, even though the electricity grid really is a European grid. Excess electricity will be curtailed locally and not homogeneously throughout Europe. Therefore, the measures for reducing excess electricity should to also be employed locally.

For these reasons, the export of excess electricity is declared out of scope in this report.

Demand side management offers some potential to shift the consumer demand in time. It might play a role, e.g. in smart charging of electricity vehicles. However, the amount of demand that can be shifted is very difficult to model. More importantly, the duration of continuous excess electricity events may exceed the potential time shift that can be accomplished by demand side management (typically a couple of hours). There is doubt whether demand side management will be sufficient to accommodate very large shares of variable renewable electricity in the future (>50%). It is found that demand side management has almost no effect in a German 2030 scenario, due to the short duration of effect [Consentec & IAEW, 2011].

Increased flexibility of combined heat and power plants (CHPs) refers to the practice of changing the output ratio of heat and power. At times of high volatile production, a flexible CHP can produce heat from an alternative source (thermal storage, backup burner) and reduce its electricity production [Wünsch et al., 2011]. Increased flexibility of CHPs is not investigated in this study.

This report focuses on the two options of either storing electricity or converting it into another useful energy carrier.

Giebel [2000] concludes for Europe that only at distances of 3000 km, wind park generation is no longer correlated at all. The situation in Europe is worse as for example in Texas, U.S., where correlation decreases quicker with distance [Katzenstein et al., 2010].

1.1. Justification

A German study [Consentec & IAEW, 2011] has evaluated different technologies (demand side management, electricity storage, power-to-methane conversion and increased flexibility of combined heat and power plants). It investigates how an increasingly fluctuating residual demand can be met by dispatchable generation capacity in the future[4] in order to guarantee a reliable electricity supply. The evaluated technologies can increase the flexibility of the electricity system and therefore they can also help bringing down curtailment. The study stresses that conventional electricity storage and demand side management are not sufficient to solve the issue of surplus electricity generation, as the achievable time-shift is too short. Storing surplus electricity for long times (days - weeks) and at large amounts only seems feasible with the conversion to hydrogen (or methane) [Consentec & IAEW, 2011]. The discussion focuses on securing a reliable supply by a more flexible dispatchable generation park; potential curtailment is not discussed. It is not possible to conclude how curtailment can be reduced and which technology would be suited best.

A study by Wünsch et al. [2011] investigates how heat storage in combined heat and power plants can be used to increase flexibility and integration of renewables in Germany. The study only considers government-owned district heating facilities, while industrial and small-scale units are neglected. By equipping CHPs with thermal storage, they can reduce their electricity output at times of low electricity demand while still satisfying the demand in the heating network. If these thermal storages can also be heated electrically, combined heat and power plants could actually be turned into electricity consumers at times of high electricity supply. Wünsch et al. [2011] underline the potential of converting excess electricity into heat. The study estimates that electricity generation of the considered CHPs could be lowered by up to 4 – 6.5 GW_{el}. The achievable reduction varies over time and depends on the demand for heat, the storage capacity and electric heating capacity of the thermal storage. It is not possible to conclude how much excess electricity could be converted by the measures over a year and in how far curtailment could be reduced.

A literature research did not reveal other material that quantitatively addresses the potential of reducing curtailment by power-to-heat, power-to-gas or power-to-power storage. It is not known which strategies are the most suitable in bringing down curtailment rates. Furthermore, it is not known how power-to-power, power-to-heat and power-to-gas conversion would cost if only excess electricity is converted.

[4] Dispatchable generation capacity will have to ramp up and down more quickly and more frequent in future scenarios

1.2. Research question

Are power-to-power, power-to-heat and power-to-gas conversion suitable measures for reducing curtailment in the future?

The following deliverables are required in order to answer the research question:

- a characterization of three examples, each representing one conversion technology
    - power-to-power conversion: central battery storage
    - power-to-heat conversion: domestic hot water supply by resistance heating
    - power-to-gas conversion: generation of hydrogen
- a forecast for excess electricity in the year 2020
- an analysis of how the conversion technologies perform with respect to the following indicators
    - curtailment reduction. How effectively can excess electricity be absorbed?
    - levelized cost. At which cost is the converted excess electricity delivered?
    - CO_2 mitigation. How much CO_2 emissions can be avoided by converting excess electricity?

The Methodology describes why these deliverables are addressed and what steps are taken in order to reach them.

1.3. Scope

- The research focuses only on events of oversupply of electricity. It investigates potential measures of how to deal with oversupply. It is not concerned with the question of how renewables can be integrated in general.
- The purpose of the excess electricity utilization strategies is only the handling of excess electricity that would otherwise be curtailed. Potential applications in load following or grid reliability services are not considered in this research.
- Effects of insufficient transmission and distribution grids are not considered[5]. All simulations are based on a copper-plate assumption.
- The model only considers The Netherlands. The Netherlands has access to only a limited area to install wind turbines. The power generation from large installed capacity of wind energy will generate a very correlated power output, which amplifies the probability of excess events. Furthermore, the Netherlands currently does not have direct access to large storage facilities (pumped hydro or compressed air energy storage). These properties reinforce occurrence of excess electricity and make The Netherlands an interesting case study.

[5] Curtailment may currently be caused by grid insufficiency, but there are strong indications that future curtailment will mainly be due to surplus feed-in [Oesterwind, 2012].

- The study does not take into account the import and export of electricity[6]. System operators have to guarantee for a reliable grid without relying on other countries [Consentec & IAEW, 2011].
- It is assumed that all strategies, which are proposed here, can make unimpeded use of excess electricity. Excess electricity can be obtained at zero cost. Establishing incentives and regulatory framework that ensure the free access to excess electricity is not in scope of this work.
- The economic characterization is based on a projection for the year 2020. Potential cost reductions (learning effects) are neglected. The analysis of scenarios that could be reached in a more distant future is based on the technology envisioned for the year 2020. Moreover, scaling effects are also not considered in the analysis (economy of scale).
- It is assumed that the conversion technologies investigated in this study do not have any competitors. Potential other measures (import/export, conventional storage or demand side management) may reduce excess electricity, but are declared out of scope for this analysis.
- Curtailment reduction technologies are allowed to operate on excess electricity only. Converting electricity at times of positive residual demand is not permitted.

The study deals with scenarios that are characterized by a certain percentage of 'integrated volatile electricity' (from wind & solar power). The percentage of total renewable electricity is not considered. This is justified by the following argument:

While the generation from wind and solar is highly volatile, other renewable sources may be more reliable, e.g. co-firing biomass in coal plants, hydro (river) and geothermal power. In addition to having a limited potential[7], these renewables do not add to the volatility of the electricity supply and therefore are of low interest in the context of this study.

[6] Trading electricity on a European market has the potential to reduce excess electricity. Exporting excess electricity to neighboring countries requires joint efforts and planning. There are some indicators that countries are not always willing to accommodate excess electricity from neighboring countries [renewablesinternational.net, 2011; Morris, 2013]: A large wind production capacity is installed in the northern part of Germany, while large consumers of electricity are situated in the south. Since the German transmission lines are not always sufficient, there frequently is an oversupply of electricity in the north of Germany. It is often exported to Poland and the Netherlands. Poland is reluctant to absorb German oversupply because it interferes with their domestic production. Similarly, the Netherlands has to deal with the fact that its gas power plants are required for fewer hours of the year. The difficulties in coordinating the flow and use of excess electricity are of such a dimension that measures are taken to actively shut down interconnectors [Easton, 2012]. As the amounts of excess electricity increase in the future, it will require enormous efforts in bringing European countries in an agreement on how to jointly deal with excess electricity.
Therefore, there is reason to believe that the export of domestic oversupply is not always a feasible option.

[7] The potential of hydro river power is very limited in The Netherlands [Quintel Intelligence, 2010]. Furthermore, it is very unlikely that large-scale geothermal electricity generation will operate by 2020.
The only alternative to increasing reliable renewable electricity production lies in the use of biomass. Currently, about 12% of the fuel for pulverized coal plants consists of wood pellets, which increases the renewability of those plants. However, the co-firing of biofuels relies on subsidies and it is not certain that the practice will continue in the future [Quintel Intelligence, 2010]. Importing foreign biomass on a large scale is not considered sustainable from an economic and environmental point of view. The literature does not indicate that co-firing biomass of non-domestic origin will increase in the future.

2. Methodology

In order to evaluate the performance of excess electricity conversion technologies, the indicators ‘curtailment reduction’ and ‘levelized cost’ are analyzed:

$$\text{curtailment reduction} = \frac{\text{electricity absorbed by technology}}{\text{total excess electricity}}$$

$$\text{levelized cost} = \frac{\text{capital recovery factor} \cdot \text{investment cost} + \text{annual operation cost}}{\text{energy output of conversion technology}}$$

(for a detailed description, see page 42)

The curtailment reduction indicates how much excess electricity can be absorbed by a technology. It depends on, for example, the installed capacity and the availability of a technology. An effective technology can reach high curtailment reduction per installed capacity. Levelized cost provides insights into the cost of delivering energy (power, heat, hydrogen) via the conversion of excess electricity. By comparing the levelized cost of an excess conversion technology to the cost of delivering the equivalent energy by conventional means, it can be concluded if a conversion technology can be cost-effective.

In order to produce the information that is required to calculate the two performance indicators, a simulation is set up that models the occurrence and conversion of excess electricity. Figure 1 outlines the inputs into the simulation and how the results of this study are derived.

The simulation requires several inputs. First of all, the conversion technologies are described and their energetic and economic properties are characterized for the year 2020. For each technology, all necessary information is gathered from the literature. In case of the power-to-heat route, data is also based on an interview with Hans Overdiep [2013].

Furthermore, the simulation of excess electricity conversion requires a forecast of how much intermittent electricity will be available during which hour of the future scenario. Projections for installed generation capacities are gathered for the year 2020. In particular, the capacities of wind (on- and offshore) and solar are determined. Also, the future development of inflexible generation and demand for electricity is identified. This is achieved by a literature review. Numerous reports are available that describe how European and national targets might translate into installed capacities by 2020. However, it is not sufficient to just project the installed generation capacities, it also has to be known how much power is actually produced at which time. The simulation of hourly power generation is adapted from the Energy Transition Model [Quintel Intelligence, 2010]. The link between installed intermittent generation capacity and hourly energy production is made by scalable profiles that represent the typical behavior of intermittent generation. A profile is a normalized representation of the hourly electricity production by one megawatt of installed capacity. The procedure for creating theses profiles is adopted from the Energy Transition Model. For example, the profile that represents the hourly electricity production from solar PV is based on solar irradiation measurements. For a more detailed description of profile generation, see Appendix B.

Once all inputs are specified, the simulation is compiled in the software Wolfram Mathematica[8]. The simulation produces all necessary outputs that are required to calculate the performance indicators. The following paragraphs describe the functionality of the simulation.

Non-dispatchable power generation (wind, solar, inflexible CHP) is treated with priority over dispatchable power plants. Electricity production from non-dispatchable is used first in satisfying demand before dispatchable producers are turned on. This is due to the fact that wind and solar generation have zero marginal operation cost. Furthermore, renewable electricity has to be integrated into the system whenever it is available. Inflexible generation does have marginal operation cost, but since it cannot be shut off, it also has priority over dispatchable power plants.

For every hour of the future year, the model calculates the

- electricity demand
- production from wind, solar and inflexible CHPs (i.e. non-dispatchable generation)
- residual demand for electricity
- capacity of excess electricity
- excess power that can be absorbed by a curtailment reduction technology
- dispatch of conventional power plants
- electricity price

To illuminate how the model derives the forecast for excess electricity, Figure 2 gives an example of non-dispatchable supply and electricity demand during two weeks in 'June 2020'. Whenever the residual demand is negative, electricity is in excess.

$$\text{residual demand } (t) = \text{demand}(t) - \text{non-dispatchable generation}(t)$$

In subsequent modeling step, the forecasted excess electricity can be absorbed by a curtailment reduction technology, according to its available installed capacity (MW) and the characteristics provided in this report. Excess electricity conversion is therefore applied directly on the residual demand curve, before dispatchable power plants have been dispatched and the demand is fully met. Power-to-gas and power-to-heat will only shave off the peaks of excess electricity (during negative residual demand), while power-to-power conversion also affects the positive residual demand due to the discharge of electricity.

After the excess electricity has been (partially) converted by a technology, the remaining positive residual demand is met by dispatchable power plants. It is assumed that the installed capacities of dispatchable power plants will not change until 2020. The simulation is based on

[8] www.wolfram.com

the installed capacities of conventional plants as they are defined in the Energy Transition Model for 2010[9].

The model calculates an electricity price according to merit order mechanism, which is based on the short-term marginal generation costs of the dispatchable power plants[10]. The electricity price is set to the marginal operation costs of the least expensive power plant that is not required to meet the current demand for electricity.

If all dispatchable power plants are required in order to fulfill the residual demand, the electricity price is set to a maximum of 600 €/MWh[11] [Quintel Intelligence, 2010]. Once supply and demand are balanced, all participants sell their electricity at the same price.

Finally, all results are calculated that are required to derive the performance indicators.

The main focus of this study lies on the year 2020, which is the default scenario. However, it is also possible to change the input parameters of the simulation. The installed capacities that are projected for the year 2020 yield a scenario in which 40% of the energy production originates from wind and solar. By scaling the installed capacity for solar and wind up or down proportionally, scenarios of varying renewability are created. The ratio of installed capacity of wind and solar is fixed at 3.1 (which represents the 2020 scenario; ~13 GW wind and ~4 GW solar).

By increasing the installed capacity of wind and solar generation beyond 2020 levels, the performance of conversion technology is analyzed in scenarios of varying shares of integrated volatile electricity (wind and solar). Special focus lies on the 2020 and 60% scenario[12]. The purpose of increasing the volatile generation capacity further is the evaluation of conversion technologies in scenarios of more excess electricity. The purpose does not lie in an exact forecast of excess electricity.

Finally, it is possible to draw conclusions on how the conversion technologies compete with each other in different future scenarios.

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[9] This assumption does not reflect reality, but it is sufficient for the analysis of excess electricity. The dispatchable power plants are only used for setting the electricity price, which is an indicator for the benefits of the power-to-power conversion.

[10] Data taken from the Energy Transition Model [Quintel Intelligence, 2010], on 11.02.2013. Displayed in Appendix A.

[11] The simulation of the 2020 scenario shows that the most expensive power producers (gas turbines) are only required for 2 hours of the year in order to meet the demand. Therefore, the maximum price of 600 €/MWh is a rather insignificant parameter.

[12] The 60% scenario is identical to the 2020 scenario, but it has twice the amount of installed generation capacity from solar and wind. As the name suggests, 60% of the electricity demand are delivered from solar and wind.

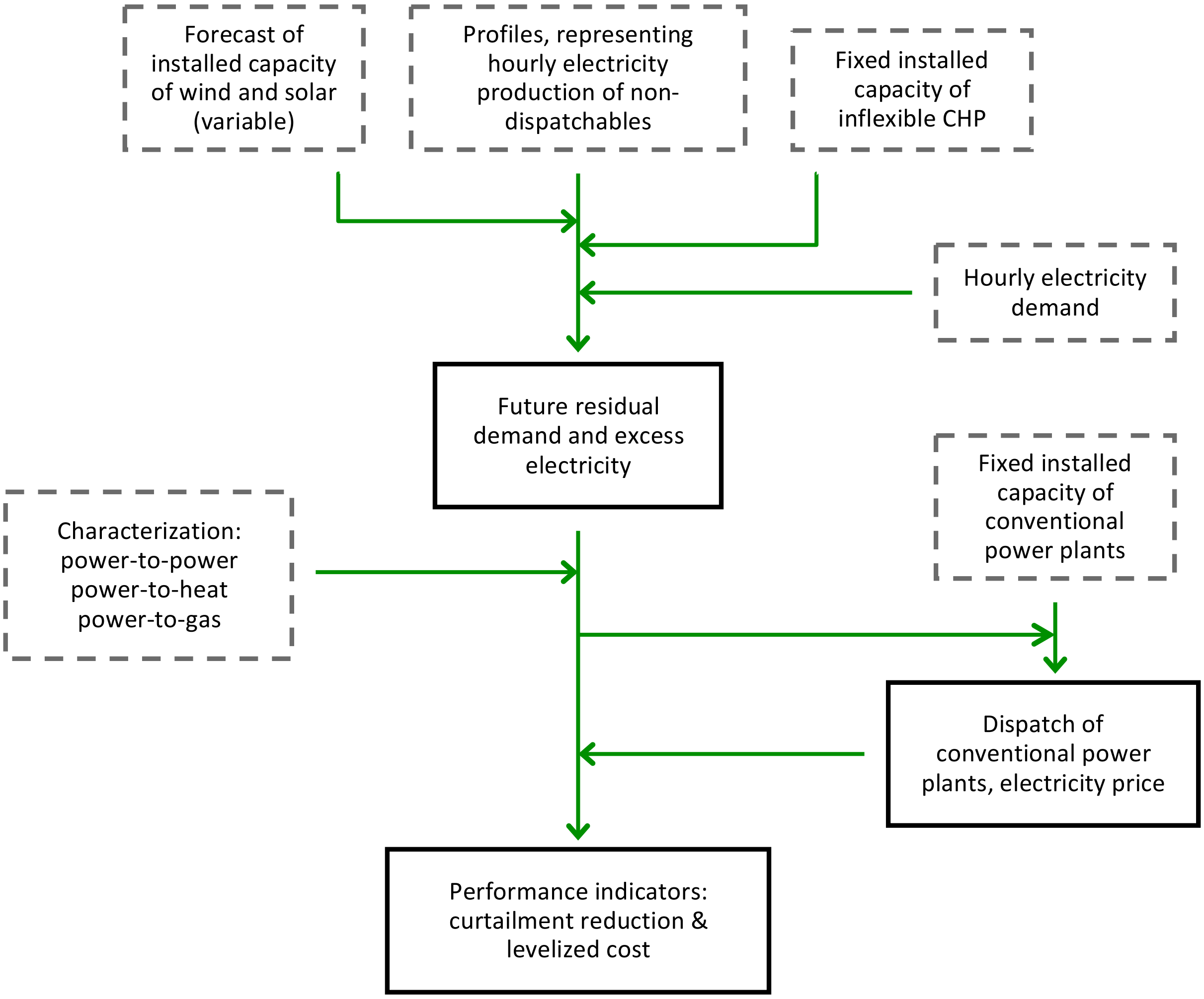

Figure 1: Methodology. Dashed lines represent inputs, regular lines represent results.
By changing the installed capacity of wind and solar, scenarios of varying renewability are created (2020 scenario by default). The conversion technologies are evaluated in these future scenarios (only one technology at a time). Adding a certain installed capacity of a conversion technology, e.g. power-to-gas, changes the shape of the residual demand curve, as power is 'consumed' during excess events. After applying the conversion technology to the residual load curve, the dispatchable power plants are assigned according to merit order, which is necessary to characterize the energy flow of power-to-power conversion that also needs to discharge to the grid.
Once the energy flows and economic characterization are known, the performance indicators can be derived.

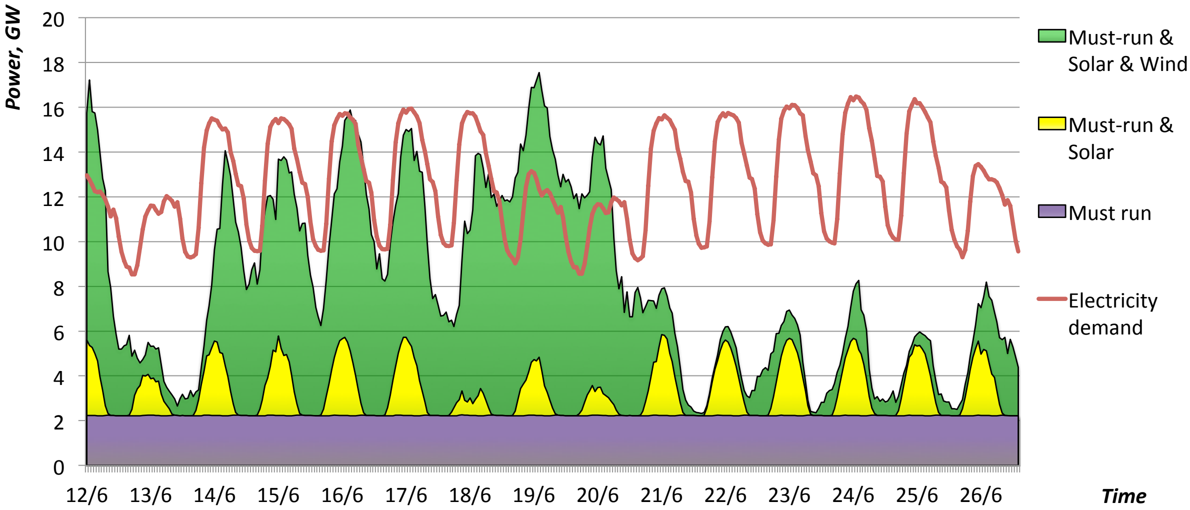

Figure 2: Simulation of excess electricity. The chart displays how the amount of excess electricity is forecasted by the simulation. The data shown here illustrates the situation in June 2020.

The simulation computes the electricity output of non-dispatchable producers (must-run CHPs, solar and wind) and compares it to the electricity demand. The generation from must-run CHPs, solar and wind is stacked on top of each other, i.e. the top of the green area represents the accumulated generation. Whenever this total non-dispatchable generation exceeds the demand for electricity, there is an oversupply.

3. Characterization of strategies for converting excess electricity

3.1. Power-to-heat conversion

3.1.1. Description and Layout

When converting power to heat, it is crucial that there is actually a demand for heat. Producing heat that does not serve a purpose is equivalent to wasting electricity. Therefore, the power-to-heat conversion route has to satisfy a demand for heat. One of the most reliable demands for large quantities of heat is the domestic hot water demand. In contrast to space heating, hot water is consumed at rather constant rates throughout the year [AEE, 2009]. Therefore, it is decided to simulate the conversion of excess electricity with the purpose of domestic hot water preparation in this study.

Most residential houses in the Netherlands satisfy their demand for hot water with gas heaters [Foekema et al., 2008]. These systems either already have a hot water storage tank or they can be equipped with a small preheating tank. Two possible systems setups are outlined; see Figure 3 and Figure 4. Conversion of excess electricity heats the water in the preheating or default storage tank.

Figure 3 represents households that satisfy their hot water and space heating demand with a combined boiler system (including a storage tank for hot water). 27% of all Dutch households are equipped with these heating systems [Foekema et al., 2008]. Electricity heating can easily be included in the heating system. Figure 4 displays a setup of a tankless heater. These systems can heat water at high capacity; therefore, they do not need a storage tank by default. 38% of all Dutch households are currently equipped with such a system. By adding a small preheating tank at the cold water inlet, these systems can be enabled to convert excess heat.

Taken together, these two systems present in 65% of Dutch households. In addition, about 20% of households have some form of electric boiler[13] that is used for hot water generation only. Potentially, these boilers can also be heated with excess electricity. In total, it is estimated that 75% of the 7.5 million Dutch households could be equipped with a power-to-heat converter. In the future, different heating systems may be built, for example biomass heaters, heat pumps or solar thermal heaters. Power-to-heat conversion can also be integrated with these new technologies.

