# The Role of Hydrogen in the Dutch Electricity System

*Technical report*

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# Summary

In this technical report, we look at the role that novel power-to-gas, repowering and storage technologies, including hydrogen, synthetic methane storage and batteries, may play in the transition to a low-carbon electricity system in the Netherlands. More precisely, this study seeks to identify which generation, conversion and storage technologies should be deployed, and in what quantities, in order to supply the electrical load at minimum cost whilst satisfying technical constraints and pre-specified policy targets. The study relies on an energy system model recently published in the academic literature, and a scenario-based approach is adopted to evaluate the influence of various techno-economic assumptions formulated in the study.

For emission reduction goals of the Dutch electricity system of 49%, 75% and 99%, we find that the usage of conversion and storage technologies is optimal only in the case of a 99% emission reduction goal. Emission reductions of 49 and 75 percent are possible only with scaling up onshore wind and especially offshore wind - no storage technologies, such as hydrogen, are needed. These findings stay valid also in the face of various sensitivity analyses of the techno-economic assumptions used.


# 1. Introduction

In the Paris Climate Agreement, the Netherlands has committed to a switch from its fossil fuel-based energy system to an energy system characterised by zero-carbon emissions and the usage of renewable energy sources (RES). More precisely, the Dutch 'Climate Law', which was passed in 2019, stipulates that emissions should be reduced by 49% compared to 1990 levels by 2030, and shrunk by 95% by 2050 across the entire Dutch economy. The consequence is that the Netherlands should transition towards 100% renewable electricity generation by 2050 (Klimaatakkoord, 2019). In particular, by 2030, 70% of all electricity needs to be renewable, which is a challenge given that currently only 14.93% of produced electricity comes from renewable energy sources (CBS, 2019). The renewable electricity goals are to be met with offshore and onshore wind, distributed and utility-scale solar PV plants, but also bio-energy and geothermal energy (Rijkoverheid, n.d.). This increase in renewable, mostly intermittent energy sources results in challenges for security of supply. To ensure that the load can be served at all times, both electricity infrastructure development and the usage of flexibility options should be promoted. Hydrogen is one of the possibilities to provide flexibility to the electricity system. The objective of this research is to evaluate the role of power-to-gas and gas storage technologies in the Dutch electricity system and how they compare with alternatives, e.g. batteries. We hope to shed some light on the potential of hydrogen as a storage technology and its role in the future Dutch electricity system.

# 2. Research Question and Scope

The present document is concerned with the role that novel power-to-gas, repowering and storage technologies, including hydrogen, synthetic methane storage and batteries, may play in the transition to a low-carbon electricity system in the Netherlands. More precisely, this study seeks to identify which generation, conversion and storage technologies should be deployed, and in what quantities, in order to supply the electrical load at minimum cost whilst satisfying technical constraints and pre-specified policy targets. Hence, the purpose of this Special is twofold. On the one hand, the analysis gives insight into the complementarity and interaction between traditional renewable and fossil fuel-based electricity generation technologies as well as the aforementioned energy conversion and storage technologies. On the other hand, the capacities of each technology required to satisfy the electricity demand whilst reducing carbon dioxide emissions are assessed quantitatively, along with total system costs. The study relies on an energy system model recently published in the academic literature, and a scenario-based approach is adopted to evaluate the influence of various techno-economic assumptions formulated in the study.

# 3. Methodology & Modelling

## *3.1. Model Description*

### 3.1.1. Basic Assumptions

The problem of modelling the electricity system of a country in its full complexity remains a daunting challenge to this day, in spite of the vast computational power modern computers afford. Thankfully, such a level of detail is unnecessary for the purpose at hand. Indeed, in the context of medium-term planning studies, the main objective is to identify system configurations satisfying short and long-term adequacy requirements, which can be achieved with a simplified representation of the physics and operation of the power system. The most salient assumptions introduced to construct the simplified energy system model used throughout the study are described next.

Firstly, the physics of the transmission and distribution systems are reduced to a power balance law, which guarantees that power generation matches the load at every hour in the time horizon considered. In other words, the full spatial extent of the power system is neglected, and the network is collapsed into a single node. As a result, such a model cannot identify upgrades to the power transmission and distribution infrastructure that would be required to host a given generation mix. Likewise, it cannot evaluate the frequency and voltage stability of power system designs. However, it will yield minimal system designs guaranteeing short-term adequacy, and, by optimising over a time horizon spanning at least a year, medium-term adequacy as well.

Secondly, it is assumed that investment decisions in power generation, energy conversion and storage assets are made by a central planner who also operates the system, and whose purpose is to minimise the total system cost. This mode of operation, whereby the cheapest technologies are built and dispatched whenever possible, approximates the problem faced by a market operator, and thus also the resulting market outcomes, despite the fact that multi-agent interactions inherent in real market processes are not captured. It also implies that the operation of various assets is perfectly coordinated, which may not be the case in practice, and such a framework will therefore tend to underestimate costs resulting from such inefficiencies.

Thirdly, it is assumed that the central planner has perfect foresight and perfect knowledge of the state of the world. Put differently, the model is fully deterministic. Indeed, realizations of the load and renewable production are assumed known ahead of time, as if a perfect forecast were available for the entire investment and operational horizons. Likewise, all investment and operating costs as well as technical parameters are assumed known with certainty. As a result, the model cannot capture the short-term and long-term reserve requirements typically needed in practice, and may tend to undersize the generation portfolio.

Finally, it is assumed that electricity can be imported from or exported to neighbouring countries via an electricity interconnection whose capacity is fixed. Electricity exchanges are only constrained by the capacity of the interconnector and possibly a budget constraint which, for instance, sets the maximum volume of electricity that may be imported in any given year. Hence, unless the interconnector is saturated or the annual imports budget has been entirely used up, electricity can be imported from neighbouring countries at any time, even when local renewable production levels are especially low. This assumption usually implies that power system adequacy is overestimated. Indeed, as a result of the correlation between local and regional renewable resource regimes, it appears unlikely that neighbouring countries will always be able to supply the desired electricity when low renewable generation events occur.

Additional assumptions of a somewhat more technical nature are detailed in (Berger, et al., 2018; Berger, et al., 2019). It is worth noting that the nature of all aforementioned assumptions is such that the model will provide a conservative lower bound on costs and capacities required in the system. Such a modelling approach is neither well-suited to evaluate whether an individual technology or plant has a positive business case, as seen from the perspective of the owner and operator of a given asset.

### 3.1.2. Data

In order to instantiate the energy system model, input data is required. Broadly speaking, the data fall into five categories, which are reviewed next.

Firstly, techno-economic data is required to accurately represent investment and operational choices the system planner and operator can make. More precisely, the investment, operating costs as well as all technical parameters governing the sizing and operation of all candidate technologies must be specified. Secondly, information about the quality and availability of intermittent renewable resources over the entire horizon considered must be provided. For a given resource, this will typically take the form of a time series of capacity factors indicating to the system operator how much of the installed capacity will be available for power generation at any time instant. Then, the hourly electricity demand for which the power system will be sized must be specified. Once again, this will typically take the form of a time series representing the electricity load over the entire horizon of interest. In the model used throughout this study, it is assumed that electricity exchanges can take place between the Dutch power system and neighbouring countries. Though the interconnection capacity is assumed fixed, regional wholesale prices must be specified for the system operator to identify whether and when it is worth importing or exporting electricity. Finally, policy targets representing constraints on system design and operation must be defined and specified in the model. In the case at hand, these policy targets represent carbon dioxide emissions and electricity import quotas, expressed annually.

The data used in this study is further discussed in the scenario description section, while tables providing the values of the main techno-economic parameters can be found in the appendix, along with a full list of references.

### 3.1.3. Model Capabilities

Based on the aforementioned assumptions and input data, a simplified energy model can be constructed. This model, which is formulated as a mathematical optimisation problem, selects the technologies that should be deployed among a set of candidate technologies, along with their respective capacities, in order to supply the electricity load at minimum cost whilst respecting physical, operational and policy constraints. In addition, a set of high-level, techno-economic metrics can be extracted to evaluate the performance of the system design identified by the model. For instance, the total system cost, the electricity cost, the cost breakdown by technology, the energy flows and the carbon dioxide emissions can be retrieved easily. Some of these metrics will be reported in the upcoming section presenting and discussing the results of the present study. In summary, Figure 1 shows the scope of model capabilities. In particular, it is worth emphasizing that the model used in this study does not account for hydrogen demand for applications other than seasonal storage and repowering, and it is therefore not suited to evaluate the role hydrogen could play in the full energy system, e.g., by displacing fossil fuels in certain key economic sectors.

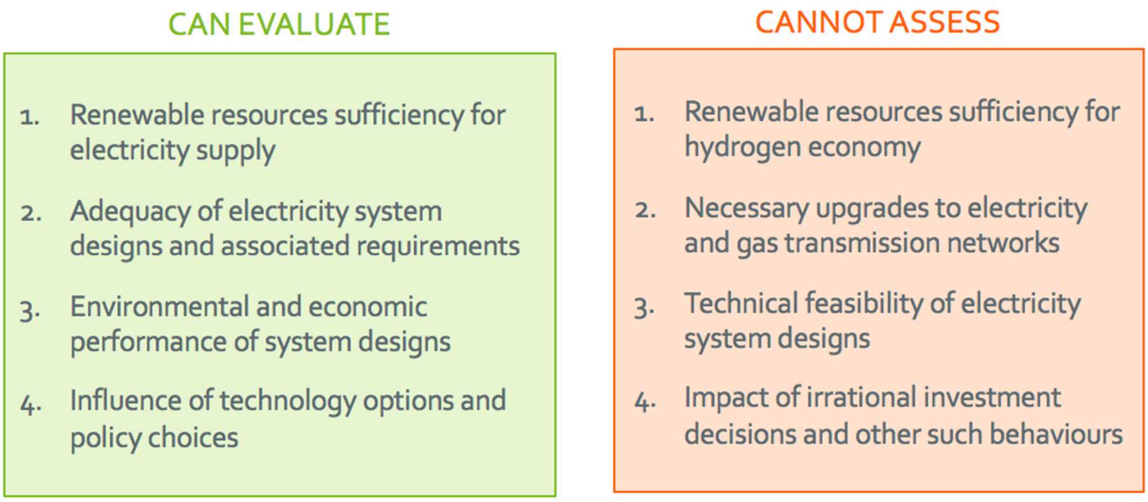


*Figure 1. Capabilities of the underlying model. Source: University of Liege.*

### 3.1.4. System Configuration

The technologies and a schematic of the system configuration considered in the present study are shown in Figure 2.

