Flattening the Curve

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Disclaimer

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Summary

This report aims to identify a solution for bridging the gap between future offshore wind energy production and industrial electricity demand ('flatten the curve'). The research is carried out for RVO (Netherlands Enterprise Agency), TKI Industrie & Energie and TKI Offshore Energy.

To meet our CO2 emission reduction goals, multiple decarbonisation pathways are explored. Electrification of our energy demand is one of the decarbonisation pathways with a major potential. Electrification makes it possible to phase out fossil fuels on a large scale, provided that sufficient renewable electricity is available. The Dutch industry's electricity demand may increase further due to the emergence of new sectors. However, the exact increase in electricity demand is uncertain.

The growth in electricity demand in the industry will be accompanied by a strongly growing supply of renewable electricity generation. For the Netherlands, electricity generation by offshore wind farms is expected to account for a large part of the renewable share. In the latest scenario study by the Dutch grid operators, an installed offshore wind capacity of 21.5 GW is expected around 2030, and this is expected to increase to 38 GW-72 GW by 2050.

In theory, there is a match between the growth pattern of electricity demand in the industry and the developments in the offshore wind sector. Reducing emissions through electrification can only be successful with sufficient renewable electricity. And offshore wind can only develop with an increasing demand for electricity (direct or indirect). However, when looking at the hourly production of offshore wind and demand curves, there is a problem that becomes visible. The electricity production curve of offshore wind depends on wind speeds, which fluctuate over time. When we try to match the production hours of offshore wind production with industrial power consumption, this conflicts with the curves of industrial demand. Historically, industrial processes run mostly continuously, with the result that industrial electricity demand is fairly constant throughout the year. This results in moments of electricity surplus as well as moments of shortage throughout the year. In Figure 1, the surplus and shortage are due to the mismatch between the power curves of offshore wind and industrial demand. The hours are sorted from most renewable production to least renewable production. On the left (the peak), the renewable production is higher than the industrial demand. This means there is an energy surplus. On the right (the valley), the industrial demand is higher than the renewable production, which means there is an energy shortage. (We recognise that other technologies also influence the power curve and the amount of surplus and shortage.)

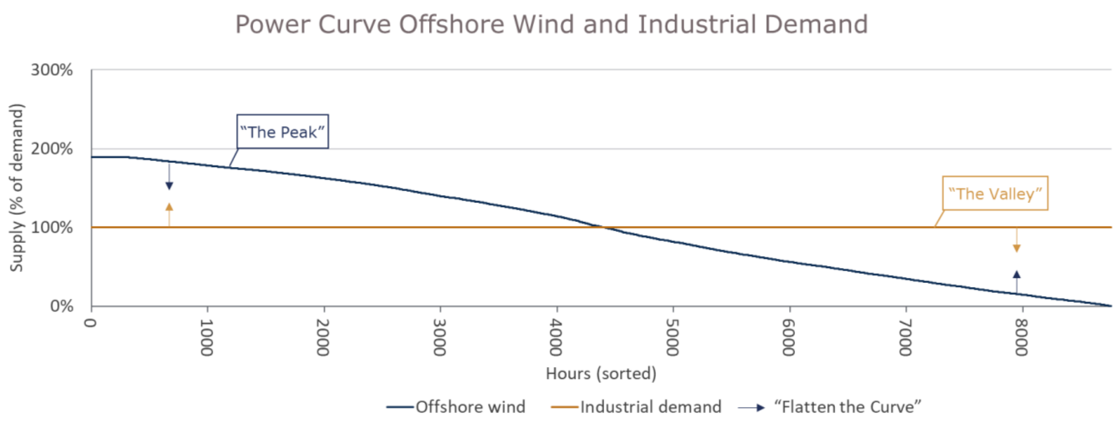

Figure 1. Power curve offshore wind and industrial demand

In this research, we will dive into the symbiotic relationship between far-reaching electrification in the industry and the development of offshore wind. We will analyse the mismatch between industrial demand and offshore supply and search for techno-economic solutions to bring both curves closer to each other. Furthermore, we propose policy measures to enable the techno-economic solution.

Methodology

The scope of this research is restricted to certain areas. This research focuses specifically on the relationship between offshore wind and the industry and does not consider other demand or supply sectors. The analysis includes offshore infrastructures in order to examine the differences in transporting hydrogen or electricity, but calculations regarding onshore infrastructures are not included in this study.

The modelling conducted in this research is done with the year 2050 as a horizon. The scenarios explored are zero-emission scenarios aligned with the climate goals of the Paris Agreement. Technology cost predictions for the year 2050 are utilised, although it is important to note that these predictions come with a high level of uncertainty due to the long time horizon.

As for the weather profiles used in the analysis, we selected the year 2012 as it is commonly considered an average weather year from a historical perspective. Additionally, we employed a flat demand profile for the industrial demand.

Use of scenarios

Predictions for the Dutch energy system in 2050 diverge greatly, especially since the amount of electrification in the industry is highly uncertain. Therefore, we use different energy scenarios to diversify energy supply and demand to increase the robustness of the results. The scenarios differ in terms of energy supply (offshore wind) and electrical demand (industrial demand).

The analysis in this study employs three different scenarios (National Leadership, International Trade[1]and Direct Electrification[2], see section 2.2) to assess the temporal imbalances and examine the impact of specific technologies on the imbalances within each scenario. It is important to note that the objective of this study is not to compare the scenarios directly but rather to utilise them for the purpose of analysing imbalances and technical solutions for reducing imbalance. The scenarios are modelled with the help of the Energy Transition Model (ETM).

Modelling approach

To find solutions for the mismatch between supply and demand, we reviewed technical solutions. We then tested these solutions on their ability to reduce imbalance and compared them on a system-cost basis. A system cost approach is a methodology used to analyse and optimise energy systems based on their overall yearly cost. It involves the full spectrum of costs associated with the energy system, including capital investments, operating expenses, storage, maintenance costs, fuel prices, and any other relevant economic factors.

The system cost approach aims to identify the most cost-effective configuration and operation strategy for an energy system. It takes into account the interactions and dependencies between different components, such as hydrogen power plants, transmission and distribution infrastructure, storage systems, hydrogen imports, and renewable energy sources.

We calculated the system costs with an external Excel module. In this model, outputs of the ETM scenario are combined with cost data from literature (section 2.4.4) to find the yearly system costs. Capital expenditures are annualised using a weighted average cost of capital (WACC) of 6%. Outputs of the ETM are coupled to this module to calculate the system costs. This way, the effect of the individual solutions on system costs can be calculated.

Results

As mentioned above, we used three scenarios for this research: National Leadership, International Trade and Direct Electrification. For every scenario, we calculated when and how electricity surplus and electricity shortage occurred. These were considered the base case scenarios, in which no additional technological solutions are introduced to reduce imbalance. In the base case scenarios, the surplus is defined as curtailment: electricity that can't be used by the industry because it is higher than the baseload demand. Shortages are defined as the electricity that is needed when the offshore wind production is lower than the industrial baseload demand. In the next report, we investigate solutions to minimise the surplus and shortage while comparing the overall system costs, starting with the addition of sufficient hydrogen backup power generation to accommodate baseload power demand.

Table 1 gives the surplus and shortages for each base case scenario. It is evident that scenarios with increased offshore wind capacity have a bigger surplus, and the scenarios with higher baseload demand from the industry have a higher shortage but a lower surplus.

[1] Netbeheer Nederland (2023). Het energiesysteem van de toekomst: De II3050-scenario’s.

[2] TKI Industrie en Energie (2021). Routekaart Elektrificatie in de Industrie.

The National Leadership scenario has the highest surplus, and the Direct Electrification scenario has the highest shortage. In general, the imbalances will increase till 2030.

Table 1. Surplus and shortage per scenario.

Scenario	Year	Surplus (TWh)	Shortage (TWh)
Climate Ambition	2030	27.6	16.7
Direct Electrification	2030	5.5	45.7
National Leadership	2040	69.0	15.4
International Trade	2040	53.9	15.5
Direct Electrification	2040	78.2	46.0
National Leadership	2050	103.6	31.8
International Trade	2050	45.9	20.0
Direct Electrification	2050	78.2	49.9

Technical solutions

To decrease shortages and surplus, we propose technical solutions. In all scenarios, back-up power generation is necessary to fill (at least a part of) the valley of the curve. Flexible power generation, such as H2tP (hydrogen-to-power), is essential for supplying baseload electricity during times of low renewables.

Electrolysis is an effective solution to lower total system costs. However, offshore electricity production that can be used for baseload demand should transported as electrons instead of hydrogen. This research used three design concepts for power-to-gas, which are visualised below (Figure 2). The dedicated offshore design concept (design concept II) leads to much higher system costs. Onshore power-to-gas (design concept I) and hybrid offshore power-to-gas (design concept III) both lead to lower system costs than the dedicated offshore design.

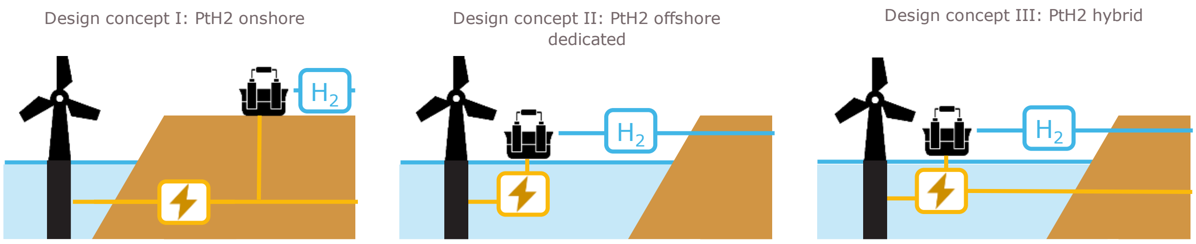

Figure 2. Conceptual drawing of the three electrolysis design concepts.

Hybrid boilers are an effective measure to deal with imbalance, but potentially significant onshore infrastructure costs are not included in this study. Hybrid steam cracking furnaces can also lead to reduced system costs, but only if the lifetimes of readily depreciated old furnaces are extended when new electric furnaces are installed.

The impact of offshore solar PV is ambiguous and differs among scenarios. This study looked at a situation where the capacity of offshore solar PV is matched to the capacity of offshore wind. In general, this study finds that the capital and operational expenditures increase due to the added offshore solar PV, nullifying the cost savings of reduced use of back-up plants and reduced hydrogen imports.

Industrial process flexibility is categorised as production reduction or production shift. In this study, we only consider production reduction. Using temporary industrial production reduction can reduce the required back-up generation capacity to a limited extent. In certain sectors, this offers significant flexibility potential at relatively high electricity prices, as shown in Table 2. However, reduction in system costs is limited as industrial production reduction is relatively expensive.

The average potential of (temporary) industrial production reduction among industrial sectors is assumed to be roughly 20%. This assumption is based on the idea that it is relatively easy (and thus cheaper and safer) for industrial production facilities to partially reduce production but much harder to completely reduce production. The electricity price at which industrial sectors would be willing to reduce production (the willingness to pay) is also estimated (section 3.2.4). Table 2 shows that the willingness to pay differs among sectors but also between scenarios, as it is largely dependent on the electricity demand of a sector in a given scenario. Prices range between < 200 to > 8000 €/MWh, illustrating that not only the capacity but also the willingness to accept is an important indicator for the effectiveness of industrial production reduction.

Table 2. Approximation of industrial process flexibility potential (20% average production reduction assumed per sector) and the willingness to accept the three 2050 scenarios.

	Direct electrification (Roadmap Electrification in the Industry)	**National Leadership** (II3050)	**International Trade (II3050)**
Process flexibility	3346 MW (willingness to accept)	3454 MW (willingness to accept)	1784 MW (willingness to accept)
• Steel	109 MW (at 846 €/MWh)	109 MW (at 846 €/MWh)	109 MW (at 846 €/MWh)
• Refineries	696 MW (at 182 €/MWh)	77 MW (at 1559 €/MWh)	73 MW (at 2962 €/MWh)
• Steam cracking	1047 MW (at 216 €/MWh)	296 MW (at 570 €/MWh)	183 MW (at 939 €/MWh)
• Electrochemistry (excl. green H2)	141 MW (at 199 €/MWh)	141 MW (at 199 €/MWh)	141 MW (at 199 €/MWh)
• Other chemicals	598 MW (at 1188 €/MWh)	1089 MW (at 653 €/MWh)	627 MW (at 1134 €/MWh)
• Synthetic fuels	0 MW	956 MW (at 296 €/MWh)	0 MW
• Food	187 MW (at 5342 €/MWh)	250 MW (at 3985 €/MWh)	233 MW (at 4273 €/MWh)
• Paper	54 MW (at 2307 €/MWh)	54 MW (at 2311 €/MWh)	53 MW (at 2356 €/MWh)
• Other	514 MW (at 5953 €/MWh)	484 MW (at 6330 €/MWh)	366 MW (at 8367 €/MWh)

Although the application of thermal buffering for industrial purposes is still in its early stages, its potential seems to be substantial. Thermal buffering could be coupled to many power-to-heat systems. This research looked at high-temperature (e-boilers) and low-temperature storage (heat pumps). Thermal buffers combined with e-boilers reduce system costs by lowering hydrogen imports by reducing the required capacity for back-up power plants. However, thermal buffers combined with heat pumps increase system costs due to the high CAPEX of additional heat pump capacity that is required and due to the lower energy density of low-temperature thermal buffering.

Battery storage appears less promising when only the needs of the industry are considered. There is a major cost increase due to the high CAPEX of battery storage. Furthermore, because of the relatively low storage volume of battery storage, it is not effective in reducing the H_2tP back-up capacity. While battery storage installed specifically for industrial power demand does not reduce system costs, battery storage that is 'freely available' from other sectors, for example, electric vehicles, does reduce system costs. This means that somewhere in the energy system, excess battery capacity needs to be available.

In Table 3, the solutions mentioned above are presented with the effect on the system costs per scenario. A plus (+) means that the system costs are lower, and the energy system economically profits from the solution. Some of the solutions show an increase in total system costs. Especially high capacities of dedicated offshore electrolysis lead to extra system costs. Other forms of electrolysis cause a cost decrease.

Table 3. Effect on system costs per technical solution.

Positive impact on system costs (++) = > -10% (of total system costs)
Small positive impact on system costs (+) = -1% to -10%
No significant impact (0) = -1% to 1%
Small negative impact on system costs (-) = 1% to 10%
Negative impact on system costs (--) = > 10%.

Solution		National Leadership	International Trade	Direct Electrification
1.	A. Power-to-hydrogen onshore	+	+	+
	B. Power-to-hydrogen offshore dedicated	--	--	--
	C. Power-to-hydrogen hybrid	+	+	+
2.	A. Hybrid heat - boilers	+	+	+
	B. Hybrid heat - furnace	0	0	0
	C. Hybrid heat – existing furnace	+	+	+
3.	Offshore solar PV	0	0	0
4.	Industrial process flexibility[1]	0	0	0
5.	A. Thermal buffering – E-boiler	+	+	+
	B. Thermal buffering – Heat pump	-	-	-
6.	A. Electricity storage - Batteries	-	-	-
	B. Electricity storage – EV storage	+	+	+

1 Limited industrial process flexibility has a positive effect on the total system costs. However, large capacities become increasingly more expensive (see section 3.2.4).

Sensitivity analysis

The assumptions regarding the forecasted costs of various technologies and the import price of hydrogen for 2050 are highly uncertain but have significant implications for the analysis results. Using a sensitivity analysis, the effects of these uncertainties can be explored. This report shows the sensitivities of the hydrogen import price, the CAPEX costs of offshore solar PV, and the costs for offshore islands.

A higher hydrogen import price leads to a stronger decrease in system costs for each technology that reduces hydrogen demand (hybrid boiler, thermal buffering and offshore solar PV) or increases hydrogen production (hybrid or onshore PtH2, offshore solar PV). As offshore solar PV both reduces hydrogen demand for H2tP back-up power and increases hydrogen production via increased load hours of PtH2, system costs decrease significantly. This is in contrast with the slight increase in system costs in the reference results of the base case scenario.

A lower hydrogen import price leads to the exact opposite of a higher import price. All the technologies except for hydrogen boiler, production reduction and thermal buffering actually increase system costs. For PtH_2, the economically viable capacity is lowered drastically, as many more load hours are required to offset the capital expenditures. Therefore, PtH_2 would only reduce system costs at a significantly lower capacity.

At 25% lower CAPEX for offshore solar PV, system costs actually decrease instead of increase. Thus, either lower offshore solar PV CAPEX or higher hydrogen import prices make offshore solar PV worthwhile (apart from technical feasibility).

Since the system costs for onshore and hybrid PtH_2 are comparable, any changes in either offshore hydrogen or electricity infrastructure make one variant more attractive than the other. Increased costs of offshore islands make the hybrid PtH_2 option more expensive, and increased costs of offshore HVDC make onshore PtH_2 more expensive. Given the uncertainty of these cost figures, no unequivocal conclusion can be drawn other than that 100% dedicated offshore PtH_2 is more expensive.

Conclusions

Back-up capacity is the cheapest method to reduce shortages in most cases

To fill the valley, the part of the curve with the shortage of renewables, a combination of back-up power plants, thermal buffering and temporary industrial production reduction leads to the lowest system costs. Within a simplified scope consisting solely of industry and offshore wind or solar PV, roughly one-quarter of back-up capacity can be reduced by a combination of thermal buffering and industrial production reduction. The use of battery storage appears less promising when only the needs of the industry are considered. However, the use of back-up capacity for industrial baseload demand could potentially be further reduced when considering other parts of the energy system that lie outside the scope of this study, such as battery storage from electric vehicles, solar farms or households.

Economic viability of offshore solar is ambiguous

The economic perspectives for offshore solar PV are uncertain. Systems with offshore solar PV only lead to reduced system costs if future hydrogen import prices turn out higher than expected and/or if the costs of offshore solar PV are reduced further than is currently forecasted. However, it is likely that there will be plenty of solar capacity available elsewhere in the system to provide electricity to the industry during periods with less wind. Furthermore, the ability of solar PV to replace back-up capacity is very limited.

Power-to-heat and power-to-gas can lower the peak and lower system costs at the same time

To lower the peak, the part of the curve with excess renewables, hybrid power-to-heat is the first option to be used by the industry to use surpluses of offshore wind, as it converts electricity to heat with high efficiency. However, the capacity of this option is limited for most scenarios in 2050. The remaining surplus is utilised by both power-to-gas and power-to-heat combined with thermal buffering.

Regarding the location of power-to-gas, there appears to be no significant preference between on- and offshore from both a financial and spatial perspective. However, system costs significantly increase when using dedicated offshore power-to-gas coupled to offshore wind, where all power generated is directly converted. This is due to a decrease in overall system efficiency as, during hours with a shortage of renewables, power is being converted into hydrogen offshore while simultaneously back-up power plants onshore are converting it back into electricity.

1 Introduction

Wind energy and industrial electrification are increasing, but the supply and demand curves are out of sync.

In line with the climate agreements made in the Paris Agreement and the objectives of the European Union, the Dutch industry will have to become climate neutral towards the year 2050. Electrification will be a crucial pillar behind this transformation. Electrification makes it possible to phase out fossil fuels on a large scale, provided that sufficient renewable electricity is available. This can be electrification through the direct consumption of electricity or indirectly through the use of hydrogen, which can be produced via electrolysis. The industry's electricity demand may increase further due to the emergence of new sectors (for example, the production of synthetic molecules) or the growth of existing sectors (for example, data centres). There are different studies that include the growth of electricity demand in the industry; see, for example, the electricity growth in three different scenarios in the industry visualised in Figure 3 (see section 2.2). This shows the high uncertainty of electrification in the industry.