[13] 'boiler' and 'miniboiler' in Foekema et al. [2008]

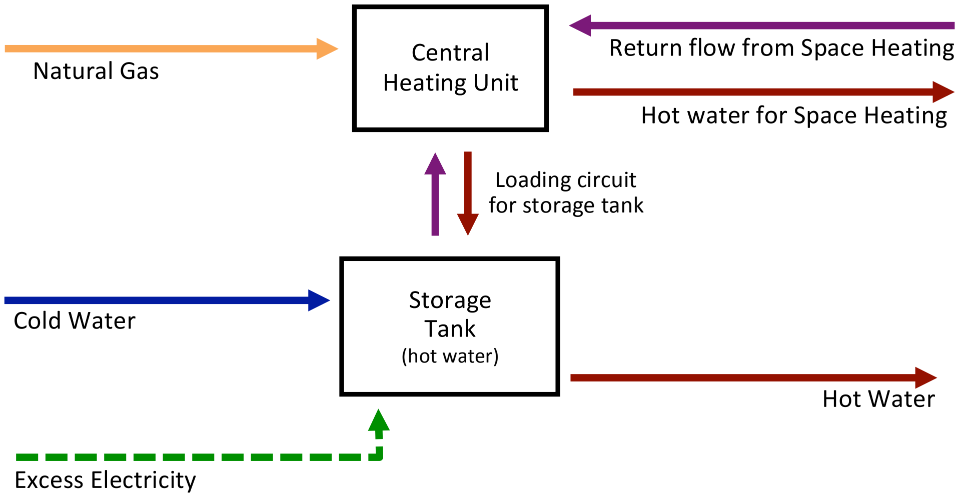

Figure 3: Power-to-heat layout in combined boiler system, schematic. This heating system satisfies the demand for space heating and hot water. Hot water is stored in a storage tank. It can be accessed on demand. Hot water is only taken from the storage tank, not directly from the heating unit. These systems already exist today, with the exception of the excess electricity input (dashed green). They can be retrofitted with an additional electric resistance heater at the bottom of the storage tank. If the storage tank itself cannot be retrofitted, an electric heating unit can be integrated into the circuit used for charging the tank with hot water. Electric heating is only useful if it results in a reduction of natural gas use, i.e. when the tank has cooled down or hot water is taken from the tank.

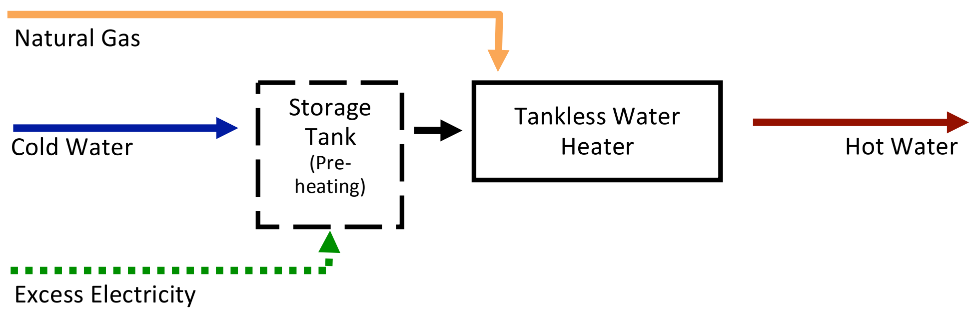

Figure 4: Power-to-heat layout in tankless water heaters, schematic. By default, hot water is prepared on demand; it is not stored in a tank. In order to integrate excess electricity conversion into the system, the installation of a preheating tank is required, where the incoming water is preheated electrically. Excess electricity only conserves energy if the preheating causes a decline in natural gas consumption.

Of course, the different heating systems and their power-to-heat converters do not function in the same way; in particular, they have different efficiencies and heat losses. Nonetheless, they are all treated in the same way in the simulation. This approach simplifies the model and ensures that the conversion is comprehensive and transparent.

Preheating tanks have a volume of 100 liter. The electric resistance heater is designed to have a maximum electric capacity of 500 W. This size ensures a reasonable heat input into the existing storage tank, while the electricity grid is not stressed excessively [Quintel

Intelligence, 2010; Hans Overdiep, 2013]. The water is assumed to enter the preheating tank 15 °C. The maximum temperature in the preheating tank is 60 °C. A higher temperature would increase heat losses and undermine the functionality of the gas heater. High inlet temperatures dramatically reduce the heat transfer and therefore lower the efficiency of the gas burner. Also, the gas burner might overheat as the cooling effect of the incoming water flow is reduced.

3.1.2. *Theoretically substitutable potential in hot water preparation*

In order to model the potential energy uptake of a power-to-heat conversion unit, the theoretically substitutable potential has to be known. Two approaches are undertaken:

It is reported that an average Dutch household consumes about 220 m^3 natural gas and 330 kWh electricity in order to satisfy the annual demand for hot water [Ybema et al., 2012]. With the figures in Table 1, these amounts of delivered energy can be converted into a final demand for hot water:

final demand for hot water =
annual gas consumption · heating value · conversion efficiency + annual electricity consumption

$$= 220\ \mathrm{m}^3 \cdot 35.17\ \frac{\mathrm{MJ}}{\mathrm{m}^3} \cdot 70\% + 300\ \mathrm{kWh} = 5416\ \mathrm{MJ} + 1080\ \mathrm{MJ} = 6496\ \mathrm{MJ}$$

This figure already provides an estimate of the theoretically substitutable potential in hot water preparation. A second calculation takes a different approach as it is based on the demand for hot water. On average, 132 l of water can be heated usefully by 45 °C per household and day (Table 1). This equates to 9065 MJ per year (only taking the specific heat capacity and temperature difference into account). The two results differ, but they are of similar magnitude. There is uncertainty in the allocation of natural gas use to space heating and hot water preparation in the first figure. The second figure is sensitive to the temperature increase in water heating and the required volume of hot water.

For this analysis, the higher value of 9065 MJ is used. The limit on the charging capacity is already quite strict (500 W) and an additional tight constraint on the daily heat production in the converter might handicap the technology. This theoretical potential in hot water preparation corresponds to 6.9 kWh per household and day, or an average rate of 287 W.

Table 1: Data used in dimensioning the power-to-heat conversion (domestic hot water).

Parameter		Unit	Source
Hot water demand			
Number of Households	7,513,000		[CBS, 2012a]
Number of persons/household	2.2		[CBS, 2012a]
Daily hot water consumption/person	62 *	Liter	[Foekema et al., 2008]
Estimated temperature increase in heating hot water	45 **	° C	[Blatter et al., 1993]
Natural gas consumption for hot water preparation per household and year	220	m^3	[Ybema et al., 2012]
Electricity consumption for hot water preparation per household and year	300	kWh	[Ybema et al., 2012]

Parameter		Unit	Source
Technical parameters			
Conversion efficiency gas-to-heat	70	%	[Milieu Centraal, 2013a]
Higher Heating Value of Groningen gas	35.17	MJ/m^3	[Rojey et al., 1997]
Emission factor natural gas	56	$kg\ CO_2/GJ_{LHV}$	[Blok, 2008]
Conversion efficiency electricity-to-heat	100	%	
Physical parameters			
heat capacity water	4181.3	J/(kg·K)	[Cengel & Boles, 2002]
Density of water	1	kg/l	[Cengel & Boles, 2002]

* Number derived from the fact that most people have a daily warm shower. This consumption already accounts for 50 l of hot water. The exact amount of additional demand is not known.

** Hot water is ususally prepared at 60 °C [Blatter et al., 1993]. The cold water has to be heated from a starting temperature of 15 °C (assumed average water temperature at entry of a household).

3.1.3. Modeling power-to-heat

At the beginning of an excess electricity event, all equipped households can start converting excess electricity. A constant heat input of 500 W into a 100 liter water tank implies a heating rate of 4.3 °C/h, which is rather low in comparison to the heating rates achieved by gas burners. Nonetheless, the potential for useful heat is only 6.9 kWh, which means that the excess electricity conversion has to be limited after this potential is reached (after 13.8 hours of charging at 500 W). Further charging at maximum capacity is no longer useful. The model uses the following mechanism:

1. As long as the theoretically substitutable potential is not exceeded within the last 24 hours, the households can convert excess electricity at the maximum installed capacity (500 W per household).
2. If more than the daily theoretically substitutable potential has been produced within the last 24 hours, conversion is limited by the actual consumption of how water (conversion becomes useful again after cold water entered the tanks). The maximum hourly conversion is given by a profile, see Figure 5.

During very long events of continuous excess, the potential for converting power to heat is assumed to follow the demand for hot water (or more precisely, the diurnal conversion of excess that satisfies the hot water demand over time).

Exact data on the diurnal consumption of gas for hot water preparation is not available (especially not for 500 W_{el} boilers). Clauss [2010] optimizes circulation pumps and provides a probability for hot water consumption. This data gives a good impression on how the hot water consumption may look like in a household (low demand during the night, high peaks in the morning and evening). Hot water use is mainly required for hot showers and at washbasins [Ybema et al., 2012]. Unfortunately, Clauss [2010] only describes the optimization of circulation pumps by investigating only one household. Therefore, his data cannot be used to represent average behavior. Valentin [2006] simulates the operation of solar thermal systems and provides a typical hot water consumption pattern for multi-family houses. He shows three peaks in hot water demand: in the morning (at 7-8 am, typical shower time), during lunchtime (1 pm) and a wider but lower peak in the evening (6-8 pm). Blatter et al. [1993] published an extensive study on hot water demand in Swiss households. They provide detailed graphs of diurnal hot water consumption on average weekdays, Saturdays and Sundays.

Based on the hot water demand profiles of Blatter et al. [1993] and Valentin [2006], profiles for the diurnal use of electricity in hot water consumption are created, see Figure 5. Since electricity is only converted into heat at 500 W, the profiles are less peaked and the profile is a bit flatter than the ones by Blatter et al. [1993] and Valentin [2006].

Figure 6 gives an impression of how the power-to-heat route converts excess electricity. It is displayed how the technology can convert with maximum capacity at the beginning of an excess event (when preheating tanks are 'cold') and how the capacity is limited to the actual demand for heat during times of continuous excess.

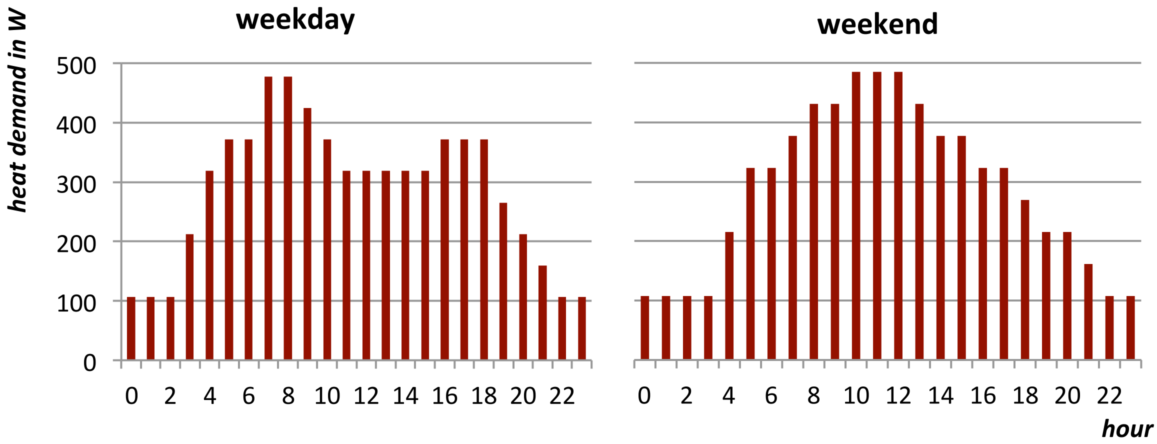

Figure 5: Diurnal energy use in domestic hot water preparation. These curves show the maximum amount of electricity that can be converted into useful heat in the event of long continuous electricity excess. The behavior differs slightly for weekdays and weekends. The integrated heat demand equals the total substitutable potential over 24 hours. Both profiles total in 6.9 kWh per day. The maximum power throughput is slightly below the installed capacity of 500 W/unit.
Based on Blatter et al. [1993] and Valentin [2006].

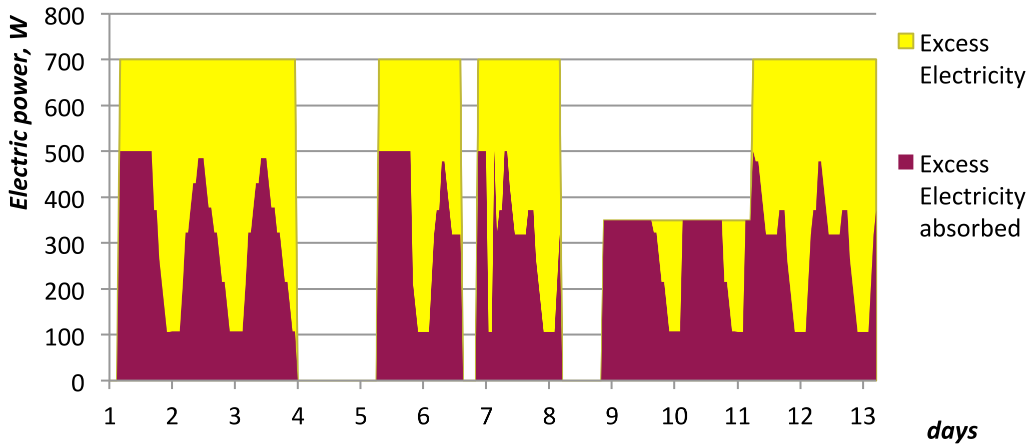

Figure 6: Example of power-to-heat availability. The excess electricity displayed here is fictitious and serves the purpose of showing how much power one representative power-to-heat unit can absorb according to the model used in this study. During the first three days of this profile, there is an excess or 700 W. For the first 13.8 hours, the heating unit can absorb excess at its maximum capacity of 500 W. Then, the daily demand for hot water is fulfilled and the unit can only convert further electricity according to the demand for hot water. This happens from day 2 to 4.
During the following absence of excess electricity, the pre-heating tanks are re-filled, so they can charge at full capacity again when excess electricity becomes available.
On the days 9 and 10, excess electricity is available at a rate that is below the heater's capacity. Therefore, it takes longer before the unit starts following hot water demand profile and limits the maximum charging capacity.

Since electric resistance heating and heating by natural gas serve the exact same purpose (heating a certain amount of water to a certain temperature), the use of electric heating decreases the demand for natural gas proportionally. As the electric heating is integrated with the regular heating system, it is assumed that the power-to-heat conversion pathway generates heat that is 'equally useful' as the heat generated by regular gas heaters.

The power-to-heat conversion has no additional constraints. The conversion can be turned on or off from one hour to the next.

3.1.4. Characterization of Costs and Benefits

Here, the costs and benefits are defined per installed unit of power-to-heat conversion. Based on the parameters defined here, an economic analysis will be carried out.

Lifetime and discount rate

The lifetime of the technology is set to 10 years. The discount rate for the initial investment is set to 4% [Quintel Intelligence, 2010]. Depending on whether the installation is perceived as an necessary or optional expenditure for households, the discount rate may vary between 4 and 10%, respectively.

Investments costs

Investment costs for retrofitting the power-to-heat route are 750 € per household. This figure is based on the following breakdown:

- 250 € for the new 100 l tank incl. electric heating unit (alternatively for equipping an existing tank with a new electric heater) [14]
- 30 € for piping and insulating material [15]
- 150 € for connecting to a "smart metering" system [16]
- 320 € labor cost (8 hours of work at 40 €/hour[17])

It is assumed in the model that installing a new preheating tank costs the same as retrofitting an existing tank with electric resistance heating. Therefore, costs for the implementation in tank and tankless systems are the same.

Since many heating systems are replaced and new ones are installed over the course of 10 years, the extra costs for making new heaters suitable for power-to-heat conversion are expected to be much lower. Additional costs of 300 € per household are estimated.[18]

For the evaluation in the future scenarios, investment costs are set to 750 € per unit. However, it may be possible that investment costs decrease to 300 € per unit over time.

Annual costs

Excess electricity for power-to-heat conversion is delivered to the households at zero cost (general assumption in this study). The electric resistance heater requires very little maintenance, which is allocated to the maintenance costs of the general heating system. The power-to-heat technology is assumed to have no annual costs.

Cost for hot water preparation and benefits of excess conversion

In this study, benefits of power-to-heat conversion are characterized by the displaced natural gas use in hot water preparation. The consumer's benefits are defined by the difference in the cost of producing heat via excess electricity conversion (levelized cost) and the price he would have to pay for producing heat from natural gas.

It is assumed that all heat from the electric heating unit is useful heat and that it directly lowers the demand for natural gas. Hot water is prepared with an efficiency of $70\%_{HHV}$ in gas boilers (Table 1). Therefore, converting 1 MWh_{el} will reduce the demand for natural gas by 1 $MWh_{el} / 0.7 = 1.43\ MWh_{gas} = 5.15\ GJ_{gas}$.

The Dutch consumer price for natural gas has increased from 30 €/MWh in 1997 to 66 €/MWh in 2007 (including taxes) [European Commission, 2007]. Until 2011, it rose to

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[14] It is found that small boilers that are usually installed in kitchens can be bought for about 200 €. This is based on the example "Daalderop elektrische boiler Close-in 15" with a 15 liter tank and 2200 W [Milieu Centraal, 2013b]. The boiler that is simulated in this study has a comparatively small capacity (500 W) and a larger tank volume. These two changes in the parameters are not expected to influence the price of the boiler much [Milieu Centraal, 2013b].

[15] Estimate taken from [Milieu Centraal, 2013b]. Compare prices for copper pipes and isolating materials.

[16] Estimate based on information technology cost. Compare for example with installing domestic Internet access.

[17] Based on the typical costs for contractors [Handwerkskammer Region Stuttgart, 2013].

[18] 150 € for including the electric heating unit into the new system and another 150 € for setting up the information technology.

74.1 €/MWh (48.6 €/MWh excluding taxes and levies) [Eurostat, 2013]. The future trend of the natural gas price (and taxation) is of course unknown. A severe shortage of natural gas is not expected in the next couple of decades, especially with the new resources that become available by the exploitation of shale gas [Helm, 2012]. A major contribution to the falling natural gas prices in the U.S. has been the introduction of significant volumes of shale gas [Bathe, 2011]. The production of shale gas may also affect the gas price in Europe. These developments give reason to believe that the price for natural gas will not increase dramatically in the coming years.

It is assumed that the consumer gas price will be 70 €/MWh in 2020 (including taxes). This equates to a monetary saving effect of 100 € per MWh of converted excess electricity.

CO_2 mitigation

After calculating the energy balance in the model, it is known how much electrical energy is converted into heat. As stated above, each MWh of converted excess electricity reduces the consumption of natural gas by 1.43 MWh.

Taking a CO_2 emission factor of 0.2016 kg $CO_2/kWh_{natural\ gas}$ into account[19], this yields avoided CO_2 emissions of 0.288 kg $CO_2/kWh_{excess\ electricity}$.

CO_2 taxation and trading of emission certificates is not taken into account in this study.

3.2. Power-to-power conversion

Central battery storage facilities are investigated as an example of the power-to-power conversion route. The modeling of distributed car batteries that are not constantly available and that also consume energy in driving is beyond the scope of this analysis.

Power-to-power conversion refers to storing electricity in a way that it can be returned to the grid with a time offset. The power-to-heat and gas conversion routes only add an extra useful demand to the grid at times of high supply, but they are not able to return electricity to the grid (in this study).

Unfortunately, the potential for new pumped hydro storage plants is very low in Western Europe and it is non-existent in the Netherlands. The only access to existing pumped hydro storage is via import/export with neighboring countries, e.g. Germany and Norway.

Future storage installations will likely use other concepts than mechanical storage, for example chemical storage in batteries. Several batteries seem suitable as electricity storage, i.e. lead acid, nickel cadmium, lithium ion batteries and flow-batteries [Oglesby et al., 2011].

In contrast to nickel and lead, the lithium chemistry has more attractive technical characteristics. Especially, lithium titanate batteries have very long cycle life (>5000) and high energy densities [Burke & Miller, 2009]. Lithium titanate batteries have proven to be reliable in many situations and the increasing use in electric vehicles might make them

[19] adapted from Blok's emission factor of 56 kg CO_2/GJ of natural gas [Blok, 2008].

abundant and relatively cheap in the near future[20]. This work investigates a lithium titanate battery that is a representative of an electric vehicle battery.

Table 2: Investment costs for different power-to-power storage options. A collection of investment cost for different electricity storing options. Note that the cost refer to the charging capacity instead of the storage capacity. Some costs appear to be very low, especially for batteries, which may apply to frequency regulation but not to load shifting applications.

Storage Type	Investment Costs	Description, place, source
	€ [21]/ kW	
Pumped Hydro Storage	1155 – 2080	For very large facilities (0.9 – 1.4 GW) [Wang et al., 2012]
	600	Goldisthal, built in Germany in 2005 [Klobasa, 2007]
	1750	Raneburg-Matrei, Austria [Klobasa, 2007]
	2750	Winkeltal, Austria [Klobasa, 2007]
Compressed Air Storage	400 – 800	[Klobasa, 2007]
	770	[Wang et al., 2012]
Lead acid battery	327 - 755	[Oglesby et al., 2011]
	300 – 450	[Klobasa, 2007]
Lithium ion	693 – 1460	[Oglesby et al., 2011]
	546 – 780	[Divya & Østergaard, 2009]
Lithium titanate	541	2008 cost by [Budischak et al., 2012]
	317	2030 cost by [Budischak et al., 2012]

3.2.1. Description and Layout

The setup of the energy balance and the specific costs is rather complex for many reasons. Batteries are characterized by a maximum storage capacity in MWh and a maximum charging capacity in MW. These two figures correspond to a minimum charging duration (if batteries are charged at a rate that is below the maximum charging rate, the charging duration increases). The cell voltage changes over time, which also influences the charging rate. Moreover, the temperature of a battery has to be controlled during charging and discharging.

Furthermore, the charging of large-scale batteries, for example in electric vehicles or central storage facilities, depends on the quality of the grid connection (outlet). The charging rate may be limited by two constraints: On the one hand, the quality of the grid connection defines how much power can be drawn from the grid. An outlet has a certain voltage, which, together with the maximum current, limits the power uptake. On the other hand, the charging rate also depends on the dimension of the inverter/converter unit and the properties of the battery itself. For electric vehicles, fast charging increases the wear of the battery and reduces their lifetime [Pillai, 2010].

[20] Lithium titanate batteries are starting to be used in electric vehicles, for example by Mitsubishi [Lucas, 2011].
[21] Throughout the report, a conversion rate of 1 USD = 0.76 € is used.