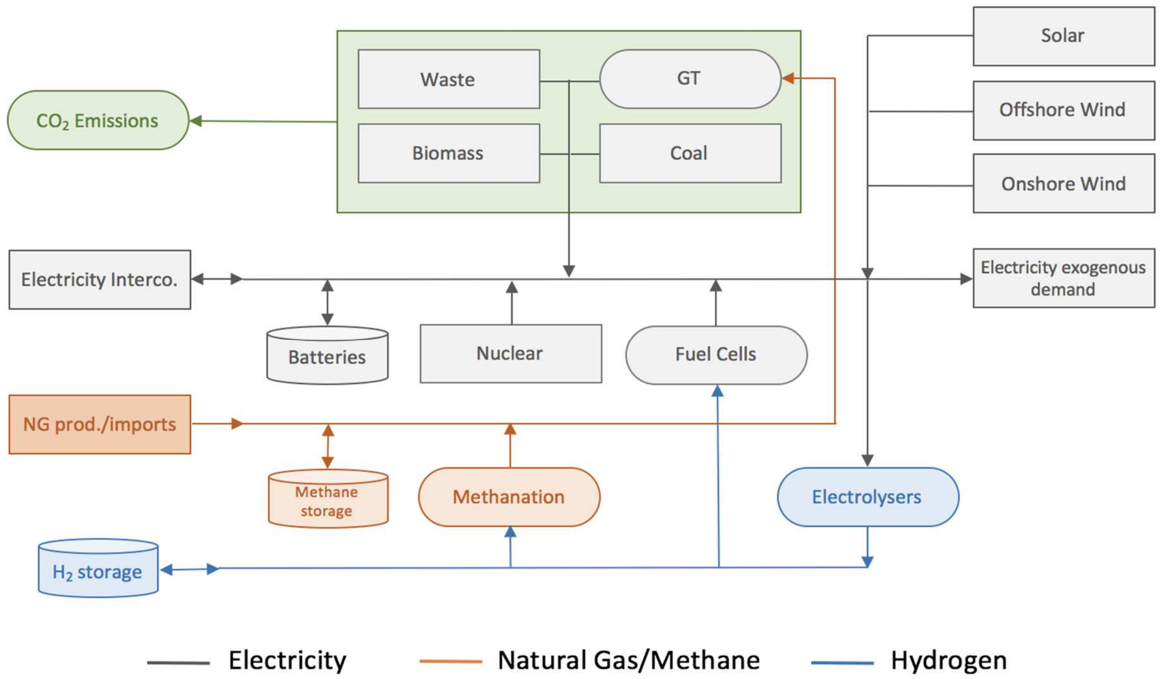


*Figure 2. Schematic of system configuration. Source: University of Liege.*

Three energy carriers are considered, namely electricity, hydrogen and synthetic methane/natural gas. For the purpose of the study, synthetic methane and natural gas are assumed to be interchangeable. Arrows represent energy flows (and their directions), while boxes represent technologies or system boundaries. In particular, both the electricity interconnection and storage systems may experience bi-directional flows, which is shown by bi-directional arrows. It is worth noting that the supply of exogenous carriers like waste, biomass, uranium or coal is not explicitly modelled and it is therefore excluded from the schematic. The colour of arrows indicates the type of energy carrier, while the colour of boxes indicates the output carrier of the corresponding technology. Finally, the technologies emitting carbon dioxide are found in the green box.

## 3.2. Comparison with other models and studies

To the best of the authors' knowledge, at least two similar models have been used in previous studies of the Dutch energy system, namely the OPERA and COMPETES models. Their basic features are first reviewed, before key differences between them and the present model are briefly discussed.

On the one hand, a whole energy system approach is adopted in the OPERA model (ECN, 2014). Hence, several energy carriers are considered, e.g., electricity, natural gas or hydrogen, along with several sectors such as transportation or heating. The model relies on an optimisation framework, whereby a central planner invests in technologies and operates the energy system so as to minimise the cost of serving energy demand across sectors while satisfying a set of technical, policy or market constraints. A wide range of technological options is considered on both the supply and demand sides, including power-to-gas technologies but notably excluding gas storage technologies and other long-term energy storage options. Depending on the context, the spatial resolution of OPERA may be higher than that of the model used in this report, e.g., with one node used to represent a region of the Netherlands, whereas a single-node, country-wide representation has also been used in some studies. In addition, each node is subdivided into three voltage levels. Transmission between regions takes place at the highest voltage level, and is modelled via a simple transportation model. A similar approach is adopted for the gas network. Within a region, the underlying electricity network is not modelled, but power flows between voltage levels are constrained by the capacity of the transformers. A similar technique is applied to model the gas network. In contrast to the model used in this Special, the time resolution of OPERA is quite low, as time periods are aggregated into so-called time slices, of which only a few dozen (i.e., the ones deemed representative, from a production or demand perspective) are kept for each year in the planning horizon. Finally, the OPERA model has not been published, nor have the software implementation and the full data used in past studies been made openly available.

On the other hand, the COMPETES model focuses exclusively on power systems and electricity markets. At least two variants of the model exist (Özdemir, 2018). The first one is tailored to perform generation-transmission expansion planning assessments, whereas the second one is designed to tackle the unit commitment problem. Only the former is discussed in the following. The capacity expansion model relies on a centralised optimisation framework, such that all investment and operational decisions are made by a single agent with perfect foresight and knowledge, with the goal of minimising the cost of serving electricity demand profiles while satisfying a set of constraints. A variety of electricity generation technologies are considered, along with some storage technologies and demand-shifting strategies. However, power-to-gas or seasonal storage technologies do not appear among candidate technologies. In terms of spatial resolution, several nodes may be considered, while electricity exchanges between nodes are modelled via a transportation model and capped by net transfer capacities. The temporal resolution used in COMPETES is comparable to the one used in the present model, with an optimisation horizon of one year with hourly resolution. Finally, the full COMPETES model has not been disclosed, nor has a tool implementing the model been made publicly available.

Though OPERA and COMPETES have their own strengths and weaknesses and also share similarities with the model used in this report, none of them could be readily leveraged to tackle the research question pursued in this report. Indeed, the OPERA model does not include gas storage technologies, and the time-slice approach does not allow to accurately capture time coupling effects introduced by seasonal storage technologies. Moreover, the COMPETES model does not include power-to-gas and seasonal storage technologies, which therefore make it impractical for our purposes.

## *3.3. Scenario description*

The present study intends to provide a snapshot of the technology mix and configurations making it possible to achieve different levels of carbon dioxide emissions reductions for the power system, with a focus on the role of variable renewable energy, power-to-gas and storage technologies. All plants are aggregated into technology classes, and the central planner can only invest in variable renewable energy, power-to-gas and storage technologies to expand their capacities. Existing and maximum installable capacities are also taken into account for these technologies. By contrast, the capacities of all other technologies are set *a priori* based on predictions by the Dutch Planning Bureau. The reference year is chosen to be 2025, for which techno-economic data is retrieved. A full yearly optimisation horizon with hourly resolution is considered, and investment costs are reduced to yearly equivalents. For each technology, the equivalent investment cost value is obtained by multiplying the full investment cost value by the ratio of optimisation horizon length to technology lifetime. Finally, RES capacity factor and wholesale price time series were retrieved for 2017, and are used as proxies for those signals in 2025. Likewise, the electricity load time series was extracted for 2017 and used as a proxy. In other words, the evolution of electricity demand profiles as a result of, e.g., increased electrification, the introduction of electric vehicles, or the implementation of energy efficiency measures is not accounted for.

Then, several scenarios were designed to illuminate the effects of certain policy choices and technological developments on RES, power-to-gas and storage development. Firstly, we differentiate between two main policy scenarios: a scenario where 1990 emissions from the electricity sector, which are estimated to be around 40 Mt, must be reduced by 49% and a scenario where emissions reduction should reach 99%. We also compute an intermediate variant with 75% emissions reduction[1]. Secondly, we explore two technology scenarios: a reduction of CAPEX of offshore wind and electrolysis, and reduction of CAPEX of solar PV and batteries. These scenarios serve as a sensitivity analysis with respect to cost assumptions made for the main future generation and storage technologies. Lastly, we check how important the electricity interconnection is by running the 99% scenario without any electricity exchanges, as if the system were to function in complete autarky. This scenario can also be viewed as a security of supply scenario. The full data for the reference scenario can be found in the appendix.