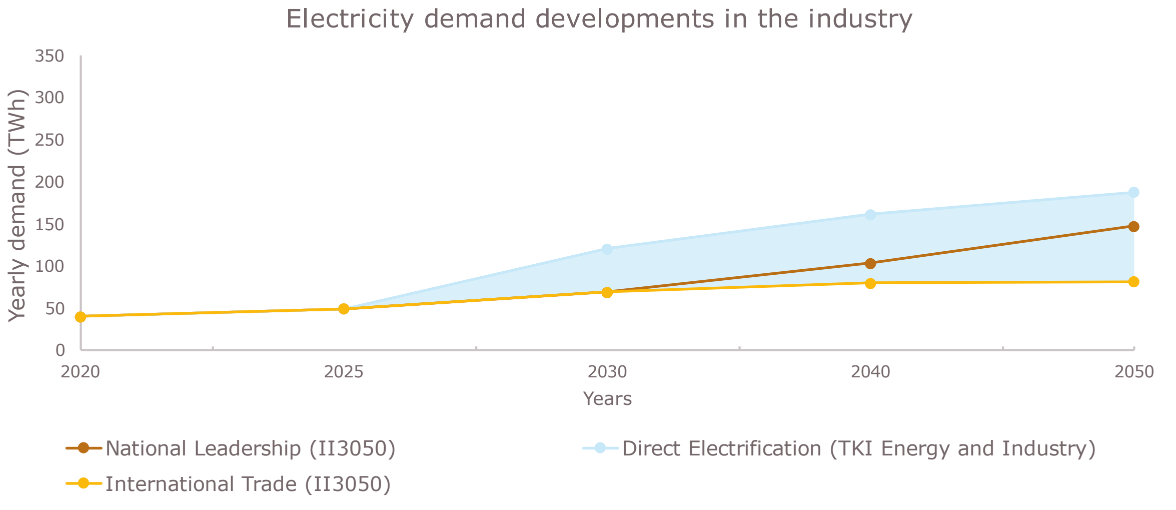

Figure 3. Potential electrification in Dutch industry according to three different scenarios (see section 2.2)[3][4]

The growth in electricity demand in the industry will be accompanied by a strongly growing supply of renewable electricity generation. Electricity generation by offshore wind farms is expected to account for a large part of the renewable share for the Netherlands. In the latest scenario study by the Dutch grid operators, an installed offshore wind capacity of 21.5 GW is expected around 2030, and this is expected to increase to 38 GW-72 GW by 2050. The expected development of offshore wind is visualised in Figure 4.

[3] TKI Industrie en Energie (2021). Routekaart Elektrificatie in de Industrie.

[4] Netbeheer Nederland (2023). Het energiesysteem van de toekomst: De II3050-scenario's.

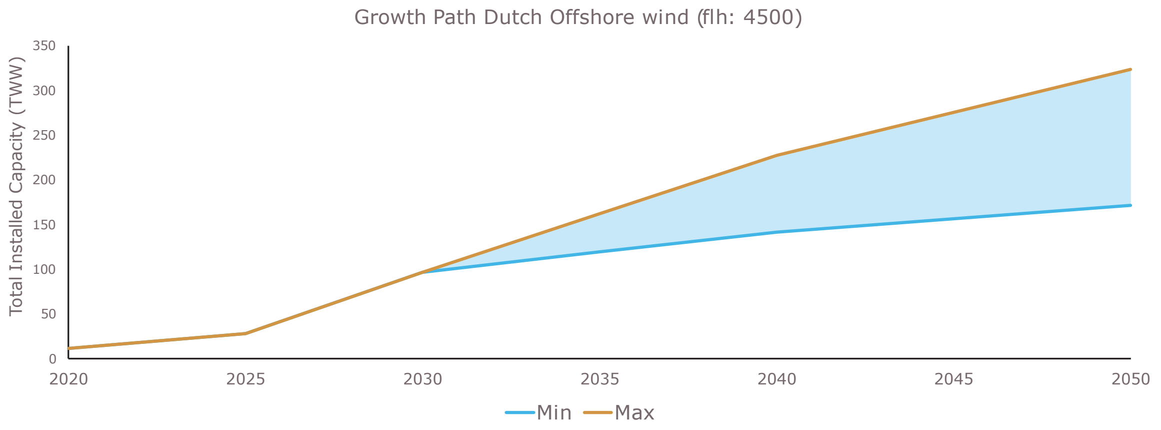

Figure 4. Projections of offshore wind (including wind turbines for dedicated hydrogen).[5]

In theory, there is a match between the growth pattern of electricity demand in the industry and the developments in the offshore wind sector. Reducing emissions through electrification will only be successful with sufficient renewable electricity. And offshore wind can only develop with an increasing demand for electricity (direct or indirect). However, when looking at the hourly production and demand curves, there is a problem that becomes visible. The electricity production curve of offshore wind depends on wind speeds, which fluctuate continuously. When we try to match the production hours of offshore wind production with industrial power consumption, this conflicts with the curves of industrial demand. Historically, industrial processes run mostly continuously, with the result that industrial electricity demand is fairly constant throughout the year. This interaction results in moments of electricity surplus as well as moments of shortage throughout the year. This mismatch is shown in Figure 5.

Figure 5 shows the surplus and shortage due to the mismatch between the power curves of offshore wind and industrial demand. The hours are sorted from most renewable production to least renewable production. On the left (the peak), the renewable production is higher than the industrial demand. This means there is an energy surplus. On the right (the valley), the industrial demand is higher than the renewable production, which means there is an energy shortage. (Other technologies can also influence the power curve and the amount of surplus and shortage).

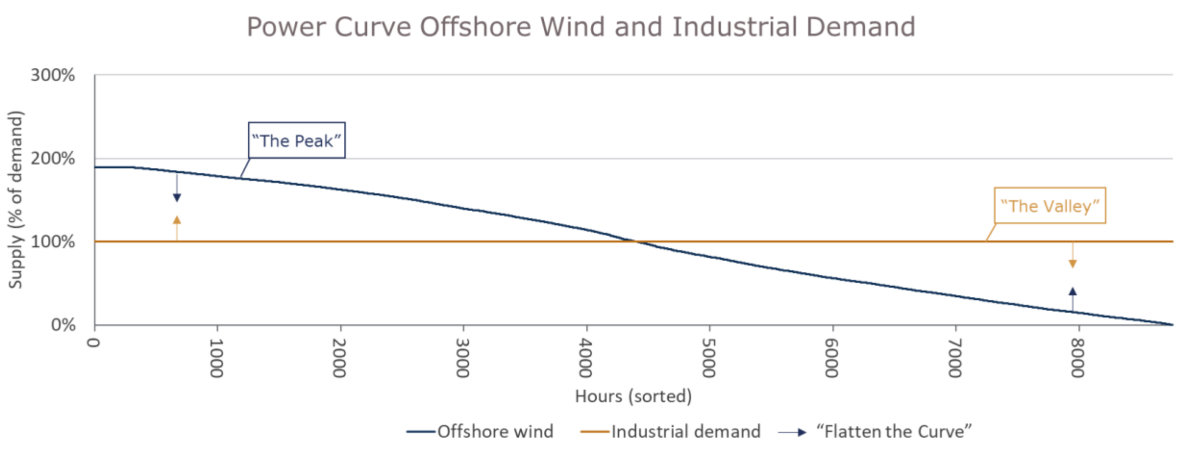

Figure 5. Power curve of offshore wind and industrial demand.

[5] Netbeheer Nederland (2023). Het energiesysteem van de toekomst: De II3050-scenario's.

In this research, we will dive into the symbiotic relationship between far-reaching electrification in the industry and the development of offshore wind. We will analyse the mismatch between industrial demand and offshore supply and search for techno-economic solutions to bring both curves closer to each other. We identify innovation gaps, for example, for technologies with technical potential but with low technology readiness levels. Furthermore, we propose policy measures to enable the techno-economic solution.

2 Methodology

This chapter presents the methodology employed in this study, focusing on the modelling of offshore wind production and industrial demand using various scenarios. The second section (2.2) provides detailed explanations of the scenarios we used, including the KNMI scenarios, the Roadmap Electrification, and the II3050 energy system scenarios. The scenarios' outcomes are then utilised to calculate the overall system costs for every situation. To assess the total system costs, we constructed a financial model, which is discussed in the third section. The fourth section examines the various methods employed for data collection.

2.1 Scope

This research focuses specifically on the relationship between offshore wind and the industry. It does not consider other sectors of demand or supply (with the exception of the addition of offshore solar PV to offshore wind farms). Onshore solar PV has a huge impact on the curves and thus conceals the relation between offshore wind and industrial electrification. Therefore, this is left out of the analysis. The analysis includes offshore infrastructures in order to examine the differences in transporting hydrogen or electricity, but calculations regarding onshore infrastructures are not included in this study.

The modelling conducted in this research is done with the year 2050 as a horizon. The scenarios explored are zero-emission scenarios aligned with the climate goals of the Paris Agreement. Technology cost predictions for the year 2050 are utilised, although it is important to note that these predictions come with a high level of uncertainty due to the long time horizon.

As for the weather profiles used in the analysis, we selected the year 2012 as it is commonly considered an average weather year from a historical perspective. Additionally, we employed a flat demand profile for the industrial demand.

The focus of the research is primarily on technologies that are considered ready and promising for further analysis and investigation. This means that technologies such as tidal energy and wave energy are not included because of their perceived lower level of technology readiness, as indicated by interviews conducted during the study.

2.2 Use of scenarios

Predictions for the Dutch energy system in 2050 diverge greatly, especially since the amount of electrification in the industry is highly uncertain. Therefore, we use different energy scenarios to diversify energy production and demand to increase the robustness of the results. The scenarios differ in terms of energy supply (offshore wind) and electrical demand (industrial demand).

The analysis in this study employs different scenarios to assess the temporal imbalances and examine the impact of specific technologies on the imbalances within each scenario. It is important to note that the objective of this study is not to compare the scenarios directly but rather to utilise them for the purpose of analysing imbalances. Figure 6 shows the scenarios used for the imbalance analysis.

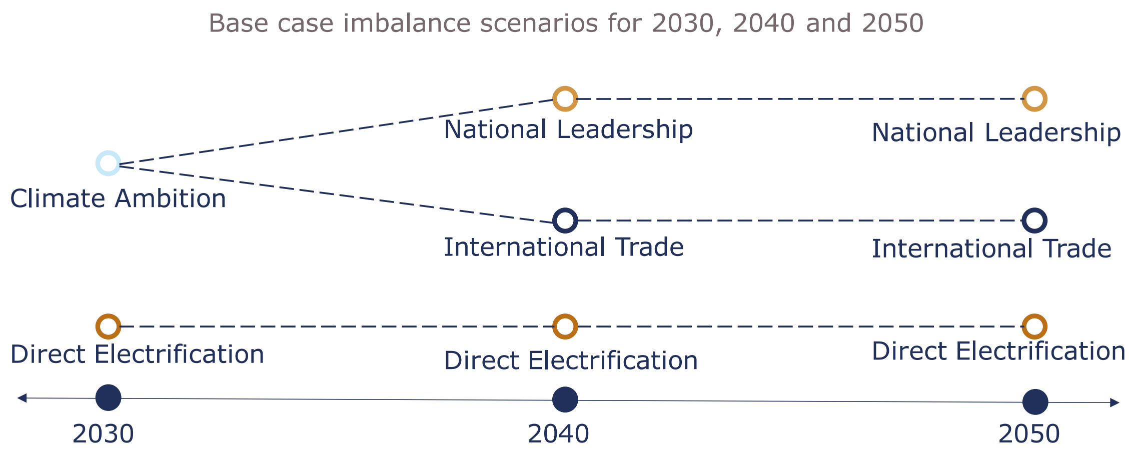

Figure 6. Imbalance scenarios for 2030, 2040 and 2050.

The modelling is based on three scenarios in 2050, which are National Leadership, International Trade and Direct Electrification. National Leadership and International Trade are two scenarios from the II3050 scenario study. Direct Electrification is a scenario of TKI Energy and Industry, which has a strong focus on electrification of the industry. The offshore wind capacities and total demand for electricity are given in Figure 7.

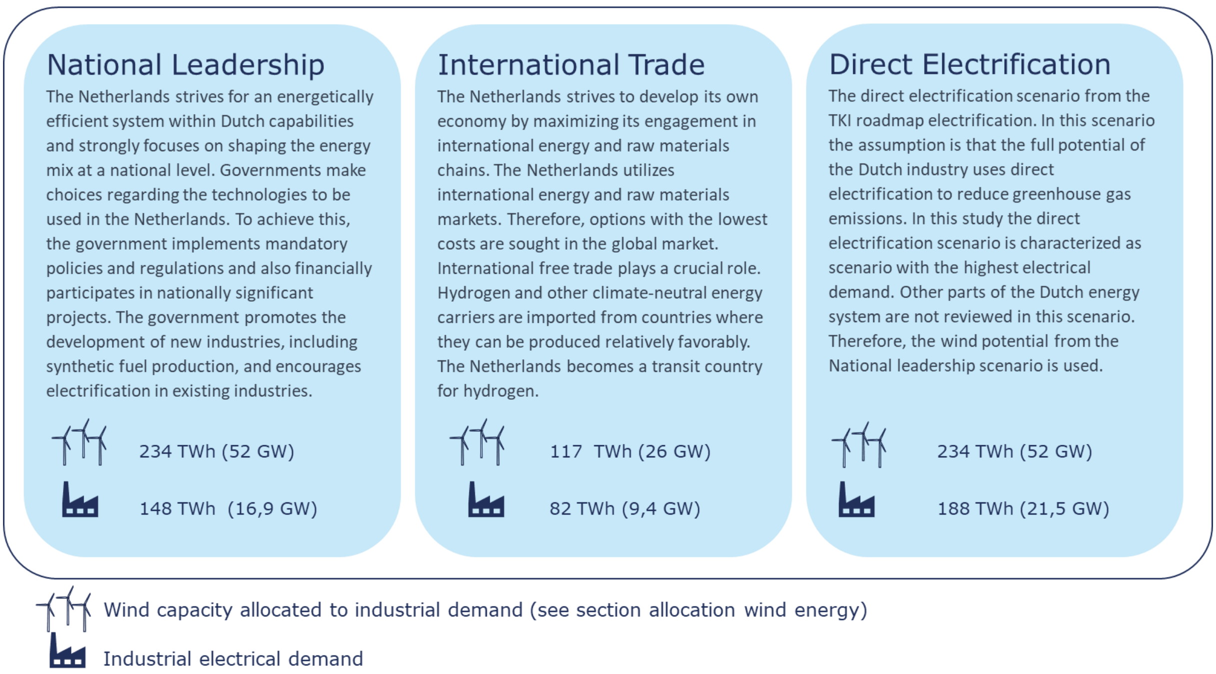

Figure 7. 2050 scenarios for offshore wind capacity and electrical demand

For every 2050 scenario, we modelled solutions to flatten the curve. The method we used for this is presented in section 4.2.

2.2.1 Wind allocation

The II3050 scenarios encompass the entire energy system, but our study focuses on a specific segment: the industry and offshore wind sector. However, it is important to note that not all offshore wind energy can be utilised by the industry. Therefore, we allocate a portion of the offshore wind supply specifically to the industry. This allocation is based on the percentage of electricity used in the industry compared to the total amount of electricity used and the amount of renewable energy compared to offshore production. This means in a scenario with more, other, renewable production, more offshore wind is allocated to the industry. This comes to the following formula:

$$Offshore\ capacity\ (allocated\ to\ the\ industry) = Offshore\ capacity\ (total) * \frac{Electricity\ demand\ (industry)}{Electricity\ demand\ (total)} * \frac{Renewable\ production}{Offshore\ production}$$

When we apply this formula to the offshore wind capacities, we come to the following numbers for offshore wind capacity for the different scenarios (Figure 8), including a variant where offshore solar PV is added to offshore wind on a 1:1 capacity basis in 2050.

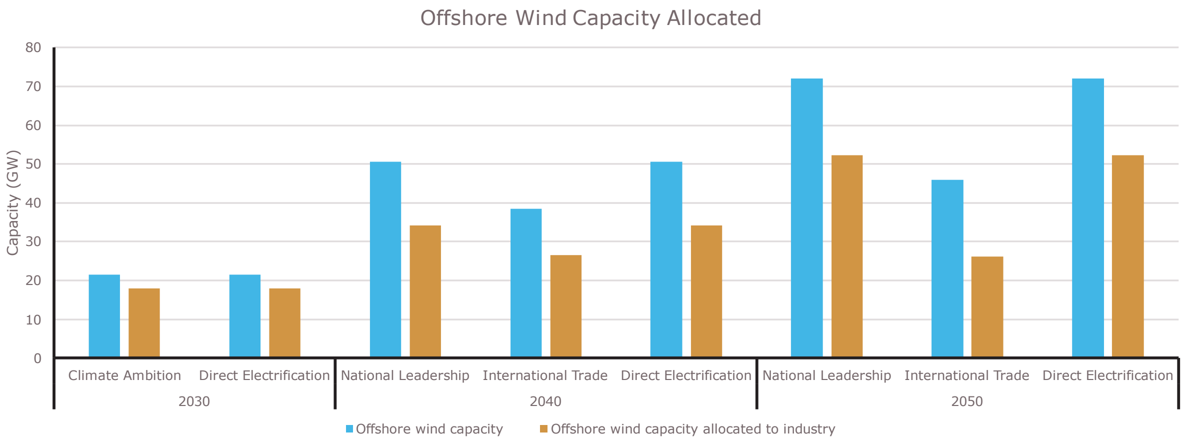

Figure 8. Offshore wind capacity for the different scenarios.

2.3 Modelling approach

2.3.1 Use of the Energy Transition Model

In this study, the Energy Transition Model (ETM) serves as the foundation for the modelling process (see text box). As mentioned before, in order to ensure the robustness of this study, the scenarios we used vary in terms of electric demand and offshore wind capacity. The wind energy scenarios draw upon two II3050 scenarios: the National Leadership scenario and the International Trade Scenario. As for the demand scenarios, they are based on the II3050 scenarios and the Roadmap Electrification.

The Energy Transition Model of Quintel

The Energy Transition Model (ETM) is an interactive online simulation tool for energy systems. It allows you to explore and quantify potential future energy systems in great detail. The ETM is free to use, open source, and is available for (EU) countries, municipalities, and many other regions. The model is owned by Quintel. Quintel is an Energy Modelling, Strategy and Research firm.

As a reference point, the base scenarios with only offshore wind and non-flexible industrial power demand are depicted. This inevitably leads to an imbalance curve between supply and demand. To address this imbalance, we propose a set of solutions based on interviews, working groups, and literature research. These solutions (see section 3.4) are then incorporated into the three base scenarios to assess the impact of individual technical solutions within each scenario. We will make the comparison based on the effect these solutions have on system costs.

2.3.2 System cost approach: Additional modelling module

To compare the (technical) solutions to flatten the curve, we used a system cost approach. A system cost approach is a methodology used to analyse and optimise energy systems based on their overall yearly costs. It involves the full spectrum of costs associated with the energy system, including capital investments, operating expenses, maintenance costs, fuel prices, and any other relevant economic factors.