In general, batteries can be tuned for high charge/discharge rates (kW) or high storage capacities (kWh). Batteries in electric vehicles need to be optimized for both, as they need to charge within a reasonable time (charging capacity), generate strong discharge currents occasionally and they need to store large amounts of energy (storage capacity). As this study is concerned with the reduction of curtailment on a large scale, batteries are modeled to serve longer-term electricity storage (load-shifting) instead of short-term balancing services. Correspondingly, this study's battery characterization is based on costs that are expressed in €/kWh.

3.2.2. Modeling power-to-power

In order to ensure that the parameters charging capacity, storage capacity and charging duration are set to a reasonable ratio, the characterization of power-to-power storage is based on the characteristics of Tesla electric vehicles [Tesla Motors Ltd., 2013]. This approach is also taken by Pillai [2010]. One battery unit has a maximum charge of 85 kWh and can be charged at a rate of 10 kW [Tesla Motors Ltd., 2013]. This corresponds to a minimum charging duration of 8.5 hours.

Batteries are assumed to have a charging and discharging efficiency of 90% each [Budischak et al., 2012] (in order to be charged with 9 kWh, the battery consumes 10 kWh during the charging process, and it returns 7.2 kWh back to the grid during discharge). Divya & Østergaard [2009] report a self-discharge of only 1% per month for lithium ion batteries. A self-discharge is not considered and assumed to be included in the round-trip efficiency of $(90\%)^2 = 81\%$. This includes losses in AC/DC converters, as the batteries themselves have an efficiency of almost 100% [Divya & Østergaard, 2009].

The model operates the battery storage in the following way: If excess electricity is available, the batteries are charged in accordance with their charging capacity and storage capacity. When the residual demand is positive, batteries can discharge and electricity is sold back to the grid (losses being taken into account). However, there is a discharge threshold that ensures that discharge is only activated during periods of relatively high demand. In this study, power-to-power storage can only generate benefits by exploiting the fluctuations of the electricity price. It is found in the Energy Transition Model that gas fired power plants go online when the residual demand exceeds ~5 GW. Setting the discharge threshold for battery storage to 5 GW (residual demand) ensures that batteries do not discharge during off-peak times, which would undermine their potential business case.

The discharge threshold influences the performance of power-to-power conversion. To raise economic benefits, it is useful to discharge at high market prices and to increase electricity throughput. However, these are conflicting targets. The benefits per unit of electricity are higher during peaking demand. However, a high threshold will lower the ability to deal with excess, as the electricity throughput decreases due to a decreased availability (fully charged). The influence on of the discharge threshold on the economic performance is addressed below.

A typical charging and discharging pattern can be seen in Figure 7.

Power-to-power storage is modeled with the following assumptions: The conversion has the same flexibility as the rest of the model, i.e. it can change its operation mode (charging/discharging) from one hour to the next. It is not possible to charge and discharge simultaneously. The maximum charging and discharging rate is equal to the installed capacity. The charging and discharging efficiencies are independent of the charging rate. The round-trip efficiency, maintenance cost and technology lifetime are also not affected by the charging rate.

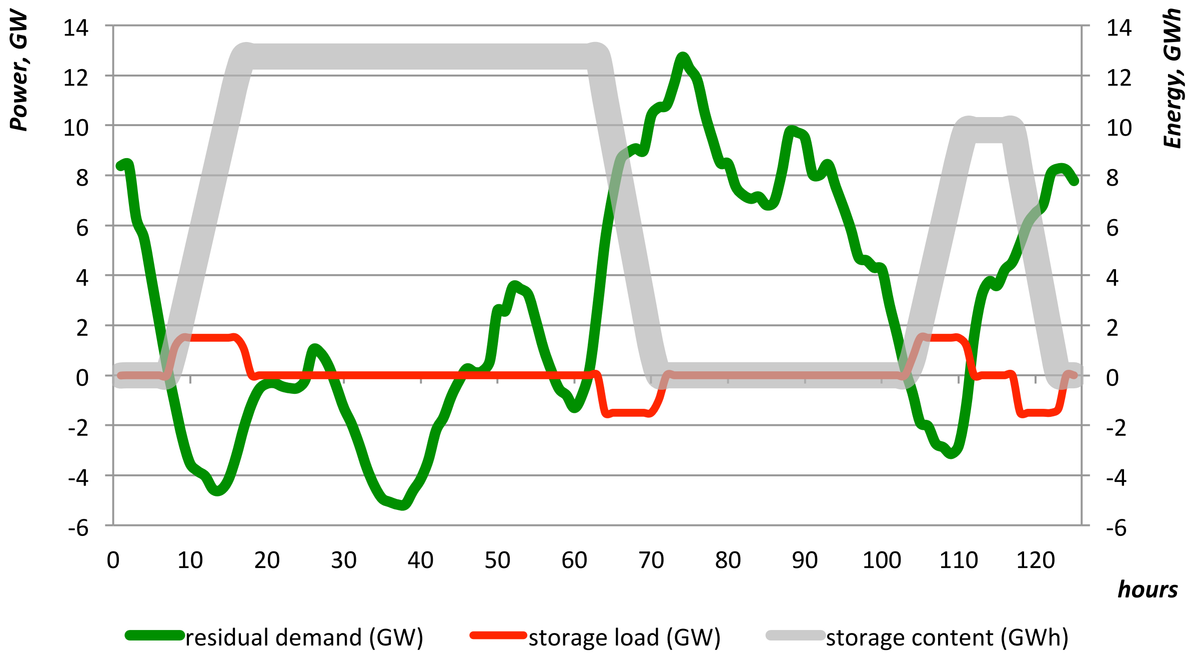

Figure 7: Modeling power-to-power, exemplary. The excess electricity can be stored in batteries only if storage is available, i.e. not already fully charged. From hour 6 onwards, excess electricity becomes available (negative residual demand). It can be fed into storage at a rate equivalent to the installed charging capacity (1.5 GW in this example). When the excess power exceeds 1.5 GW, storage can no longer fully cope with it, part of the excess cannot be stored. After ~8.5 hours of continuous charging, storage is fully charged and no longer available.
During the positive residual demand at hour 26 and around the hours 50 – 55, no electricity is discharged because the demand is not high enough (threshold of 5 GW). Only when the residual demand is large enough, discharge is possible (hour 62).
A considerable amount of excess cannot be absorbed because the batteries are fully charged and therefore not available. Furthermore, the discharge threshold decreases the availability, which again lowers the performance.
Note that the amount of electricity returned to the grid is slightly smaller than the absorbed amount. This is due to the round-trip efficiency of 81%.

3.2.3. Characterization of Costs and Benefits

Lifetime and discount rate

The number of charge/discharge cycles can be larger than 5000 for lithium titanate batteries [Burke & Miller, 2009]. As will be seen in the modeling of a highly renewable future scenario (60% from solar and wind), the batteries are only required to run about 100 full cycles per year. Therefore, it can safely be assumed that the power-to-power conversion technology has a lifetime of 15 years. This lifetime is also used by Budischak et al. [2012] in their analysis.

It is likely that central battery storage facilities will be built and owned by the electrical power industry. Power companies are reported to use a discount rate of 10% for large power plants [Roques et al., 2008; Quintel Intelligence, 2010].

Investment costs

It is not surprising that the battery characterizations found in the literature are not always consistent. This is due to the fact that batteries are designed with different specifications for various purposes. Some batteries are optimized for a high charging capacity, while others aim for a high storage capacity, which strongly influences the costs of the system. Other parameters also play a role, e.g. maintenance costs and lifetime. While many publications refer to battery costs per kWh (storage capacity), this study relies on costs per kW (charging capacity) (the performance of power-to-power conversion will be evaluated as a function of installed capacity).

Data from different sources cannot be compared easily. While two batteries may have identical specific costs per stored energy content (kWh), the batteries might be charged at very different rates (and for different durations). Therefore, the same cost per kilowatt-hour may translate into different cost per kilowatt.

This study takes the following approach: Since power-to-power conversion serves the purpose of longer-term storage (hours, days), the costs per storage capacity from Budischak et al. [2012] are used (instead of costs per charging capacity, which would refer to high-power applications). As Budischak et al. [2012] provide data for 2008 and 2030, the costs are interpolated to the year 2020. The investment costs for central batteries (lithium titanate) are 190 €/kWh[22]. This figure already considers future price reduction due to learning effects.

Unfortunately, Budischak et al. [2012] do not give a detailed description of the relation between charging and storage capacity of a unit. Nonetheless, the investment cost of 190 €/kWh need to be converted into '€/kW' because the model operates with capacity-based figures. Taking the specifications from above, a battery unit of 85 kWh storage capacity would cost 16,150 €. With the assumption that a battery unit can be charged with up to 10 kW, the capacity-specific investment costs equal 1,615 €/kW.

$$capacity\ specific\ cost\ =\ \frac{storage\ specific\ cost\ \cdot\ storage\ capacity}{charging\ capacity}$$

Similarly, a battery unit of only 45 kWh still cost 190 €/kWh, but only 855 €/kW (still with 10 kW charging capacity). This procedure ensures that the investment cost properly scale with the storage capacity of the battery while the model actually uses the charging capacity (installed capacity) as an input. The storage capacity of a battery dictates 'for how long the installed capacity is available'.

Unless otherwise specified, the results presented this study are based on the economic data stated for an 85 kWh battery unit.

[22] Throughout the report, a conversion rate of 1 USD = 0.76 € is used.

Annual costs

Budischak et al. [2012] report annual operation and maintenance cost of 9.39 €/kW for central lithium titanate batteries, which is used in this study. O&M cost are fixed, i.e. they do not depend on operation time.

The O&M cost have been compared to other literature, which suggests that a figure of 10 €/kW is reasonable [Poonpun & Jewell, 2008]. It is believed that the main contribution to O&M cost originates from the replacement of batteries.

Cost for electricity production and benefits of excess conversion

In this study, the income of a storage facility is only determined by selling electricity back to the grid. In reality, storage facilities can also generate income by offering different services (the ramping up and down of power supply, frequency control and provision of system reserves) [Poonpun & Jewell, 2008; Oglesby et al., 2011].

The costs for producing electricity via power-to-power conversion have to be compared with the generation cost of competing conventional power plants. The simulation sets a price for electricity based on the short term marginal operation cost of dispatchable power plants, see Appendix A.

It can be derived from the Energy Transition Model that a discharge threshold of 5 GW makes battery storage compete with combined-cycle gas plants [Quintel Intelligence, 2010]. These power plants have short-term marginal operation cost of about 47 €/MWh_{el} [Quintel Intelligence, 2010]. Therefore, it can be concluded that the price for electricity is higher than ~ 47 €/MWh_{el} during the discharge of battery storage. Depending on the discharge threshold, the benefits of power-to-power conversion are expected to be between 0 (no discharge threshold) and 83 €/kWh (marginal operation cost of most expensive participant). The marginal operation costs depend heavily on fuel prices and CO_2 emission cost. Both these influences are not considered in the simulation.

CO_2 mitigation

The reduction of CO_2 emissions is estimated in the following way: Taking the round-trip efficiency into account, the simulation calculates the amount of electricity that is discharged to the grid. It is not known exactly, which conventional power plants are replaced during the battery discharge. The combined cycle gas power plant that is typically replaced has a conversion efficiency of 60% [Quintel Intelligence, 2010]. Other gas power plants that might be replaced by storage discharge have higher marginal operation cost, lower conversion efficiency and therefore higher emissions.

Storage discharge therefore mitigates at least 0.336 t CO_2/$MWh_{\text{el. discharged}}$ (taking an emission factor of 0.2016 kg CO_2/kWh for natural gas into account [Blok, 2008]).

An upper limit for CO_2 emission reduction is the replacement of the least efficient coal plant. With an efficiency of 45.3% and an emission factor 0.342 kg CO_2/$kWh_{\text{primary energy}}$, an emission reduction 0.755 t CO_2/$MWh_{\text{el. discharged}}$ could be reached [Blok, 2008; Quintel Intelligence, 2010].

There may be a tradeoff between maximizing CO_2 mitigation and benefits, which is closely related to the issue of setting the discharge threshold. Displacing coal plants (at low residual demand) will generate fewer benefits, as the electricity price is low. Only a considerable increase in CO_2 emission cost would change this situation. CO_2 taxation and trading of emission certificates is not taken into account in this study.

Validation of cost specifications

In order to validate the figures that have been introduced above, they are compared with 'added cost to cost of electricity' that are induced by battery storage. This figure is also compiled by Poonpun & Jewell [2008].

Considering battery storage as a regular storage facility (not operating on excess exclusively), the following added cost are derived:

$$\text{added cost} = \frac{\text{alpha} \cdot \text{Initial Investment} + \text{annual O\&M}}{\text{annual discharged electricity}} = 0.1 \ {}^{€}/_{\text{kWh}}$$

with:
alpha (capital recovery factor) = 0.131
Initial investment = 1615 €/$kW_{el\ input}$
annual O&M = 9.39 €/$kW_{el\ input}$
annual discharged electricity = 250 [days] · 1 kW · 8.5 h = 2125 $kWh_{el\ output}$

It is assumed that the battery storage can generate electricity (discharge of full storage capacity) on 250 days per year. The resulting added cost of 0.1 €/kWh[23] are rather low in comparison to the figures of Poonpun & Jewell [2008], who provide a range of 15 – 40 €/kWh. This can be explained by the fact that this report uses reduced battery cost that are expected for the year 2020.

It is concluded, that the characterization of power-to-power conversion is rather optimistic and assumes a steep decline in battery cost (190 €/kWh investment cost).

3.3. Power-to-gas conversion

3.3.1. *Description and Layout*

Excess electricity can also be transformed into a useful energy carrier via power-to-gas conversion. Electricity is used to produce 'green' hydrogen. There are numerous pilot projects in Germany that all started recently, around the year 2012. Most of them are expected to start operation in 2013 or 2014 [Müller-Syring & Henel, 2012]. One example is the pilot plant by E.ON in Falkenhagen, Germany, that will convert excess electricity (and possibly also conventional electricity) into hydrogen [EON, 2012].

The production of methane or methanol is possible but will lower the efficiency of the process and raise the costs [Kersten, 2012]. Furthermore, the source and availability of CO_2 is uncertain and not part of this analysis. This study only considers the production of hydrogen, which is then blended in with the natural gas in the gas grid.

[23] A calculation based on the smaller battery with 45 kWh storage capacity leads to the same result.

The power-to-hydrogen conversion is made up of three units: an AC/DC converter, an electrolyzer and a compressor, see Figure 8. Large units have lower specific costs as the system dimension has a strong influence on the economics [Ivy, 2004]. This analysis is based on the largest units that are currently reported in the literature. Further up-scaling will likely be achieved by building several modules.

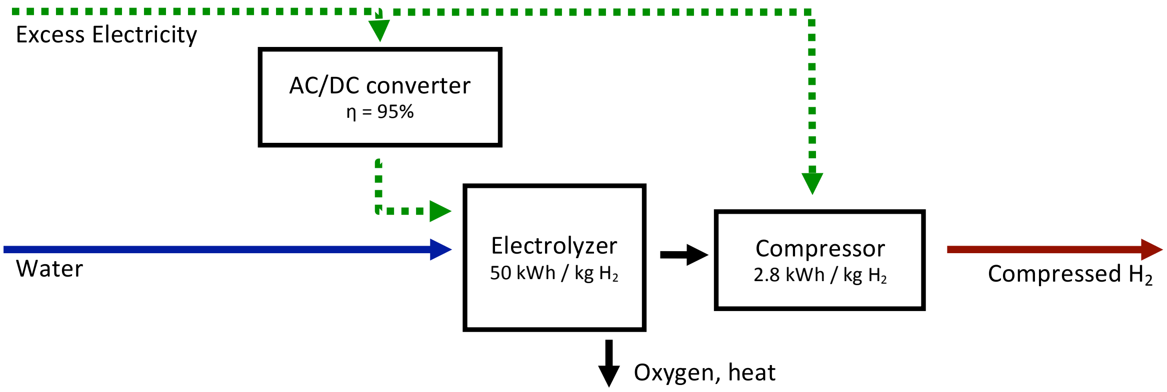

Figure 8: Power-to-Hydrogen process layout. The figure shows the energy balance for the power-to-hydrogen conversion. Electricity is required at 2.8 kWh + 50 kWh / 0.95 = 55.43 kWh to produce one kilogram of compressed hydrogen. In other words, 1 kWh of excess electricity is converted into 0.01804 kg H_2 and 0.1432 kg O_2 (0.201 Nm^3 H_2 and 0.100 Nm^3 O_2). This translates into an overall system efficiency of 60.1%$_{LHV}$.
Process description by Greiner et al. [2007].

The technology characterization is based on electrolyzer units of 2 $MW_{el\ input}$. For such a converter unit, a power converter of 2.2 $MW_{el\ input}$ and a compressor of 120 $kW_{el\ input}$ are required [Greiner et al., 2007]. According to nameplate capacity, such 40 kg H_2 can be produced per hour (445 Nm^3). This facility is slightly larger than the E.ON project in Falkenhagen, Germany, that produces up to 360 Nm^3/hour [EON, 2012].

Slightly different conversion efficiencies are found in the literature, that correspond to the size and type of the electrolyzer. In a publication for the German parliament, Kersten [2012] gives an upper limit for system efficiency: The entire process from electricity to hydrogen can have an efficiency of up to 64 – 77%, depending on the pressure of the produced hydrogen.

Williams [2011] provides a requirement of 53 $kWh_{el\ input}$ for producing 1 kg H_2 (total process, with a 75% efficient electrolyzer). Ivy [2004] characterizes several large-scale systems from American manufacturers. The best overall efficiency that is reached by a large system is 53.5 $kWh_{el\ input}/kg_{H2}$. This system has a total power requirement of 2330 $W_{el\ input}$, produces 43.6 kg H_2 per hour at 30 bar, with an overall efficiency of 62.3%$_{HHV}$ (electrolyzer model: Norsk Hydro: Atmospheric Type No.5040, 5150 Amp DC) [Ivy, 2004].

Greiner et al. [2007] provide a breakdown of the energy balance for their 2.2 $MW_{el\ input}$ system, which is used for the model implementation in this work, see Figure 8. They come to a very similar energy balance and system efficiency as Williams [2011] and Ivy [2004].

Hydrogen has an energy content of 120 MJ/kg (LHV) [Greiner et al., 2007]. Considering the energy balance displayed in Figure 8, the power-to-gas conversion has an efficiency of 120 MJ / 55.43 $kWh_{el\ input}$ = 60.1%.

Greiner et al. [2007] do not state explicitly to which pressure the hydrogen is compressed. Their energy requirement is slightly higher than the value reported by Ivy [2004], who explicitly states that the energy balance considers the compression to 30 bar. It is therefore assumed Greiner et al. [2007] base their characterization on a final pressure of ≥ 30 bar. It is further assumed that 30 bar are sufficient for pipeline feed-in.

3.3.2. Modeling power-to-gas

The conversion of electricity to hydrogen is assumed to be irreversible in this study, i.e. the hydrogen is not stored and then converted back into electricity. Converting hydrogen back into electricity would be a power-to-power conversion, which is already represented by battery storage. Alternatively, hydrogen can be sold to the industry that demands pure hydrogen, for example in metal treatment or oil refining.

Instead, this study assumes that hydrogen is blended in with natural gas in the gas grid. The 'green' hydrogen can be consumed in the same manner as natural gas, e.g. in space heating, industrial burners and gas power plants.

The modeling of power-to-gas conversion is straightforward. Excess electricity can be converted at the installed conversion capacity at any hour of the year. The total annual electricity consumption yields the annual electricity converted into hydrogen.
The characterization given in Figure 8 is used to describe any amount of installed capacity. There is no limit on storage capacity as the natural gas grid is large enough to deal with the injected hydrogen.

3.3.3. Characterization of Costs and Benefits

Lifetime and discount rate

The hydrogen-producing unit is made up of different components that may have different lifetimes [Greiner et al., 2007]. Since the electrolyzer is the main cost driver (90% of system costs), the system lifetime is set to the electrolyzer lifetime, which is 15 years [Greiner et al., 2007].

It is likely that power-to-gas conversion facilities will be built and owned by the electrical power industry. Power companies are reported to use a discount rate of 10% for large power plants [Roques et al., 2008; Quintel Intelligence, 2010].

Investment costs

An overview of how the costs for the power-to-gas route are made up is shown in Table 3. The specific costs per kW of installed capacity are: 1330 €/$kW_{el\ input}$ investment costs and 51 €/$kW_{el\ input}$ annual O&M costs.

Table 3: Power-to-gas cost breakdown. The installed capacities match Figure 8 and are based on a 2 MW electrolyzer. Costs are taken from Greiner et al. [2007].
The total system costs are calculated in the following way: A power converter of 2105 kW is required to satisfy a 2000 kW electrolyzer. Together with the compressor, the entire unit consumes 2105 kW + 120 kW = 2225 kW at rated capacity. Multiplying the installed capacity with the respective investment cost yields the specific costs for the entire unit. The investment cost are divided by the capacity, which results in specific investment cost of 2,957,684 € / 2225 $kW_{el\ input}$ = 1329 €/$kW_{el\ input}$. O&M cost are calculated in the same way.
The system lifetime is set to the lifetime of its most costly component.

Component	Installed capacity per conversion unit (Figure 8)	Investment cost	Annual O&M cost	Lifetime
	kW	€/kW	% of investment cost	Years
Alkaline electrolyzer	2000	1300	4	15
Compressor	120	700	4	10
Power converter (AC/DC)	2105	130	2	10
Total system		1329 €/kW	50.7 €/kW	~15

Saur [2008] also published investment costs for the power-to-hydrogen route. He claims that the electrolyzer contributes 57% to the overall system costs. In the cost breakdown by Greiner et al. [2007], the electrolyzer is responsible for 88% of the total cost. This indicates that there is quite some uncertainty in the costs, although many reports agree on a similar range. In the future, the cost for the power-to-gas conversion route might decrease significantly. Saur [2008] identified a potential for a 40% decrease in electrolyzer cost.

Annual costs

Excess electricity is available at zero costs. Operation and maintenance costs of the technology have been determined above: 50.7 €/$kW_{el\ input\ capacity}$.

Regular cost for power-to-gas conversion and benefits

Power-to-gas conversion produces hydrogen and oxygen at a certain cost. Benefits can be achieved by selling these products. Hydrogen can only be sold at the same price as natural gas (based on its energy content) as it is blended in with natural gas. The future gas price for natural gas is of course unknown; the model assumes a current wholesale price of 28.9 €/MWh_{gas} (without taxes and levies) [Eurostat, 2013]. Based on its energy content, hydrogen can be sold to the grid at 0.9633 €/kg hydrogen.

Further benefits might be generated from selling oxygen. Oxygen can be used in blast furnaces or electric arc furnaces of the metal industry. It may also be used in glass melting. A large future potential may be the use in electric power plants (pure or enriched oxygen combustion) [Kato et al., 2005]. The price for oxygen in these industrial contexts is not known.

For the purpose of this work, the costs for producing oxygen are estimated in the following way: The electricity consumption of the most efficient oxygen generation technology (cryogenic air separation) is 0.5 kWh/Nm^3 [Kato et al., 2005]. Assuming electricity to cost 0.0829 €/kWh (industrial electricity price, excluding taxes [Eurostat, 2013]), the marginal cost for producing oxygen are 0.0415 €/Nm^3 (0.029 €/kg).