# 4. Results

## *4.1. Scenario 1: 49% CO2 Emissions Reduction*

The first scenario aims to identify the system configuration which would allow for a reduction of carbon dioxide emissions from the power system by 49% from 1990 levels. Figure 3 displays the capacities of generation and conversion technologies which should be deployed to achieve this goal. Remarkably, in this scenario, neither storage nor power-to-gas technologies are needed. Indeed, increasing the capacity of onshore and offshore wind power plants to roughly 11 GW each is sufficient to reach adequacy whilst meeting the carbon dioxide emissions reduction target. It is worth mentioning that the onshore wind capacity is fully exploited and that solar PV capacity is not deployed any further, mostly as a result of the low capacity factor values of this resource in the Netherlands. In this scenario, no RES electricity is curtailed. Moreover, roughly 10 TWh of electricity is imported, while approximately 14.9 TWh of electricity is exported, resulting in net exports of 4.9 TWh. This phenomenon, which is partly driven by low wholesale market prices in neighbouring areas, can also be partly explained by the assumption that electricity can be exchanged with neighbouring countries irrespective of their local instantaneous production or consumption.

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[1] The 49% scenario is chosen to reflect the Dutch policy goal to decarbonize its economy by 49% by 2030. The goal of decarbonizing the Dutch electricity system by 70% in 2030 is reflected by the intermediate 75% emission reduction scenario in this study.

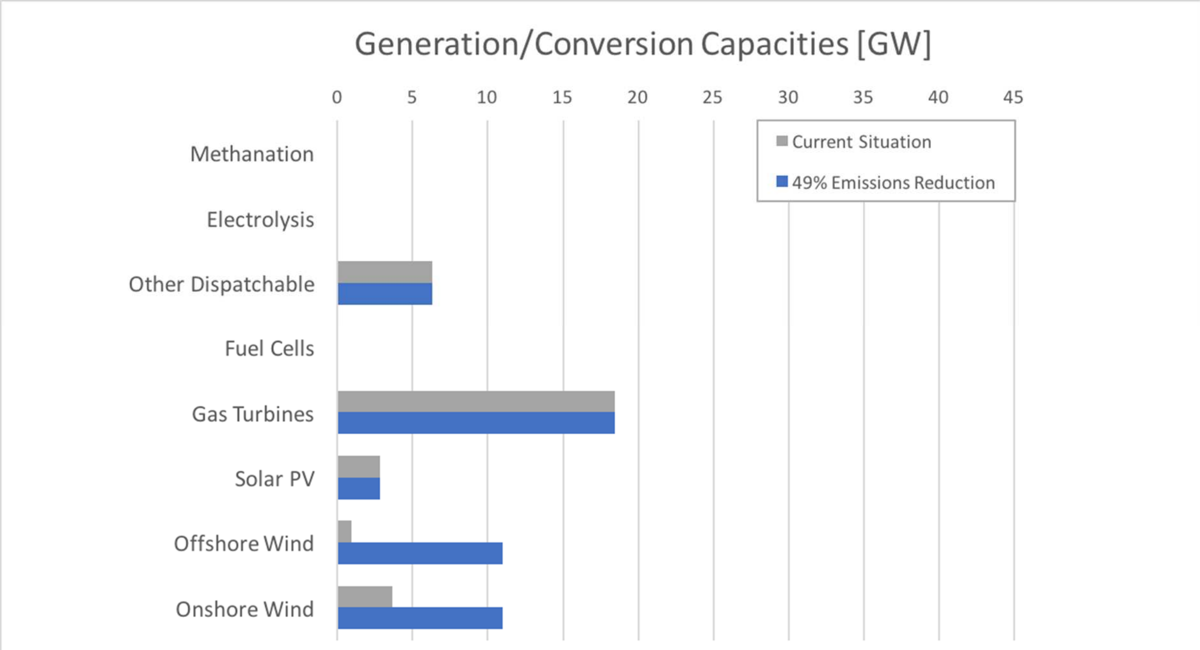


*Figure 3. Capacities of generation and conversion technologies in the 49% emissions reduction scenario.*

Figure 4 shows system operation over a four-week period between the months of January and February. It can be seen that coal-fired (dark grey) and gas-fired (brown) power plants are used for power generation when RES production fails to satisfy the load. In addition, gas-fired power plants are sometimes employed to produce some surplus electricity, which is exported. This can be explained by the fact that wholesale electricity prices in neighbouring regions (as given by the input data) are sometimes higher than the marginal price of gas turbines. Table 1 gives a detailed view of the associated full load hours and capacity factors of various technologies.

The total system cost, which includes both investment and operating costs, stands at 4.7 billion €/y, whereas the average electricity price is around 44.8 €/MWh. Approximately 40% of the total system cost stems from the use of natural gas-fired power plants, whereas 37% and 13% of it result from the investment in offshore and onshore wind power plants, respectively. The remaining 10% are split between electricity imports (6.4%) and dispatchable power plants operation (3.6%).

*Table 1. Load hours and capacity factors of various technologies in the 49% emissions reduction scenario.*

| | *Electro-lysis* | *Fuel Cells* | *Metha-nation* | *Gas Turbines* | *Biomass* | *Waste* | *Nuclear* | *Coal* |
|---|---|---|---|---|---|---|---|---|
| **Full Load Hours (hrs/year)** | 0 | 0 | 0 | 4742 | 12 | 121 | 8760 | 3420 |
| **Capacity Factor (%)** | 0 | 0 | 0 | 21 | 0 | <1 | 99.9 | 16.1 |

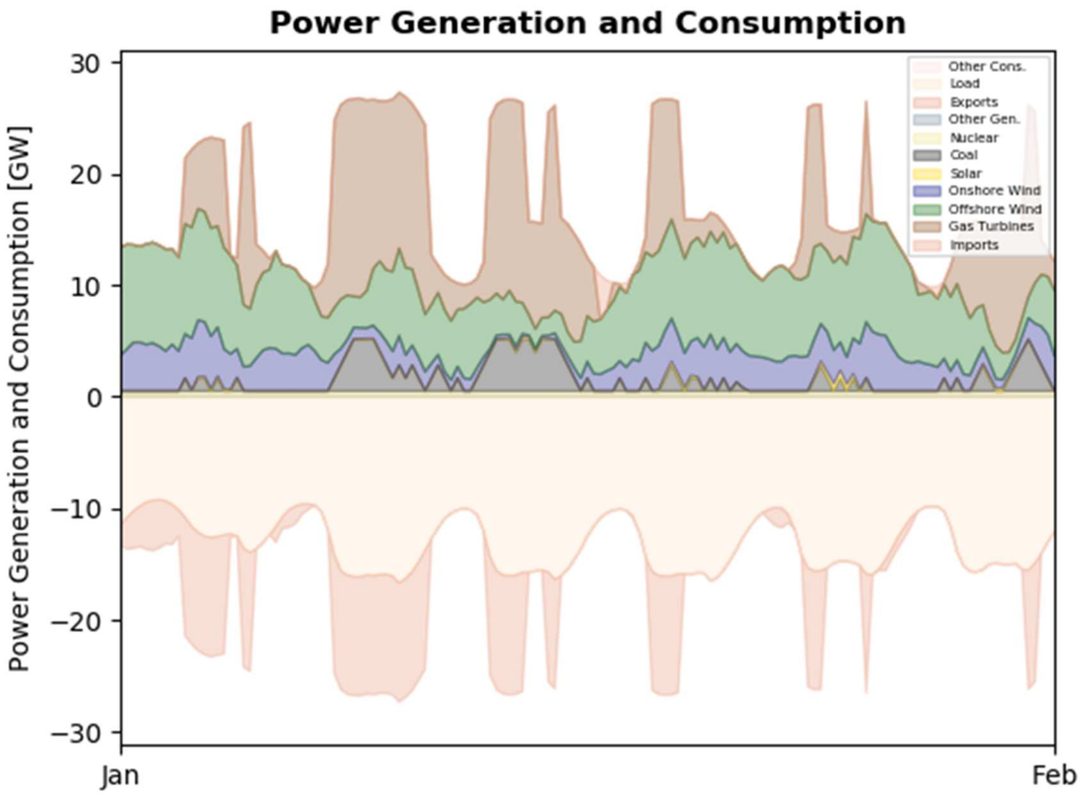


*Figure 4. System operation during a winter month (i.e., January) for the 49% emissions reduction scenario.*

Figure 5 displays a proxy of electricity prices over the year, with the dashed line showing the average (annual) electricity price. More precisely, this proxy quantifies the cost of serving one additional unit of electricity demand at any time instant, while respecting all constraints imposed on the electricity system. Hence, it often represents the cost of the marginal technology. However, in cases where the system is operating near its (adequacy) limits, this proxy essentially reflects the cost of investments in additional capacity that should be made to serve the extra consumption. The relative flatness of the electricity price profile shown in Figure 5 is a consequence of the fact that the marginal technology is often a fossil fuel-based dispatchable one. Indeed, the installed capacities of renewable power generation technologies are not sufficient to supply the load in its entirety. Thus, very often, the marginal technology is gas-fired power plants with a marginal cost around 55 €/MWh, which includes fuel costs of 20€/MWh and a carbon dioxide levy of 25€/t, respectively. The marginal cost of coal-fired power plants is slightly lower, at roughly 51 €/MWh.