The system cost approach aims to identify the most cost-effective configuration and operation strategy for an energy system. It takes into account the interactions and dependencies between different components, such as hydrogen power plants, transmission and distribution infrastructure, storage systems, hydrogen imports and renewable energy sources.

We calculated the system costs with an external Excel module. In this model, outputs of the ETM scenario are combined with cost data from literature (section 2.4.4) to find the yearly system costs. Capital expenditures are annualised using a weighted average cost of capital (WACC) of 6%. Outputs of the ETM are coupled to this module to calculate the system costs. This way, we were able to calculate the effect of the individual solutions on system costs.

Dealing with shortage

In some scenarios, for example, in the base case scenarios, a shortage of electricity occurs. This means that the modelled system cannot provide the baseload electricity demand. To assess the different solutions, the solution is firstly modelled into the energy system. As the second step, to avoid a shortage, back-up hydrogen power plants are added. This means the solution is prioritised over the modelling of the back-up plants. Electricity imports, such as cross-border imports but also electricity production by other sources (for example, solar PV on land or natural gas power plants), into the system, are not considered in this study, as it would effectively broaden the scope of the analysis beyond the industrial and offshore wind sectors. Hydrogen can be imported from outside the system, which can be from other parts of the Dutch energy system or from abroad. The imported hydrogen has a fixed import price. The costs for additional back-up power plants and the imported hydrogen are integrated into the total yearly system costs. A surplus of electricity is curtailed instead of exported and has; therefore, no value within the system costs analysis.

2.3.3 Searching for solutions: Techno-economical assessment of solutions for reducing imbalance

We identified eleven technological categories for dealing with surpluses and shortages of offshore wind generation. These are listed in Figure 9. We assessed the options using energy system modelling on an hourly basis combined with system cost analysis. Therefore, these options must both have quantifiable effects on production or consumption curves and have substantial cost parameters. Two categories do not meet these requirements, namely new wind turbine/wind farm designs and medium-term electricity storage.

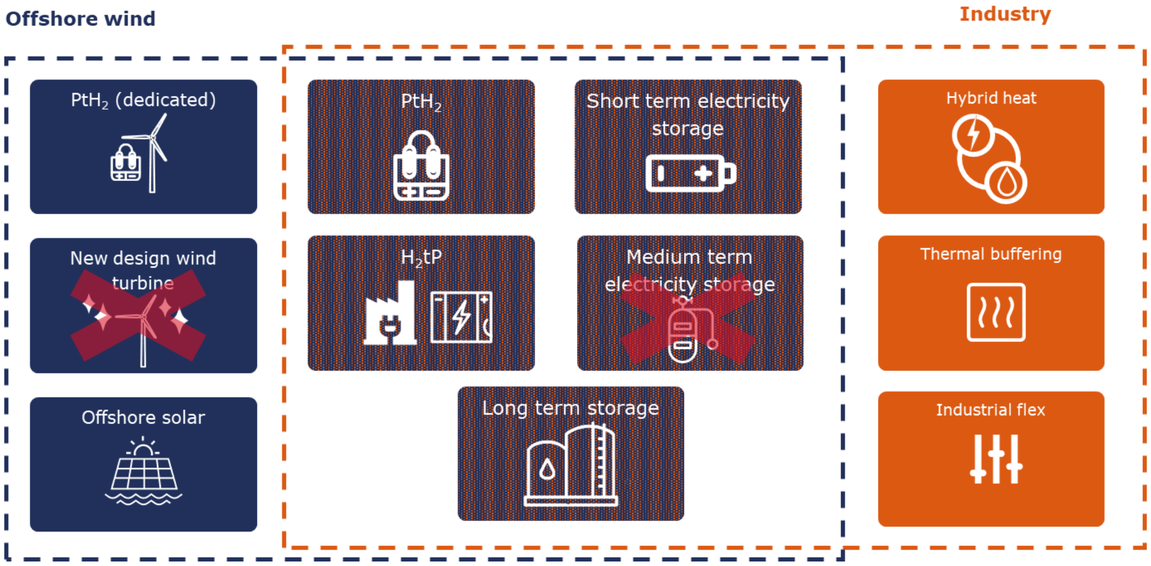

Figure 9. Eleven identified technological categories for reducing surpluses and shortages of offshore wind generation, of which nine meet the criteria to be included in this report. Two are excluded due to the lack of quantifiable effect on production or consumption.

In interviews with representatives of the offshore wind sector, several new wind turbine/wind farm designs have been discussed. For example, we considered offshore wind farms containing turbines with different hub heights. However, no significant changes in the production profile are expected, as differences in hub heights primarily reduce wake losses. Furthermore, options for increasing the rotor sizes of wind turbines with respect to the generators have been suggested for effectively increasing the load factor of wind turbines. However, in essence, this option is similar to simply curtailing power production. Finally, more far-fetched (but technically feasible) options were discussed for increasing the maximum wind speeds with which wind turbines could generate power. However, both the effects on the production profile and on the system costs are not quantifiable for these options.

Medium-term electricity storage in the form of redox flow batteries has also been considered for this study. A redox flow battery is a type of electrochemical cell where energy is provided by two chemical components dissolved in liquids that are pumped through the system on separate sides of a membrane. An important characteristic of redox flow is a higher energy-to-power ratio than batteries have; it can discharge for multiple hours. However, forecasts regarding the costs of this technology are not yet sufficiently reliable for inclusion in the analyses.

Modelling eight solution categories

We added the eight technological categories that have made the cut to the base scenarios in the ETM one by one. When added to the scenarios, the capacities of each technology are optimised to minimise system costs, taking into account the possible limitations. If an option reduces system costs, it is kept in the system. But if it increases system costs, it is not kept in the system. We propose to add the eight technological solutions in the following order.

1. Hydrogen back-up plants: the shortage of the base scenario is solved with the help of hydrogen back-up power plants. The hydrogen back-up plants are removed when a solution is added tot the model, and the "new" back-up is optimised with the help of the new shortage.
2. Power-to-hydrogen (PtH_2) is added to make use of the surplus and to cover a part of the hydrogen import.
    - A variant is included with dedicated PtH_2 directly coupled with offshore wind.
3. Power-to-heat is added as hybrid heat.
4. Offshore solar PV is added in between offshore wind farms.
5. Industrial process flexibility is integrated into the system.
6. Thermal buffering: heat is stored to be used in times of limited electricity supply.
7. Batteries are added to the energy system.

The order in which these solutions are incorporated into the system follows a certain logic. For example, thermal buffering and battery storage are added after offshore solar PV, as they capitalise on a higher volatility of renewable power supply. After each step, the earlier steps are reoptimised (see Figure 10).

Figure 10. Order in which technological solutions are added to 'flatten the curve'.

2.4 Data collection

2.4.1 Summary of key data for the Direct Electrification, National Leadership and International Trade scenarios

This study uses three different scenarios for its analyses: the Direct Electrification scenario from Roadmap Electrification in the Industry[6], the National Leadership scenario from II3050[7] and the International Trade scenario, also from II3050. Table 4 shows the key parameters of these scenarios for the year 2050. The years 2030 and 2040 are not further analysed with regard to technical solutions for reducing imbalance.

There are substantial differences among the scenarios regarding electricity and hydrogen demand, but also regarding hybrid boiler capacity. Therefore, system costs will also vary

[6] TKI Industrie en Energie (2021). Routekaart Elektrificatie in de Industrie.

[7] Netbeheer Nederland (2023). Het energiesysteem van de toekomst: De II3050-scenario's.

among the scenarios. It is important to note that system costs are not compared among scenarios. System costs will only be compared for different technologies within scenarios.

Table 4. Key parameters of the three scenarios for the year 2050 were used in the analyses. Electricity demand for electric boilers is based on continuous operation using electricity throughout the year; this provides a reference situation in which no flexibility is present. Electricity demand for producing the required hydrogen is not included.

	Direct Electrification (Roadmap Electrification in the Industry)	**National Leadership** (II3050)	**International Trade (II3050)**
Electricity demand [TWh]	**188**[I]	**147**	**82**
Steel	4[I,II]	4	4
Refineries	38[I]	6	7
Steam cracking	56[I]	12	7
Electrochemistry (excl. green H2)[III]	6[I]	6	6
Other chemicals	27[I]	48	29
Food	16[I]	11	11
Paper	6[I]	3	3
Synthetic fuels	0[I]	38	0
Other	34[I]	19	15
Hydrogen demand [TWh]	**13**[IV]	**106**	**55**
Industrial hydrogen production and hydrogen in waste gases [TWh]	**-**[IV]	**16**	**8**
Hybrid boilers [MW][V]	**6226**	**1070**	**1186**
Steel	0	0	0
Refineries	1222	334	474
Steam cracking	1630	15	0
Electrochemistry (excl. green H2)	0	0	0
Other chemicals	320	529	424
Food	1002	148	222
Paper	457	44	65
Synthetic fuels	0	0	0
Other	1595	0	0
Electricity for P2H [TWh]	**140**	**?** [VI]	**?** [VI]
LT (< 200 °C)	16	? [VI]	? [VI]
HT hybrid boiler (> 200 °C)	55	9	10
HT other (> 200 °C)	70	? [VI]	? [VI]

I The original Roadmap scenario data only contains electrification potential. This is added to the current electricity consumption of the Dutch industry, based on the historic base year in the Carbon Transition Model.[8]
II The original Roadmap scenario assumes ULCOWIN for steel production. Instead, DRI with hydrogen combined with electrification is assumed for the steel industry as ULCOWIN is not available as a technology in the Energy Transition Model.
III Non-hydrogen electrochemistry electricity demand is approximated by the historical electricity demand of Nobian in the Carbon Transition Model, the non-ferrous metals sector.
IV The original Roadmap does not contain green hydrogen consumption, 46 PJ solely comes from steel production using DRI (see point II). The Roadmap assumes that all other hydrogen feedstock demand is covered by blue hydrogen production. The volume is unknown and lies outside the scope of this study.
V Hybrid boilers can switch between electricity and a gaseous energy carrier. This can be hydrogen or biogas.
VI.The II3050 scenarios do not differentiate all electricity demand by application.

2.4.2 Offshore wind generation profile

In the approach described below, we present an approximation of the production profile of offshore wind power for future scenarios. In these scenarios, a significant portion of the Dutch Exclusive Economic Zone is used for offshore wind farms. The profile of the year 2012 is used as a reference year as it corresponds well with long-term historical average wind speeds. The production profile for 2012 is shown in Figure 11. The profile corresponds to 4460 full load hours.

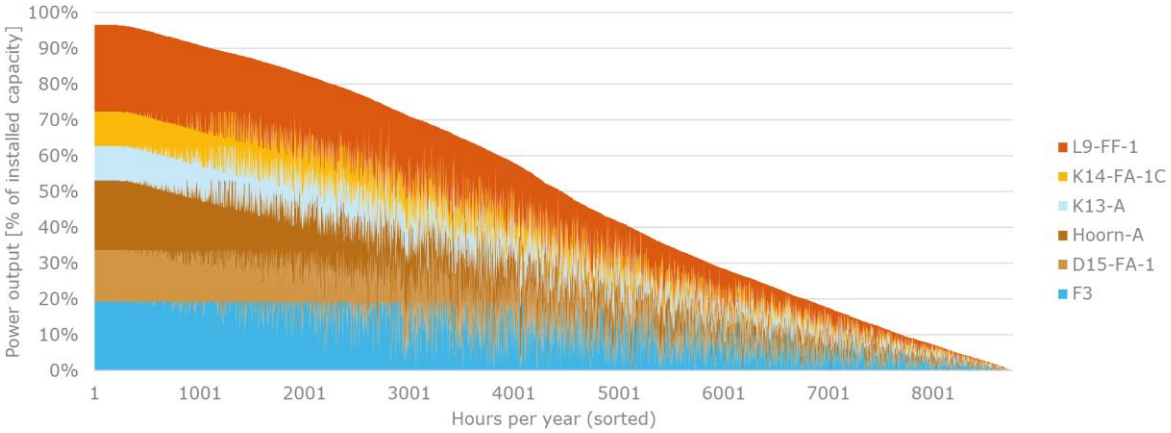

Figure 11. Production profile of offshore wind based on wind data from multiple weather stations in the Dutch North Sea. The names of the weather stations (L9-FF-1, etc.) are also shown in the map in Figure 9. Power output is represented as a percentage of total

Offshore wind generation profiles are created based on weather data from the KNMI.[9] This data contains wind speeds at ten-minute intervals for several offshore weather stations in the Dutch Exclusive Economic Zone in the North Sea (see the left map in Figure 12). We first cleaned the data by filling in the missing data. We then converted wind speeds to the wind speeds at hub height using the Hellman equation[10], which is:

$$v_{wind,hub} = v_{wind,data} \cdot \left(\frac{h_{hub}}{h_{data}}\right)^{\frac{1}{ln\left(\frac{h_{hub}}{z_0}\right)}} \quad (1)$$

Where the meaning of the abbreviations is:

- $v_{wind,hub}$ = wind speed at hub height (m/s)
- $v_{wind,data}$ = measured wind speed at the weather station (m/s)

[8] https://carbontransitionmodel.com/.

[9] KNMI Data Platform (2022). Wind – wind speed, direction, standard deviation at a 10 minute interval. https://dataplatform.knmi.nl/dataset/windgegevens-1-0.

[10] https://windpowerlib.readthedocs.io/en/stable/temp/windpowerlib.wind_speed.hellman.html.

- h_{hub} = hub height of the wind turbine (m)
- h_{data} = height of the weather station (m)
- z_0 = roughness length (0.0002 assumed for the North Sea).

We corrected the wind speeds to account for wake losses. Wake losses in offshore wind parks refer to the reduction in wind speed and energy experienced by downstream wind turbines due to the turbulence and drag caused by the wake (airflow disturbance) generated by upstream turbines. In literature, wake losses between 10% and 20% are reported in large offshore wind parks[11]. Recent studies find possible underestimations of wake losses due to inter-wind farm wakes[12], which will increase when more offshore wind parks are operational. However, at the same time, technical innovations such as 'active wake control' may even lead to a reduction in wake losses.[13] In this study, we assume wake losses of 15%.

Climate change effects are not taken into account in this analysis. Climate change effects can influence wind speeds. This effect is more significant over a longer period of time. In the study of Gernaat et al. (2021), an average decrease of 5% wind speed is shown to be expected over a period of a hundred years.[14] Since this research focusses on a timeframe of less than thirty years, the climate change effect is not included in our model.

To convert wind speeds into a power generation profile, we used the 15-megawatt IEA reference offshore wind turbine.[15] This turbine has a hub height of 150 meters, a cut-in wind speed of 3 m/s and a cut-out wind speed of 25 m/s. The power curve of the wind turbine is shown in Figure 10. After making the power generation profiles, we multiply the profiles by a factor of 96,5% to account for the availability of offshore wind turbines.[16]

The offshore wind power generation profiles are combined according to the distribution of operational wind parks, planned wind parks and search locations for additional wind parks (Figure 12 on the right). A list of the selected weather stations and the relative weight of the corresponding power generation profiles are listed in Table 5. Figure 11 clearly shows that there are significant hourly fluctuations in wind speeds among different locations in the North Sea, confirming that it is necessary to simulate power production profiles based on wind speeds at multiple offshore locations.

[11] Example: BLIX, Pondera & Energy Solutions (2020). Determination of the cost levels of wind farms (and their grid connections) in new offshore wind energy search areas.

[12] Baas, P., & Verzijlbergh, R. (2022). The impact of wakes from neighbouring wind farms on the production of the IJmuiden Ver wind farm zone.

[13] TNO (2022). Active wake control validation methodology.

[14] Gernaat et al. (2021). Nature Climate Change, volume 11, issue 2, pp. 119-125.

[15] NREL (2020). Definition of the IEA 15-Megawatt Offshore Reference Wind Turbine.

[16] Guidehouse & Berenschot (2021). Systeemintegratie wind op zee 2030-2040.

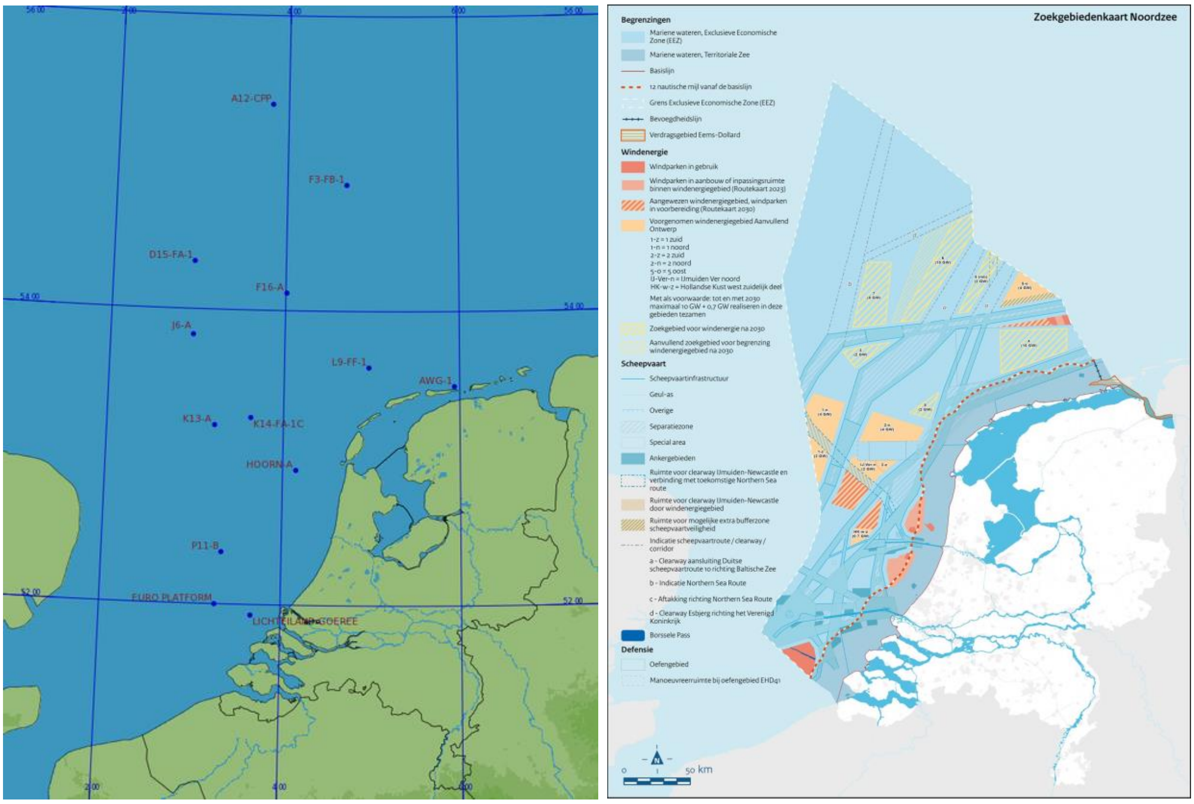

Figure 12. Offshore KNMI weather stations in the Dutch Exclusive Economic Zone in the North Sea (left) and an overview of operational and planned offshore wind parks towards 2030 as well as search areas for additional parks after 2030 (right).