In order to sell 1 MWh of hydrogen to the gas grid, 1.64 MWh of excess electricity are required. In the conversion process, 29.6 kg hydrogen and 235 kg oxygen are produced.

Concluding, hydrogen can be sold to the grid at the price for natural gas: ~ 30 €/MWh. Oxygen may yield additional benefits of ~ 7 €/MWh. These benefits refer to the produced amounts of hydrogen in MWh, which enables an easy comparison to the levelized cost of the power-to-gas conversion.

In practice, selling oxygen might yield much higher prices[24], but this estimate gives a lower limit of what the benefits if oxygen is sold. At the same time, the benefits from oxygen are so low that they will hardly influence the economic evaluation at all. After all, the business case of power-to-gas conversion lies in the production of hydrogen.

It is not known who the main customer for the oxygen might be. It is uncertain whether selling oxygen will be profitable for power-to-gas plants in the future. Oxygen would have to be captured, purified and compressed. The transport would have to be carried out by trucks due to the lack of alternative infrastructure. All of these steps cost money and will reduce potential benefits. For these reasons, this study uses the marginal cost for producing oxygen. This is a rather safe assumption. Should oxygen be sold, the price will be higher than these marginal production costs.

CO_2 mitigation

It is assumed that power-to-hydrogen does not cause any CO_2 emissions during operation. Mixing green hydrogen with natural gas in the gas grid reduces CO_2 emissions. Every kWh of hydrogen directly reduces the consumption of one kWh of natural gas. Under the assumption that natural gas has an emission factor of 0.202 kg $CO_2/kWh_{\text{primary energy}}$ (same as above), the CO_2 mitigation effect is 0.202 kg CO_2 per kWh_{hydrogen}. Since power-to-gas conversion has an efficiency of 60%, this effect translates to only 0.121 kg $CO_2/kWh_{\text{excess converted}}$.

[24] Oxygen can yield much higher prices on the market. Compare for example with the price for medical oxygen that has been investigated in Japan: Kato et al. [2005] report that hospitals pay a price ranging from 60 and 10,000 yen/Nm^3 (0.46 – 77 €/Nm^3; with 1 yen = 0.7692 eurocents).

Validation of cost specifications

In order to validate the figures that have been introduced above, they are compared with the 'cost for producing hydrogen', which are also reported in the literature. Considering a power-to-gas conversion unit of 2 $MW_{el\ input}$ that operates for 8000 full load hours, hydrogen would be produced at the following cost: [25]

$$\text{cost of hydrogen}=\frac{\text{alpha}\cdot\text{initial investment}+\text{annual O\&M}+\text{annual fuel cost}}{\text{annual hydrogen production}}=1.56\ {}^{€}\!/_{\text{kg}}$$

with:
alpha (capital recovery factor) = 0.131
Initial investment = 1329 €/kWel input
annual O&M = 50.71 €/kWel input
annual fuel cost = 0
annual hydrogen production = $8000\ h \cdot 0.01804\ kg_{H2}/kWh_{el\ input} = 144.3\ kg_{H2}/kW_{el\ input}$

The production cost of 1.56 €/kg hydrogen compares well with the costs provided by Levene et al. [2007]. If electricity was provided for free, they deduce hydrogen costs slightly below 2 $/kg (~1.5 €/kg) for a comparable electrolyzer.

3.4. Overview of technologies

Table 4: Summary of technology characterization. The investment cost, annual O&M cost and the CO_2 mitigation effect refer to the amount of excess electricity that is absorbed by a technology. The potential benefit represents an average income that might be generated by selling the energy carrier produced by the conversion.

Technology	Investment cost	Annual O&M cost	Potential benefit	CO_2 mitigation	Prominent limitations
	$€/kW_{el\ input}$	$€/kW_{el\ input}$	$€/MWh_{output}$	$t\ CO_2/MWh_{el\ input}$	
Power-to-heat	1500	0	100	0.288	Limited conversion capacity in continuous excess events (> 14 h).
Power-to-power, 85 kWh	1615	9.39	20 - 80	0.35 - 0.7	Limited storage capacity stops conversion when storage fully charged.
Power-to-power, 45 kWh	855	9.39	20 - 80	0.35 - 0.7	Has to discharge during positive residual demand before operation can continue.
Power-to-gas	1329	50.7	30 - 40	0.121	-

[25] Formula adapted from cost-of-electricity calculation, see Blok [2008], equation [11.3], page 196.

4. Development of 2020 scenario

In order to evaluate strategies for avoiding curtailment of excess renewable energy, two future scenarios are created. The first scenario is a Dutch 2020 scenario, which is then modified into a more renewable scenario that comprises 60% of integrated volatile electricity.

The European Union has set the target that 20% of EU final energy consumption has to be provided by renewable resources [EREC, 2011; Daniëls et al., 2012]. In order to reach this goal, all countries had to agree to a national action plan that describes how this goal can be reached. The Netherlands has a binding national target of 14% final renewable energy by 2020 [Rosende et al., 2010]. In order to accomplish this, all sectors have to improve. Since, the potential in transport energy and heating energy is limited or the improvement would be very costly, a large increase in renewability has to be accomplished by the electricity sector. In many future scenarios, the request for 20% final renewable energy consumption translates into a need for 40% renewable electricity [EREC, 2011].

Most scenarios realize a share of 40% renewable electricity by adding a lot of wind power to the system. Solar photovoltaic energy plays a role, but is a less significant contributor. Biomass is of low priority, as the extensive use of biomass in power plants would call for enormous imports and land use.

4.1. Installed capacities in 2020 scenario

The following paragraphs explain, how the 2020 scenario is created. For every participant, the situation of today (2010 – 2012) is reported and the forecasted until 2020 is described.

The reports that are used for identifying the future installed capacity are either aiming at reaching the 40% target at minimum cost, or they identify which target could be reached with proactive support and a beneficial engagement by the industry. In consequence, the forecasts in the literature may differ from each other. In these cases, a value from the medium range is used for this study.

4.1.1. Wind energy

4.1.1.1. Onshore

2,088 MW of installed capacity were built on land at the end of 2011 [CBS, 2012b]. For this research, it is assumed that 50% of the wind mills operate according to a inland wind profile and 50% according to a coastal wind profile [CBS & w-i-n-d.nl, 2012].

After evaluating the 2020 targets for renewable electricity and consulting several reports that forecast installed capacity, see Table 5, it is concluded that the installed capacity will range between 4,000 and 6,000 MW. For the 2020 scenario, a default value of 5,495 MW is set, which is an optimistic but achievable figure. In order to reach this capacity by 2020, an annual growth by 11% is required.

Inland turbines are assumed to have 2500 full load hours, while turbines in coastal areas have 3000 full load hours [Quintel Intelligence, 2010; Fraunhofer Institute, 2012].

4.1.1.2. Offshore

At the end of 2011, only 288 MW of wind capacity were installed offshore. However, the growth rate is much higher in comparison to onshore development. The expected installed capacity for 2020 is 7,438 MW (a range between 5,178 and 7,947 MW is found in literature), see Table 5. This corresponds to an annual growth rate of 43%.

Offshore turbines are assumed to have 4000 full load hours [Fraunhofer Institute, 2012].

4.1.2. Solar Energy

The forecast for installed solar PV capacity is highly uncertain. At the end of 2011, 130 MW were installed in the Netherlands. The growth rate of this technology heavily depends on the price development of PV modules and the incentives created by policies. A huge spread is observed in the literature. Very optimistic forecasts imply an annual doubling of installed capacity. Since the current installed capacity is relatively low (e.g. in comparison to Germany), a rapid increase is possible. For this research, a figure of 4,146 MW is assumed for a 2020 scenario. This figure is extremely optimistic; however, it turns out that solar energy operates at such a low load factor in the Netherlands that the impact on the electricity mix is very low.

Solar PV modules are assumed to have 1050 full load hours [Quintel Intelligence, 2010].

Table 5: Forecasted volatile installed capacity in 2020: Different reports are found that forecast the installed capacity of wind and solar energy. Based on these numbers, the 2020 scenario is created.

Comment and source	Wind Onshore	Wind Offshore	Solar PV
	MW	MW	MW
National Renewable Action Plan of the Netherlands. This scenario fulfills the minimum requirement for 14% renewable energy supply (final) in 2020. It has only very little PV. These figure are found in both [Beurskens et al., 2011] and [EREC, 2011].	6000	5178	722
This publication foresees a different scenario in order to fulfill a slightly elevated target of 20% renewable energy supply (primary) by 2020 [Rosende et al., 2010].	5380	7438	4146
There are more optimistic scenarios reported that assume a more rapid expansion of offshore wind and solar energy. These are based on industry roadmaps or ‘realizable deployment under proactive support’. These figures are found in [Rosende et al., 2010] and [EREC, 2011].	5495	7947	7103
Target by Daniëls et al. [2012].	4000	6000	-

4.1.3. Must-run CHPs

Another important input parameter for the 2020 scenario is the inflexible electricity generation capacity. Since events of excess electricity supply are investigated, it is important to know which plants cannot switch off during an excess event and thereby increase the excess. Some large-scale thermal power plants plants (with the exception of gas plants) may have difficulties with frequent start-ups and shut-downs and their electricity production cannot be ramped up or down quickly. This may lead to a certain minimum electricity generation that is 'must-run' and that does not adapt to the residual load. It is very difficult to predict this amount of must-run capacity from conventional power plants. A forecast of hourly power generation that will be produced regardless of the actual demand for electricity could neither be found in the literature nor created for this study. It is assumed that dispatchable power plants can switch off entirely during an excess event.

However, there is another inflexible participant that may generate electricity during excess electricity events: Some combined heat and power plants follow a heat demand, which might turn them into 'must-run' electricity producers during an excess event. About 7,000 MW_{el} of decentralized CHP capacity was installed in 2008 [Daniëls et al., 2012]. Under fixed policy, this capacity is going to grow to 8,400 MW_{el} by 2020 [Daniëls et al., 2012].

It can only be estimated which CHP capacity is 'must-run' and which is flexible. CHPs are usually installed to satisfy a heat demand, i.e. in buildings (district heating), greenhouse horticulture and industry. However, these three applications have very different specifications. If the heat demand can be satisfied by alternative means (thermal storage, backup heating system), a CHP can be turned off when its electricity output is not required. Some CHPs (especially in the agricultural sector) have a gas-fired burner as backup, which makes the CHP redundant and therefore flexible. Agricultural CHPs are typically flexible in The Netherlands. In contrast, industrial CHPs are perceived to be inflexible, because they are used to cool away high temperature heat (if they are turned off, energy is wasted).

According to Daniëls et al. [2012], the must-run capacity for 2020 is 3,700 MW_{el}. These CHPs are found mostly in district heating installations, co-digestion installations and in industry.

Seebregts et al. [2009] also provide a prognosis for must-run CHP in 2020. They claim that the total CHP capacity will be roughly 13 MW. Their category 'joint venture/industry/refinery' CHPs has a capacity of 4 MW, which is interpreted as must-run capacity.

Converting a forecasted installed CHP capacity into a viable input parameter for the simulation is not straightforward. The Energy Transition Model calculates with standardized participants that represent certain classes of power plants. Since the simulation of this study is based on the Energy Transition Model, a set of predefined participants is inherited along with the shortcomings of the participant characterization.

The Energy Transition Model defines number of units and full load hours for each standardized participant, so that the resulting energy balance represents CBS statistics. Therefore, a megawatt of installed capacity in the Energy Transition Model may translate into a different amount of annual energy production than envisioned by Daniëls et al. [2012] or Seebregts et al. [2009].

Furthermore, the Energy Transition Model is not perfect in all aspects. For example, when the data for this study was gathered, the Energy Transition Model still contained an industry CHP, which was driven by wood pellets. After a revision, it was decided to remove this particular participant from the Energy Transition Model because it does not mirror reality. For the purpose of this analysis, the wood pellet CHP is eliminated and its energy output is allocated to the natural gas driven CHP in industry. This shows that the simulation of inflexible CHPs is not very exact.

After evaluating the above, it is decided to install the following capacities as inflexible must-run CHPs. The installed capacity of central space heating CHPs is assumed to remain constant at today's level (Energy Transition Model: 406 MW_{el}). Waste incineration is set to 650 MW_{el}, and industrial CHPs (natural gas) are modeled with 2880 MW_{el}. These numbers sum to about 3.9 GW_{el} of installed must-run capacity in 2020.

Note that the actual power generation follows a profile and is determined by the amount full load hours. Central space heating CHPs and waste incineration operate far below their rated capacity most of the time.

The cumulative output of all inflexible participants is always between 2.2 – 2.6 MW_{el} throughout the year.

4.1.4. Electricity demand

The Energy Transition Model calculates with an annual demand for electricity of 417.95 PJ (=116.1 TWh, based on the year 2010).

There is a target of 20% reduction in energy consumption by 2020 [Government of the Netherlands, 2013]. From the historic trend it can be seen that an increasing number of appliances lead to an increased final demand for electricity [Daniëls et al., 2012; ECN, 2012], even though the efficiency of many appliances could be improved over time. The demand for electricity is not expected to change within the coming years, the demand in 2020 is set to 116.1 TWh.

4.1.5. Conventional dispatchable plants

It is expected that the conventional electricity generation park will shift towards more efficient power plants. Old gas and coal plants are less efficient and therefore have higher operating costs. In total, it is expected that least 10 GW of new gas and coal plant capacity will go online in the coming years [Daniëls et al., 2012].

The marginal operation costs determine the price for electricity, which in turn has an effect on the benefits that power-to-power facilities can generate. These marginal costs may change in the future, as they are a function of power plant type, fuel price and CO_2 emission taxation. Seebregts et al. [2009] give a forecast of marginal operation costs in 2020; they foresee an increase in costs for coal plants, while the costs for gas plants stay constant.

Another shortcoming is that the simulation does not include flexible CHPs in the merit order mechanism. The simulation only considers conventional power plants when the electricity price is calculated.

In spite of that, the specification of future conventional power plants only marginally affects this study as this report exclusively focuses on events of excess electricity. It is unclear how increasing fuel and CO_2 prices and increased conversion efficiencies will affect the electricity market price. Therefore, the installed capacities of conventional dispatchable power plants remain constant and are based on the 2010 figures from the Energy Transition Model.

4.2. Installed capacities in 60% scenario

In order to see how the electricity conversion technologies behave in a more renewable scenario (with more excess electricity), a 60% scenario is created. This is accomplished by doubling the installed capacities of wind turbines and solar PV of the 2020 scenario, see Appendix A. All other parameters stay constant. The resulting scenario satisfies 60% of the demand with wind and solar energy.

4.3. Installed capacities, summary

The following chart gives an overview of the installed capacities that are modeled in this study:

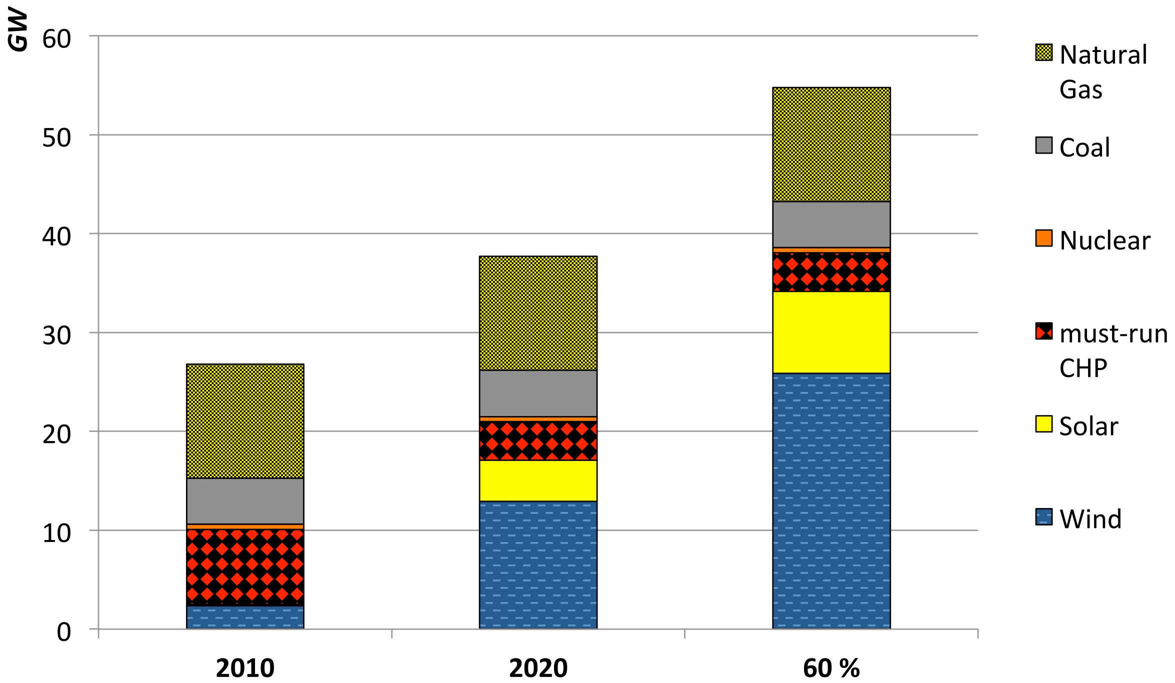

Figure 9: Installed capacities in 2020. Excess electricity is simulated based on these installed capacities and the profiles that describe electricity production over time. Exact figures can be seen in Appendix A.

5. Results

Based on the model that has been described above, the following results are obtained. Firstly, the forecasted excess electricity is portrayed. The frequency and duration of excess events is analyzed for the 2020 scenario. Furthermore, it is shown how the amount of excess will increase with growing shares of volatile electricity production.

Second, the performance of the three conversion technologies is investigated with regard to the performance indicators curtailment reduction and levelized cost.

5.1. Future excess events

The first result of the simulation is the forecast of the residual demand for the year 2020. Figure 10 gives an impression of how volatile the residual demand is over the entire year.

The residual demand curve is affected in many ways: While wind power generation fluctuates without a strong seasonal pattern, solar generation drops almost to zero in winter. The must-run power production is rather constant throughout the year. Industrial CHPs and waste incineration is modeled with a constant output; only the generation from 400 MW_{el} of district heating CHPs varies with outside temperatures (~10% of total must-run capacity). As the electricity demand is generally lower during the summer months, the positive peaks in the residual demand curve are more prominent in winter than in summer.

All these effects influence the residual demand curve, but the combined effects do not lead to an apparent pattern in excess electricity curve. Only during the time around June and July, excess events are less frequent. An analysis of this phenomenon revealed that the offshore wind profile has a dip during these two months (the model uses a wind profile that is based on 2010 wind speed measurements). This dip in the summer months is not typical; it is not observed in the years 2011 and 2012.

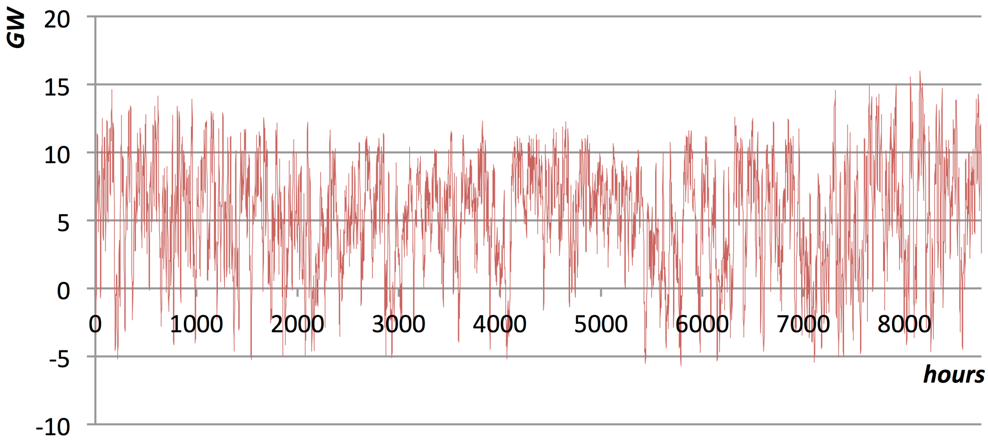

Figure 10: Residual load curve in 2020 scenario. The residual demand equals the electricity demand reduced by the production from all intermittent sources (must-run CHP, solar and wind). Excess electricity occurs when the residual demand becomes negative.

5.1.1. Magnitude of excess electricity

Accumulating all excess events that are observed in Figure 10, yields the total amount of excess for 2020, see Table 6. An important result is that excess electricity indeed occurs in the 2020 scenario. In total, 2 TWh of oversupply are observed. This excess electricity occurs for 960 hours, at strongly varying capacity.

The data shown in Table 6 confirms that the two future scenarios match the targeted shares of integrated volatile electricity and that their naming is justified. 49 TWh of wind and solar electricity can be produced. 2 TWh of production are in excess. The resulting 47 TWh of integrated electricity represent 40% of the total demand (116 TWh).

This compares well to the forecasts in the literature. For example, Daniëls et al. [2012] identify a requirement of 55 TWh from renewable sources in order to reach the targets for 2020.

The installed capacity of inflexible CHPs is so low that the CHPs on their own never cause any excess events. As inflexible participants cannot switch off by definition, therefore their electricity output cannot be curtailed. All excess electricity and possible curtailment is allocated to wind and solar production.

Table 6: Excess electricity in 2020 and 60% scenarios. The 60% scenario has twice the installed capacity of wind and solar than the 2020 scenario. Also see Appendix A.
* total volatile production: wind and solar power that could be produced theoretically (without taking curtailment into account)
** integrated volatile energy: wind and solar power that is actually integrated into the grid (with partial curtailment)

	2020 scenario	60% scenario	Unit
Total excess duration	984	3950	hours
Average excess capacity	2060	7130	MW
Maximum excess capacity	5700	20500	MW
Average residual demand	5300	- 310	MW
Maximum residual demand	16000	15700	MW
Volatile production from wind and solar*	49	98.0	TWh
Excess electricity	2.0	27.6	TWh
Integrated electricity from wind and solar	47	70.4	TWh
Total demand for electricity	116	116	TWh
Integrated electricity from wind and solar	40	61	%
Curtailed volatile energy / total volatile production*	4	29	%
Curtailed volatile energy / integrated volatile energy**	4	40	%

Future excess electricity is also analyzed for varying installed capacities of wind and solar. If the installed volatile capacity is increased further, the excess electricity will rise over-proportionally, see description of Figure 11.

It is found that ratio of curtailed volatile electricity and integrated volatile electricity is only 0.04 in 2020. It seems that excess electricity and curtailment do not play a major role in

2020. The total excess of 2 TWh is observed at various capacities throughout the year, its distribution over time is analyzed below.

However, the amount of excess increases dramatically when the 60% scenario is approached. The residual demand is negative on average in the 60% scenario, which leads to an enormous amount of excess electricity (27.6 TWh). The ratio of curtailed volatile electricity and integrated volatile electricity has increased to 0.4.