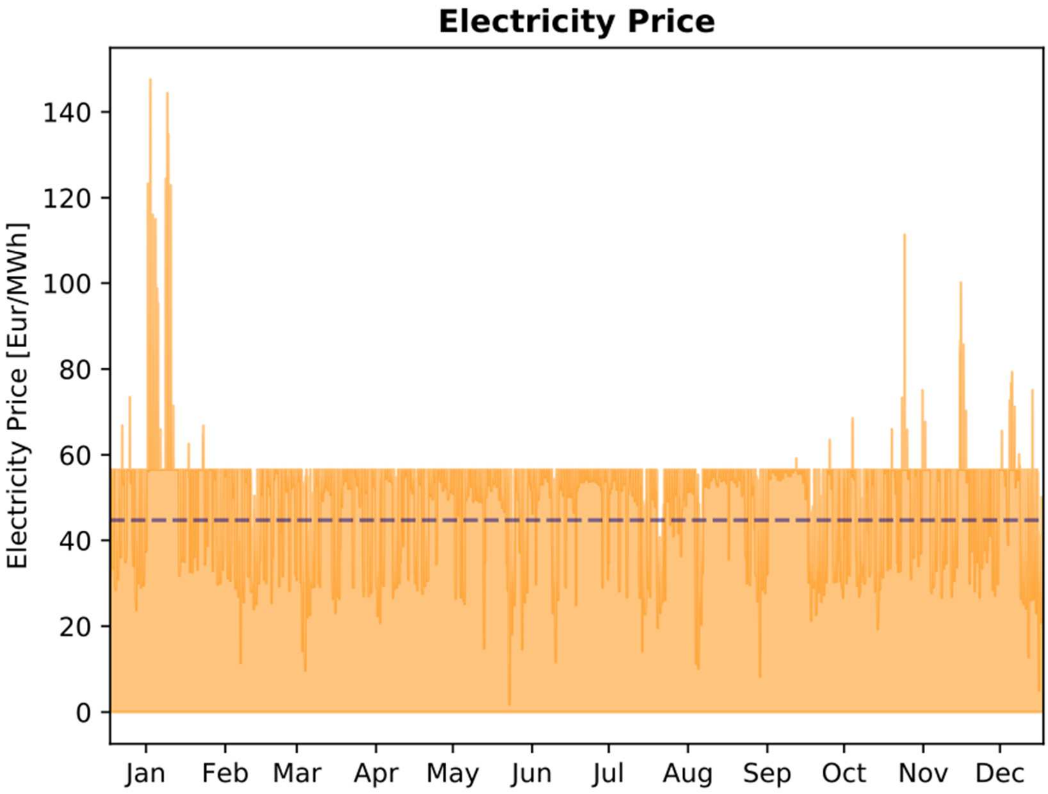


*Figure 5. Electricity prices in the 49% emissions reduction scenario.*

## 4.2. Scenario 2: Offshore Wind and Electrolysis CAPEX Reductions

The second scenario investigates the outcome of offshore wind and electrolysis CAPEX reductions, still with a view to decreasing carbon dioxide emissions by 49% from 1990 levels. Figure 6 summarises capacity deployments in this scenario. Storage technologies are still absent from the technology mix and are therefore not shown. Then, it is worth observing that no electrolysis capacity is built, despite the substantial reduction in investment costs. This result indicates that in such circumstances, it is still more economically attractive to oversize the renewable portfolio than relying on power-to-gas and storage technologies to achieve carbon dioxide emissions cuts. This claim is supported by the fact that electricity curtailment appears in this scenario, and stands at around 162 GWh, mostly from offshore wind. Secondly, it can be seen from Figure 6 that the offshore wind capacity increases substantially, whereas the onshore wind capacity shrinks compared to the scenario without CAPEX reductions. This shift can be explained by the fact that the capacity factor of the offshore wind resource (approx. 45%) is slightly more than double that of the onshore wind resource (around 20%). Hence, a 50% reduction of offshore wind CAPEX makes the energy-to-cost ratio of offshore wind slightly more favourable than that of onshore wind. System cost and average electricity price remain virtually the same, as the shift to offshore wind only provides marginal savings.

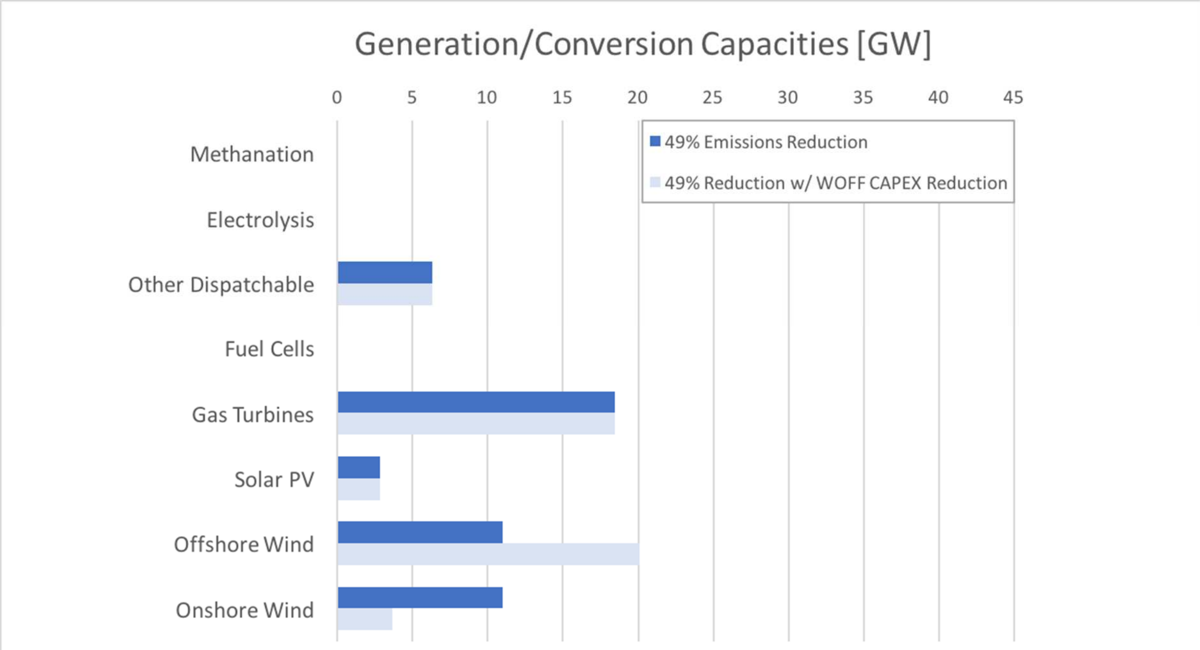


*Figure 6. Capacities of generation and conversion technologies for 49% emissions reduction, without and with offshore wind and electrolysis CAPEX reductions.*

## 4.3. Scenario 3: Solar PV and Battery CAPEX Reductions

The third scenario explores the impact of solar PV and battery CAPEX reductions, still in the context of a 49% decrease of carbon dioxide emissions from 1990 levels. Somewhat surprisingly, the capacity deployments are strictly identical to those observed in the first scenario. This can be explained by inspecting the capacity factors of all three variable renewable energy technologies considered. Indeed, the capacity factor of the solar resource is around 8% for the weather year considered in this study, which is around 2.5 times smaller than that of the onshore wind resource and approximately five or six times smaller than that of the offshore wind resource. In addition, the investment cost ratios between onshore wind and solar, on the one hand, and offshore wind and solar PV, on the other hand, are smaller than or comparable to 2.5 and 5-6, respectively. Since solar PV also displays poor synchrony with the load, it is therefore not the preferred option for electricity generation at these latitudes. For the reasons detailed above, the system cost and average electricity price remain unchanged.

## 4.4. Scenario 4: 75% Emissions Reductions

The fourth scenario seeks the system design making it possible to reduce carbon dioxide emissions by 75% from 1990 levels. From a qualitative standpoint, results are comparable to the 49% emissions reduction case. Indeed, neither power-to-gas nor storage technologies are required in this scenario. In fact, the reduction in carbon dioxide emissions is enabled by the deployment of additional offshore wind capacity, which reaches approximately 17 GW. Roughly 54 GWh of electricity produced via solar PV is curtailed, which corresponds to approximately 2.5% of the electricity generated with this technology. Virtually no electricity produced by onshore wind turbines is curtailed, while 860 GWh, or 1.4%, of the electricity generated by offshore wind turbines is curtailed. The volume of electricity imports remains the same as in the previous scenarios, and corresponds to the annual imports budget. The volume of annual electricity exports rises to roughly 23.1 TWh, which corresponds to a 55%

increase from the 49% emissions reduction scenario. This can be explained by the substantial increase in installed offshore wind capacity, whose surplus production can be exported at a profit. The system cost and average electricity price increase moderately, to 5.2 billion €/y and 49 €/MWh, respectively.

## *4.5. Scenario 5: 99% Emissions Reduction*

The fifth scenario considers more stringent carbon dioxide emissions cuts, and system configurations that would enable them. Figure 7 displays generation and conversion technology deployments necessary to achieve the desired carbon dioxide emissions reduction, while Figure 8 shows the capacities of storage technologies and volumes of curtailed electricity in scenarios 4 and 5. Firstly, it is clear that a massive amount of RES capacity must be deployed. Indeed, close to 70 GW of RES capacity is required, which is approximately 5 times higher than the peak load value recorded in the weather year used throughout this study. This apparent overcapacity can be explained by two key observations. On the one hand, the average capacity factors of intermittent RES resources are low compared to those of traditional dispatchable power plants. As a result, much higher capacities must typically be installed to supply a given load level. On the other hand, given the stringent carbon dioxide emissions reduction constraint, low-carbon or carbon-free electricity must supply the load even in times of scarcity. In other words, traditional fossil fuel-based power plants cannot be entirely relied upon and the renewable portfolio must be oversized accordingly. Deploying conversion and storage technologies or taking advantage of the (limited) complementarity between local renewable resource types may also help to supply sufficient carbon-free electricity when the dominant renewable resource contributes very little to the power mix, as discussed next.