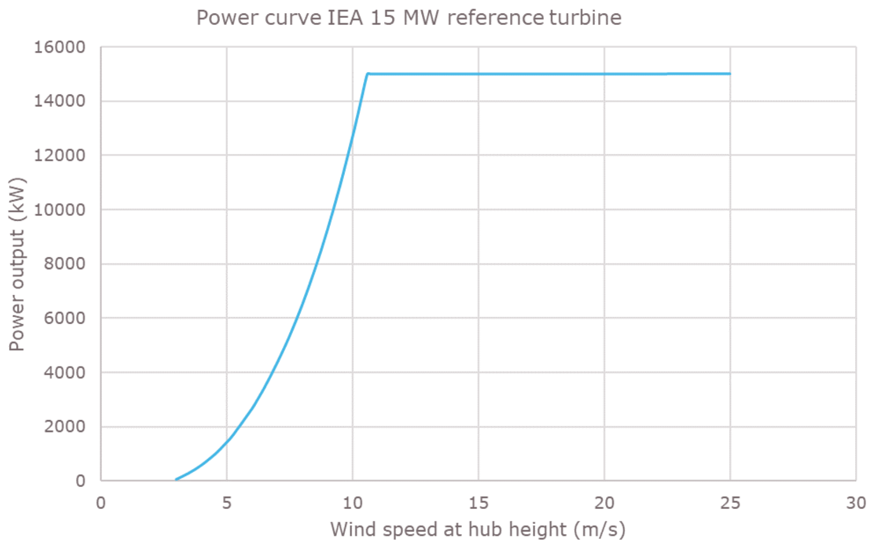

Figure 13. Power curve of 15 MW IEA reference offshore wind turbine.

Table 5. List of weather stations and corresponding weights to approximate the distribution of operational wind parks, planned wind parks and search locations for additional wind parks in the Dutch North Sea.

Platform	Weight	Latitude/longitude
F3	20%	54.85389 / 4.69611
D15-FA-1	15%	54.32556 / 2.93583
Hoorn-A	20%	52.91806 / 4.15028
K13-A	10%	53.21778 / 3.22028
K14-FA-1C	10%	53.26944 / 3.62778
L9-FF-1	25%	53.61444 / 4.96028
Total	**100%**	

2.4.3 Offshore solar PV generation profile

The result of the approach described below is an approximation of an offshore solar PV power production profile for a future scenario in which offshore solar PV systems are installed near offshore wind farms. The production profile of 2012 is shown in Figure 14, which corresponds with 930 full load hours.

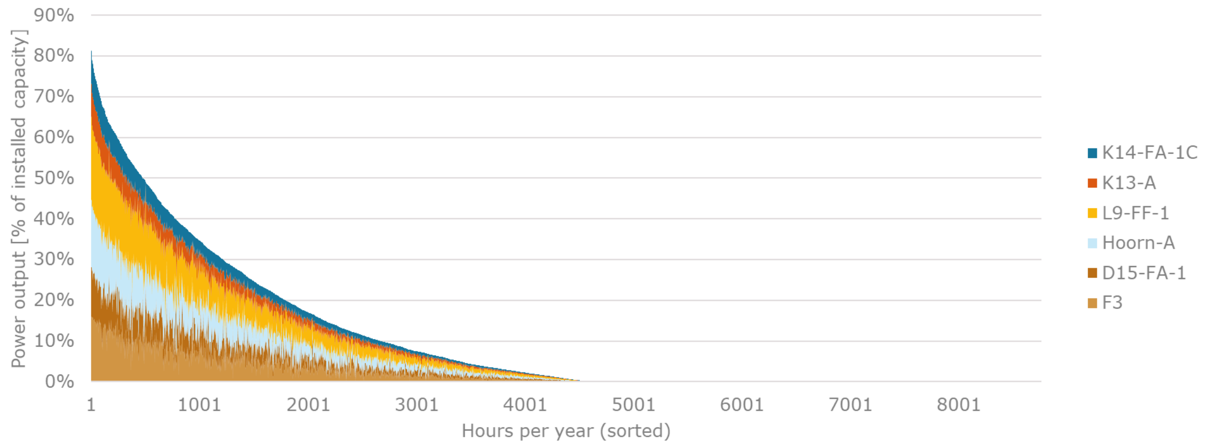

Figure 14. Production profile of offshore solar PV based on irradiation data from multiple weather stations in the Dutch North Sea. Power output is represented as a percentage of total installed capacity and sorted based on total power output.

These offshore solar PV generation profiles are based on satellite solar radiation data from the Copernicus Atmosphere Monitoring Service (CAMS).[17] This data contains global solar irradiance at fifteen-minute intervals. The year 2012 is chosen as a reference year to match the weather year of the offshore wind profile.

We used the following formula to convert the solar irradiance to solar PV power output:

[17] https://atmosphere.copernicus.eu/data.

$$p_{PV} = (DHI + BHI \cdot tf) \cdot PR \qquad (2)$$

Where the abbreviations are:

- p_{pv} = solar PV power output (W)
- DHI = diffuse irradiation on horizontal plane (W/m^2)
- BHI = beam irradiation on horizontal plane (W/m^2)
- tf = tilt factor (1,11) to correct for the increase in BHI due to the tilt of solar panels (15°)
- PR = performance ratio (0.85) to correct for system losses in the PV system.

The locational data and weights listed in Table 5 are also applied to the solar PV profiles. This way, the solar PV generation is allocated according to the distribution of offshore wind generation capacity. Figure 14 shows that there are significant hourly fluctuations in solar irradiance among different locations in the North Sea due to cloud formation. This confirms that it is necessary to simulate power production profiles based on irradiance data at multiple offshore locations.

2.4.4 2050 cost data

Table 6 contains forecasts for capital and operational expenditures for different technologies in 2050. Note that most of these technologies are still under development, and the cost figures, therefore, have large uncertainty margins. We explore the impact of this uncertainty in a sensitivity analysis (section 3.2.7).

Table 6. Cost assumptions. See footnotes for references and the table caption (I, II, III, etc.) for additional explanations.

	Costs	**OPEX (% of CAPEX)**	**Lifetime** (years)
Hydrogen import/blue hydrogen production	60 €/MWh[I]		
Offshore wind	2100 €/kW[18]	3%[19]	25[20]
Floating solar PV	600 €/kW[21]	2%[22]	25[assumption]
PtH_2 onshore	750 €/kW[23]	2%[23]	25[20]
PtH_2 offshore	1013 €/kW[III]	2%[III]	25[III]
H_2tP onshore	750 €/kW[IV]	2%[IV]	25[IV]
Electricity storage onshore	600 €/kW[V,24]	4%[24]	15[24]
Electricity storage offshore	810 €/kW[III]	4%[III]	15[III]
Hydrogen storage onshore	0.15 €/kWh[25,VI]	1%[assumption]	25[assumption]
Hydrogen storage offshore	0.23 €/kWh[25,VI]	1%[assumption]	25[assumption]
Offshore HVDC platform	300 €/kW[20]	1%[assumption]	25[20]

[18] IRENA (2019). Future of wind.

[19] Peak Wind (2022). OPEX Benchmark – An insight into the operational expenditures of European offshore wind farms.

[20] Guidehouse & Berenschot (2021). Systeemintegratie wind op zee 2030-2040.

[21] Expert interview with Oceans of Energy, information retrieved via the Energy Transition Model by Quintel Intelligence.

[22] TKI Wind op Zee (2022). Challenges and potential for offshore solar.

[23] Blanco, H., Nijs, W., Ruf, J., & Faaij, A. (2018). Potential for hydrogen and Power-to-Liquid in a low-carbon EU energy system using cost optimization.

[24] NREL (2021). Cost Projections of Utility-Scale Battery Storage: 2021 Update.

[25] TNO & EBN. (2022) Haalbaarheidsstudie offshore ondergrondse waterstofopslag.

Offshore HVAC platform	141 €/kW[20]	1%[assumption]	25[20]
Offshore HVDC cable	275 €/kW[20,VII]	1%[assumption]	25[20]
Offshore HVAC cable	80 €/kW[20,VII]	1%[assumption]	25[20]
HVDC converter	125 €/kW[20]	1%[assumption]	25[20]
Hydrogen compression station	81 €/kW[26]	4%[27]	10[27]
Offshore hydrogen compression platform	30 €/kW[20]	1%[assumption]	25[20]
Offshore hydrogen pipeline	41 €/kW[20,VII]	1%[assumption]	25[20]
Offshore artificial island	211 €/kW[20,VIII]	1%[assumption]	25[20]
Hybrid boiler	60 €/kW[28]	2%[28]	15[28]
Hybrid furnace	1050 €/kW[IX]	10%[IX]	20[IX]
Thermal buffering volume	15-80 €/kWh[X, 29]	3%[29]	25[29]
Thermal buffering power capacity	60[28]-1200[30] €/kW[X]	3%[28]	15[28]
Industrial process flexibility fixed costs	24 €/kW/year[31]		

I.Estimate of production costs of green hydrogen in 2050 between: 1 – 1.5 €/kg for more favourable regions.[32] Estimate of transport and conversion costs of hydrogen in 2050: 0.7 – 1.3 €/kg for distances up to 10,000 km.[33] Energy density of hydrogen is roughly 30 MWh/kg.
II Assumed to be similar to OPEX of regular offshore wind in terms of % of CAPEX.
III 35% higher CAPEX than the onshore variant.20 OPEX as % of CAPEX and lifetime assumed similar as offshore.
IV Currently the cheapest hydrogen-to-power technology is a hydrogen gas turbine (+/- 1000 €/kW) but no significant further cost reductions can be expected from this mature technology. However, since fuel cell technology is similar to electrolyser technology, we assume CAPEX, OPEX and lifetime to be similar as well.
V 4 hour battery assumed: 4 kWh capacity for each 1 kW power.
VI Cost figure corresponding to salt caverns.
VII Average distance of 250 km assumed from offshore wind connection point to shore for HVDC. Average distance of 45 km assumed from offshore wind farm to the offshore island for HVAC.
VIII Costs based on artificial islands with 10+ GW electrolyser capacity. The land area required for both H2tP and electricity storage is assumed to be similar to the land area required for electrolysers in terms of m2/kW.
IX Data from Carbon Transition Model (CTM). Integrated steam cracker CAPEX of 1800 €/(ton ethylene/year), where roughly 35% of CAPEX is for the furnaces. Electricity use of electric steam cracker in the CTM is 0.6 MW/(kton ethylene/year).
X Volume costs range based on solid state thermal buffering (low) and latent heat thermal buffering (high). Capacity costs range based on e-boiler (low) and industrial heat pump with COP (coefficient of performance) → 3 (high).

[26] ACER (2015). UIC Report – Gas Infrastructure.

[27] Ramsden, T.G., Steward, D.M., James, B.D., Ringer, M. (2008). Current Forecourt Hydrogen Production from Grid Electrolysis.

[28] Energy Transition Model.

[29] IRENA (2020). Innovation Outlook: Thermal Energy Storage.

[30] Grosse, R., Christopher, B., Stefan, W., Geyer, R. & Robbi, S. (2017). Long term (2050) projections of techno-economic performance of large-scale heating and cooling in the EU.

[31] TenneT (2023). Adequacy Outlook.

[32] Pwc (n.a.). The green hydrogen economy.

[33] Irena (2022). Global hydrogen trade to meet the 1.5 °C climate goal.

3 Results

Wind energy and industrial electrification are increasing in the Netherlands, resulting in increasingly larger surpluses and shortages. Technical solutions are required to 'flatten the curve'.

3.1 Analysing the problem: imbalance between supply and demand in eight scenarios

In this section, we will analyse the imbalance between the supply of wind energy (allocated to the industry) and the industrial electrification demand in eight base-case scenarios. We have used scenarios for 2030, 2040 and 2050 to create an energy system with offshore wind production and industrial demand. Other supply and demand sectors are omitted to find the correlation between offshore wind and industry. In this way, the scenarios can be used to find the imbalance between offshore wind and industrial demand. This means that we did not model flexibility technologies in the base case. The scenarios used are presented in Figure 15. The scenarios are based on studies of Netbeheer Nederland and TKI Energy and industry[34,35,36].

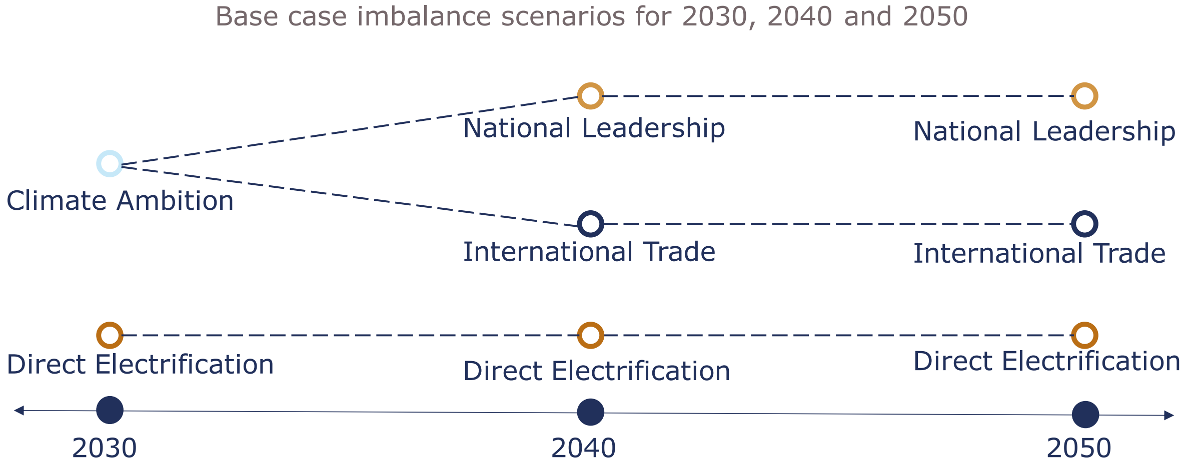

Figure 15. This study considers eight imbalance scenarios for three time horizons (2030, 2040 and 2050).

For every scenario, the electricity surplus and electricity shortage is calculated. In the base case scenarios, the surplus is defined as curtailment: electricity that can not be used by the industry since it is higher than the baseload demand. The shortage is defined as the electricity that is needed when the offshore wind production is lower than the industrial baseload demand. In the next chapters, we propose solutions to minimise the surplus and shortage while comparing the overall system costs, starting with the addition of sufficient hydrogen backup power generation to accommodate baseload power demand.

In Table 7, the surplus and shortage are given for each base scenario. It is evident that the scenarios with increased offshore wind capacity have a bigger surplus, and the scenarios

[34] Netbeheer Nederland (2023). Het energiesysteem van de toekomst: de II3050-scenario's.

[35] Netbeheer Nederland (2023). Scenario's investeringsplannen 2024.

[36] TKI Energie en industrie (2021). Elektrificatie: cruciaal voor een duurzame industrie.

with higher baseload demand from the industry have a higher shortage but a lower surplus. The National Leadership scenario has the highest surplus, and the Direct Electrification scenario has the highest shortage. In general, the imbalances increase until 2030. In the following sections, we give the different scenarios a more in-depth explanation.

Table 7. Surplus and shortage per scenario.

Scenario	Year	Surplus (TWh)	Shortage (TWh)
Climate Ambition	2030	27.6	16.7
Direct Electrification	2030	5.5	45.7
National Leadership	2040	69.0	15.4
International Trade	2040	53.9	15.5
Direct Electrification	2040	78.2	46.0
National Leadership	2050	103.6	31.8
International Trade	2050	45.9	20.0
Direct Electrification	2050	78.2	49.9

National Leadership

The National Leadership scenario includes the highest offshore wind capacity of the II3050 study. The power profile is visualised in Figure 16. From 2030 until 2040, the amount of offshore wind that is allocated to the industry increases from 18 GW to 33 GW. This further increases to around 50 GW in 2050. The electrical demand in the industry also grows in these scenarios but at a much slower pace. Therefore, the surplus of electricity grows over the years. The electricity surplus increases from 27.6 TWh in 2030 to 103.6 TWh in 2050. The shortage of electricity in this system doubles between 2040 and 2050.

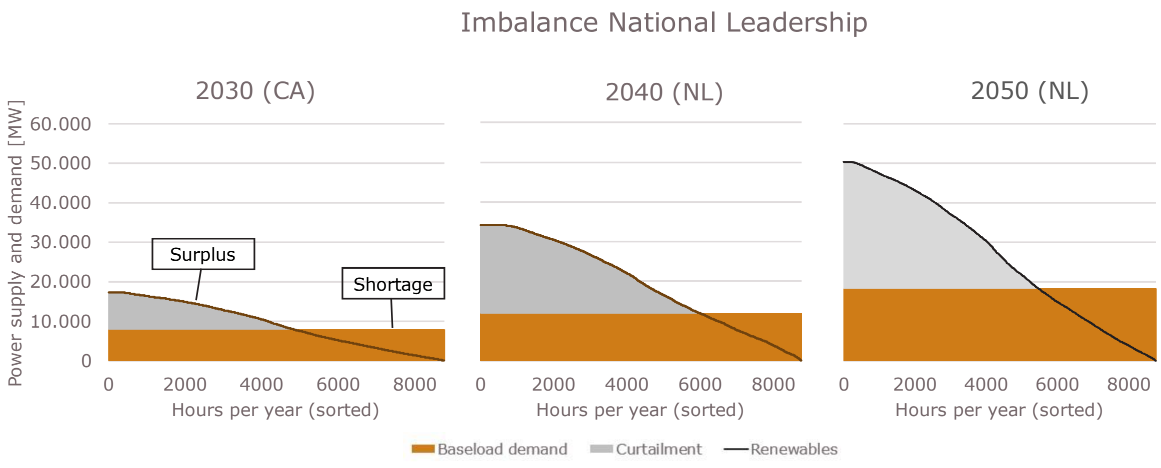

Figure 16. Power curves of the National Leadership scenarios.

International Trade

The International Trade scenario is characterised as the scenario with the highest imports of hydrogen. Therefore, there is less electrification of the industry and less development of offshore wind. The power curves are visualised in Figure 17. In this scenario, the capacity of wind allocated to the industry grows from 19 GW to 29 GW. After 2040, the offshore wind capacity remains the same. Electrification of the industry is also limited: the baseload remains around 10 GW over the years. As a result of the lower electricity demand and limited offshore wind developments, the electricity surplus and shortage are lower than in the National Leadership scenario.

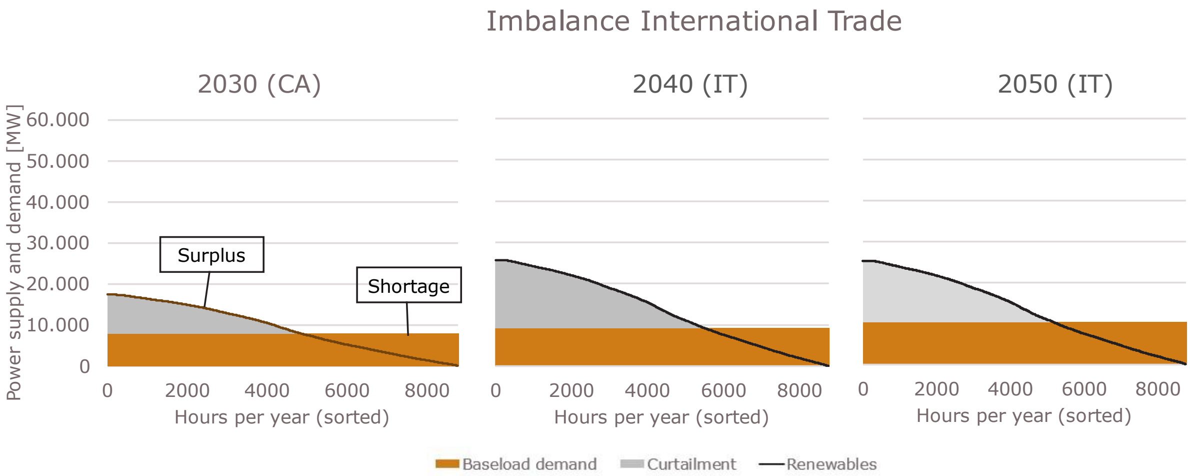

Figure 17. Power curves of the International Trade scenarios.