The chart also shows that excess electricity only occurs when the integrated volatile electricity is larger than 20% (9.6 GW of wind and solar, 2.2 GW of must-run CHPs). Technically, the first excess electricity could be observed as soon as the installed non-dispatchable capacity exceeds the minimum electricity demand (8.5 GW), but the profiles used in the simulation only allow for excess at higher installed capacities.

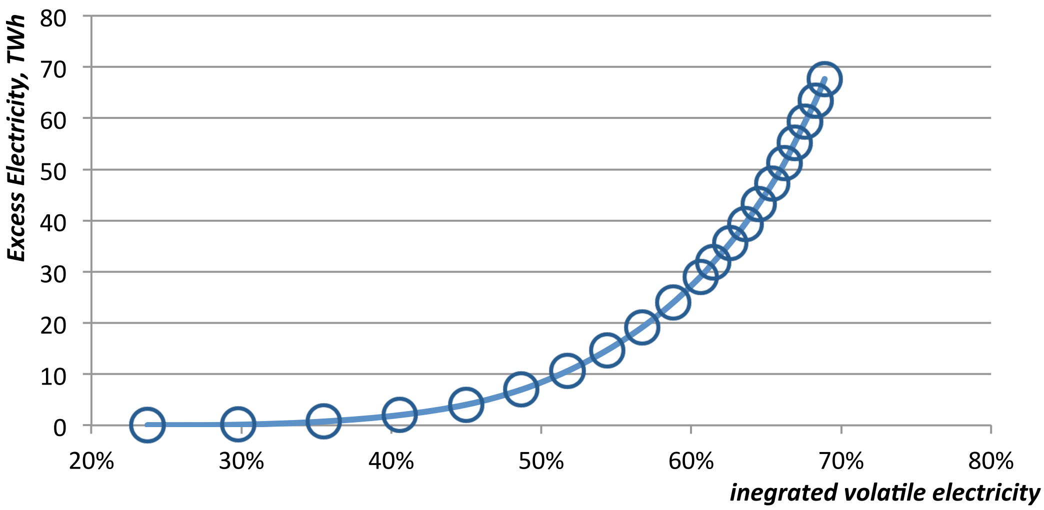

Figure 11: Excess electricity as a function of the share of integrated volatile electricity. The installed capacities that are projected for the year 2020 yield a scenario in which 40% of the energy production originates from wind and solar. By scaling the installed capacity for solar and wind up proportionally, scenarios of varying renewability are created. The ratio of installed capacity of wind and solar is fixed at 3.1 and taken from 2020 scenario (~13 GW wind and ~4 GW solar).
The term 'volatile electricity' refers to the share of the total demand for electricity that is met by wind and solar generation. The chart only refers to integrated volatile electricity, as opposed to volatile generation potential.
The curve roughly follows a parabolic function. Excess increases dramatically above 40%.

5.1.2. Distribution of excess electricity throughout year

In order to provide a more detailed view on the characteristics of excess electricity in 2020, Figure 12 and Figure 13 are presented. Figure 12 shows the distribution of the excess capacity in 2020. It could be referred to as an 'excess duration curve'. Two thirds of the 2 TWh of excess occur at capacities below 2.5 GW.

A similar outcome is found for the 60% scenario (not shown here). The shape of the excess duration curve looks very similar. Two thirds of the 27 TWh of excess occur at capacities below 9.5 GW.

Figure 13 provides information about the continuity of excess events, which cannot be judged upon from the information contained in Figure 12. Continuous events of excess are filtered out in a post-processing step of the 2020 simulation. Excess electricity may be available continuously from 1 up to 43 hours. The majority of continuous excess events (75%) last for less than 10 hours. This means that the technologies that are supposed to reduce curtailment would have to start up for only very short amounts of time. Excess electricity cannot be converted in a continuous manner. Conversion technology that cannot be operated very flexibly has a disadvantage in dealing with short excess events.

The fluctuations in electricity demand, wind and solar generation all influence the shape of excess electricity. It is found that excess electricity mirrors the intermittent character that it inherits from its origins.

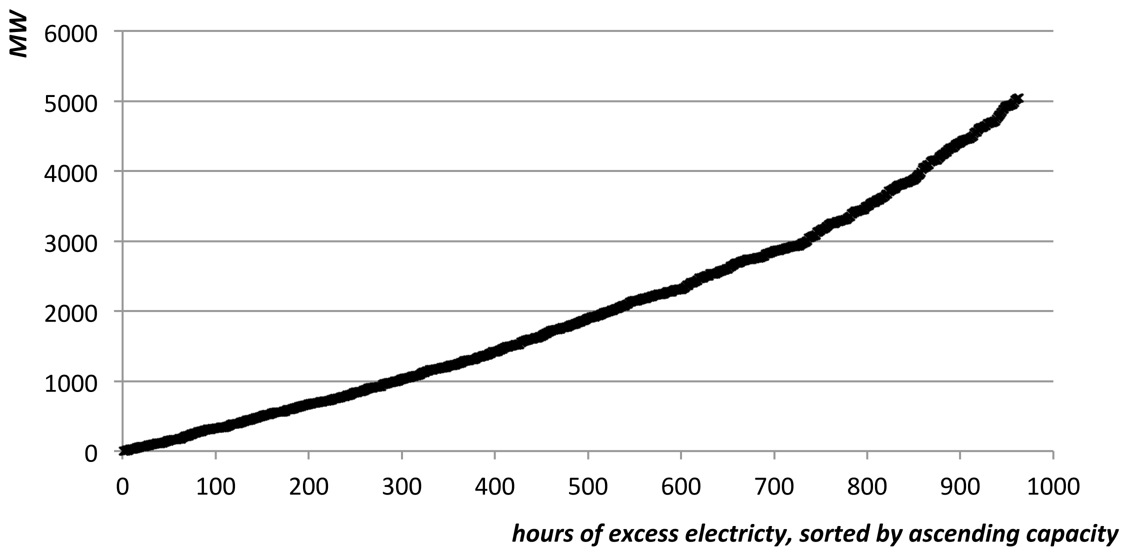

Figure 12: Capacity of excess events in 2020: excess duration curve. The horizontal axis lists the 'hours' of excess electricity in ascending order of excess capacity. Since the calculation for future excess electricity is based on hourly intervals, excess electricity can only be forecasted with an hourly resolution. All hours of excess are sorted in ascending order of their capacity for this chart, forming an 'excess duration curve'.

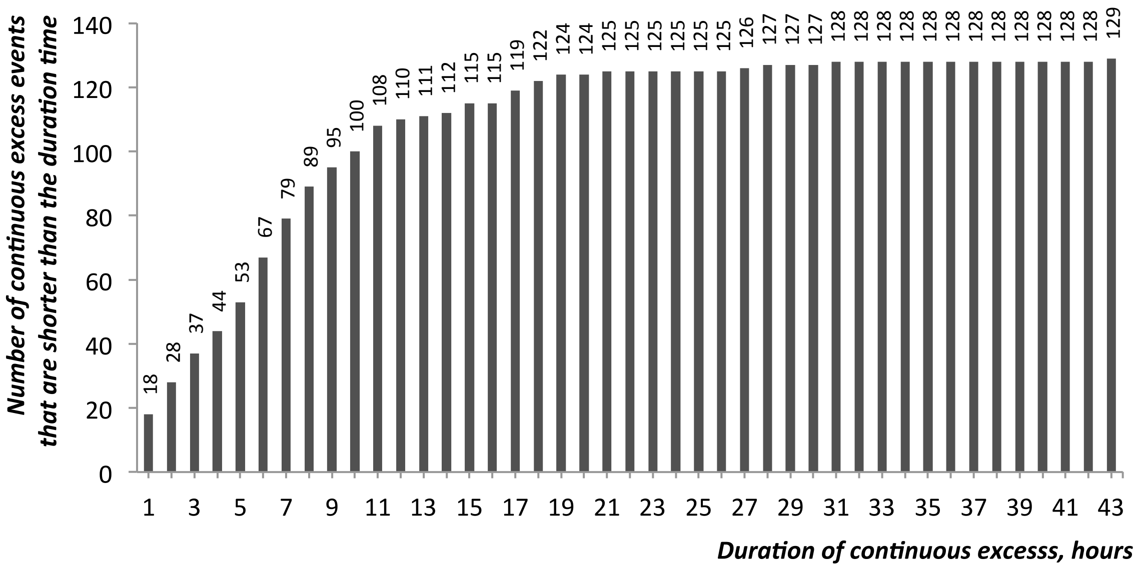

Figure 13: Histogram of continuous excess events in 2020. The amount of continuous excess events is analyzed. Intervals of continuous excess electricity can occur for only one hour (smallest time interval in the simulation) to 43 hours. Most of the excess electricity occurs for rather short intervals; 90% of all continuous excess events are shorter than 17 hours.

5.1.3. Comparison to findings in the literature

This section compares the findings on future excess electricity to others projections found in the literature.

This study arrives at a renewable electricity share greater than 40%[26] in 2020. The projections for the installed capacities of wind and solar are taken from other reports that target a 40% renewability. The fact that this study arrives at a similar renewability share validates that the profiles constructed here produce meaningful results. It is not easy to compare the forecast of future excess electricity to other sources because projections are hard to find in the literature. Some forecasts have been found, but it often remains unknown what these forecast are based on exactly.

As mentioned in the introduction, Münch [2012] projects that up to 20% of the potentially available electricity from wind and solar will be curtailed in Germany in the year 2020. This study arrives at a value of 4% (Table 6).

Henel [2012] quotes a study[27] that arrives at 4 – 10 TWh of oversupply in Germany in 2022 (based on forecasted wind and solar energy production and electricity demand). Based

[26] 40% integrated volatile electricity translates into a system renewability greater than 40%. Additional renewable electricity may originate from biomass and hydro power.

[27] Henel [2012] provides the following source, which could not be accessed:
Peter Hinsching, Robert Haastert, Markus Niggemann and Rene Lindner. 2012. Power-to-Gas: Hohes Potenzial für ein neues Geschäftsfeld. Energiewirtschaftliche Tagesfragen 62 Vol. 5.

on a rough estimation[28], this amount of excess would translate into 4% curtailed electricity (of the amount of integrated renewable electricity). This would be very comparable to the result of this study, although two different countries are considered.

Albrecht [2010] presents figures for Schleswig-Holstein, a German state of similar geography to the Netherlands. However, Schleswig-Holstein has a much lower demand for electricity. Wind capacity in Schleswig-Holstein might reach 12 GW by 2020, which can cause 4 TWh of oversupply that cannot be integrated into the grid (also taking the transmission to other states of Germany into account) [Albrecht, 2010]. A large share of wind turbines will be built in the northern part of Germany, were electricity demand is low. Therefore, most of the oversupply is expected to occur in Germany's northern states and the figures from Albrecht [2010] and Henel [2012] might actually complement each other quite well.

Slot [2013] claims that Germany, Ireland and the UK taken together, will have to deal with an amount of only 1.45 TWh in 2020.

Denholm & Hand [2011] analyze the situation in Texas, USA. Their findings indicate that the electricity grid can handle a share of 40% from wind and solar without causing significant excess electricity (~1% of volatile generation is curtailed). However, a further increase in renewability will cause a sharp increase in curtailment rates.

This study forecasts a curtailment rate of wind and solar energy of about 4% in 2020 in the Netherlands. A forecast for the Dutch situation could not be found in the literature. However, the excess that is forecasted here is in line with German studies [Albrecht, 2010; Henel, 2012].

Since The Netherlands has only limited space, Dutch wind parks cannot be spread out very much and their output will probably be correlated. However, The Netherlands is a smaller country and the distances between wind parks and electricity consumers are much shorter. A larger correlation in volatile generation and a smaller balancing area have adverse effects on the amount of excess electricity. It is not possible to conclude if the excess electricity expected in Germany can be used to make a prediction for The Netherlands.

5.2. Performance of conversion technologies in 2020 and 60% scenario

5.2.1. Definition of indicators

The following indicators are used to evaluate the performance of the technologies. The first is a simple ratio of the amount of electricity that is absorbed by a technology and the total annual excess electricity (without applying the technology).

$$\text{Curtailment Reduction} = \frac{\text{energy absorbed by technology}}{\text{total excess}}$$

[28] Based on a German electricity demand of 600 TWh per year [Consentec & IAEW, 2011] that will be satisfied by 40% from renewables.

Levelized cost (LC) is used as an economic indicator[29].

$$LC = \frac{\alpha \times I + OM}{E}$$

with:

LC:	Levelized cost (€/$MWh_{absorbed}$)
I:	initial Investment (€)
OM:	annual operation and maintenance cost (€)
E:	annual energy output of conversion technology (MWh_{out})
r:	Discount rate
L:	Lifetime
α:	Capital recovery factor $\alpha = \frac{r}{1-(1+r)^{-L}}$

The levelized cost indicator is a measure for the costs of the energy delivered by a conversion technology. For example, power-to-heat conversion generates useful heat; the levelized cost represents the cost for delivering hot water via excess electricity conversion. If these costs are lower than the marginal cost for producing hot water by a natural gas burner, the conversion of excess electricity is profitable. Similarly, levelized costs indicate the cost for generating power and hydrogen in the respective conversion technologies.

Note that the performance indicator curtailment reduction refers to the amount excess electricity that is absorbed in a conversion (energy input) and the levelized cost refers to the amount of energy that is delivered by a conversion (output). To avoid confusion, the levelized cost are displayed with the unit €/MWh_{out} throughout this report. For the power-to-gas route this means that all cost are allocated to the production of hydrogen. Oxygen is a co-product that does not induce cost.

CO_2 emission reductions may also be evaluated. However, the emission reductions are only approximations. They depend on the kind of fuel that is displaced and its conversion efficiency. Since CO_2 taxation or emission allowances are not considered in this study, CO_2 mitigation does not have any influence on the economic performance.

The following passages compare the conversion technologies and analyze their performance with respect to the two indicators, curtailment reduction and levelized cost.

Due to their individual characteristics, the conversion technologies absorb different amounts of excess per installed capacity. In order to facilitate a meaningful comparison, the installed capacities have to be set to fair and justified values for each technology. Firstly, the investment cost is kept constant for all technologies. Second, the effect of increasing installed capacities is evaluated. Third, the curtailment reduction will be set to a constant value and the technologies are compared in scenarios of increasing volatility.

[29] Formula adapted from cost-of-electricity calculation, see Blok [2008], equation [11.3], page 196.

5.2.2. *Performance at identical investment cost*

It is found that 4 million power-to-heat installations can bring down curtailment by 66% in 2020[30]. The investment cost for building these units is 3 billion €. Therefore, it is decided to allow each technology to be installed up to a limit of 3 x 10^9 € investment cost. The corresponding installed capacities are displayed in Table 7 and Table 8. The model calculates how well the technologies perform individually, i.e. the technologies are not installed simultaneously, which would make them compete for a fixed amount of excess electricity.

For 2020, it is found that power-to-gas conversion has the highest potential of reducing curtailment. This is a consequence of the medium-high investment cost in combination with high availability. However, the levelized cost of the power-to-gas conversion noticeably exceeds the levelized cost of power-to-heat. This is mainly due to the difference in operation and maintenance cost. Furthermore, power-to-gas reduces CO_2 emissions the least. In comparison to the other technology, power-to-gas suffers from a rather low conversion efficiency, which brings down the effect that can be achieved in the CO_2 mitigation.

Power-to-power storage is simulated with two different storage capacities. As outlined in the technology characterization, batteries with a lower storage capacity are cheaper to buy. Therefore, the installed capacity can be much higher for the 45 kWh battery units. However, these batteries are fully charged rather quickly, which causes the conversion to stop frequently. In consequence, the 45 kWh actually perform almost identical to the 85 kWh variant. The larger battery units are more expensive, but they can also absorb excess for almost twice as long.

Power-to-power conversion does not perform very well, regardless of the unit size that the economics are based on. The investment costs of the 85 kWh battery units exceed the investment cost of all competing technologies. Therefore, it scores very low on the installed capacity and all following indicators.

The CO_2 emission reduction depends on the amount of absorbed excess and the specific mitigation effect defined in the characterization chapter. Power-to-power has the largest mitigation effect per absorbed energy unit. Although power-to-gas conversion is able to convert a similar amount of excess, it has a low mitigation effect.

It can be argued that the power-to-power storage is hindered, because of the discharge threshold (residual demand has to be larger than 5 GW for storage to be discharged). Indeed, the power-to-power conversion route could reduce curtailment by about 10 extra percent points if the threshold was eliminated in the 2020 scenario. At the same time levelized cost would decrease by about 100 €/MWh_{out}. This is due to the fact that availability and energy conversion are increased.

Another important performance indicator is the load factor of the conversion. Since excess electricity occurs for only about 1000 hours in 2020, it can already be concluded that the

[30] The figure of 3 billion € is chosen arbitrarily. It is found that 100% curtailment reduction is difficult to realize, because the installed capacity of a technology would have to be equal or larger than the peak excess power.

conversion technologies have a very low load factor. This operation time is an upper limit as long as only excess electricity is converted. 1000 full load hours are equivalent to a load factor of 11%. As Figure 12 revealed, most of the excess occurs at relatively small capacity (compared to peak excess power). The amount of full load hours that a technology can reach in practice depends on the shape of the excess curve and on the amount of installed capacity. Small installed capacities lead to more full load hours (with an upper limit of 1000 full load hours). The power-to-gas conversion has the highest availability. Given the figures of Table 7, its load factor is calculated to 8%[31].

However, the load factor is not always a useful indicator. Power-to-power storage has to discharge before it can absorb excess again. Therefore, its potential operation time is less than half as the operation time of the other technologies (depending on the distribution of excess throughout the year and on whether there are opportunities for discharge between excess events). It might be suggested to change the definition of the load factor (e.g. no longer referring to the duration of a year). However, it is not believed that a tweaked indicator will benefit the discussion.

Based on the data from Table 7, all technologies have a load factor of roughly 10%. This already gives a strong indication that it might be difficult to find a profitable business case.

In the 60% scenario, installed capacities remain the same. The power-to-power conversion route is clearly disadvantaged because of its limited storage availability (storage is often fully charged). Lowering the discharge threshold can only marginally improve its performance. Only the levelized cost can be lowered, which is direct consequence of increased throughput.

Apart from CO_2 mitigation, the ranking of technologies is identical to the 2020 scenario. The spread in performance increases.

Table 7: Technology performance at constant investment costs, 2020 scenario. Constant investment costs: 3 billion euro. Amount of excess electricity: 2.03 TWh. The categories investment cost, installed capacity and curtailment reduction refer the uptake of excess electricity. Only the indicator levelized cost addresses the cost for delivering the conversion output.

	Investment cost	Installed capacity	Curtailment reduction		Levelized cost	CO_2 avoided
	€/kW_{in}	MW_{in}	GWh_{in}	%	€/MWh_{out}	1000 t
Power-to-power, *85 kWh*	1615	1860	815	40	624	220
Power-to-power, *85 kWh,* no discharge threshold	1615	1860	1010	50	503	275
Power-to-power, *45 kWh*	855	3510	897	44	589	245
Power-to-power, *45 kWh,* no discharge threshold	855	3510	1109	55	476	300
Power-to-heat	1500	2000	1335	66	277	385
Power-to-gas	1329	2257	1520	75	558	110

[31] Load factor = absorbed excess / (hours per year * installed capacity)

Table 8: Technology performance at constant investment costs, 60% scenario. Constant investment costs: 3 billion euro. Amount of excess electricity: 28.3 TWh. The economic figures remain the same as in the 2020 scenario; only the energy flow changes.

	Investment cost	Installed capacity	Curtailment reduction		Levelized cost	CO_2 avoided
	€/kW_{in}	MW_{in}	GWh_{in}	%	€/MWh_{out}	1000 t
Power-to-power, *85 kWh*	1615	1860	1588	5.6	321	430
Power-to-power, *85 kWh,* No discharge threshold	1615	1860	2216	7.8	230	600
Power-to-power, *45 kWh*	855	3510	1795	6.3	295	485
Power-to-power, *45 kWh,* No discharge threshold	855	3510	2396	8.5	221	650
Power-to-heat	1500	2000	5500	19	67	1580
Power-to-gas	1329	2257	8025	28	105	585

5.2.3. Effect of installed capacity on curtailment reduction and levelized cost in 2020

The following two charts display the effect of increasing installed capacity on the two indicators curtailment reduction and levelized cost (Figure 14). Of course, a larger installed capacity can absorb higher peaks of excess power. In order to absorb more excess electricity, the installed capacity has to be increased.

All curves follow a similar shape in the respective charts. If only a small amount of capacity is installed, building more capacity has a rather large impact on the curtailment reduction. This is due to the fact that higher peaks of excess power can be dealt with. With increasing installed capacity, this effect fades out. Building more capacity can absorb higher peaks, but since these peaks only occur for very few hours of the year, the total amount of absorbed energy increases only marginally. Therefore, there is a saturation effect for all curves.

For power-to-power conversion, there is a second effect: A larger installed capacity means that more battery units are built. More battery units not only cope better with high excess capacities but also with longer excess events, because it takes longer until all units are fully charged.

Power-to-heat and power-to-gas behave very similar in the curtailment reduction chart. At about 3.3 GW installed capacity, excess electricity can be reduced by 90%. The power-to-heat route already reaches the limit that is given by the maximum theoretical potential in the Netherlands. There are only about 7 million households to equip. With the specified maximum capacity of 500 W per household, the installed capacity cannot exceed 3.5 GW. The other two conversion pathways have less obvious capacity limits, which are discussed below.

In general it is observed that the levelized cost increase with more installed capacity. Doubling the installed capacity also doubles the investment and O&M cost. However, twice the installed capacity will not lead to a doubling in energy conversion, as can be seen in the curtailment reduction chart. In consequence, the levelized cost increase significantly.

A contradiction in reaching large curtailment reduction and low levelized cost is observed.

Power-to-heat conversion has by far the lowest levelized cost. Power-to-gas delivers hydrogen at roughly twice the cost, which is a direct consequence of its high O&M cost. For the power-to-power route, it is found that the discharge threshold has a negative influence. It limits the energy throughput, especially at lower installed capacities. This has a strong influence on the levelized cost.

Apart from evaluating the performance as a function of installed capacity, it is also interesting to find out which conversion technology would have the lowest levelized cost, given a certain target of curtailment reduction. The charts in Figure 14 already contain this information, but to make this information more readable, Figure 15 is compiled. As seen above, power-to-heat has the ability to absorb excess electricity very well, relative to the installed capacity. It has the lowest levelized cost, which is due to the fact there are no operation and maintenance cost.

In the year 2020, power-to-heat is the cheapest option, regardless of how much curtailment shall be avoided.

Again, the influence of the discharge threshold for the power-to-power conversion becomes apparent. At curtailment reduction rates below 60%, the power-to-power is competitive with power-to-gas conversion, if the discharge threshold is abolished.

In comparison to the default power-to-power conversion (85 kWh with threshold), the 45 kWh variant performs better at low curtailment reduction rates. However, at curtailment reduction rates above 70%, the lower storage capacity becomes disadvantageous and offsets the effect of lower investment cost. In comparison to the other two technologies, both batteries (85 and 45 kWh) perform very similarly.