In this scenario, electrolysis, fuel cell, hydrogen storage and battery technologies are deployed. As mentioned above, this observation suggests that deploying conversion, storage and repowering technologies is more economically attractive than further oversizing the renewable portfolio in order to achieve very strict carbon dioxide emissions reductions. More precisely, given the substantial capacity of RES needed, massive electricity surpluses are generated throughout the year. If these surpluses cannot be exported and no storage technologies are available, they must be curtailed. Hence, in such a context, it appears that storing these surpluses and using them in times of scarcity is the cheapest option. Then, it is worth noticing that methanation plants are not deployed, in spite of the availability of gas-fired power plants to repower synthetic methane. Given the low-efficiency of the power-to-hydrogen-to-methane-to-power chain, it is usually more profitable to export the unused electricity surplus than to displace the small volumes of natural gas still burned in gas-fired power plants which must be purchased. For the first time in the scenarios envisaged in this study, some additional solar PV capacity is built. Since the carbon budget is very strict, fossil fuel-based dispatchable power plants cannot always be activated when wind production is low. In this context, it appears that deploying additional solar PV capacity in combination with storage is preferable to oversizing the RES portfolio, which suggests that exploiting the diversity of RES resources and technology options is cheaper than simply oversizing the offshore wind capacity.

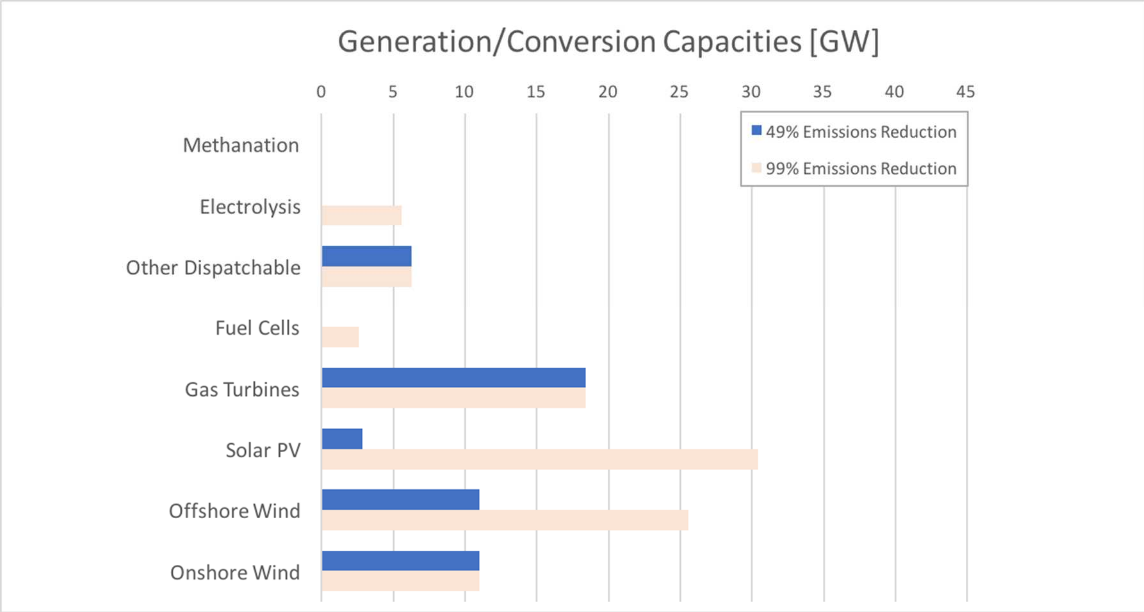


*Figure7. Capacities of generation and conversion technologies in the 49% and the 99% emissions reduction scenarios.*

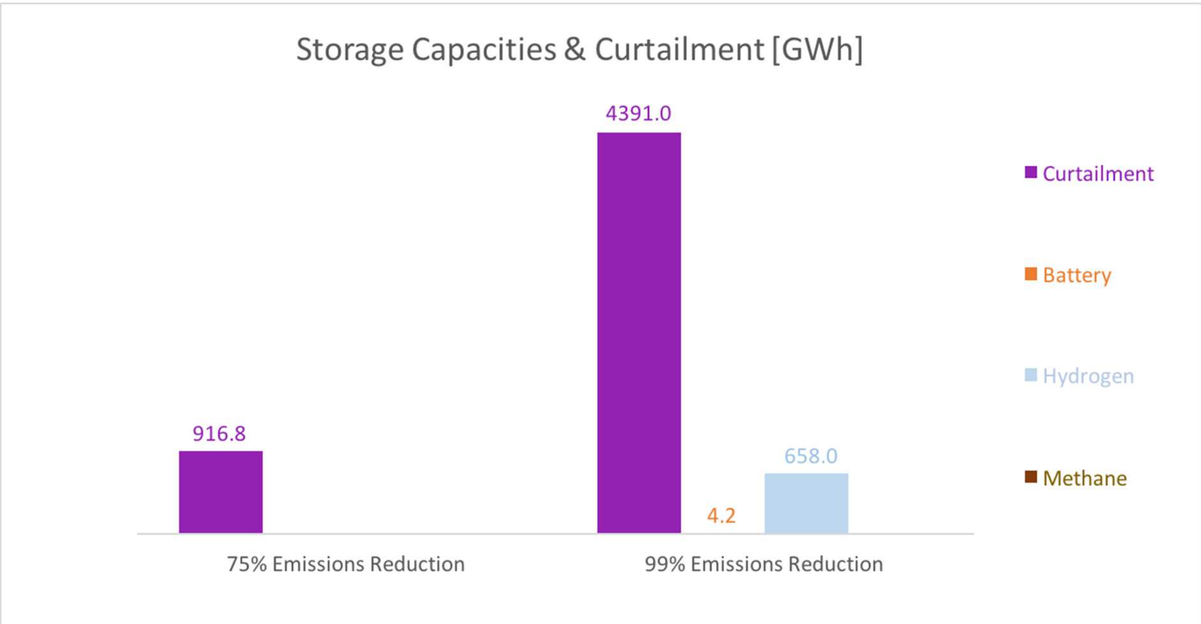


*Figure 8. Capacities of storage technologies and curtailment volumes in the 75% and 99% emissions reduction scenarios.*

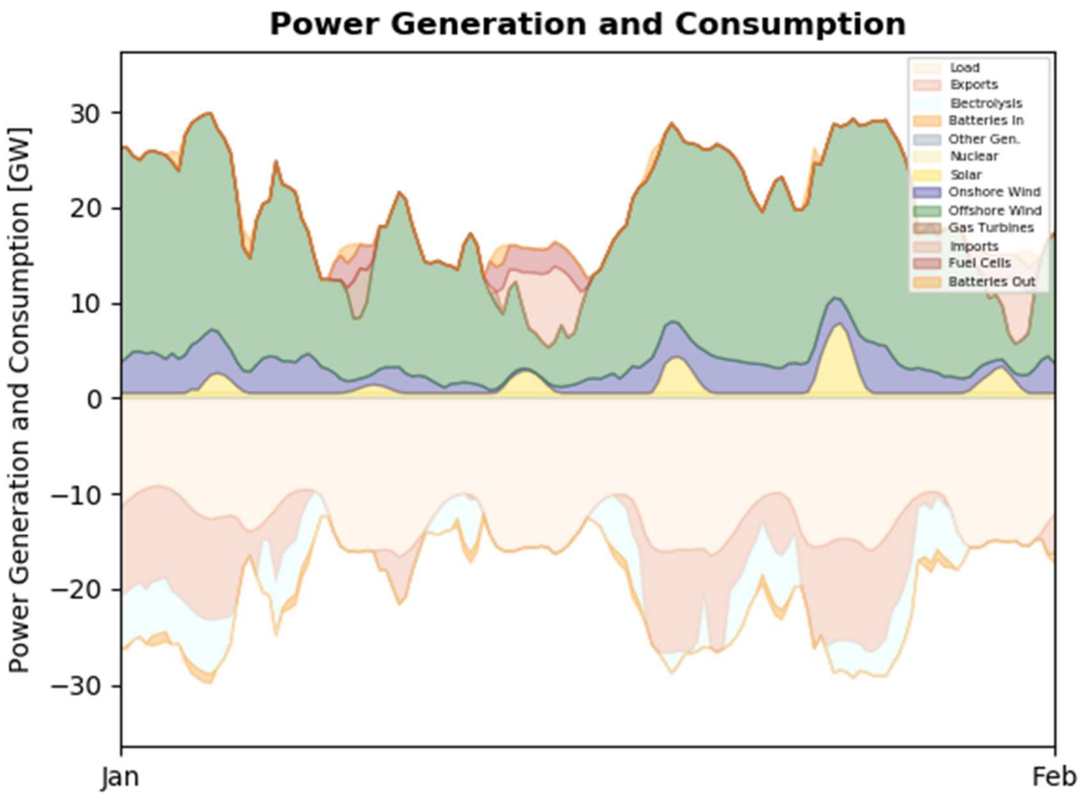


*Figure 9. System operation during a winter month (between January and February) in the 99% emissions reduction scenario.*

In this scenario, the level of curtailed electricity from solar PV rises sharply to around 2 TWh or 9.1% of total production. Curtailment levels are lower for wind power plants. Indeed, roughly 684 GWh of electricity, or 3.1%, of the electricity produced by onshore wind turbines is curtailed. By contrast, 1.7 TWh, or 1.8%, of offshore wind electricity is curtailed. Electricity import volumes remain the same, while electricity exports soar to 35.7 TWh. Since the RES portfolio is oversized, large volumes of surplus electricity are produced throughout the year, and there is an economic incentive to export them.

Figure 9 displays system operation over a four-week period between the months of January and February. It can be observed that fuel cells and imports supply a substantial share of the demand in times of scarcity. By contrast, the considerable surpluses produced at other times are mostly exported. These observations support the developments of the previous paragraphs. Table 2 provides additional insight into system operation, by providing load hours and capacity factor values for a subset of technologies.