Direct Electrification

The Direct Electrification scenario is produced by TKI Energy and Industry in the Roadmap Electrification. The full electrification potential of the industry is modelled and visualised in Figure 18. Since no offshore wind was modelled in the original scenario, we have modelled the capacities of the National Leadership scenario into this energy system. The Direct Electrification scenario has the highest baseload electricity demand by far. This increases to more than 20 GW in 2050. This leads to a much bigger shortage for 2030, 2040 and 2050.

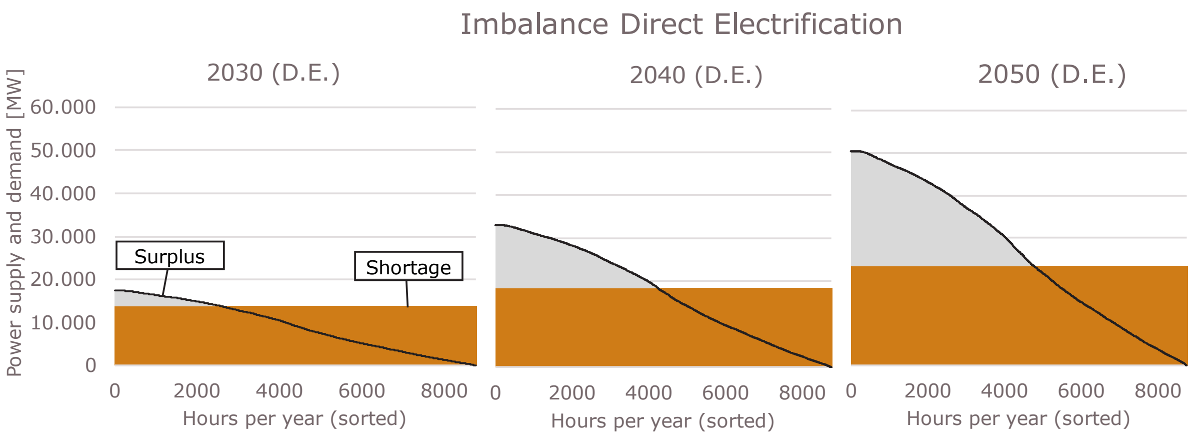

Figure 18. Power curves of the Direct Electrification scenarios.

3.2 Searching for solutions: techno-economical assessment of solutions for reducing imbalance

In this section, the solutions are presented one by one. After a solution is added, the system is balanced again. For the method we used, see section 2.3

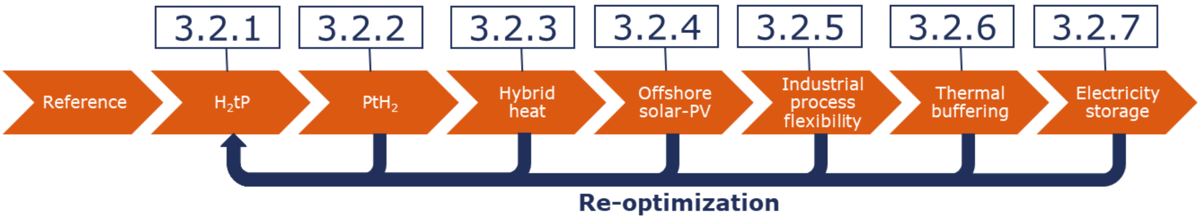

Figure 19. Order in which technological solutions are added to 'flatten the curve'.

3.2.1 H2-to-power: flexible power generation such as H2tP is essential for supplying baseload electricity during times of low renewables

To address the reference imbalance situation depicted in Figure 16, Figure 17 and Figure 18 across the three scenarios, the initial measure involves incorporating flexible power generation to serve as a backup during periods when offshore wind power generation falls short of meeting the power demand. This study considers hydrogen turbines, or other forms of hydrogen-to-power (H_2tP), as flexible power generation technology. However, other technologies (such as nuclear power plants, biomass power plants or natural gas turbines with carbon capture and storage) could also provide low carbon flexible/baseload power, albeit with different fuel requirements and/or costs. H_2tP is selected as a reference technology as it is a relatively cheap form of low-carbon backup capacity compared to other forms of flexible generation.[37]

Since there are a few hours a year where offshore wind production is nearly zero, during those hours, the required backup generation capacity is roughly equal to the baseload electricity demand. See Figure 20 for the system costs and the backup capacity required. The capacity of backup demand ranges between 11 GW and 25.5 GW for the International Trade and Direct Electrification scenario, respectively. These scenarios are indicated as the base case scenarios in which no other flexibility solutions are modelled. Figure 21 illustrates how flexible H2tP is dispatched in order to complement shortages of offshore wind production for the three scenarios.

[37] TenneT (2023). Adequacy Outlook.

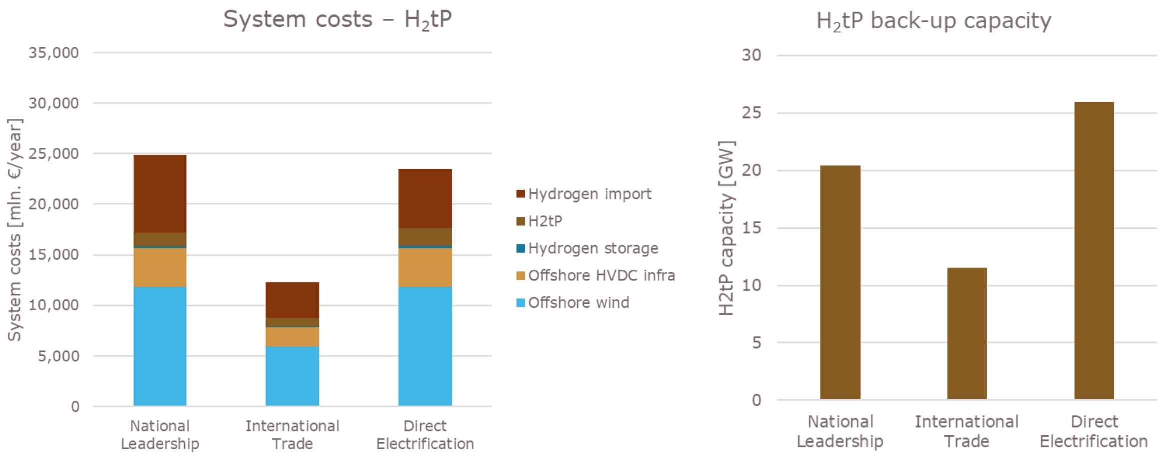

Figure 20. System costs (left) and hydrogen-to-power (H2tP) backup capacity required (right) per scenario.

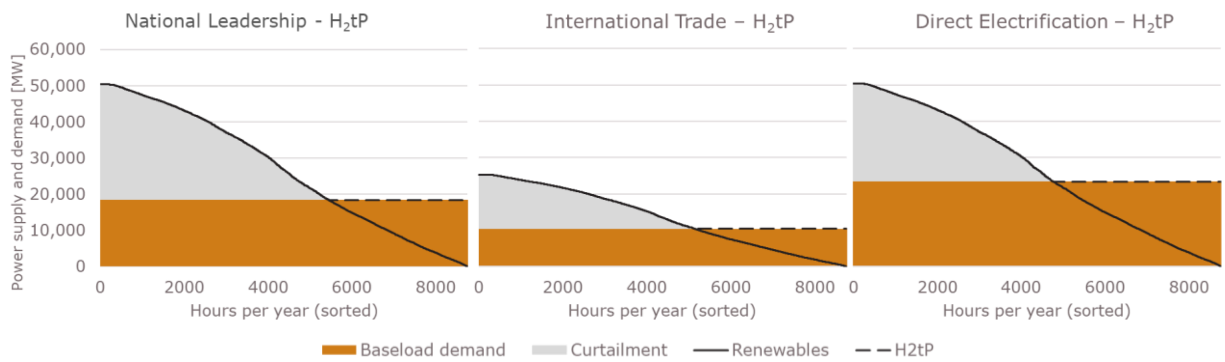

Figure 21. Illustration of flexible H2tP dispatch for complementing offshore wind in supplying electricity demand per scenario.

Power-to-H2: offshore electricity production that can be used for baseload demand should transported as electrons and not as hydrogen

The next step is adding electrolysers for better utilisation of surplus power generation by offshore wind. Three design choices are considered for combining electrolysis with offshore wind (see Figure 22):

1. **PtH$_2$ onshore**: electricity produced by offshore wind transported to shore using High Voltage Direct Current (HVDC) cables, direct electric utilisation of baseload electricity and conversion of surplus electricity to hydrogen onshore.
2. **PtH$_2$ offshore dedicated**: electricity produced by offshore wind is directly converted to hydrogen on offshore islands and transported through pipelines, with no transport of electricity to shore.
3. **PtH$_2$ hybrid**: electricity produced by offshore wind that can be used for baseload demand, transported to shore using HVDC cables. Conversion of surplus electricity to hydrogen is done on offshore islands and is transported through pipelines.

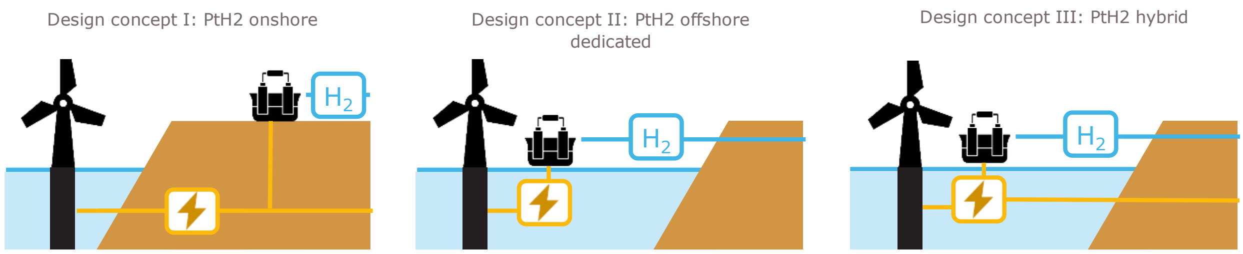

Figure 22. Conceptual drawing of the three electrolysis design concepts.

Producing hydrogen offshore replaces expensive HVDC infrastructure with cheaper pipelines but requires investments in offshore islands and offshore PtH_2. Figure 23 shows that for the onshore and hybrid designs, the total system costs are comparable. However, this is based on rough future cost estimates (see section 2.4.4) for various technologies which are undergoing continuous developments. Therefore, no conclusive evidence is found in favour or against either onshore or hybrid PtH_2. Both designs lead to lower system costs compared to a system without any PtH_2 (see Figure 23).

However, offshore dedicated PtH_2 is much costlier, as offshore power generation cannot be used directly for baseload electricity demand. This results in the simultaneous operation of PtH_2 and H_2tP, causing a decrease in overall system efficiency.

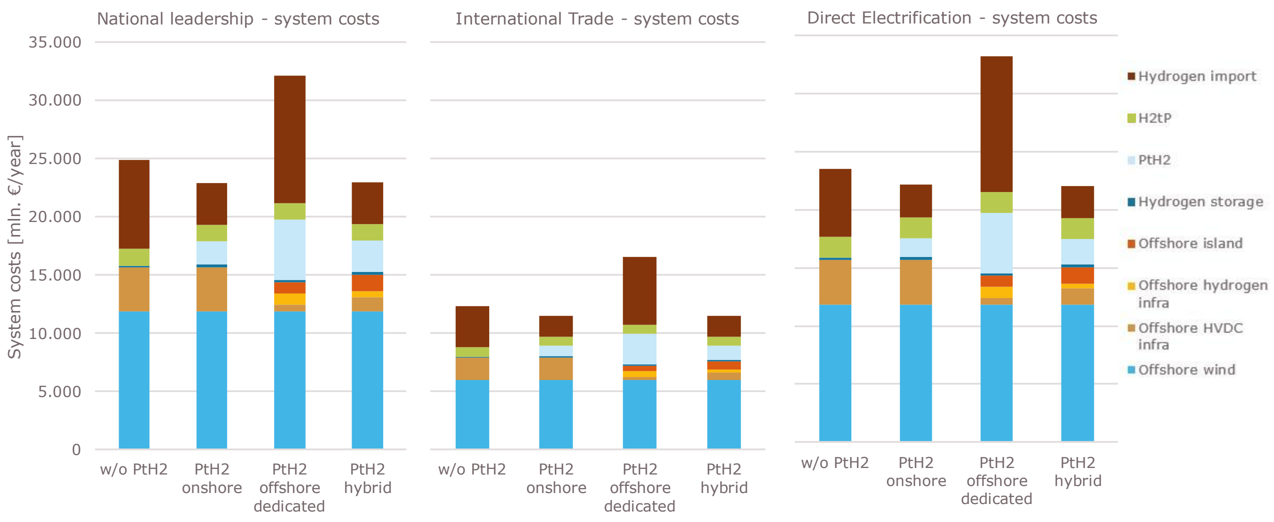

Figure 23. The three scenarios with the system cost for three PtH2 design choices: onshore, offshore dedicated and hybrid, compared to the reference system costs without PtH2.

While the figure above shows that 100% dedicated offshore PtH_2 is much costlier than the alternatives, it does not show what happens with system costs when only a limited amount of offshore wind capacity is fully dedicated to offshore PtH_2. Figure 24 illustrates what happens to system costs when a certain share of offshore wind capacity is directly coupled to PtH_2 (offshore dedicated), while the remaining capacity is used for baseload power first and only surpluses are used for either onshore or offshore PtH_2 (onshore/hybrid). The figure shows that, as more offshore wind is used for dedicated hydrogen production, the total system costs increase gradually at first but more swiftly at higher percentages of dedicated PtH_2 offshore wind.

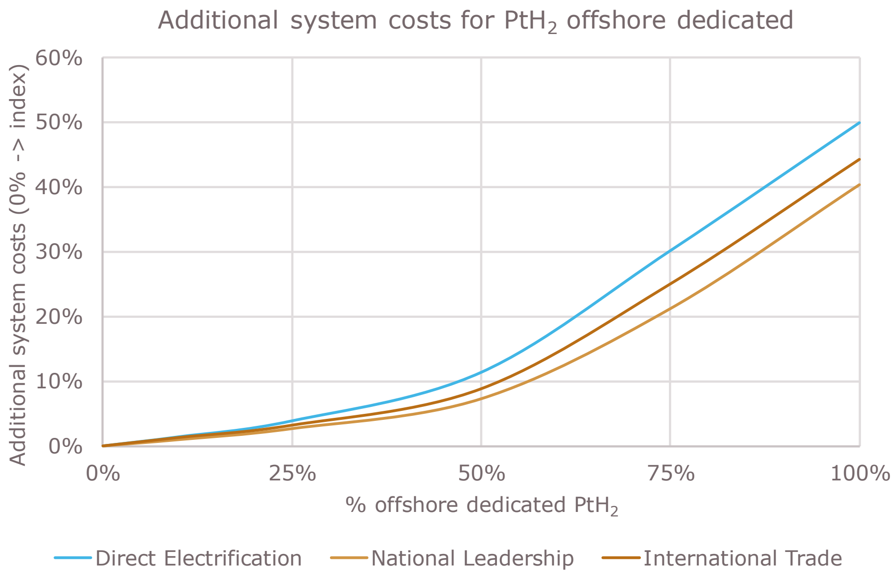

Figure 24. Additional system costs resulting from different shares of offshore wind, combined with dedicated offshore PtH2. For example, at 25%, only one-quarter of offshore wind capacity is directly coupled to PtH2 (offshore dedicated), while three-quarters are used for baseload power first, and only the surpluses are used for either onshore or offshore PtH2 (onshore/hybrid).

For both onshore and hybrid design options, electrolysers utilise surplus electricity only after the baseload demand is met. To minimise the system costs, each electrolyser is required to generate a sufficient quantity of hydrogen so that the revenue – calculated as the product of the volume of hydrogen and its price – exceeds the total costs associated with the electrolyser, including capital and operational expenditures. If this condition is not met, it would be more cost-effective to curtail electricity and resort to importing hydrogen instead. Based on PtH_2, with an efficiency of 70%, CAPEX of 750 €/kW and an H_2 import price of 60 €/MWh (section 2.4.4), electrolysers reduce system costs at a minimum of 1600 full load hours. Figure 25 illustrates how excess electricity is utilised by PtH_2 and how the excess renewables are curtailed.

While electrolyser capacity is based on minimal system costs for the onshore and hybrid designs, for offshore, dedicated PtH_2 electrolyser capacity is matched to the offshore wind capacity. See Figure 26 for the PtH_2 capacities for the three design choices.

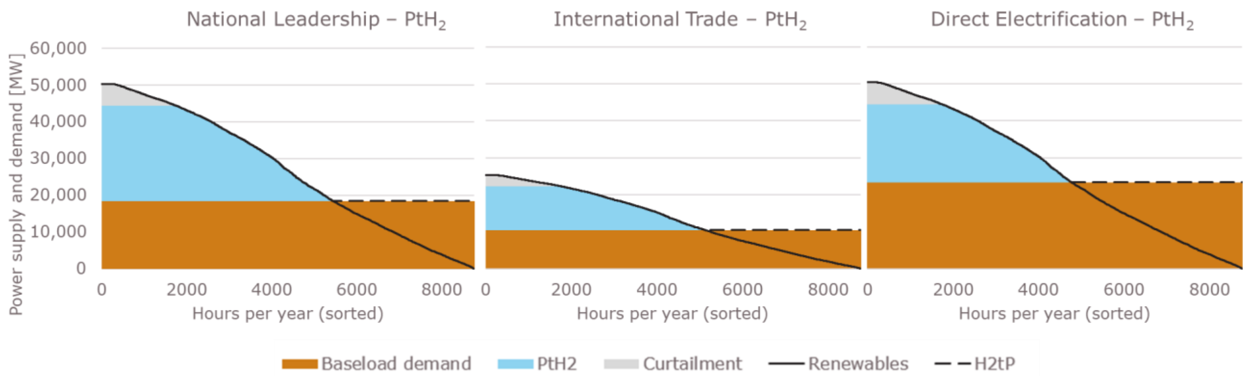

Figure 25. Illustration of excess electricity utilisation by PtH2 and how the excess renewables are curtailed for the three scenarios.