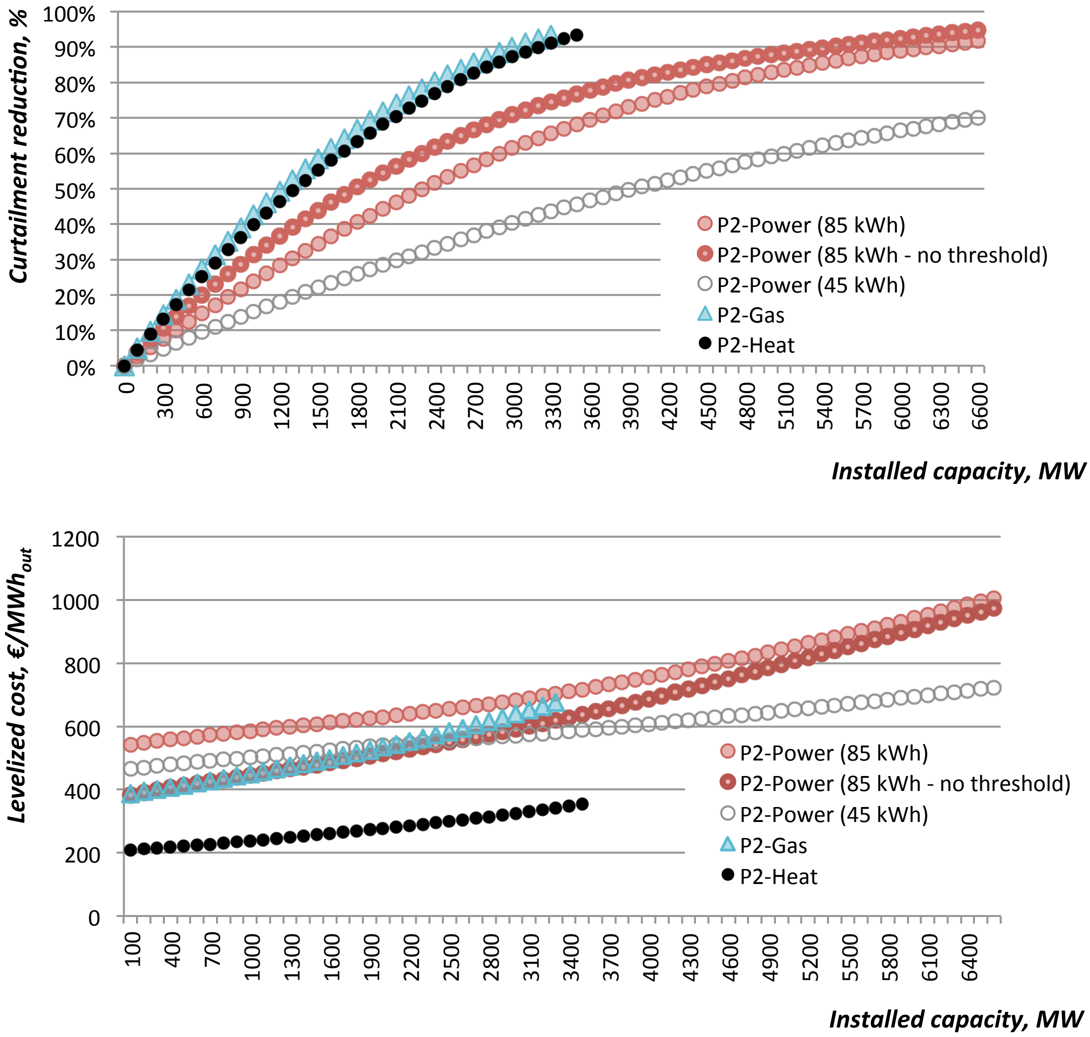

Figure 14: Effect of installed capacity on curtailment reduction and levelized cost in 2020.
Power-to-power storage is modeled with a discharge threshold of 5 GW (unless indicated otherwise). Curtailment reduction: The top chart displays the percentage of excess electricity that can be converted and therefore does not have to be curtailed in 2020. As the installed capacity increases, more curtailment is avoided. Compare for example with Figure 12, which shows an excess duration curve. Power-to-gas and power-to-heat have a very similar curtailment reduction potential. At about 3 MW installed capacity, 90% of the curtailment can be avoided. There is a saturation effect as the amount of excess electricity is finite. Power-to-power conversion is noticeably limited by its availability. Levelized cost: The bottom chart shows the levelized cost as a function of installed capacity. The levelized cost refers to the amount of useful energy output (not the absorbed energy).

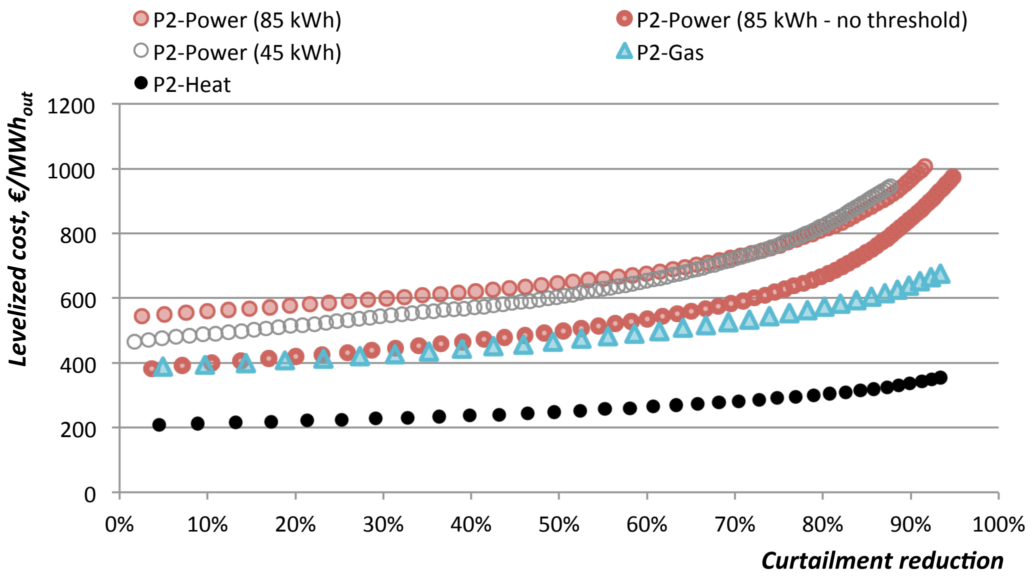

Figure 15: Levelized cost vs curtailment reduction in 2020. Power-to-power storage is modeled with a discharge threshold of 5 GW (unless indicated otherwise).
This chart contains the same information as Figure 14. This time, the levelized cost is plotted against the curtailment reduction, instead of the installed capacity. This clearly shows that the power-to-power conversion route is the least expensive option for curtailment reduction in 2020.

5.2.4. Effect of installed capacity on curtailment reduction and levelized cost in 60% scenario

This section repeats the previous evaluation in the 60% scenario. The key findings for the 60% scenario are: Vast installed capacities are required in order to bring down the curtailment rate. Halving curtailment would require at least 4 GW of power-to-gas conversion capacity, which is the most effective technology.

The technologies behave very similarly in general. Disadvantages induced by limited availabilities become more pronounced because of the increasing amount of excess electricity. Especially power-to-power conversion suffers, in all variations. At a certain capacity (12 GW) power-to-gas conversion can reduce 90% of curtailment, while power-to-power conversion reaches a mere 30%. Power-to-heat still has a comparatively high potential of reducing curtailment although its conversion rate is reduced during long continuous excess events.

Power-to-power does not seem very suitable to deal with the excess. As seen above, the residual demand is actually negative on average. It is not useful to store electricity for later use if oversupply is that frequent. It seems more useful to convert excess electricity into other energy carriers.

Levelized cost are plotted against curtailment reduction for the 60% scenario, Figure 17. For the power-to-power conversion, the similar trends are identified as in the 2020 scenario: The 45 kWh batteries perform slightly better than the larger variation if the curtailment rate is below 17 %. Removing the discharge threshold from the 85 kWh batteries has a much larger influence: Levelized cost can be lowered significantly (~100 /MWh_{out}). In spite of that, power-to-power stays the least attractive option in the 60% scenario.

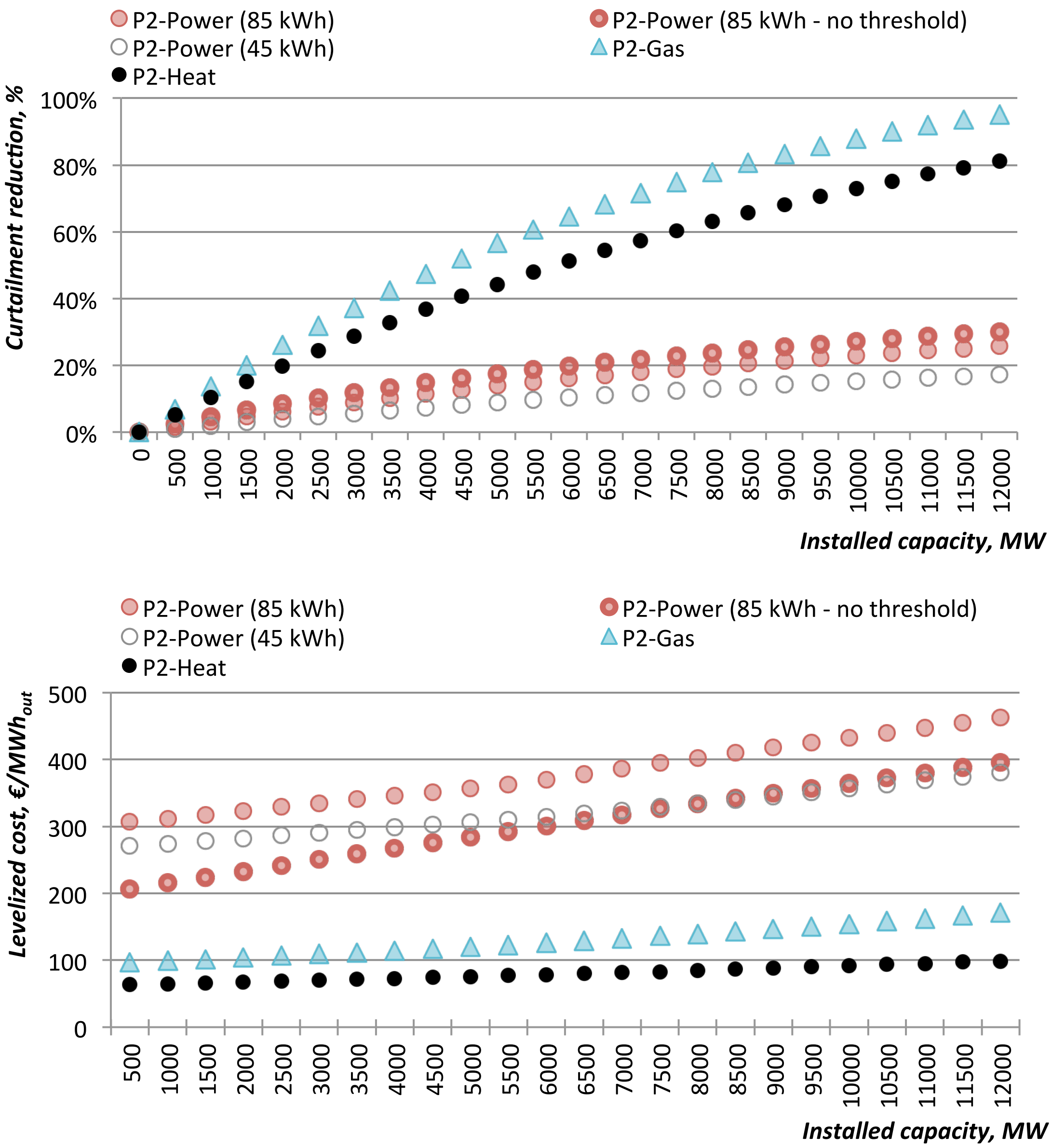

Figure 16: Effect of installed capacity on curtailment reduction and levelized cost in 60% scenario.
Power-to-power storage is modeled with a discharge threshold of 5 GW (unless indicated otherwise).

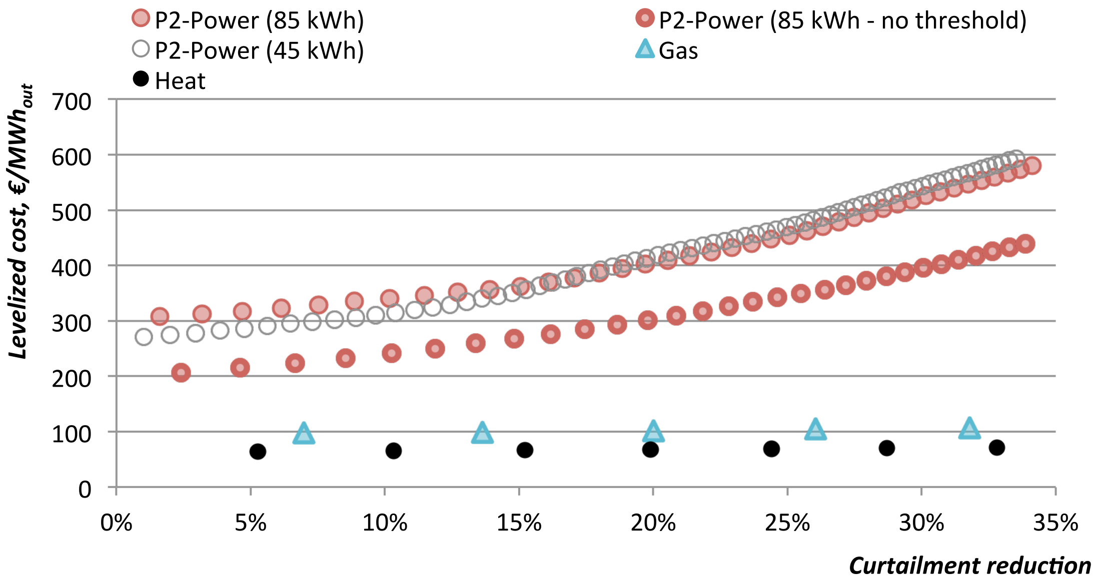

Figure 17: Levelized cost vs curtailment avoided in 60% scenario.
Power-to-power storage is modeled with a discharge threshold of 5 GW (unless indicated otherwise). Regardless of the technology, it becomes very difficult to avoid all curtailment in the 60% scenario. Fully avoiding curtailment requires vast amounts of installed capacity.

5.2.5. Performance during the transition towards the 60% scenario, at 66% curtailment reduction

So far, the results have shown how the conversion technologies perform in the 2020 and 60% volatile electricity scenario. However, which technology is most promising during the transition towards highly renewable scenarios?

Figure 18 addresses this question by plotting the levelized cost against the total share of integrated electricity from wind and solar. Under the constraint that curtailment has to be reduced by 66%, the levelized costs are calculated.

For power-to-gas and power-to-heat conversion, it is beneficial to face large amounts of excess electricity. It is observed that levelized cost decrease with rising integrated volatile electricity. As the amount of excess rises, the increase in throughput and load factor outweighs the effect of larger installed capacities on the levelized cost.

Power-to-power shows a different behavior. If there is more volatile electricity, storage benefits from frequent fluctuations in the residual demand.

As the volatility of the electricity supply increases from 30 to 40%, power-to-power benefits from more frequent charge and discharge opportunities, which leads to higher load factors and lower levelized cost. In scenarios with low amounts of excess (<40% volatile electricity), power-to-power might be able to compete with the other technologies. However, there is a turning point when the average residual demand becomes so low that the opportunities for battery discharge are constrained. In consequence, the curves representing power-to-power conversion have a minimum at 45% system volatility. The excess events last for such a long time, that storage is often fully charged and therefore cannot convert excess effectively.

Power-to-heat is the most promising technology, but there is a limit on the theoretical potential heat demand that is considered in this study. Equipping all households in The Netherlands with power-to-heat conversion would only be able to reduce curtailment by 66% in scenarios of up to 45% integrated volatile electricity. Nonetheless, the chart shows how power-to-heat would behave if the potential demand for heat was larger. In scenarios of more than 50% volatile electricity, the levelized cost of power-to-gas conversion are about 50 % higher than the cost for power-to-power conversion. Compared to the storage option, power-to-gas is the most promising option at scenarios of very high volatile electricity.

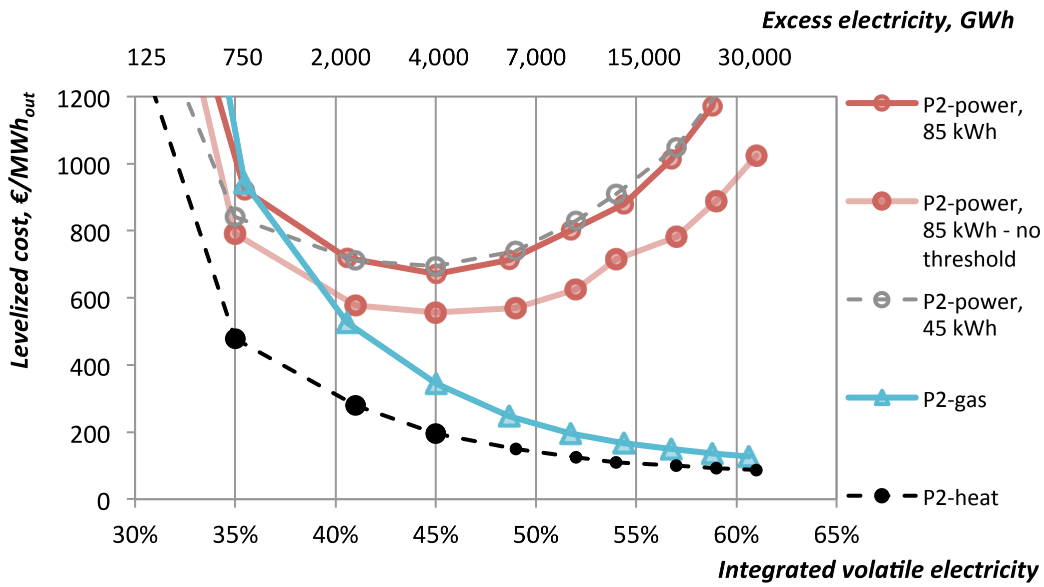

Figure 18: Levelized cost at 66% curtailment reduction in future scenarios.
The installed capacities that are projected for the year 2020 yield a scenario in which 40% of the energy production originates from wind and solar. The term 'integrated volatile electricity' refers to the share of the total demand for electricity that is met by wind and solar generation. It therefore only refers to integrated volatile electricity, as opposed to volatile generation potential.
By scaling the installed capacity for solar and wind up proportionally, scenarios of varying renewability are created. The ratio of installed capacity of wind and solar is fixed at 3.1 and taken from the 2020 scenario (~13 GW wind and ~4 GW solar).
The simulation first determines the conversion capacity that is required to bring down curtailment by 66% in the given scenario (horizontal axis). Then, the levelized cost is calculated.
The curve representing power-to-heat conversion is displayed with large and small markers. The small markers represent data points that actually exceed the potential for power-to-heat conversion in ho-water preparation (7 million households).

5.3. Profitability of excess conversion technology

Which technology is suited best for reducing curtailment in the future not only depends on the levelized cost, but also on the benefits that it can generate. In order to know whether a conversion technology can be operated profitably, the benefits of each technology have to be discussed.

All conversion technologies cannot fully replace their conventional counterparts[32] because excess electricity is not constantly available. The conversion of excess electricity into other carriers will always be a redundant technology. Therefore, the benefits of excess electricity conversion are defined by the short-term marginal operation cost of the conventional generation of gas, power and heat (instead of their levelized generation cost).

Power-to-heat

Power-to-heat conversion has the lowest levelized cost in all investigated scenarios. It benefits from an effective curtailment reduction, high conversion efficiency and low operation and maintenance cost.

The benefits of the technology depend on two parameters, the price for natural gas and the conversion efficiency of the natural gas boiler. As described in the chapter on technology characterization, power-to-heat conversion competes with a default heating system that is actually less efficient than the conversion of excess electricity to heat. Conventional gas boilers produce hot water at roughly 70% conversion efficiency (Table 1).

The consumer gas price was set to 70 €/MWh (including taxes). This equates to a monetary saving effect of 100 € per MWh of converted excess electricity. In the 2020 scenario, levelized cost are always above 200 €/MWh, which makes the technology unprofitable. However, the levelized cost can be lower in scenarios with larger shares of volatile electricity (depending on the installed capacity of power-to-heat). In the 60% scenario, the levelized cost are below 70 €/MWh for installed capacities of less than 3 GW. Curtailment could be reduced by 30% in a profitable manner if the natural gas price does not decrease in the future.

Power-to-power

The benefit for power-to-power conversion depends on the price for electricity. Only for the purpose of analyzing this benefit, the simulation calculates a price for electricity for every hour. The electricity price is set to the marginal operation costs of the least expensive power plant that is not required to meet the current demand for electricity (see methodology).

A first look at the marginal operation cost of conventional dispatchable power plants gives an impression of the benefits that power-to-power conversion can make: The price for electricity can range from 0 to 83 €/MWh[33].

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[32] P2-power: Dispatchable power plants; P2-gas: natural gas production; P2-heat: hot water preparation in gas heaters.

[33] Gas turbines have the highest marginal operation cost of 83 €/MWh. Technically, the electricity price can reach 600 €/MWh, if the gas turbines are operating (see methodology). However, this only happens for 2 hours of the year and therefore can be neglected in this analysis.

The price for electricity is influenced by fuel prices, power plant types and efficiencies and CO_2 emission cost. The fuel prices and characteristics of dispatchable power plants are not investigated here. In the technology characterization, it was claimed that power-to-power storage should have a discharge threshold of 5 GW (residual demand). This threshold was introduced because it was thought that it would benefit the profitability. This assumption is challenged in the following paragraphs. See Figure 19. It addresses an installed capacity of 3400 MW_{in} of 85 kWh batteries (with 5 GW discharge threshold) in the 2020 scenario, which yields in a curtailment reduction of 66% by default.

As it has already been found in the previous analysis, the discharge threshold limits the energy throughput, the 'load factor' and therefore also the curtailment reduction effect of battery storage. This is underlined in the first chart of Figure 19.

Next, an average benefit is calculated. In order to compare benefit to levelized cost, both have to have the same unit (€/MWh_{out}). The simulation derives the average benefit in the following way:

$$\text{average benefit} = \frac{\sum_i \text{hourly discharge}_i \cdot \text{hourly electricity price}_i}{\text{total discharge}}$$

Note, that these benefits do not pinpoint specific marginal operation cost of particular power plants, as these benefits represent an average (of varying hourly benefits).

It is observed that the average benefits increase for higher discharge thresholds. This is expected, because discharge is only permitted at higher electricity prices. However, this effect is offset by the fact that a high discharge reduces the amount of discharge. As average benefit increases, levelized cost for converting excess into useful electricity rise simultaneously.

The effect of increasing levelized cost is of much larger magnitude, as the last chart of Figure 19 shows. It is found that it is economically more interesting to convert more electricity and sell it at a much lower price. Power-to-power conversion of excess electricity should be operated without a discharge threshold.