*Table 2. Load hours and capacity factors of various technologies in the 99% emissions reduction scenario.*

| | *Electro-lysis* | *Fuel Cells* | *Metha-nation* | *Gas Turbines* | *Biomass* | *Waste* | *Nuclear* | *Coal* |
|---|---|---|---|---|---|---|---|---|
| **Full Load Hours (hrs/year)** | 4044 | 3240 | 0 | 168 | 0 | 0 | 8758 | 0 |
| **Capacity Factor (%)** | 36.8 | 33.2 | 0 | <1 | 0 | 0 | 97 | 0 |

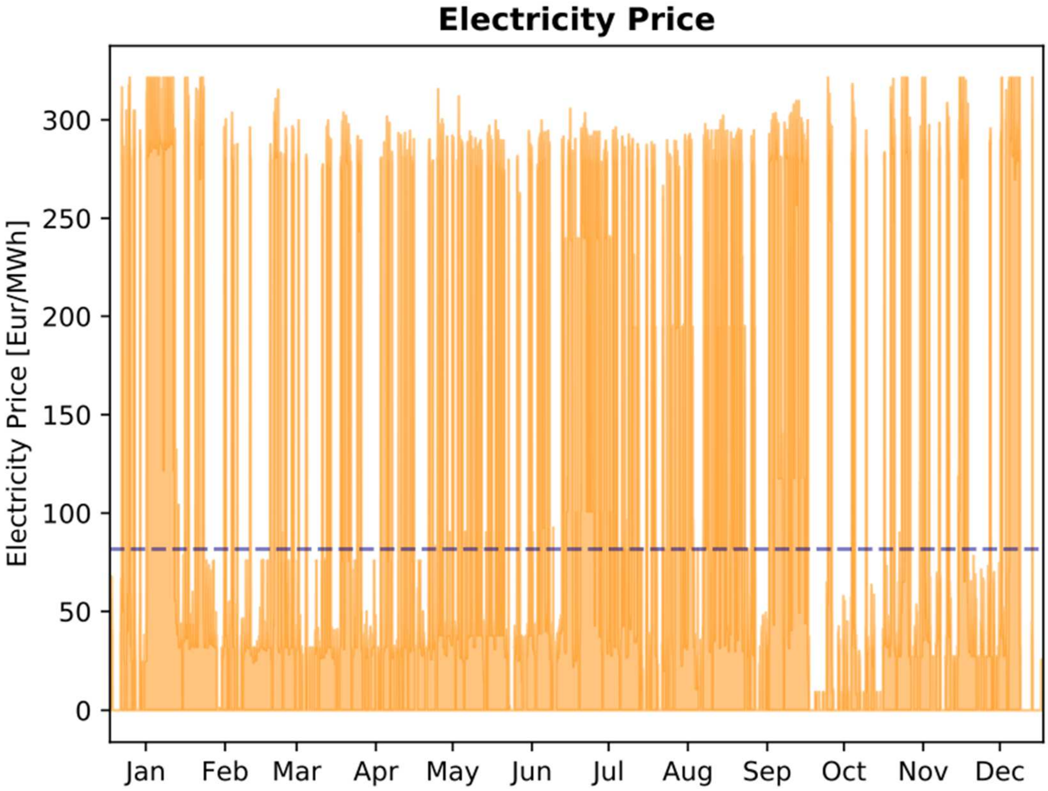


*Figure 10. Electricity prices in the 99% emissions reduction scenario.*

In this scenario, the total system cost increases substantially to 8.6 billion €/y, whereas the average electricity price soars to roughly 82 €/MWh. Investment costs in renewable capacity make up slightly less than 80% of the total system cost. In particular, offshore wind CAPEX contributes approximately 50% of the total. The deployment of fuel cells and electrolysis plants constitute major expenses, which account for roughly 10% and 5% of the total cost, respectively, along with the import of electricity, contributing another 5%. The investment and operating costs of all other technologies represent much smaller shares of the total system cost, i.e., around 2% for hydrogen storage and below 1% for other technologies. Figure 10 shows a proxy for wholesale electricity prices throughout the year, with clear price peaks in times of scarcity, which point to the fact that the system is operating near its limits when renewable generation is low. It can also be seen that high production events typically correspond to very low or zero prices. These results confirm the intuition that electricity prices are likely to become particularly volatile in power systems featuring very high shares of intermittent renewable generation and where the trade of electricity is market-based.

## *4.6. Scenario 6: 99% Emissions Reduction without Interconnection*

The last scenario evaluates the impact of flexibility provided by the electricity interconnection on system design and costs. As such, the interconnection is removed altogether, and the Dutch power system is assumed to function in complete autarky. Figure 11 and 12 show the capacity deployments required to achieve a reduction of 99% in carbon dioxide emissions without any interconnection, along with curtailed electricity volumes. Interestingly, the capacities of all technologies whose potential was not fully exploited in the previous scenario increased, at the notable exception of offshore wind. This can be explained by the fact that production surpluses, which occurred relatively often with an oversized offshore wind portfolio, can no longer be exported at a profit, thereby reducing the economic attractiveness of massively oversizing offshore wind capacity. Instead, further solar PV capacity is deployed and total renewable capacity in excess of 70 GW is still required to supply the load reliably.

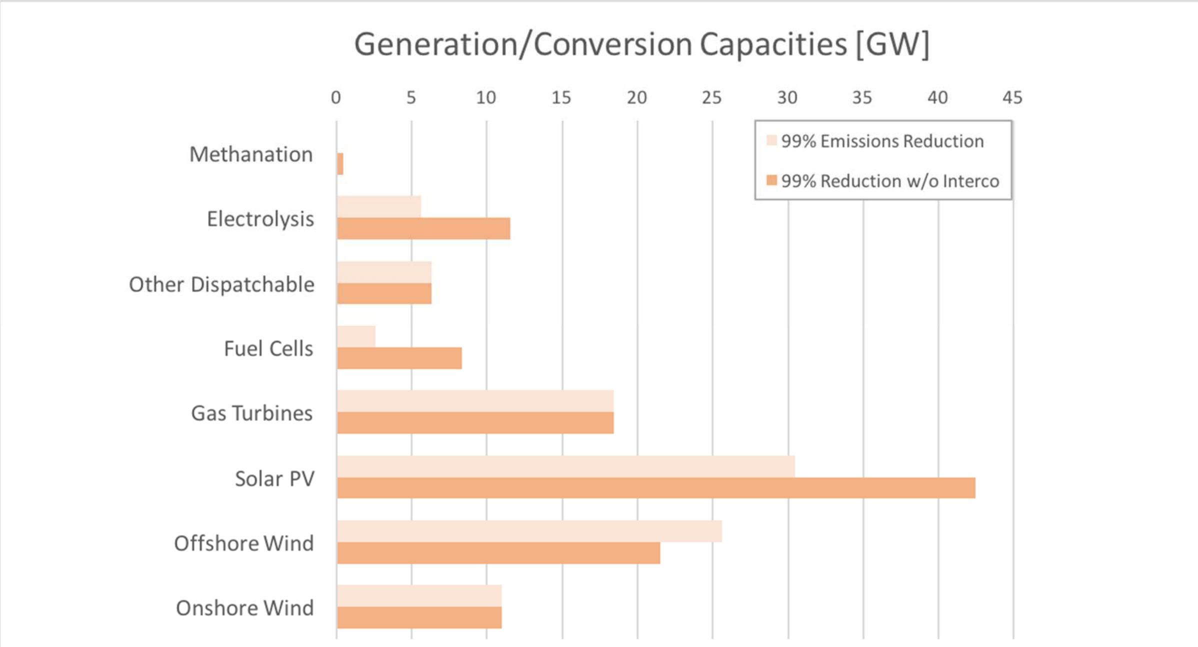


*Figure 11. Capacities of generation and conversion technologies in the 99% emissions reduction scenarios, with and without interconnection.*

All conversion and storage technologies feature in this scenario. In particular, methanation plants appear in the energy system. This can be explained as follows. On the one hand, electricity surpluses still occur in this configuration. On the other hand, surpluses can no longer be exported at a profit. They must either be curtailed or used in a different way. Then, despite the strict carbon dioxide emissions reduction target, gas-fired power plants are still run on a few occasions, for which natural gas must be purchased. In this setup, since large capacities of electrolysis and hydrogen storage technologies are necessary, it is cheaper to invest in methanation plants and convert the electricity surplus into synthetic methane.

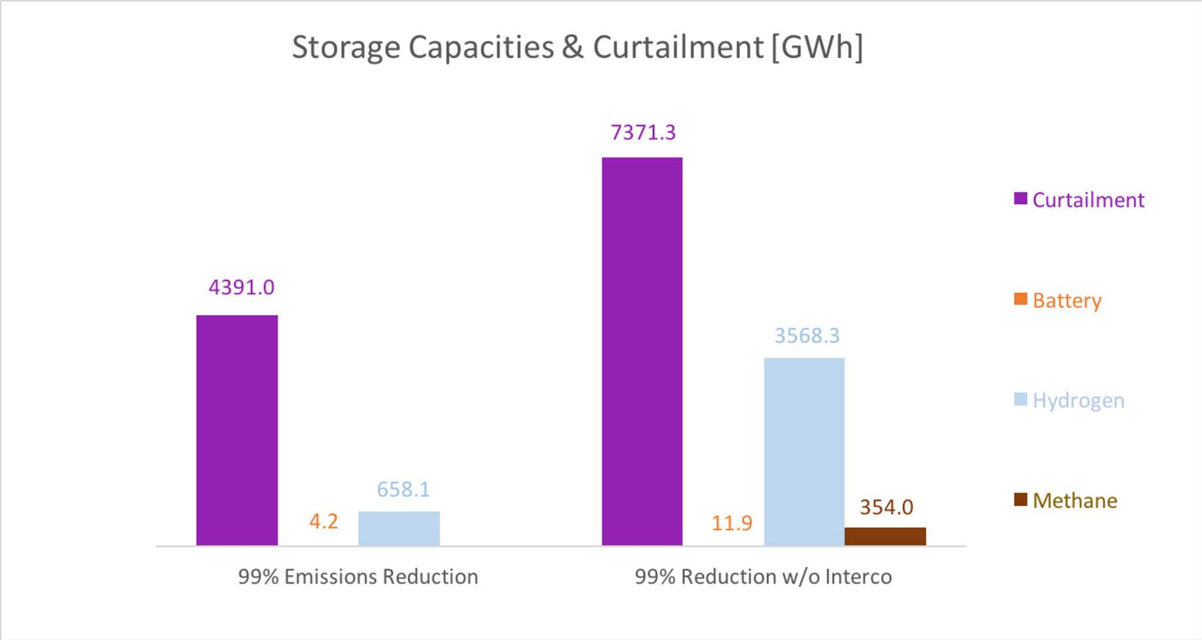


*Figure 12. Capacities of storage technologies and curtailed electricity volumes in the 99% emissions reduction scenarios, with and without interconnection.*