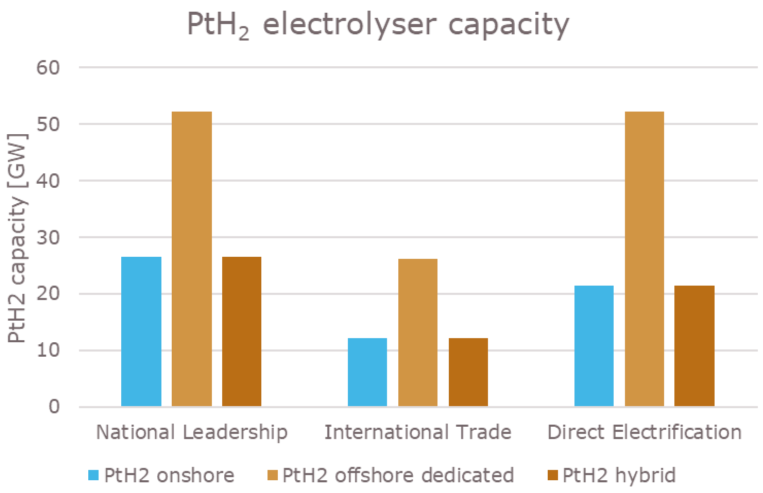

Figure 26. PtH2 capacities for the three design choices in the three scenarios.

Land usage does not seem to be a decisive factor for choosing between onshore and offshore PtH$_2$

A reason to build offshore electrolysis capacity might be to avoid land use. In the three scenarios, the onshore electrolysis ranges between 12 and 27 GW. According to a study[38] of ISPT, a 1 GW electrolyser requires roughly 10 ha of land. This means the land usage for the given electrolysis capacity of this study will be between 120 and 270 ha (1.2-2.7 km^2).

In comparison, the land area used by a large oil refinery in Rotterdam is 150 to 300+ hectares, the land area used by tank terminals in the Port of Rotterdam is over 2.800 hectares39 , and the land area of Tata Steel is roughly 750 hectares[40]. If 10% of the land area currently utilised by tank terminals were allocated to electrolysers, it would result in an electrolyser capacity of roughly 28 GW (using 10 ha per GW).

Furthermore, the land costs in industrial areas in the province Zuid-Holland (roughly 200-350 €/m2)[41] would amount to an additional 30 €/kW on top of the PtH2 CAPEX estimated at 750 €/kW, which is 4%.

This means that shortage of land areas and onshore land costs do not seem to be decisive factors in determining whether PtH2 will primarily be done onshore or offshore.

3.2.2 Hybrid heat: hybrid boilers and hybrid cracking furnaces that have already been written off significantly reduce system costs

In the next solution, we have looked at hybrid heat being added to the system in order to reduce industrial baseload demand for electricity. At moments of insufficient renewable electricity production, electricity demand for power-to-heat applications can be temporarily

[38] Hydrohub (2020). Integration of Hydrohub GigaWatt Electrolysis Facilities in Five Industrial Clusters in The Netherlands.

[39] Port of Rotterdam (2021). Facts & Figures on the Rotterdam energy port and petrochemical cluster.

[40] Tata Steel. Op bezoek bij Tata Steel in IJmuiden.

[41] Staat van Zuid-Holland (2016). Prijsontwikkeling bedrijventerreinen. https://staatvan.zuid-holland.nl/portfolio_page/prijsontwikkeling-bedrijventerreinen/.

substituted by another fuel. We assume this fuel is hydrogen because the outlooks indicate a scarcity of biomethane, and CCS is not used in the 2050 scenarios.[42]

For hybrid heating, the focus is placed on hybrid electric boilers and hybrid electric steam crackers. The potential capacities per scenario for both forms of hybrid heating are listed in Table 8. Other forms of hybrid heat, such as industrial hybrid heat pumps or hybrid electric ovens, did not come up in the interviews and are therefore not included in this study in order to limit complexity and scope. However, this does not necessarily mean that these forms of hybrid heat are not technically feasible.

We have looked at two types of hybrid heating: electric boilers and electric steam crackers.

- **Hybrid boilers:** a hybrid boiler is the most well-known form of hybrid heat. Hybrid boilers consist of a set-up using a gas boiler (using hydrogen or methane) combined with an electric boiler. If electricity prices are low, the e-boiler produces heat, but if electricity prices increase, the gas boiler will take over. In all three scenarios, the amount of hybrid boilers is specified.
- **Hybrid electric steam crackers:** based on interviews with industrial experts, hybrid electric steam crackers also came up as a potentially feasible form of hybrid heat. Hybrid electric steam crackers do not exist yet but would use both a conventional furnace and an electric furnace coupled to the same downstream separation unit. A switch between electric and conventional furnaces could theoretically be achieved by lowering the feedstock flow rate in one furnace and increasing it in the other furnace. This way, no significant temperature fluctuations result from a switch between (mostly) electric and (mostly) conventional. The technical potential in each scenario is equal to the power demand of the electric furnaces among steam crackers in each scenario.

Table 8. Approximation of industrial flexibility potential for hybrid heat for the three 2050 scenarios. In the Direct Electrification scenario, all possible electrification measures are implemented. This leads to huge differences.

	Direct Electrification (Roadmap Electrification in the Industry)	**National Leadership** (II3050)	**International Trade (II3050)**
Hybrid boilers	6226 MW	1070 MW	1186 MW
Electric steam crackers (potentially hybrid)	6841 MW	1306 MW	744 MW

Figure 27 shows that in the three 2050 scenarios, hybrid boilers (second column) reduce total system costs compared to the system without hybrid boilers in the previous solution in which PtH2 was added (first column). Costs are reduced by reducing the H2tP backup capacity required and reducing the total hydrogen demand. This reduction in hydrogen demand is due to the higher efficiency of gas boilers (+/- 90%) compared to H2tP (+/- 60%).

When using hybrid cracking furnaces instead of hybrid boilers, these cost reductions are largely nullified because of the additional capital and operational expenditures of having both electric and conventional furnaces (third column). To be economically viable from a system cost perspective, the capital costs of hybrid cracking furnaces need to be significantly reduced. This could be the case if the lifetimes of readily depreciated old furnaces are extended when new electric furnaces are installed. In this case, system costs are reduced

[42] Netbeheer Nederland (2023). Het energiesysteem van de toekomst: De II3050-scenario's.

significantly (see the fourth column in Figure 27). However, many conventional cracking furnaces in the Netherlands may have reached the end of their technical lifetimes in 2050. Therefore, depreciated cracking furnaces being available in 2050 cannot be simply assumed, and we only use hybrid boilers in the remainder of this analysis.

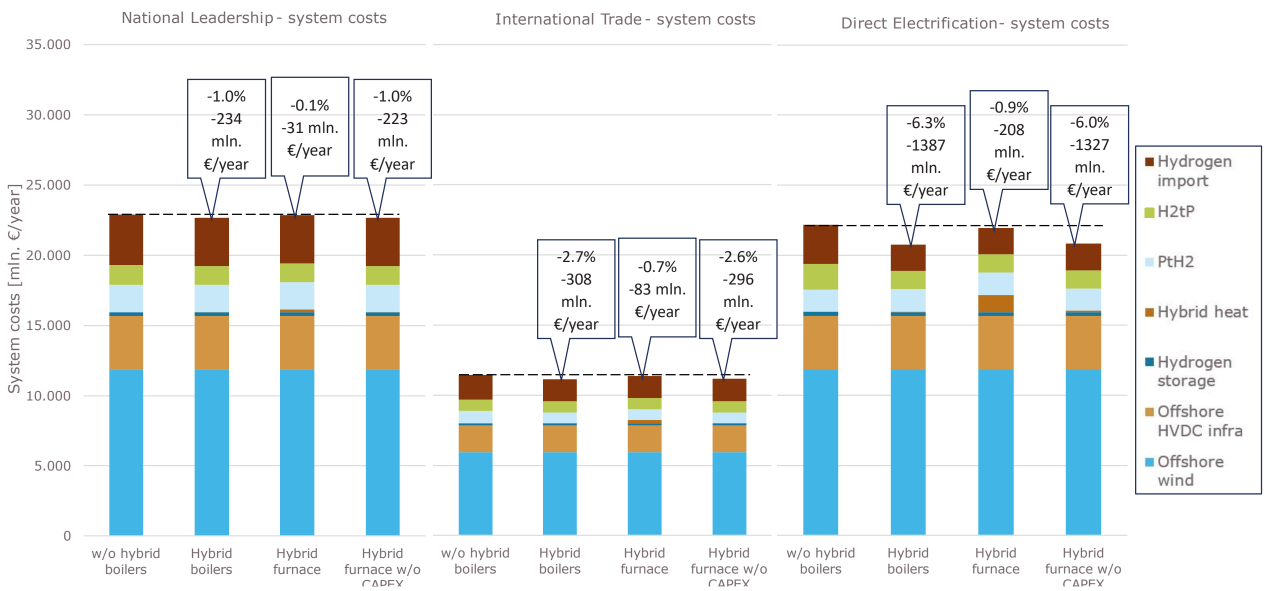

Figure 27. System costs for the three scenarios with and without hybrid boilers (second column), hybrid furnaces (third column), or readily depreciated hybrid furnaces (fourth column).

Figure 28 illustrates how hybrid boilers utilise electricity when there is an excess of renewable energy but switch to hydrogen when there is a shortage in renewables.43 This reduces the required backup capacity (see Figure 29). Furthermore, hybrid boilers switch to electricity earlier than PtH2 starts to produce hydrogen due to the higher efficiency of e-boilers (+/- 100%) compared to PtH2 (+/- 70%). Consequently, additional hybrid heat reduces the potential PtH2 capacity that can be integrated into the system.

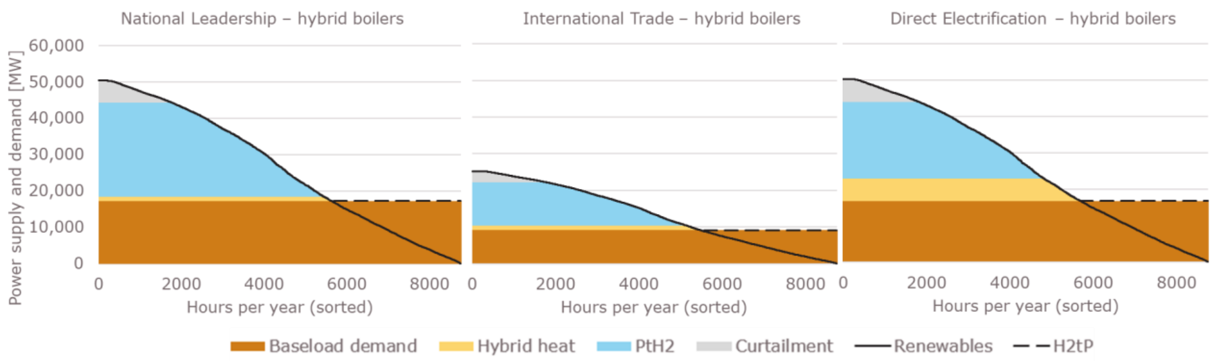

Figure 28. Illustration of excess electricity utilisation by hybrid boilers for the three scenarios and the prioritisation of hybrid heat over PtH2 due to efficiency differences.

[43] Substantiation for the hybrid heat capacities (in MWe) for each scenario is provided in section 2.4.1.

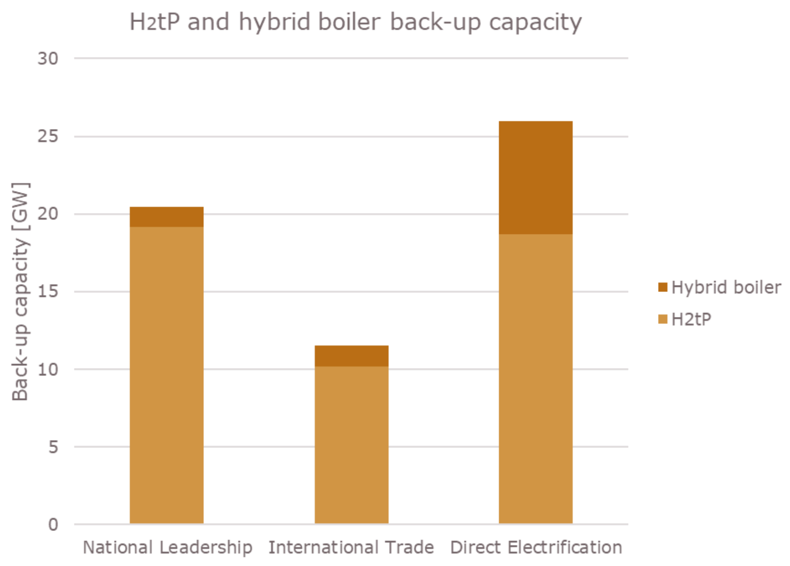

Figure 29. Backup capacity provided by H2tP and hybrid boilers for the three scenarios.

3.2.3 Offshore solar PV: the impact of offshore solar PV is ambiguous and differs among scenarios

In the next solution, offshore floating solar PV is added to offshore wind farms, utilising the offshore infrastructure already in place for offshore wind. Figure 30 illustrates how the production profile of offshore wind is complemented by offshore solar PV (for different solar PV capacities), such that there are less hours with low offshore power generation. However, as it is sometimes both sunny and windy, not all electricity produced can be transported and must be curtailed if offshore grid capacity is not increased.

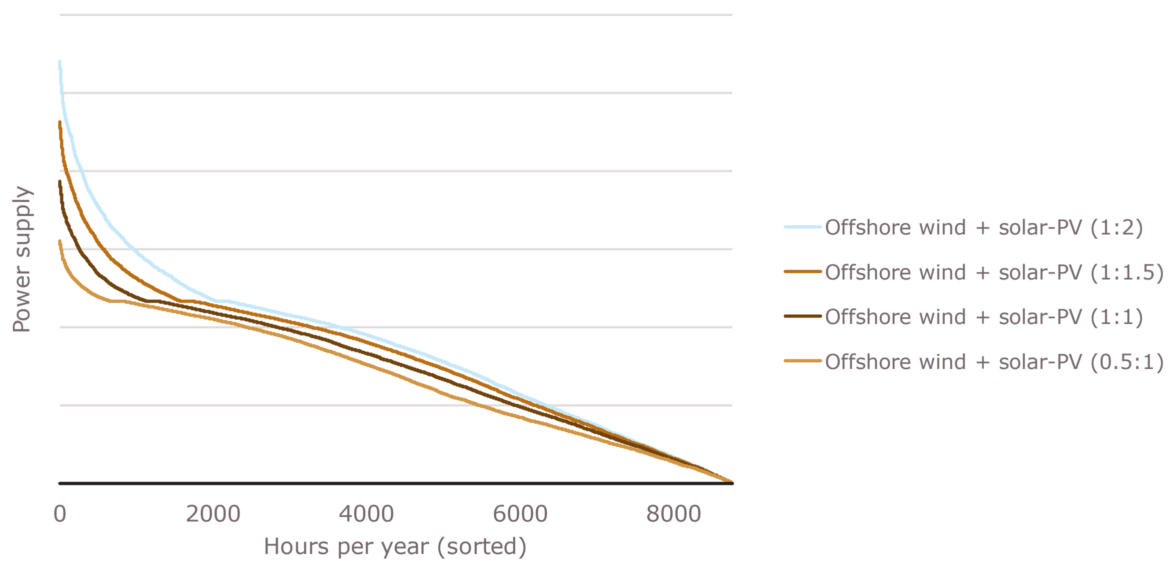

Figure 30. Hourly power production by offshore wind when combined with various solar PV capacities, wherein 1:2 refers to there being twice as much solar PV peak capacity compared to offshore wind.

For system cost analysis, we matched the capacity of offshore solar PV to the capacity of offshore wind.[44] This means that for each GW of offshore wind capacity, 1 GW of solar PV capacity is added. This way, solar PV can utilise the already available offshore electricity infrastructure. Figure 31 illustrates how the total system costs increase or decrease slightly, depending on the scenario. On the one hand, the number of full load hours of hybrid heat and PtH_2 increases, while the number of hours where there is a shortage of renewable electricity decreases (see Figure 32). This increases hydrogen production by PtH_2 and reduces hydrogen demand by H_2tP, resulting in a reduction in imported hydrogen (see Figure 33). On the other hand, the capital and operational expenditures increase due to the added offshore solar PV, nullifying the cost savings.

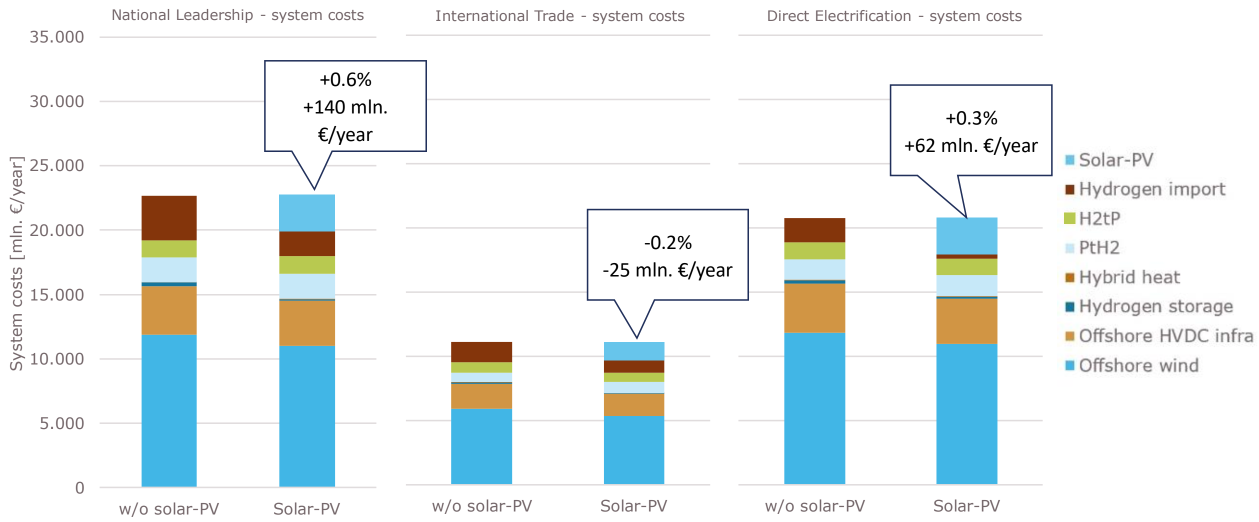

Figure 31. System costs with and without offshore solar PV for the three scenarios.

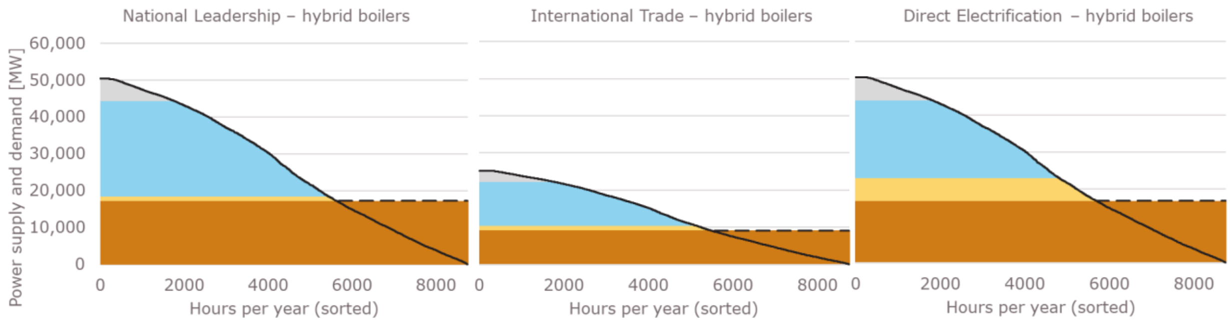

Figure 32. Illustration of increased full load hours for hybrid heat and PtH2, decreased number of hours with renewable electricity shortage higher curtailment.