Power-to-power conversion cannot generate a profit in Figure 19, which calculates the levelized cost based on a capacity of 3400 MW_{in}. It can be seen in Figure 14 that the levelized cost are always above 400 €/MWh_{out}, regardless of battery size and discharge threshold. In the 60% scenario, the levelized cost are larger than 200 400 €/MWh_{out}.

Even in the most extreme case of installing only 500 kW of the cheaper 4.5 kWh battery storage can only bring down levelized cost to 170 €/MWh_{out} (60% scenario without discharge threshold). It is not possible to find a parameter space in which power-to-power storage is profitable in this study.

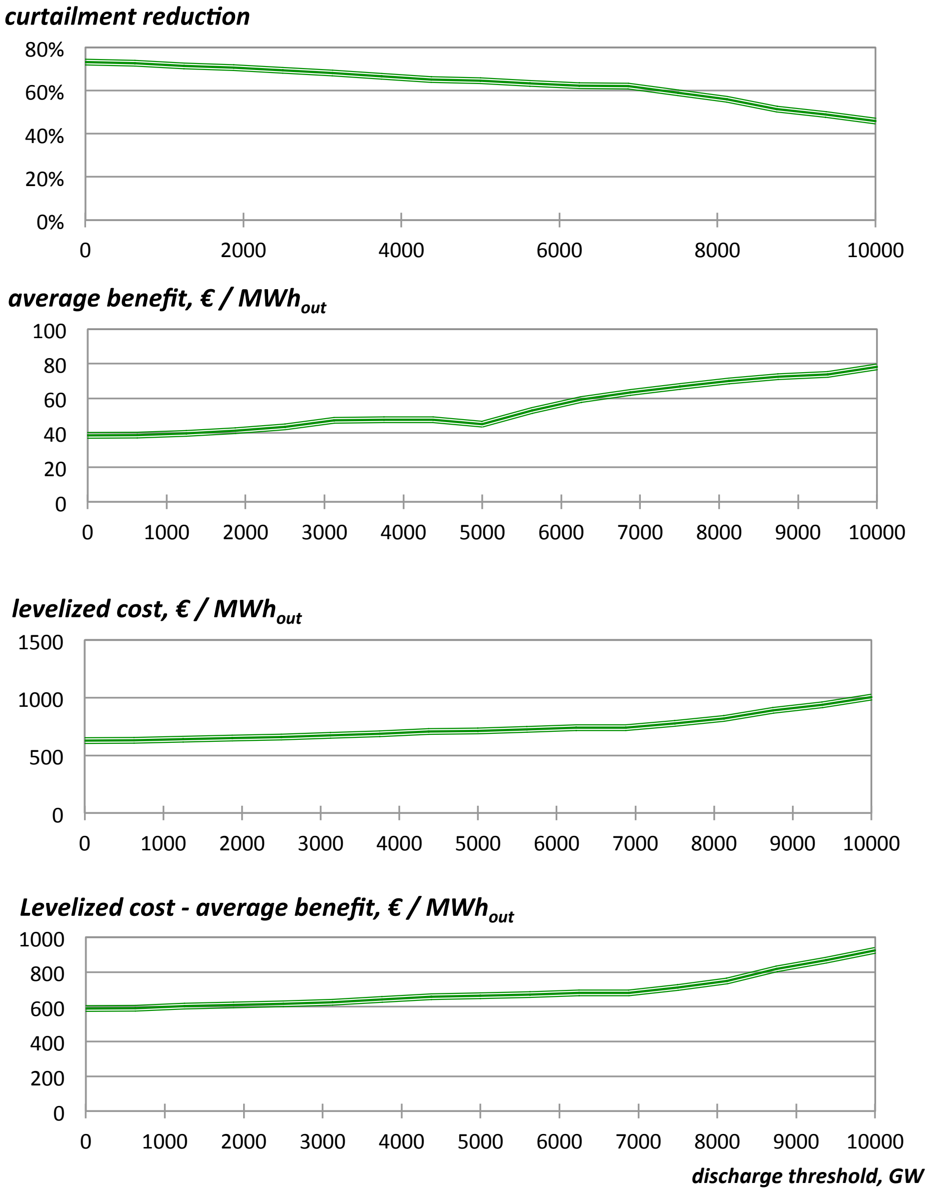

Figure 19: Effect of the discharge threshold on the economics of power-to-power convserion.
Based on an installed capacity of 3400 MW, these curves are produced for 85 kWh battery units in the 2020 scenario. At a discharge threshold of 5 GW, a curtailment reduction of 66% is achieved.
The average benefit is defined as the total annual benefit divided by the total electricity discharged. For further explanation, see text.

Power-to-gas

The benefits of the power-to-gas conversion route are determined by the price[34] for natural gas and the conversion efficiency of the conversion itself. Additionally, selling the co-product oxygen may generate further benefits. As outlined above, hydrogen can be sold at around 30 €/MWh_{out} and oxygen might yield another 7 €/MWh_{out}[35].

These benefits do not lead to an attractive business case: For 2020 it was found that levelized cost are above 400 €/MWh_{out} (increasing with installed capacity). In the 60 % scenario, levelized cost can be reduced, but they are still above 80 €/MWh_{out}. It is concluded that power-to-gas cannot be operated cost-effectively.

[34] The technology characterization identified an industrial consumer price of about 30 €/$MWh_{natural\ gas}$ (excluding taxes).

[35] Oxygen does not have a heating value; the unit refers to the amount of hydrogen produced.

6. Uncertainties and discussion of results

The results of this study are based on many assumptions. All of these assumptions can be a cause of uncertainty. First, there is uncertainty in the forecast of installed capacity for the 2020 scenario. Second, the simulation itself does not mirror reality perfectly. Third, the technology characterization itself is another source of uncertainty.

The following paragraphs outline the causes for uncertainty in more detail. The uncertainty in the technology characterization in displayed in spider diagrams.

6.1. Forecast of excess electricity

The 2020 scenario is based on a forecast of installed capacities and electricity demand. The figures have been taken from reports that outline how The Netherlands could reach the political 2020 targets. It is not known, which technology mix will be realized by 2020. A 2020 scenario can be created with various ratios of onshore/offshore wind and solar energy.

Furthermore, the profiles that are used to forecast the hourly electricity generation of volatiles are a source of uncertainty. The profiles are created in a relatively simple process, described in Appendix B.

Genuine power curves for wind turbines in the Netherlands could not be obtained from the literature. Therefore, the power output of wind turbines has to be based on wind speed measurements that are published on an hourly resolution. The same is true for other intermittent power sources, e.g. solar PV.

The following shortcomings with regard to wind and solar profiles are known:

- The profiles are based on a very limited dataset. For example, the offshore wind profile is based on only three measurements sites.
- The profiles are based on measurements taken at locations that do not necessarily represent the areas where wind and solar energy will be installed.
- All profiles are scale up with the amount of installed capacity of the respective participant. The profiles remain static no matter how much capacity is installed. It is unknown how a participant's power generation changes as the installed capacity increases. For example, doubling the installed capacity for wind turbines does not lead to an exact doubling of electric output as it is assumed in this study[36].

[36] It has been reported how the installation of an increased number of wind parks affects aggregated power duration curves. If the power output of many distributed wind parks is combined, the average hourly wind power production is steadier than the production of just one wind park. As distributed wind parks have a less correlated power output, it becomes less likely that all wind turbines are operating at their rated capacity. For aggregated power duration curves, see Holttinen [2005] and Fraunhofer Institute [2012]. A study for the EU-27, targeting the time frame 2020 – 2030, claims that the "maximum aggregated instantaneous wind power [Van Hulle & Gardner, 2009]" might only be 60% of the installed capacity (200 GW) [Van Hulle & Gardner, 2009].

- The profiles (wind & solar) are based on measurement of a single year (2010). However, the shape of the profiles will change from year to year, which influences the shape of the residual load curve and thereby also the occurrence of excess electricity. Fortunately, the annual amount of electricity production does not on depend on profiles but on constant full load hours.

These shortcomings have all been considered during the process of creating the model. The scope of this work does not allow for a more precise model. Profile creation is a difficult task, because all profiles have to have the same full load hour characteristic as the participant that they represent. For example: the offshore wind profile is based on wind speeds that are measured at three different locations. A potential improvement could be reached if more measurement sites were considered. However, averaging over more measurement sites will smooth out wind power generation and the profile might cause wind turbines to run at unreasonably high full load hours in the simulation.

The profiles that are assumed for the inflexible CHPs and the electricity demand are another cause of uncertainty. CHPs that deliver heat for residential space heating purposes may become more flexible in the future. A more flexible operation of CHPs could be enabled by two technologies: CHPs can be equipped with thermal storage, which would allow them to stop electricity production at times of low electricity prices. And it could even be possible to turn CHPs into electricity consumers at times of excess electricity. Electric resistance heaters could be used to fulfill the heat demand and load thermal storage during times of oversupply [Wünsch et al., 2011]. Increased CHP flexibility would decrease the contribution in causing excess electricity.

Yet, the amount of inflexible electricity production really is not that large in the simulation. Since dispatchable power plants are simulated as 100% flexible, the only must-run capacity (originating from inflexible CHPs) ranges between 2.2 – 2.6 MW_{el} throughout the year. In comparison to an average electricity demand of about 13 GW, this must-run production seems rather small.

The uncertainty in installed capacities and profiles affects the amount and distribution of excess electricity that is simulated. As the influences are extremely complex, it is not possible to quantify this uncertainty.

Simulation of excess electricity

Uncertainty in the forecast of excess electricity is not only caused by installed capacities and profiles, but also by the model itself.

The simulation is based on a number of simplifications. For example, the copper plate assumption neglects potential causes for curtailment in the distribution and transmission grid. Furthermore, the model allows all participants to act in an extremely flexible manner. From one hour to the next, it is possible to ramp conventional power plants up or down by 100%[37]. Both of these simplifications make this study underestimate the amount of excess electricity.

In spite of that, there are also arguments that indicate that too much excess electricity might be forecasted: The simulation neglects the option to export excess electricity to neighboring countries. Furthermore, the market might adapt to the volatile supply of renewable electricity. Demand side management and the introduction of electricity vehicles (higher electricity demand) might reduce the amount of excess significantly.

The simulation calculates excess electricity and its potential conversion with an hourly resolution. Although the results are not expected to change significantly[38], a higher resolution would be desirable. It was not possible to acquire data with higher time resolutions for all participants that are considered in the simulation.

The 60% scenario has the same weaknesses as the 2020 scenario. In fact, the 60% scenario is uncertain in many ways: The electricity demand may change significantly and the very large installed capacities of wind and solar capacities might have different characteristics than the profiles represent.

As the main result of this study is the evaluation of the conversion technologies, the uncertainty of the excess forecast is of lower priority. The behavior of conversion technology is not expected to react strongly to changes in the residual demand curve.

Despite all the uncertain parameters in the simulation, the residual demand, and especially the excess electricity curve, are believed to be of sufficient quality to facilitate the characterization of excess conversion technologies.

6.2. Technology characterization

The evaluation of the technology performance depends not only on the forecast for excess electricity, but also on the characterization of the technology itself. A sensitivity analysis investigates the uncertainty of the performance indicators for each technology. A fully automated sensitivity analysis, and especially a multi-criteria-analysis, is not feasible, given the number of parameters and modeling steps. For this reason, relevant input parameters of

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[37] In reality, power plants usually cannot ramp their electricity production up or down within one hour. For example: If a power plant (e.g. coal) is not required for the upcoming 5 hours, it might not be able to shut down for these 5 hours, because there is not enough time to complete the shut down and start-up procedure. The power plant might have to continue operation at part-load. Another constraint that might prohibit the shutdown of a power plant might be the regulations on reserve capacity. In case of an unforeseen increase in demand or reduction of volatile generation, extra dispatchable capacity might be required in short notice.
These reasons indicate that dispatchable power plants might actually not be able to shut down. Their flexibility is overestimated in the simulation.

[38] Quintel Intelligence investigated which time resolution is most suitable in order to produce meaningful results without slowing the simulation down too much. Improving the time resolution from 1 hour to 15-minute intervals does not lead to significant changes in the results (residual load curve, amounts of produced energy etc.).

the technology characterization are varied and discussed with the help of spider diagrams. Additional uncertainties and influences on the technology performance are also discussed qualitatively.

All spider diagrams are calculated within the context of the 2020 scenario. The installed capacities are chosen so that a curtailment reduction of 66% is achieved.

Power-to-heat

The characterization of power-to-heat conversion leaves little room for uncertainty in comparison of the other technologies. The only two relevant parameters in the technology characterization are the investment cost and the discount rate. Both indicators directly influence the levelized cost directly. Figure 20 shows the sensitivity of the levelized cost to the two parameters.

The discount rate is only 4% by default, while the other technologies are simulated with a discount rate of 10%. The sensitivity analysis shows that setting the discount rate to 10 % will raise the levelized cost to 365 €/MWh_{out} for the power-to-heat conversion (not visible in the spider diagram). Still, the power-to-heat route would have the lowest levelized cost in the 2020 scenario (compare Figure 15 and Figure 18). The uncertainties in investment cost and discount rate do not challenge the results of this study.

Power-to-heat conversion not only has the lowest levelized cost, but it also profits from the highest benefits in comparison to the other technologies. From an economic perspective, it is therefore concluded that power-to-power conversion is the most suitable technology for reducing excess electricity (although it is not profitable in 2020).

A drawback of the power-to-heat conversion is the limited potential. This study only considers the demand for residential hot water preparation. The number of households is finite and the electric heating capacity per unit is rather low. Raising the heating capacity might increase the potential.

Moreover, there is a very larger potential in the demand for space heating that could partially be met by converting excess electricity. However, the technology cost would increase. Also the stress on the electricity grid would grow, which would further raise system cost. It therefore cannot be concluded whether using excess conversion for space heating is an attractive option.

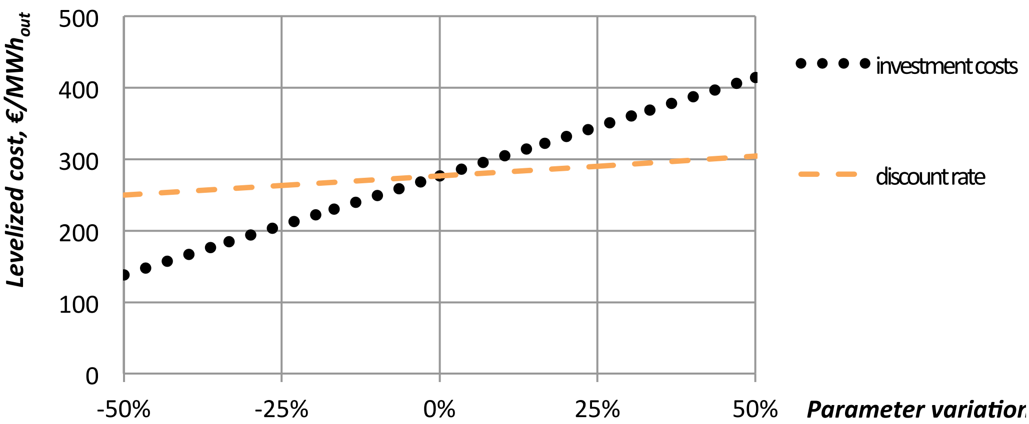

Figure 20: Uncertainties in the characterization of power-to-heat. The analysis is carried out in the 2020 scenario. The curtailment reduction rate is set to 66% in the base case by installing a capacity of 1950 MW_{in} (3,900,000 households).
The following base values are varied: Investment cost = 1500 €/kW_{in}; discount rate: 4%. Levelized cost: 276 €/MWh_{out}.

Power-to-power

Figure 21 displays the effects of several parameters on the performance of power-to-power conversion. Since the economic evaluation has shown that a discharge threshold is not a useful means for optimizing performance, the sensitivity analysis considers power-to-power conversion without a discharge threshold.

The influences of the investment cost, annual O&M cost, discount rate and round-trip efficiency are analyzed. The investment cost and annual O&M cost are varied in a range of ±50%. The investment cost has the strongest influence on the technology performance and causes significant uncertainty in the levelized cost. Should the investment cost decrease by 50% in the future (for example through learning effects and economy of scale), it is possible that levelized cost are reduced from 570 (base case) to 300 €/MWh_{out}. In contrast, the annual O&M cost have a negligible effect on the levelized cost, at least in the considered range.

The round-trip efficiency is varied between 70% and 100% (base case: 81%). A round-trip efficiency of 100% cannot be exceeded for technical reasons. Note that a higher (charging) efficiency actually reduces the curtailment reduction effect. A low charging effect will cause losses during charging, which enables the batteries to be charged for a longer time. Of course, a higher efficiency is beneficial for the levelized cost as they refer to the amount electricity delivered back to the grid. As the round-trip efficiency can only be varied in a range of -1 to +20% (in comparison to the base case), the uncertainty caused by this parameter is low.

The fourth parameter displayed in the spider diagram is the discount rate. The uncertainty range of the parameter could not be identified. It is found to have a rather strong effect on the levelized cost as it is directly coupled with the investment cost in the calculation of the levelized cost.

Further uncertainty lies in the setup of the simulation of power-to-power conversion. As stated in the technology characterization (page 23), the entire analysis is based on investment cost of 190 €/kWh. This figure is converted into a cost / charging capacity (€/kW). This transformation is based on the assumption that batteries are charged at a fixed capacity of 10 kW. This charging capacity is of course uncertain. Changing it would have the same effect as changing the original investment cost (€/MWh) directly. Therefore, the parameter 'investment cost' is uncertain in two ways. Nonetheless, it is believed that the characterization of investment cost is rather optimistic and it is doubtful if improvements can be realized in the near future.

As the potential benefits of power-to-power conversion are far below 80 €/MWh_{out} (see page 53), it can be concluded that the technology cannot be operated profitably if a 66% curtailment reduction shall be reached in 2020. This finding is very robust.

Power-to-power will need a different business case than just load-shifting in order to become attractive. Battery storage might be able to gain higher benefits through ramping and balancing services rather than load shifting. However, this cannot be simulated in this study.

Additional improvements in the economics may be realized in distributed batteries. For example, there is a large potential for managing (plug-out) electric vehicles as a virtual storage plant [Pillai, 2010]. The battery cost could be allocated to the electric vehicle, which might decrease the investment cost of power-to-power storage significantly. *"*On a daily average, about 90% of the time the vehicles are not used for transportation, where the battery storages of electric cars could provide grid ancillary services earning revenue. Apart from this remuneration, the synergy between renewable energy and V2G-capable cars aggregated to form large battery storages in the electricity grid are very compelling [Pillai, 2010 (page 30)]" (V2G: vehicle to grid).

Power-to-power storage could also be integrated into residential houses in the future. The political incentive could be to encourage local electricity producers to consume their own electricity (captive energy use). For example, residential battery storage could be used to store the electricity that is produced by a solar panel during the day. Captive energy use could lower the stress on the electricity grid (which is currently used to balance the residential demand and residential solar production, which is not correlated). By reducing the feed-in of solar electricity, excess electricity could be reduced. An additional functionality of distributed batteries could be the absorption of excess electricity occurring in the grid.

An upper limit for the potential for power-to-power conversion in The Netherlands could not be identified. To reach an installed charging capacity of 2790 MW_{in}[39] in distributed electric vehicles, about 279,000 vehicles would need to be equipped with a 10 kW battery. In order to reach a curtailment reduction of 66%, these units need to have a capacity of 85 kWh. Furthermore, they would need to be available (connected to the grid, empty storage) during electricity excess events.

[39] base value in sensitivity analysis, 2020 scenario, 66% curtailment reduction

Although the idea is intriguing, it might be very hard to reach this number of electricity cars by 2020. Furthermore, electricity cars are not yet designed to 'charge on demand'. The grid will have to become 'smart' in order to ensure that electric vehicles charge during a potential excess event. Also, it is questionable whether the electricity grid will be able to cope with an extra load of about 3 GW of simultaneous distributed demand.

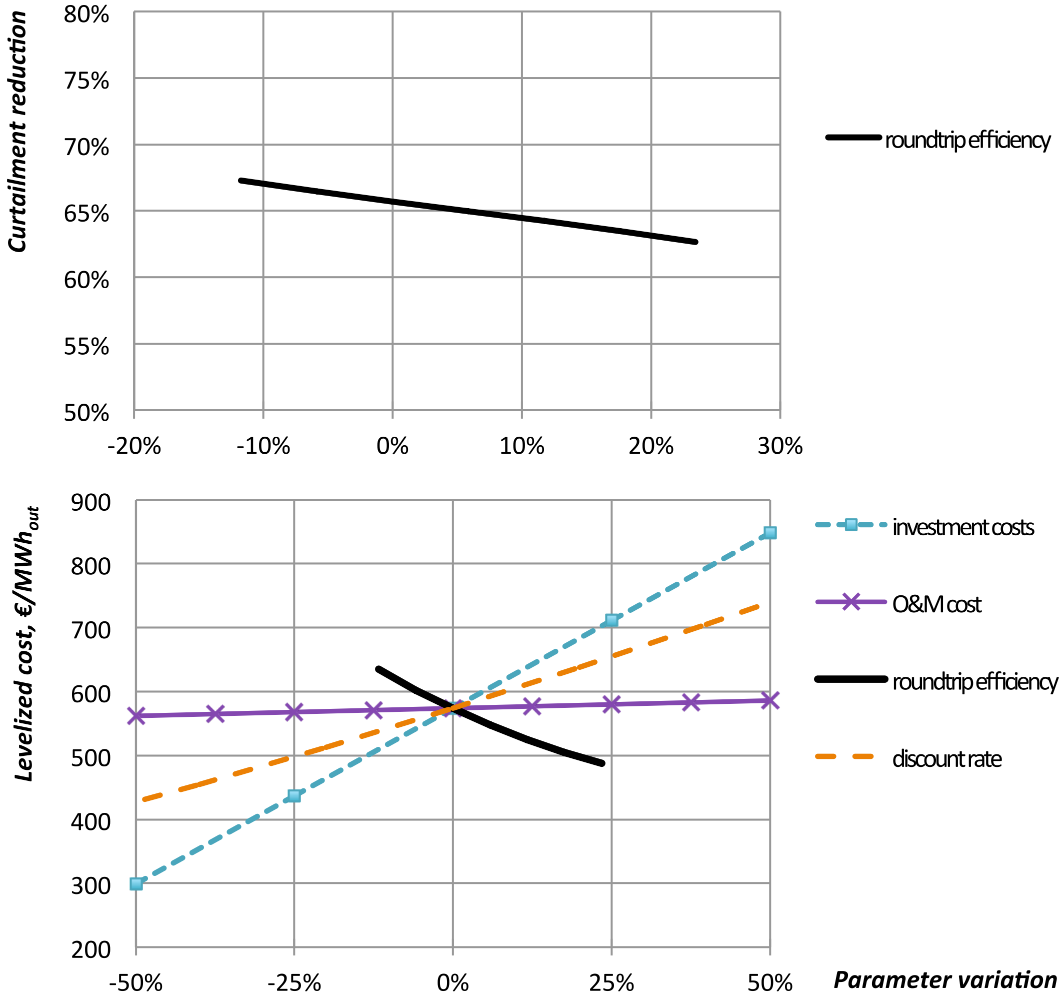

Figure 21: Uncertainties in the characterization of power-to-power. The analysis is carried out in the 2020 scenario. The curtailment reduction rate is set to 66% in the base case by installing 2790 MW_{in} of the 85 kWh batteries (no discharge threshold).
The following base values are varied: Investment cost = 1615 €/kW_{in}, annual O&M cost: 9.39 €/kW_{in}, round-trip efficiency: 81 % (90% charging and 90% discharging efficiency); discount rate: 10%. Levelized cost: 574 €/MWh_{out}.