In previous scenarios, electricity exports provided an economically attractive option to absorb RES production surpluses, indirectly and artificially reducing curtailment. This claim is supported by the fact that in this scenario, curtailment volumes are found to increase in absolute terms for each RES technology. Indeed, the volume of curtailed electricity from solar PV increases to 2.68 TWh, or 8.7% of solar PV production. In addition, roughly 1.44 TWh, or 6.5%, of onshore wind electricity are curtailed, while 3.2 TWh, or 3.9%, of offshore wind electricity are curtailed. Since no interconnection is considered in this scenario, no electricity exchanges take place with neighbouring countries.

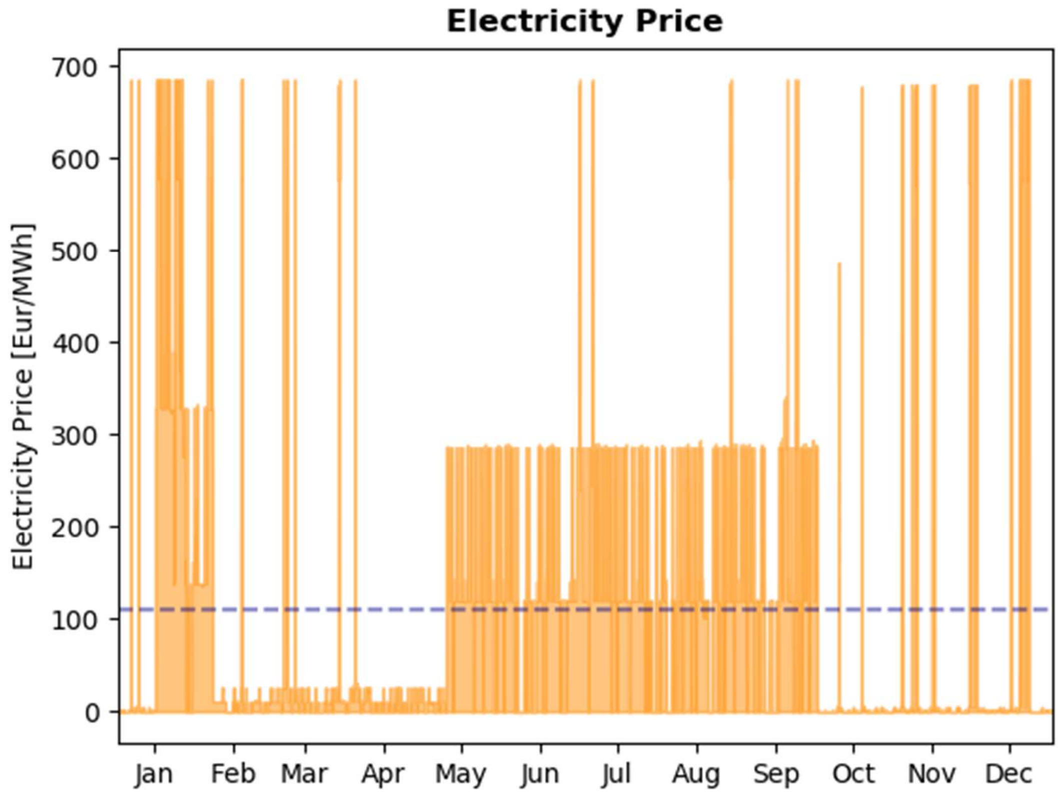


*Figure 13. Electricity price in the 99% emissions reduction scenario without interconnection.*

The impact of removing the electricity interconnection on system cost and average electricity price is substantial. Indeed, the former climbs to 11.6 billion €/y, which corresponds to a 26% increase from the previous scenario, while the latter soars to 110 €/MWh. Two causes can be brought forward to explain the sharp increase in system cost and average electricity price. Firstly, in previous scenarios, provided that the annual electricity imports budget constraint was respected, the full capacity of the interconnector (roughly 10 GW) could be used to import electricity in times of scarcity. This flexibility artificially reduced the need for carbon-free dispatchable capacity such as fuel cells, along with the associated energy conversion and storage technologies. Secondly, wholesale prices paid for electricity imports were generally low, typically around 30 €/MWh, such that a non-negligible share (10%) of the total electricity demand could be supplied by cheap, carbon-free electricity. For obvious reasons, switching to renewable alternatives comes at a high cost. It is also worth noting that the magnitude of the largest price spikes has roughly doubled compared with the previous scenario. Such high price values again reflect the fact that the power system is operating at or near its limit at these times, and deploying extra capacity would be required to relieve the burden on the system.

## 4.7. Summary of scenario results

Figure 14 displays the generation and conversion capacities across the different scenarios. The generation and conversion capacities increase from 32.3 GW in the current situation to 100 GW in the 99% emissions reduction scenario and to 120 GW in the 99% emissions reduction scenario without interconnection, respectively.

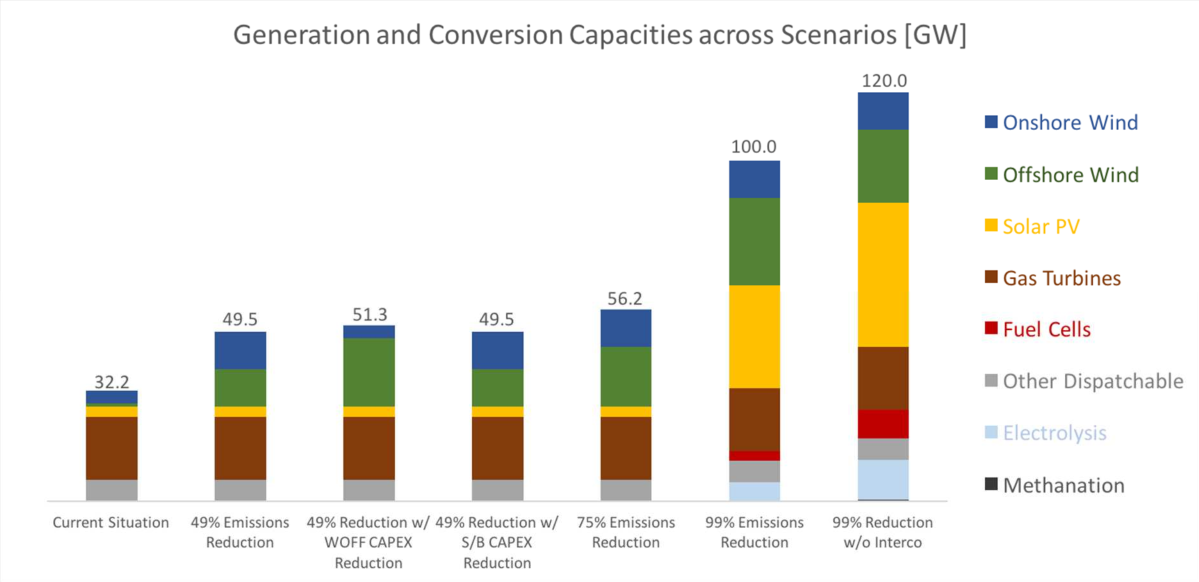


*Figure 14. Capacities of generation and conversion technologies deployed across scenarios.*

Energy storage technologies are only deployed in the 99% emissions reduction scenarios, while methane storage only appears in the 99% emissions reduction scenario without interconnection. Likewise, methanation plants are only built in the latter scenario.

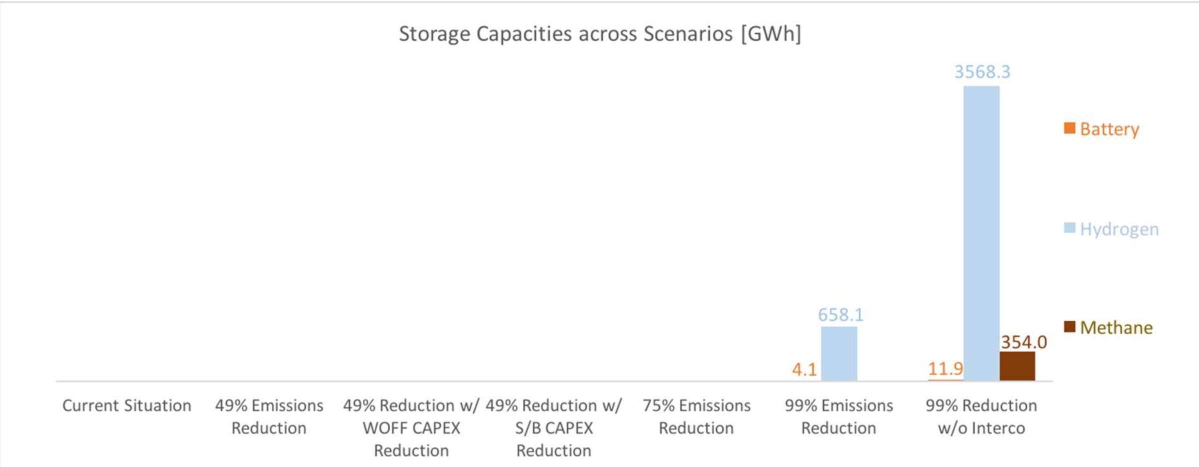


*Figure 15. Capacities of storage technologies deployed across scenarios.*

Despite the availability of hydrogen and methane storage in the 99% scenarios, large amounts of RES electricity are curtailed, as summarised in Figure 16.