[44] Since the offshore wind capacity that is allocated to industry for this analysis is based on both total renewable generation (offshore and onshore) and industrial and non-industrial demand of the underlying II3050 scenarios (see section 2.2.1), the addition of offshore solar PV will require recalibration of the allocation. This results in 48.4 GW offshore wind and offshore solar PV for the National Leadership and Direct Electrification scenarios and 23.7 GW for the International Trade scenario.

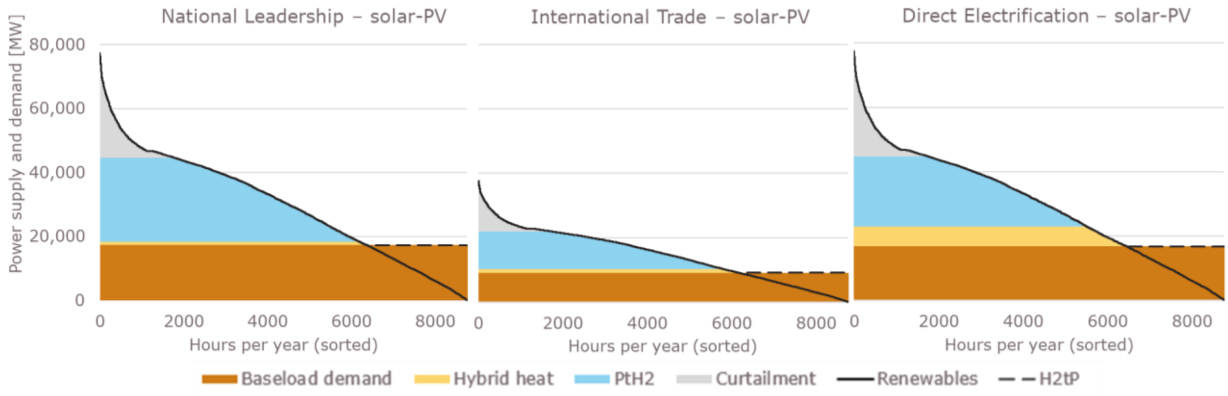

Figure 33. Illustration of increased full load hours for hybrid heat and PtH2, decreased number of hours with renewable electricity shortage higher curtailment as a result of combining offshore solar PV with offshore wind (left) compared to only offshore wind (upper image Figure 8).

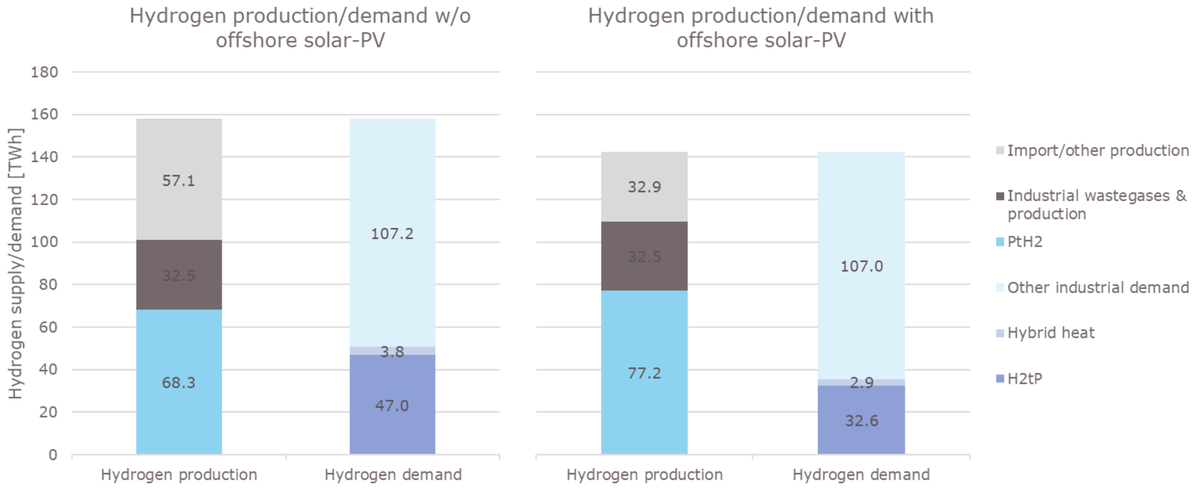

Figure 34. Production and demand without and with offshore solar PV for the National Leadership scenario.

A critical note must be placed along with these results for offshore solar PV

This analysis set-up is meant for comparing system costs within scenarios and not for comparing system costs between scenarios, as explained in section 2.1. Adding offshore generation in the form of solar PV adds additional generation *to* the system instead of adding flexibility or conversion steps (e.g. PtH_2 or hybrid heat) *in* the system. This effectively creates a new scenario subvariant, making cost comparisons less conclusive than for the other technologies.

While these results do not provide definitive confirmation or rejection of the cost-effectiveness of combining offshore solar PV with offshore wind, the next analysis (industrial process flexibility) will utilise scenarios with solar PV as a baseline for comparison. The reasoning behind this decision is that the future production mix, including both offshore and onshore sources, is expected to incorporate substantial onshore solar PV capacities. Consequently, by incorporating the solar PV generation profile in this analysis, irrespective of whether it's onshore or offshore, the level of representativeness of the actual energy system will be enhanced.

3.2.4 Industrial process flexibility: process flexibility categorised as production reduction or production shift

As a next step, we considered industrial process flexibility as a means to reduce baseload demand at times of renewable electricity shortages. Industrial process flexibility can be achieved by buffering (semi-)finished products while keeping a stable outflow of products or by adjusting the production volume being sold to customers.

Industrial flexibility by flexible operation of the main production processes is already present in sectors like the chlor-alkali industry, where electricity consumption is high, and the production technologies can handle variations in production levels. Although process flexibility is currently mostly limited to industries such as the chlor-alkali industry, it is anticipated that adoption in other sectors will grow as industrial electricity demand increases while increasing volumes of intermittent renewable energy generation will cause more volatility of electricity prices.

Process flexibility can be classified into two categories: production shift and production reduction. In this study, we only considered production reduction as a source of process flexibility. Production shift is sector-dependent and could not be incorporated in the model.

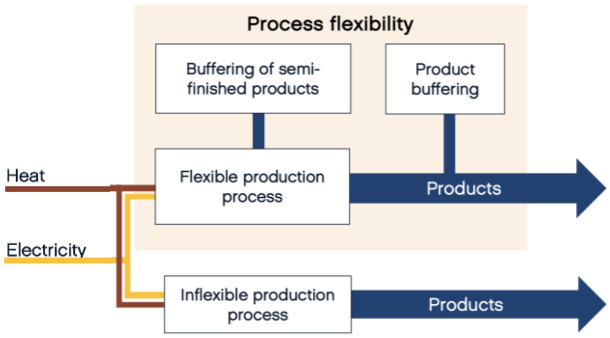

Figure 35. Schematic overview of industrial process flexibility through either buffering of (semi-)finished products or without buffering, resulting in flexible product output.

Production reduction offers significant flexibility potential at relatively high electricity prices

Industrial flexibility through production reduction is a simple concept at its core. Industries reduce production output in order to reduce electricity demand at moments of high prices or insufficient transmission capacities.

Based on interviews conducted as part of this study, energy-intensive industries cannot easily reduce production volumes by shutting down completely and starting up at a later moment in time. Instead, a production reduction of approximately 20-30% turns out to be more feasible for many energy-intensive industries. This can be done without major consequences to production facilities, operational safety or product quality. Fluctuations in production are preferably not changed on an hour-to-hour basis, but they are feasible for several hours or longer. For companies utilising high-pressure compressors, these often become the limiting factor in reducing production volumes. However, there are significant variations between companies, even within the same sectors. Furthermore, reducing production volumes does not necessarily result in a proportional reduction in electricity demand.

Internationally operating companies serving global markets can compensate for production reduction by increasing production in other locations. However, other companies with direct dependencies on downstream customers may be less able to effectively reduce production volumes in practice.

Furthermore, companies that are able to temporarily reduce production rates at higher electricity prices will probably only do so if they are actually exposed to these high electricity prices. For example, a company that has a fixed price Power Purchase Agreement (PPA) will likely not respond at all. But companies that do direct trading on the electricity markets or have a PPA that rewards or mandates flexibility might respond more actively to high electricity prices.

Given these differences between companies regarding their ability or willingness to deploy process flexibility through production reduction, this study works with the assumption that, on average, industrial sectors are able to reduce a part of their production volume and thereby reduce electricity demand by 20%. Figure 36 shows the potential process flexibility capacity through production reduction for different industrial sectors if energy-intensive base industries are able to temporarily reduce production volumes by 20% on average. The estimated electricity price at which production is reduced is also shown in the Figure 36.

These electricity prices at which production is reduced and the willingness to accept (WTA) are not well known and may vary significantly among sectors and companies. The WTA is roughly approximated per sector (to limit the complexity of this study) based on industrial financial data and industrial electricity demand using the formula below. See Table 9 and Table 10 for the data used and the resulting WTA per sector for each scenario.

$$Willingness - to - accept = \frac{(R_h - FFC_h) * PV_f}{E_f} * (1 + FP) \qquad (3)$$

Where:

- **Willingness-to-accept** = the minimum price at which production is reduced by an industrial sector in order to reduce its power demand (€/MWh).
- **R_h** = Historical revenue of an industrial sector (mln. €).
- **FFC_h** = Historical feedstock and fuel costs of an industrial sector, excluding electricity (mln. €).
- **PV_f** = Production volume in a future scenario relative to the historical production volume (%).
- **FP** = Flexibility premium required to activate process flexibility (20% assumed).
- **E_f** = Electricity demand of an industrial sector in a given future scenario (TWh), excluding electricity used for hybrid electric heating, as this electricity demand is already shifted towards a different fuel long before the electricity price reaches the willingness to accept.

When the marginal profit of the last product produced reaches zero, the producer becomes indifferent about whether or not to produce it. The marginal profit is equal to the revenue minus the variable costs. Thus, marginal profit goes to zero when the total of the variable costs are equal to the revenue. Variable costs of the energy-intensive industry mainly comprise energy[45] and feedstock costs. Other costs, such as labour or depreciation costs, are not directly coupled with temporary changes in production rates and are therefore referred to as fixed costs in this proposition. If the marginal profit becomes negative (marginal loss), a producer is incentivised to decrease the production rate. This principle is illustrated in Figure 36.

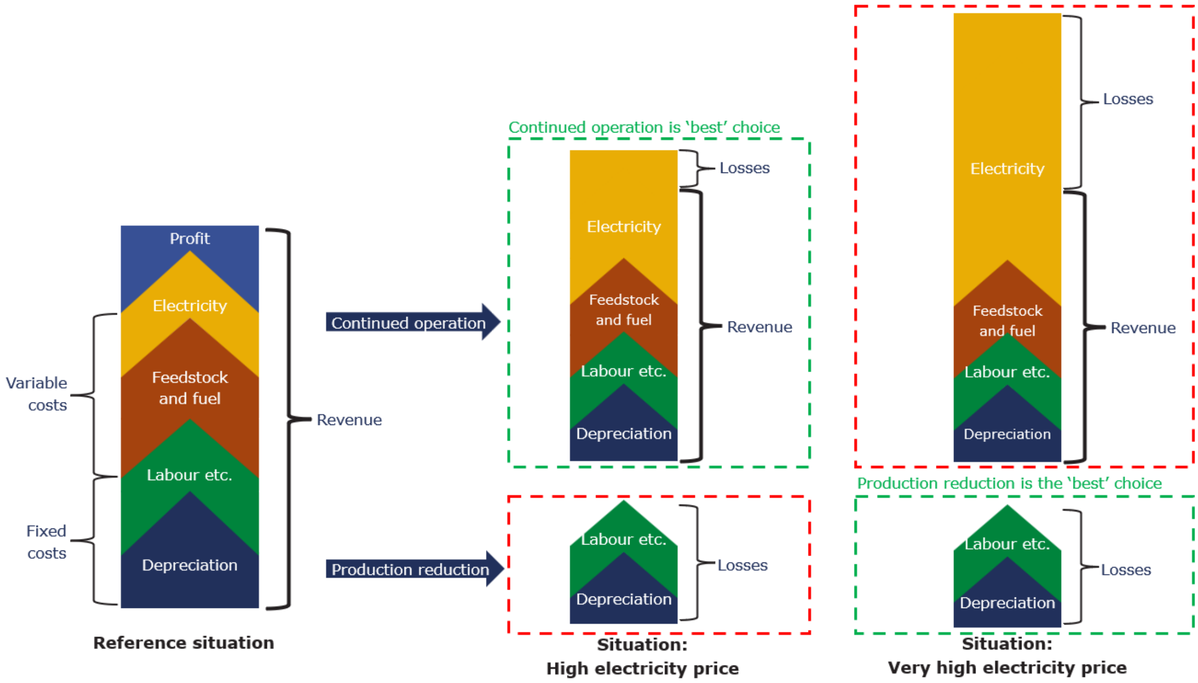

Figure 36. Schematic and simplified illustration of the effect that electricity prices have on profit/losses. At a 'very high' electricity price, losses can be minimised by reducing production, but at lower electricity prices, it can be profitable or less loss-making to continue production.

Historical revenue is used to calculate the electricity price at which marginal profits reach zero. If the production volumes of a given industry have changed in a scenario, the historical revenue is not representative anymore. The future revenue is estimated based on the historical revenue multiplied by the change in production volume.

Furthermore, reducing production volumes can also incur additional costs, such as penalties from contracts or accelerated depreciation of assets caused by the fluctuation in production levels. A flexibility premium (FP) of 20% is therefore assumed, meaning that the electricity price needs to reach 120% of the indifference price (or the willingness to pay) in order to result in a change in production volume.

This approach provides useful insight into the approximate costs at which different industrial sectors may reduce production in order to reduce exposure to high electricity prices. However, this approach comes with several limitations:

- Financial and energy data are based on sectoral averages, while there may be significant differences among companies within sectors.

[45] Production reduction and power reduction are assumed to be proportional at an industrial sector level. This is currently not necessarily the case for every company, but as industries electrify their energy demands, their total electricity demand may become more aligned with their production output. The marginal profit per unit produced then becomes proportional to the marginal profit per unit electricity consumed.

- Revenues are derived from historical data, while future revenues are influenced by changes in product prices. These changes have an impact on the marginal profit.
- Feedstock and fuel costs are also derived from historical data, while future prices may be subject to large changes due to the energy transition.
- A willingness to accept prices based on historical data does not apply to companies that can pass higher energy costs on to customers.
- Contractual restrictions may inhibit companies from responding to price fluctuations using temporary production reductions. However, contracts could be adapted if process flexibility becomes more entrenched in industrial practices.

Table 9. Approximation of industrial process flexibility potential (20% average production reduction assumed per sector) and the willingness to accept for the three 2050 scenarios.

	Direct electrification (Roadmap Electrification in the Industry)	**National Leadership** (II3050)	**International Trade (II3050)**
Process flexibility	3346 MW (willingness to accept)	3454 MW (willingness to accept)	1784 MW (willingness to accept)
Steel	109 MW (at 846 €/MWh)	109 MW (at 846 €/MWh)	109 MW (at 846 €/MWh)
Refineries	696 MW (at 182 €/MWh)	77 MW (at 1559 €/MWh)	73 MVW (at 2962 €/MWh)
Steam cracking	1047 MW (at 216 €/MWh)	296 MW (at 570 €/MWh)	183 MW (at 939 €/MWh)
Electrochemistry (excl. green hydrogen)	141 MW (at 199 €/MWh)	141 MW (at 199 €/MWh)	141 MW(at 199 €/MWh)
Other chemicals	598 MW (at 1188 €/MWh)	1089 MW (at 653 €/MWh)	627 MW (at 1134 €/MWh)
Synthetic fuels	0 MW	956 MW (at 296 €/MWh)	0 MW
Food	187 MW (at 5342 €/MWh)	250 MW (at 3985 €/MWh)	233 MW (at 4273 €/MWh)
Paper	54 MW (at 2307 €/MWh)	54 MW (at 2311 €/MWh)	53 MW (at 2356 €/MWh)
Other	514 MW (at 5953 €/MWh)	484 MW (at 6330 €/MWh)	366 MW (at 8367 €/MWh)

Table 10. Data used for calculating the average willingness-to-accept per industrial sector.

	Steel	**Refineries**	**Steam cracking**	**Electrochemistry**[I]	**Other chemicals**	**Synthetic fuels**[III]	**Food**	**Paper**	**Other**
Revenue 2019 [B €][46]	4.5[47]	35.2	17.5	0.6[II]	42.9		78.2	8.1	155.8
Feedstock and fuel costs 2019 [B €][46]	1.4[I]	23.5	9.9	0.1[II]	19.2		44.9	4.0	53.7
Electricity demand excl. hybrid [TWh]									
Historical (2019)[48]	0.7	2.0	1.4	2.8[II]	8.5		6.7	2.1	11.7
National Leadership	5.4	3.1	11.8	2.8[II]	43.6		10.0	2.1	19.4
International Trade	4.4	2.9	7.3	2.8[II]	25.1		9.3	2.1	14.6
Direct Electrification	4.3	27.8	41.9	2.8[II]	23.9		7.5	2.2	20.6
Production volume									
Historical (2019 index)	1.00	1.00	1.00	1.00[II]	1.00		1.00	1.00	1.00
National Leadership	1.00	0.34	0.75	1.00[II]	1.00		1.00	1.00	1.00
International Trade	1.00	0.61	0.76	1.00II	1.00		1.00	1.00	1.00
Direct Electrification	1.00	0.36	1.00	1.00[II]	1.00		1.00	1.00	1.00
Willingness to accept [€/MWh]									
Historical (2019)	4991	7034	6587	199[II]	3360		5996	2329	10434
National Leadership	678	1559	570	199[II]	653	296[III]	3985	2311	6330

[46] CBS (2023). Bedrijfsleven; arbeids- en financiële gegevens, per branche, SBI 2008.

[47] Tata Steel. Integrated Report & Annual Accounts 2018-19.

[48] Carbon Transition Model.

International Trade	835	2962	939	199[II]	1134		4273	2356	8367
Direct Electrification	846	182	216	199[II]	1188		5342	2307	5953

I Coking coal, pulverised coal and iron ore use based on Carbon Transition Model, combined with prices for coal[49] and iron ore[50].

II Costs, revenue, and energy demand based on the chlor-alkali industry.[51] No change in electricity demand is assumed as the energy demand of the primary production process (chlor-alkali electrolysis) already mainly consists of electricity.

III Synthetic fuel production has no historical financial and energetic data as it is not yet produced at scale. Instead, revenues are approximated based on a CAPEX of roughly 2000 €/(ton product/year)[52], OPEX of 5%[53], a lifetime of 30 years[53], WACC of 6% and a profit margin of 30%. Electricity demand for synthetic fuel production can vary significantly based on the production process. Processes using an electrified Reverse Water Gas Shift (RWGS) reaction require roughly 1.1 GWh/kton product (based on thermodynamic efficiency of 80% and some electricity demand of the Fischer-Tropsch reactor). However, processes using direct CO2 reduction to CO require multiple times as much electricity, while processes using RWGS fuelled with hydrogen require much less electricity. For this study, a 1.5 GWh/kton product is assumed.