Power-to-gas

Figure 22 displays the influence of the parameters investment cost, annual O&M cost, conversion efficiency and discount rate on the economic performance of the power-to-gas route. These parameters do not affect the curtailment reduction.

Similarly to sensitivity in power-to-power conversion, the investment cost is the main cause of uncertainty here. The levelized cost hardly reacts to changes in annual O&M cost.

Again, the discount rate directly influences the investment cost in the calculation of the levelized cost. Therefore, it has a rather strong influence.

The conversion efficiency of the process is varied in the range of 50 – 77%, 60% being the base value that was identified in the technology characterization. 50% is chosen arbitrarily as a bottom limit, while 77% is the maximum theoretical efficiency that the process can reach. Variations in the conversion efficiency do not affect the curtailment reduction. The amount of absorbed electricity is only determined by the installed capacity. The conversion efficiency determines the amount hydrogen that is produced from the absorbed excess. An increased conversion lowers the levelized cost significantly. Although the range of uncertainty in the efficiency is small in comparison to the investment cost, the levelized cost reacts strongly to the efficiency.

Furthermore, the conversion efficiency also has an influence on the benefits. The benefits rise if more hydrogen is produced per unit of excess electricity. However, this has already been considered in this analysis. The benefits and levelized cost both address the amount of delivered energy (hydrogen) and take the conversion efficiency into account.

This discussion reveals that power-to-gas conversion is not profitable, despite the uncertainties.

There are several other uncertainties that have not been addressed yet. First of all, power-to-gas conversion is modeled with an availability of 100%. However, it is not guaranteed that hydrogen can always be added to the natural gas grid. There may be constrains that ensure a certain quality of the network gas. Therefore, it might not be possible to feed in hydrogen at varying rates.

Several reports are found that investigate the maximum hydrogen content that the gas network can cope with. A study by Müller-Syring & Henel [2012] is based on the assumption that a hydrogen concentration 5 vol-% can be reached. Tiekstra & Koopman [2008] are more optimistic; they claim that "…up to a 20% hydrogen level might be feasible in some European countries [Tiekstra & Koopman, 2008]". However, they also point out that pipelines have to be evaluated a case-by-case. For example, some steels may react with hydrogen, which reduces the lifetime of a pipeline. Nonetheless, integrating 5 – 10 vol-% of green hydrogen into the gas grid represents a large potential for converting excess electricity. A quantitative figure of the amount of hydrogen cannot be presented as the amount of gas consumption varies throughout the year and the physical feed-in of hydrogen into the gas grid (blending station) might be a bottle-neck.

The literature also discusses the possibility of storing hydrogen in storage facilities. It is possible to store hydrogen at high pressures in underground salt caverns [Stone et al., 2009; Crotogino & Donadei, 2010; Roads2HyCom, 2013]. Therefore, it is also be possible to store a mixture of natural gas and hydrogen in salt caverns. The Netherlands does not have access to large storage capacity in salt caverns. Storing hydrogen (or mixtures of natural gas and hydrogen) would probably be possible in emptied gas fields in The Netherlands. However, emptied gas fields are usually porous structures. The pores were small enough to stop methane from escaping the gas field, but it might be possible that hydrogen escapes the reservoir [Stone et al., 2009]. Alternatively, hydrogen can also be stored in manmade underground tanks [Roads2HyCom, 2013].

This study only considers the cost for producing hydrogen at a pressure of about 30 bar. All further processing steps (blending with natural gas, managing homogeneity of the network gas and storing hydrogen) will lead to additional cost. It is not possible to give a quantitative figure.

Selling hydrogen to the gas grid leads to relatively low revenues for the hydrogen producer. The value of natural gas from gas grid is defined by its heating value, i.e. its energy content.

It may be worthwhile to investigate other business cases that potentially enable the technology to operate cost-effectively. Several examples are identified:

Hydrogen can be a transport fuel for cars (fuel cell). As the issue of storing hydrogen in a vehicle are not overcome yet, it might also be interesting to convert hydrogen into methanol, which would be a convenient fuel [VNCI, 2012].

However, the conversion to methanol requires a rather pure source of CO_2 [VNCI, 2012] and the conversion process from electricity to methanol would suffer from a lower conversion efficiency, which would drive up the production cost [Kersten, 2012]. Nonetheless, transport fuels are sold at a higher price than natural gas, which would also increase the benefits significantly.

Hydrogen can also be stored and converted back into electricity in a fuel cell or turbine. This route would be equivalent to power-to-power conversion, because electricity is returned to the grid. Storing hydrogen increases system costs. The round-trip efficiency would be rather low (~40%).

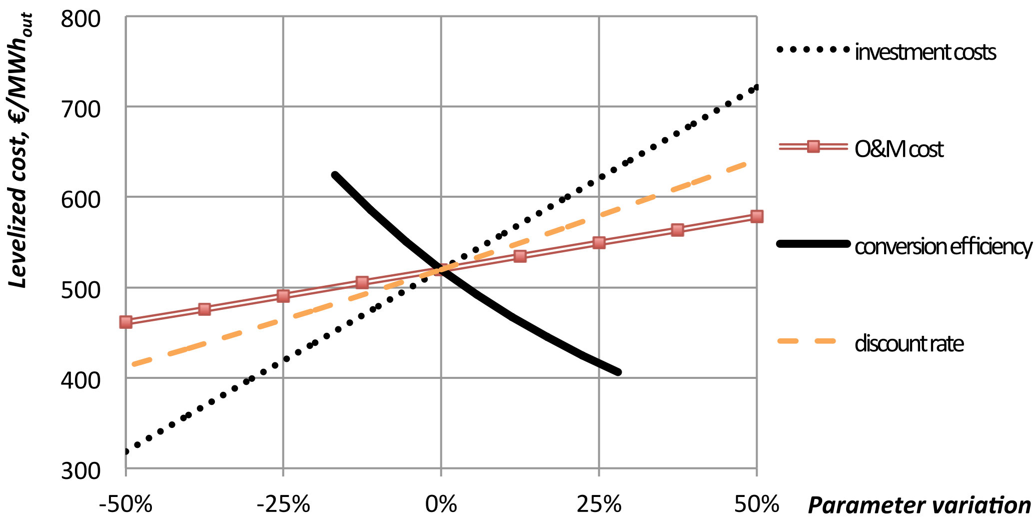

Figure 22: Uncertainties in the characterization of power-to-gas. The analysis is carried out in the 2020 scenario. The curtailment reduction rate is set to 66% in the base case by installing a capacity of 1820 MW_{in}.
The following base values are varied: Investment cost = 1329 €/kW_{in}, annual O&M cost: 50.7 €/kW_{in}, conversion efficiency: 60.1 %; discount rate: 10%. Levelized cost: 520 €/MWh_{out}

6.3. General remarks on excess electricity

Throughout this report, it is assumed that excess electricity can be obtained at zero cost. This is justified because a product that does not address a demand has no economic value. However, excess electricity does not occur spontaneously. The production of volatile electricity and the demand are forecasted. It is questionable whether a market will knowingly produce excess electricity and give it away for free in the future.

Since it is not known how the electricity market will change if share of 40% volatile electricity is exceeded, it is highly uncertain if and how excess electricity will be traded[40].

It may sound appealing to allow conversion technologies to buy electricity at the regular market. If the conversion was not limited to excess electricity, the levelized cost could be brought down considerably. By increasing the full load hours of the technologies, they might become economically more attractive. Also, a more continuous operation would decrease the wear and tear during start-ups and shutdowns.

Although economically interesting, the conversion of ‘non-excess’ electricity might undermine the primary goal of the conversion technology. The original motivation is the increase of system renewability, which causes excess electricity by installing large amounts of volatile capacity. Conversion technology is considered with the intention of further increasing system renewability by integrating renewable electricity that would otherwise be curtailed. However, during a ‘non-excess’ event, operation of conversion technology would increase demand for electricity and thereby production from conventional dispatchable power plants. Dispatchable power will most likely originate from fossil fuel plants, even in 2020.

Excess electricity is available for only 1000 hours in the 2020 scenario. Therefore, conversion technologies would most likely convert more conventional than renewable electricity. By allowing conversion technology to also buy electricity when excess is not available, the proposed technologies would actually increase the share of fossil energy in the system.

To what extent wind and solar electricity will be curtailed in the future will also depend on the societal cost induced by curtailment. The total cost of an electricity system will likely be more expensive at high curtailment rates; but a quantitative analysis is difficult. There may be subsidies that guarantee a benefit to the producer of renewable electricity, regardless of whether electricity is actually fed into the grid. The issue of curtailment has to be discussed in the broader context of the energy transition.

[40] For example, the economic evaluation of conversion technologies might change, should electricity be priced on consumed capacities instead of amounts of electricity.

7. Conclusion

If the phenomenon of excess electricity is not addressed, free and renewable electricity will have to be curtailed in the future. In other words, wind turbines and solar panels will be turned off whenever the grid cannot integrate their electricity production. The goal of this study was to answer the question: Are power-to-power, power-to-heat and power-to-gas conversion suitable measures for reducing curtailment in the future?

The performance of the technologies was evaluated with respect to a certain amount and distribution of excess electricity, which was forecasted in a simulation of a Dutch 2020 scenario. For the year 2020, this study predicts an amount of 2 TWh of excess electricity (4% of volatile production), which occurs for about 1000 hours per year at various capacities. Excess electricity is mainly caused by large installed capacities of wind and solar, the output of which is highly volatile. Moreover, the intra-day variations in the electricity demand have a strong influence.

Conversion of excess is simulated and the performance of conversion technologies is evaluated on the basis of the indicators 'curtailment reduction' and 'levelized cost'. The technologies considered in this research have the potential of reducing curtailment significantly, but none of them can operate cost-effectively in the 2020 scenario.

In general, levelized costs increase with larger installed capacities. The amount of excess is finite and installing more conversion units will make them compete for the same amount of electricity. This trend can be illustrated with the example of power-to-heat conversion: For the very first unit of power-to-heat conversion that is installed in the 2020 scenario, levelized cost for producing heat are calculated to 200 €/MWh_{out}. The effect of one unit on the curtailment reduction is only marginal. If more conversion capacity is installed, levelized costs increase; in order to reduce curtailment by 50%, 1300 MW of conversion capacity is required, which increases the levelized cost to 250 €/MWh_{out}.

Power-to-power conversion is often limited in its available capacity because the storage capacity is limited. When batteries are fully charged, they are not available for converting electricity until the end of the excess event.

The profitability of power-to-power conversion is derived from the hourly electricity price and strategies for triggering discharge are analyzed. It is found that power-to-power storage should not postpone discharge by waiting for high electricity prices (during peak residual demand). Battery storage should be emptied as soon as possible to increase availability. For the overall economic performance, as it is simulated in this study, it is more important to maximize energy throughput (load factor) in order bring down the levelized cost.

Levelized costs of power-to-gas and power-to-power conversion are roughly 10 times larger than the potential benefit that these technologies can generate (2020 scenario, 66% curtailment reduction).

For the year 2020, none of the technologies are able to operate cost-effectively. Power-to-heat conversion is expected to generate benefits at about 100 €/MWh_{out}, which makes it the least costly alternative. Despite the uncertainties in the investment cost and other parameters, this study has not been able to find a profitable business case.

The study also examined the situation in a 60% scenario (60% electricity from wind and solar). The amount of excess electricity increases dramatically[41], which increases the throughput (load factor) of the conversion technology and thereby lowers the levelized cost.

A 60% scenario might be reached in a very distant future; therefore, uncertainties in the technology evaluation are much higher. The first technology that might become profitable is the power-to-heat conversion, followed by power-to-gas. Power-to-power conversion cannot cope well with the long continuous excess events that are observed in the 60% scenario (4000 hours of excess per year). Power-to-power conversion in batteries is not suitable for reducing curtailment in a highly volatile scenario.

The potential role of power-to-gas conversion in reducing future curtailment remains unclear. On the one hand, the technology generates small benefits because of its low conversion efficiency (60%) and the low price for natural gas. The levelized cost is several orders of magnitudes higher; and sensitivity analysis confirms that profitability can certainly not be reached by 2020. On the other hand, power-to-gas conversion might become attractive because of its unique features: Power-to-gas conversion units can be placed close to wind parks, an important source of excess electricity. Thereby, the power-to-gas route does not increase the stress on the electricity grid. Furthermore, hydrogen can potentially be stored for very long times, which enables a seasonal storage of energy.

Regarding the research question, it has to be concluded that none of the technologies can be operated cost-effectively in the 2020 scenario. Should it be decided to build a technology anyway, power-to-heat conversion would cause the lowest cost. Power-to-gas conversion is suitable in bringing down curtailment, but it remains a rather costly technology. Power-to-power conversion in central battery facilities cannot be recommended. It suffers from a limited curtailment reduction potential and very high levelized cost.

There is a trade-off between increasing economic performance and curtailment reduction, because the levelized costs increase with growing installed capacities. Even if more profitable technologies are developed, it will always remain relatively costly to absorb the highest peaks in the excess electricity curve, which only occur for very few hours of a year.

This report is concluded with some general remarks on the phenomenon of excess electricity.

Throughout this report, it is assumed that excess electricity can be obtained at zero cost. This is justified because a product that does not address a demand has no economic value. However, excess electricity does not occur spontaneously, because the generation of volatile electricity and the demand are forecasted. It is questionable whether a market will knowingly produce excess electricity and give it away for free in the future.

[41] About 28 TWh of excess are observed in the 60% scenario, which a highly uncertain figure.

Levelized costs of excess conversion technologies could be reduced, if it was allowed to also convert electricity bought on the regular market. However, this practice will undermine the aim for increased renewability.

To what extent wind and solar electricity will be curtailed in the future will also depend on the societal cost induced by curtailment. Even if the conversion of excess electricity becomes profitable in the future, it is unlikely that curtailment will be avoided completely. It has been shown that curtailment reduction follows the Pareto principle: The first installed conversion units have a large effect, while the complete reduction of excess will call for unreasonably large conversion capacities.

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Appendix

Appendix A: Description of dispatchable power plants – participants in merit order.

The following table gives an overview of all participants that are considered in the simulation. The data is provided by Quintel Intelligence [2010] and was used in the Energy Transition Model in February 2013. The figures do not match the reality exactly, especially, the number of units do not match the exact number of physically installed power plants. The Energy Transition Model assumes that all participants of a certain type act alike, which is not the case in reality, were two pulverized coal plants can have different efficiencies, full load hours and marginal operation costs. Conclusively, they would also produce different amounts electricity during a year. The Energy Transition Model adjusted so that it closely matches the energy flows that are reported by [CBS, 2012a] for the year 2010.

As the fuel and CO_2 prices change more rapidly than the annual energy flows, they are updated more frequently. The model calculates with up to date fuel and CO_2 prices (beginning of 2013).

	Profile	Effective output capacity / unit	Full load hours	Number of units in 2010	Installed capacity 2010	Installed capacity 2020 scenario	Installed capacity 60 % scenario	Availability	Marginal operation cost
		MW	h		MW	MW	MW		€ / MWh
Volatile renewables									
Wind turbine inland	Wind inland	3	2500	360	1080	2748	5495	0.95	0
Wind turbine coastal	Wind coastal	3	3000	67	200	2748	5495	0.95	0
Wind turbine offshore	Wind offshore	3	4000	65	194	7438	14876	0.92	0
Solar PV on other buildings	Solar	0.01245	1050	2550	32	1381	2761	0.98	0
Solar PV on residential houses	Solar	0.001245	1050	51000	64	2765	5531	0.98	0
Must-run participants									
Waste incineration	Industry CHP	54	6190	12	630	649	649	0.90	1.21
Central space heating CHP, natural gas	Buildings CHP	0.5	2680	872	406	406	406	0.97	99.44
Industrial CHP, natural gas	Industry CHP	25	5440	135	3440	2880	2880	0.97	116.94
Dispatchable participants									
Nuclear power plant	n.d.	1600	n.d.	0.32	510	526	526	0.90	5.54
Ingetraged gasification combined cycle coal plant	n.d.	784	n.d.	0.32	253	258	258	0.90	21.82
Pulverized coal plant	n.d.	792	n.d.	3.39	2686	2714	2714	0.88	27.55
Pulverized coal plant, incl. heat generation	n.d.	706	n.d.	2.37	1670	1687	1687	0.88	30.90
Combined cycle gas turbine	n.d.	784	n.d.	5.10	4002	4084	4084	0.90	47.16
Gas plant, incl. heat generation	n.d.	575	n.d.	5.75	3306	3373	3373	0.90	64.30
Conventional steam-turbine gas-fired power plant	n.d.	792	n.d.	4.83	3824	3863	3863	0.89	70.27
Gas turbine	n.d.	147	n.d.	1.44	212	216	216	0.89	83.15

Costs relevant to the short-term marginal operation costs:

Uranium	Coal	Natural gas	CO_2	Free allocation of CO2 emission rights
71 €/kg	99 €/t	26.5 €/MWh	5 €/t	85% *

* The percentage of CO2 emission rights that electricity production companies receive for free.

Appendix B: Profile generation

If possible, profiles are based on physical data. For volatile participants, this is usually the energy carrier that is exploited by the converter, i.e. wind speeds and light intensities. Data from different locations is combined (data from 2010). The following procedure will deliver one profile per participant:

Step 1. Conversion of primary energy into electricity output: For each location, the electricity output of a typical converter is calculated. This is done by applying conversion laws and efficiencies (including for example, cut-in, cut-out speeds in case of wind, or peak-power in case of solar cells).

Step 2. Average of power output: The electricity output is averaged over the different locations.

Step 3. Normalization. The averaged profile is normalized vertically so that the area under the profile is equal to 1/3600. Normalization ensures that the participant will produce the correct amount of MWh/year in the simulation (adapted from the Energy Transition Model). The energy output of a participant is determined by research data (effective capacity/unit, full load hours and the number of units. The annual energy output of a converter should match reality.

Step 4. Full load hour check. The profile *"should"* also reflect the full load hours of the respective participant. A profile has an intrinsic full load hour characteristic that is described by *Full Load Hours (profile) = Total(profile) / Max(profile)*. For example, a flat profile that will make a participant run at a constant load throughout the year will have 8760 full load hours even though the technology is specified to run for only 6000. Also, if wind turbines with a nameplate capacity of 3 GW are installed, it should not happen that the model operates them at 5 GW in certain hours of the year. This problem can only be avoided if the full load hours the profile are realistic.

The full load hours that are used in the model are based on research. The profiles that are created for the participants also represent the full load hour characteristics. It should be noted that the amount of full load hours has a direct influence on the annual energy production of a technology. As the full load hours of wind and solar depend on weather conditions, the full load hours actually change from year to year.

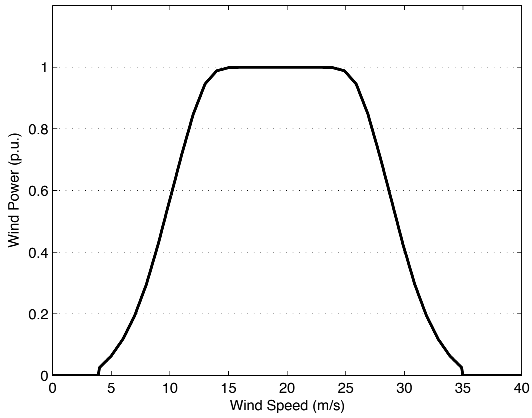
Wind and solar profiles

The wind and solar profiles that are used in the model are based on 3 or 4 measurement curves. Combining more curves leads to smoother and less peaked profiles. A smoother profile is characterized by more full load hours.

Inland wind profile: The inland profile is based on wind speed measurements from Schiphol, Berkhout, Lelystad and Wilhelminadorp[42].

It is found that large wind parks behave according to an aggregated wind speed to power conversion curve: [Gibescu et al., 2006]:

[42] Koninklijk Nederlands Meteorologisch Instituut (KNMI) publishes wind speed measurements on http://www.knmi.nl/klimatologie/uurgegevens/selectie.cgi



The wind speeds measurements are converted into hourly energy outputs in accordance to this curve, under consideration of typical cut-in, cut-out and rated speeds. These wind speeds are published by wind turbine manufacturers, for example by Vestas [2012].

Coastal wind profile: The coastal profile is based on wind speed measurements from Valkenburg, De Kooy, Stavoren and Lauwersoog[42]. The conversion to electrical power is done with the same calculation as the inland profile.

Offshore wind profile: The offshore profile is based on wind speed measurements from the locations K13, Huibertgat and Europlatform43. A forth measurement curve is not available for the year 2010. The power curve is adapted to the wind speed characteristics provided by Vestas [2011].

Solar profile: The solar profile is based on solar irradiation measurements in Schiphol, De Bilt, Leeuwarden and Twenthe44. The photon energy is converted into electric energy with a conversion efficiency of 18%.

Buildings CHPs:
The buildings CHP is based on a natural gas consumption pattern of households. The gas consumption is a good representation of space heating demand. This data is obtained from GasTerra[45]. Unfortunately, no 2010 data was available, in consequence, the profile is based on data 2012. Since 2010 starts on a different day than 2012, the data from 2012 has to be corrected so that it matches the weekend pattern of 2010. The profile is adjusted accordingly.

Industrial CHPs:
Data on the operation of industrial CHPs is not available. It is assumed that industrial CHPs are deployed in high-temperature processes, for example in refineries. These processes run

[43] KNMI: http://www.knmi.nl/klimatologie/onderzoeksgegevens/potentiele_wind/
[44] KNMI: http://www.knmi.nl/klimatologie/uurgegevens/selectie.cgi
[45] GasTerra provided Quintel Intelligence with a gas consumption pattern. The data originates from a model developed by GasTerra. It has an hourly resolution and considers outside temperatures and typical demand fluctuations on weekdays and weekends. [Contact person: Anne Braaksma/GasTerra].

constantly, they are not shut down during the night or the weekend. Therefore, industrial CHPs have a profile that is ‘always on’.

Demand for electricity

The profile for electricity demand follows actual measurements[46] of power consumption that is measured in the high voltage network. The profile is rather accurate, but has the shortcoming that it does not reflect local production and direct consumption of electricity (for example by solar and small-scale CHPs). The data is based on the year 2010 and provided by the Dutch electricity transmission system operator TenneT.

[46] The TenneT data curve for electricity demand is obtained via the TenneT website: http://www.tennet.org/bedrijfsvoering/ExporteerData.aspx?exporttype=Meetdata