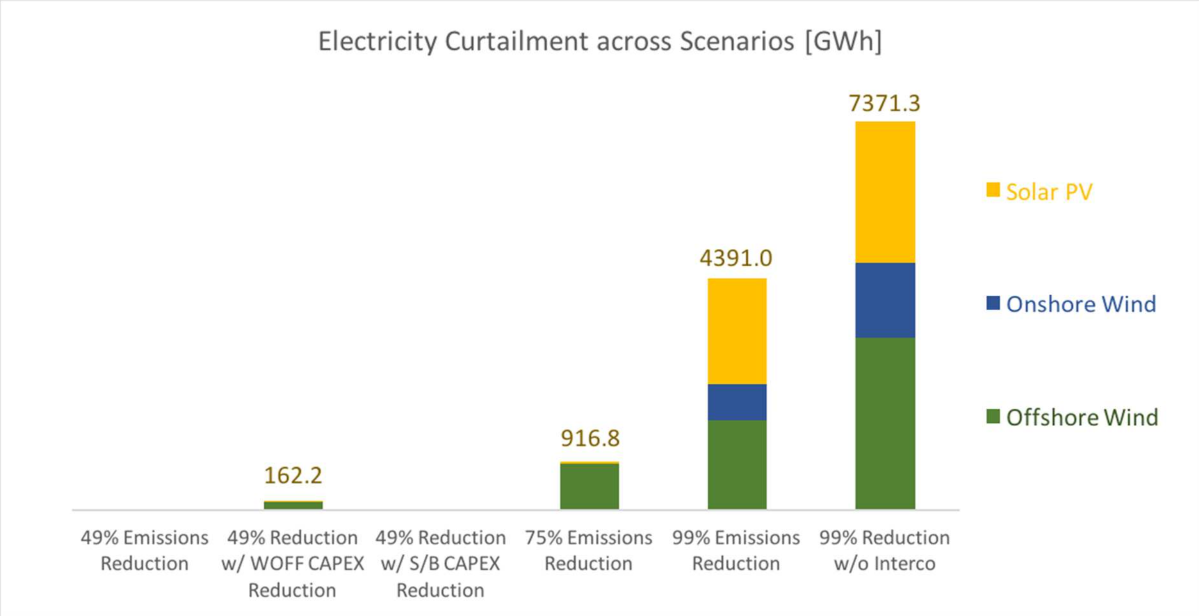


*Figure 16. Volumes of curtailed electricity across scenarios.*

# 5. Comparison with other studies

In 2014, ECN published a study aiming to identify the future role and viability of power-to-gas in the Dutch energy system. Using OPERA, ECN optimised the entire energy system, accounting for future electricity and gas demand. ECN looked at three baseline scenarios with 50%, 70% and 85% emissions reductions, respectively.

Their qualitative and, to some extent, their quantitative results, are in line with our results. In particular, it is found that no storage or conversion technologies are required in the 50% and 70% emissions reduction scenarios, which echoes the results of the present study. In their study, power-to-gas only plays a role in the Dutch energy system as part of the technology mix in the 85% emissions reduction scenario. Power-to-gas supports the integration of intermittent renewable electricity generation from wind and solar power plants, but it is not the first option in terms of lowest societal cost. Methanation is not considered part of the cost-optimal mix of technologies in any of their scenarios. The 75 GW of installed renewable energy generation capacity reported in their study come close to the findings of the present study, which indicate that at least 70 GW of installed RES capacity would be needed to achieve deep decarbonisation targets. However, while the installed electrolysis capacity found in their study amounts to 1,400 MW, the present results suggest that 5,000 MW of electrolysis capacity would be needed. The fact that the carbon dioxide emissions reduction target pursued in the present study is much more ambitious could partly explain this discrepancy. Another key difference lies in the amount of electricity storage observed in their study. Indeed, their model yields 1 TWh of large-scale and 12 TWh of small-scale electricity storage (electric vehicles). By contrast, in the 99% emissions reduction scenario, electricity storage in our model is limited to 1 GWh of battery storage and 700 GWh of hydrogen storage, respectively.

# 6. Conclusions

The conclusions of this study are manifold. Firstly, it clearly appears that the Netherlands have sufficient RES potential to supply electricity demand levels comparable to those observed in 2017 while reducing carbon dioxide emissions from the power sector by 99% from 1990 levels. Secondly, power-to-gas and storage technologies only feature in very ambitious emissions reduction scenarios. In particular, these technologies do not appear in scenarios with moderate emissions reduction targets and substantial technology cost reductions, suggesting that their emergence is heavily conditioned upon the massive deployment of RES capacity, and does not solely depend on their cost. Thirdly, electricity prices become much more volatile in scenarios with high emissions reduction targets, and the average electricity price increases substantially as well, doubling or tripling compared to the reference scenario. Then, it should be emphasised that the electricity interconnection provides much needed flexibility to the power system, making up for shortages in RES production and conveniently absorbing surpluses when they occur. This flexibility directly translates into substantial cost savings, as the system configuration seeking to meet the most ambitious emissions reduction target without any interconnection is by far the most expensive. It should be borne in mind, however, that interconnections may not be able to provide such flexibility in real systems, as electricity exchanges will ultimately depend on generation and consumption patterns on both sides of the transmission corridor. Finally, methanation only appears in the scenario without any interconnection, where synthetic methane is used to displace limited volumes of natural gas.

# Appendix

The following tables contain the relevant techno-economic data used throughout the reported analysis. All data sources are listed at the end of the appendix.

## Technology capacities and costs

*Table 3. Overview of technology capacities and costs.*

| Technology | Initial Capacity GW(h) | Max. Capacity GW(h) | CAPEX M€/GW(h) | FOM M€/GW(h)*yr | VOM €/MWh | Lifetime years |
|---|---|---|---|---|---|---|
| **Solar PV** | 2.85 | 90.0 | 800.0 | 20. | 0.0 | 20 |
| **Wind On.** | 3.675 | 11.0 | 1100.0 | 29.0 | 0.0 | 20 |
| **Wind Off.** | 0.957 | 75.0 | 2500.0 | 77.0 | 0.0 | 25 |
| **Gas Turb.** | 18.433 | 18.433 | | 27.8 | 4.2 | |
| **Fuel Cells** | 0.0 | | 2000.0 | 100.0 | 0.0 | 10 |
| **Nuclear** | 0.486 | 0.486 | | 93.0 | 2.11 | |
| **Coal** | 4.631 | 4.631 | | 18.6 | 4.2 | |
| **Biomass** | 0.489 | 0.489 | | 103.0 | 5.1 | |
| **Electrolysis** | 0.0 | | 700.0 | 35.0 | 0.0 | 15 |
| **Methanation** | 0.0 | | 400.0 | 20.0 | 0.0 | 20 |
| **Batteries** | 0.0 | | 110 (p)/220 (e) | 5.5 (p)/11.0 (e) | 0.0 | 10 (p) /10 (e) |
| **H2 storage** | 0.0 | | 5.03 | 0.253 | 0.0 | 50 |
| **CH4 storage** | 0.0 | | 0.13 | 0.00253 | 0.0 | 80 |

## Other capacities and costs

*Table 4. Overview of other relevant costs.*

| Parameter | Unit | Value | Source |
|---|---|---|---|
| **Peak electricity demand** | GW | 17.658 | ENTSO-E |
| **Electricity interconnection capacity** | GW | 10.6 | TenneT |
| **Average electricity imports price** | €/MWh | Time series | EPEX SPOT |
| **Max. electricity imports share** | % of domestic demand | 10.0 | Assumed |
| **Natural gas fuel cost** | €/MWh | 20.0 | Assumed |
| **Biomass fuel cost** | €/MWh | 35.0 | Assumed |
| **Waste fuel cost** | €/MWh | 10.0 | Assumed |
| **CO2 emissions price** | €/t | 25.0 | Assumed |
| **Electricity value of lost load** | €/MWh | 3000.0 | ELIA |

## Operational Parameters

*Table 5. Overview of relevant operational parameters.*

| Technology | Efficiency (%) | Ramp Rate (%/hour) | Min. Stable Prod. (%) | Spec. Emissions (t/MWh) |
|---|---|---|---|---|
| **Gas Turbines** | 50 | 100 | 0 | 0.202 |
| **Fuel Cells** | 60 | 100 | 0 | 0.0 |
| **Nuclear** | | 1 | 0 | 0.0 |
| **Coal** | 40 | 25 | 0 | 0.39 |
| **Biomass** | 40 | 25 | 0 | 0.33 |
| **Waste** | 40 | 25 | 0 | 0.4 |
| **Electrolysis** | 70 | 100 | 10 | |
| **Methanation** | 78 | 100 | 20 | |
| **Batteries** | $92^{A}$/ $0.1^{B}$ | | 0 | |
| **H2 Storage** | $96^{A}$ / $0^{B}$ | | 0 | |
| **CH4 Storage** | $98^{A}$ / $0^{B}$ | | 0 | |

A: round-trip, B: self-discharge rate (%/hour)

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