[49] IEA (2019). Coal 2019.

[50] Trading Economics. Iron Ore, visited at: https://tradingeconomics.com/commodity/iron-ore.

[51] Scherpbier, E. (2018). The energy transition in the Dutch chemical industry: Worth its salt? P39.

[52] Zang, G., Sun, P., Elgowainy, A. A., Bafana, A., & Wang, M. (2021). Performance and cost analysis of liquid fuel production from H_2 and CO_2 based on the Fischer-Tropsch process.

[53] Concawe (2022). E-Fuels: A techno-economic assessment of European domestic production and imports towards 2050.

Production shift may offer significant industrial flexibility but is not considered in this study

Production shift involves a temporal adjustment of production volumes, leading to a decrease in production followed by an increase or vice versa. To implement production shifting, two factors are critical: excess capacity and buffer capacity for (semi-)finished products. Excess capacity allows for the compensation of temporary dips in production volumes at a later time. This could result from:

- seasonal businesses producing only part of the year
- companies deliberately maintaining excess capacity (with high CAPEX, varies by industry)
- operations reducing or halting during nights or weekends
- firms experiencing a decrease in demand, resulting in a decrease in production
- businesses where efficiency improvements over time have created excess (unused) capacity in some or all production stages.

Buffering is essential to ensure the consistent delivery of final products. It can exist in the following forms:

- Buffering of semi-finished products like pig iron in steel production or thick juice in sugar beet processing.
- Buffering of finished products.

While some companies might already possess excess and buffering capacity, in many cases, this requires substantial investments, with costs varying across sectors and businesses. Buffering, in addition to capital investments, also incurs costs due to the tied-up capital in the storage of (semi-)finished products. Therefore, businesses further down the production chain, handling more expensive products, face higher storage costs.

Several examples of this kind of over-dimensioning of buffering capacity are detailed in the 'Whitepaper on industrial flexibility'[54] and also surfaced during interviews conducted with industrial firms for this study. Based on the cases that emerged in the whitepaper and during the interviews, it appears that the potential in terms of capacity, duration and costs for industrial flexibility through production shift varies significantly from company to company. It is challenging to make generalised statements at the industrial sector level regarding the capacity, the maximum duration of shift, and the costs of process flexibility through production shift. Consequently, production shift is not considered in this study as it requires more extensive follow-up research.

Use of temporary industrial production reduction can slightly reduce the required backup generation capacity

Reducing baseload demand by reducing industrial production decreases the need for flexible backup power but comes at a cost due to a loss of revenue by the industry. Furthermore, while in many cases it can be difficult to temporarily completely halt

[54] TKI Energie en Industrie (2022). Whitepaper industriële flexibiliteit.

industrial processes, reducing production up to 20-30% can often be done more easily without compromising on safety, product quality or degradation of equipment.

Assuming an average of 20% potential reduction in production per industrial sector and approximating the costs associated with lost marginal profit, Figure 37 depicts the potential decrease in system costs that could result from this temporary decrease in industrial production. Industrial production reduction does reduce system costs by reducing the required H_2tP capacity in each scenario. However, the potential cost reductions are relatively small. Note that production shift instead of production reduction lies outside the scope of this study. Therefore, the potential of industrial process flexibility might be underestimated.

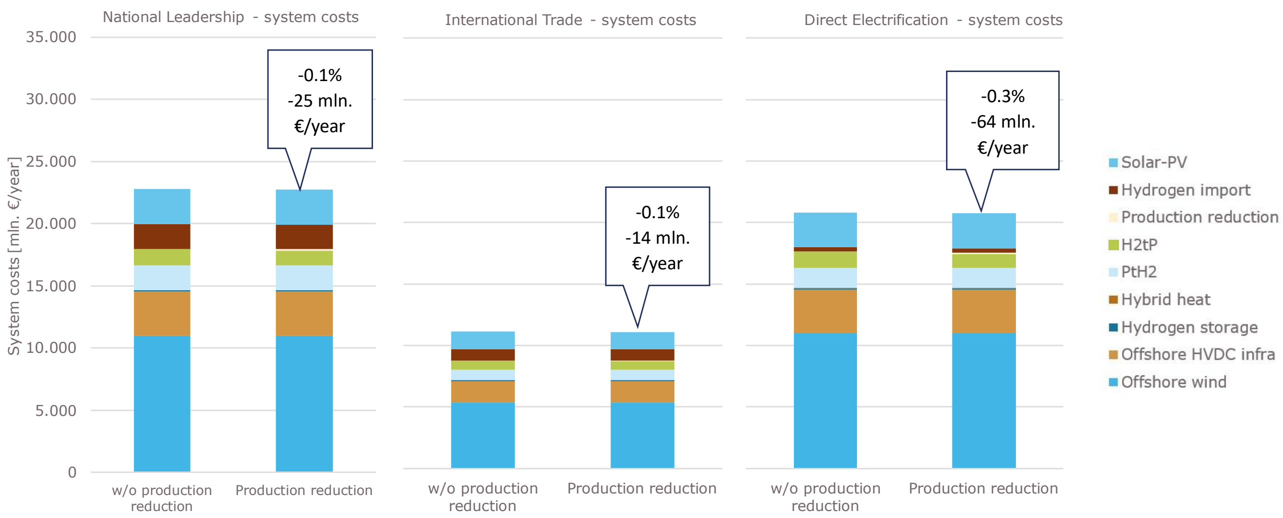

Figure 37. System costs with and without industrial production reduction for the three scenarios.

Industrial production reduction can reduce system costs by reducing the required capacity of flexible backup generation, or in this report, H_2tP capacity. For example, if the maximum residual demand (electricity demand minus renewable generation) in a hypothetical scenario year is 10 GW, there needs to be 10 GW of backup capacity available in order to prevent power shortages. However, if demand can be temporarily reduced by 1 GW, only 9 GW of backup generation capacity is required.

Figure 38 illustrates how industrial production reduction can lead to a reduction in residual demand (and therefore the need for backup generation) but does so at increasingly higher costs as larger amounts of production reduction capacities in terms of MW are deployed. There are two factors that drive up these costs:

1. As more and more production reduction capacities are deployed, the costs per MWh for reducing production increase. The first power reduction can be done relatively cheaply by the electrochemistry sector (199 €/MWh); see situation A in Figure 37. However, if power demand is reduced beyond the maximum flexible capacity of this first and cheapest sector, the second, more expensive sector must reduce power demand (synthetic fuels - 296 €/MWh); see situation B in Figure 38. Thereafter, the even more expensive steam cracking sector must reduce its power (570 €/MWh); see situation C in Figure 38.
2. The highest peaks in residual power demand occur least often, while lower peaks occur more often. In other words, reducing the first few MW of peak (residual) power demand results in only a few MWhs of reduction, see situation A in Figure 38, while

further reductions in power demand result in increasingly more MWhs of reduction, see situations B and C in Figure 38.

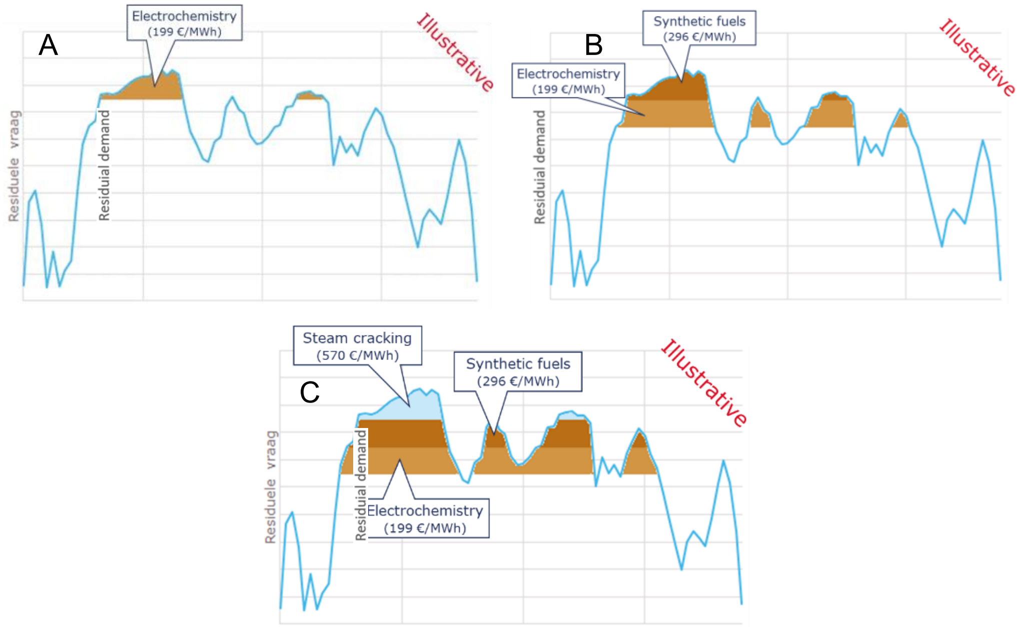

Figure 38. Illustration of reduction of residual power demand using industrial production reduction (cost figures based on the National Leadership scenario).

In Figure 39, the reduction in residual demand by reducing production in the different industrial sectors (moving down the y-axis) corresponds to production reduction/backup capacity on the x-axis of Figure 38. The three scenarios require roughly 10-26 GW of backup capacity (see Figure 18). The majority of that backup capacity must be accommodated by H_2tP. However, depending on the scenario, 1.8-3.4 GW backup could theoretically be accommodated by utilising up to 20% industrial production reduction instead of H_2tP.

Figure 39 shows the relation between increasing industrial production reduction capacity and increasing costs and then compares these with the costs of H_2tP backup generation. It is useful to compare these two types of backup, as both serve the purpose of matching supply and demand at times of low renewable power generation. The figure shows that for each scenario, it is cost-effective to utilise some industrial production reduction. At a certain point, however (2.5 GW for National Leadership – 0.5 GW for International Trade – 2.8 GW for Direct Electrification), using more industrial production reduction as backup capacity becomes exponentially more expensive compared to H_2tP.

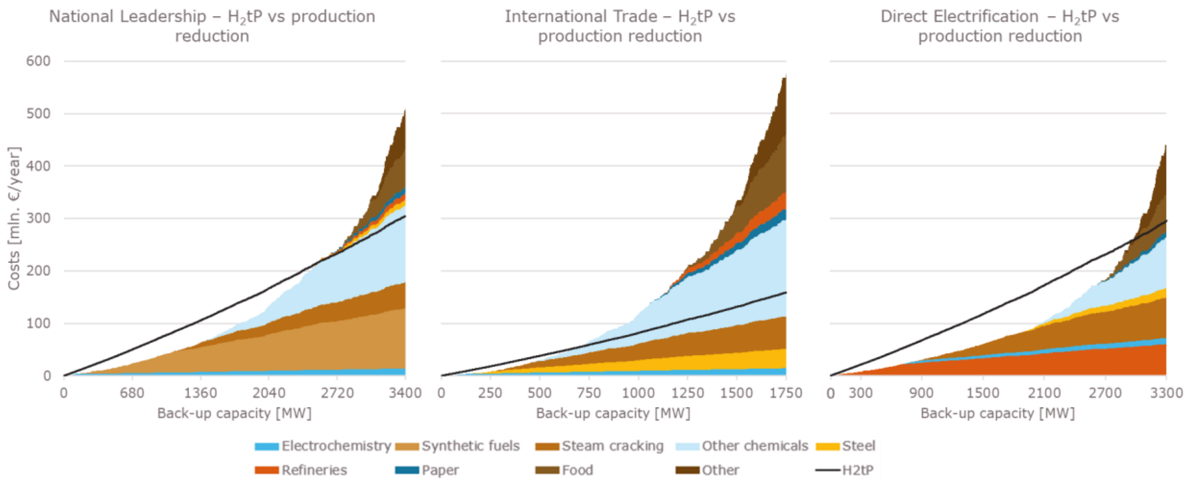

Figure 39. Cost comparison between industrial production reduction and H2tP backup capacity for the three scenarios. Beyond the highest backup capacity on the x-axes, no more industrial production reduction backup capacity is available.

The most cost-efficient combination of H_2tP with industrial production is shown in Figure 40 for each scenario. Figure 41 shows the few hours a year (within the red circles) that this industrial production reduction capacity is actually utilised.

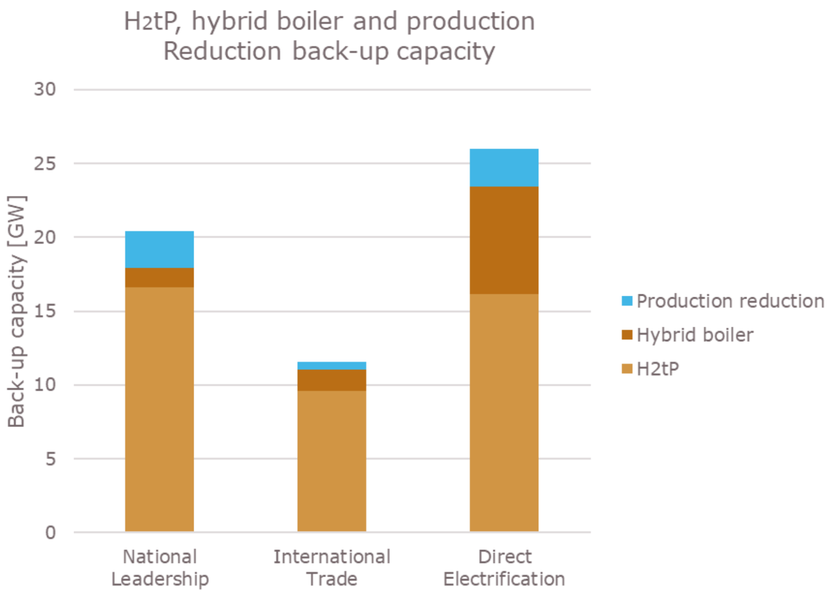

Figure 40. Backup capacity provided by H2tP, hybrid boilers and industrial production reduction for the three scenarios.

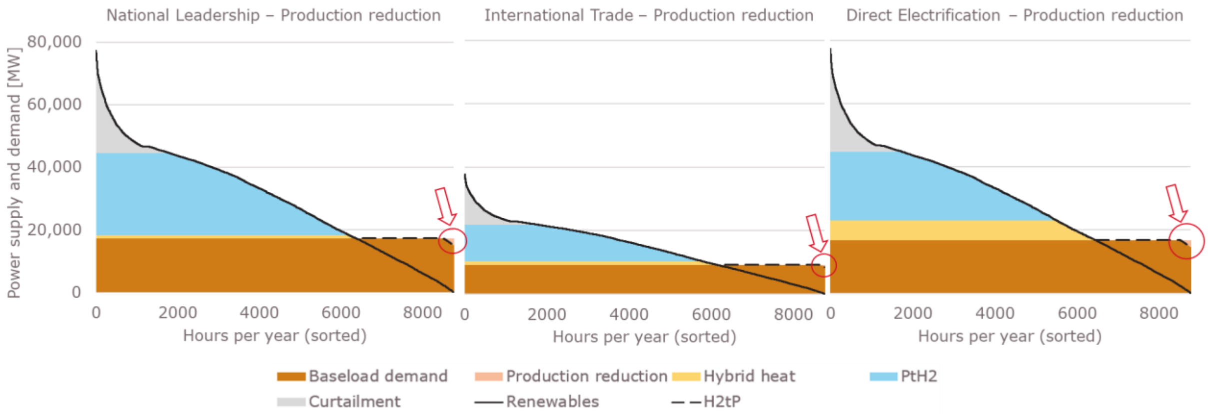

Figure 41. Illustration of how industrial production reduction can complement H2tP backup capacity, but only during the few hours a year with the least renewable generation. The use of industrial production reduction is highlighted within the red circles.

3.2.5 Thermal buffering: buffering with e-boilers reduces system costs, while thermal buffering with heat pumps increases system costs

After industrial production reduction, thermal buffering is integrated into the system to better utilise peaks in renewable electricity production and decrease the power demand for power-to-heat during periods of low renewable energy generation.

Thermal buffering can be combined with industrial power-to-heat to create flexible power demand. A thermal buffer can be heated when renewable electricity is plentiful and discharged at a later moment to provide heat for industrial processes through heat exchangers. There are many different types of thermal buffering operating at a wide range of temperatures (from below 100 °C to more than 500 °C), such as sensible heat storage (hot water, solid state such as ceramic bricks, molten salts), latent heat storage using phase change materials or thermochemical heat storage (chemical looping, salt hydration or absorption systems).[55]

Although the application of thermal buffering for industrial purposes is still in its early stages, its potential seems to be substantial. Thermal buffering could be coupled to many power-to-heat systems. There are, however, various practical considerations which may complicate or limit its application, such as spatial requirements, heat losses, but also the applied power-to-heat method.[56] For example, power-to-heat applications using very high temperatures, direct resistive heating, microwave radiative heating or process-integrated heat pumps (using mechanical vapour recompression) may be less suited for thermal buffering.

The upper limit of the technical potential of thermal buffering (defined as electrical power-to-heat capacity that can be made flexible) is equal to the total power-to-heat capacity in each scenario. Note that the technical potential for thermal buffering will partly overlap with the technical potential of hybrid heat. Furthermore, the power-to-heat capacity for the II3050 scenarios is only defined for hybrid heat but not for low temperature (heat pump) or non-hybrid high temperature. To estimate these capacities, we made an extrapolation based on the low-temperature and non-hybrid high-temperature electricity demand of the Direct Electrification scenario in relation to the

[55] IRENA (2020). Innovation Outlook: Thermal Energy Storage.

[56] EERA (2022). Industrial Thermal Energy Storage.

total electricity demand in this scenario.[57] The approximated maximum potential of thermal buffering for the three scenarios is listed in Table 11.

Table 11. Approximation of the maximum potential for thermal buffering for the three 2050 scenarios.

	Direct eEectrification (Roadmap Electrification in the Industry)	**National Leadership** (II3050)	**International Trade (II3050)**
Thermal buffering	7124 MW	3411 MW	2187 MW
• LT (< 200 °C)	695 MW	385 MW	887 MW
• HT potentially hybrid (> 200 °C)	1131 MW	933 MW	3113 MW
• HT baseload (> 200 °C)	3123 MW	1729 MW	3982 MW

In order to reduce the required H_2tP backup capacity and effectively absorb renewable surpluses, the volume of the buffer (MWh) compared to its capacity (MW) must be sufficiently large. Based on the three scenarios, roughly 25 MWh of volume for each 1 MW of capacity is optimal. Less volume would result in lower absorption capacity of excess renewables, while more volume would not be used effectively and lead to higher capital and operational expenditures. A round-trip efficiency of 80% is assumed.

Thermal buffering for low-temperature heat combined with heat pumps will effectively decrease the realised power flexibility per thermal buffer capacity. Due to the high coefficient of performance of heat pumps, the thermal output is considerably higher than the electrical input.[58] It is, therefore, important to consider not only the energy content in a thermal buffer but also the exergy/temperature.

To effectively charge thermal buffers, it is necessary to have an excess thermal capacity in power-to-heat technologies such as e-boilers or heat pumps, which surpass the heat demand of an industrial process. Two types of thermal buffering set-ups are considered:

1. High temperature (> 200 °C) thermal buffering coupled with power-to-heat with a Coefficient of Performance (COP equal or lower than 1 (e-boiler).
2. Low temperature (< 200 °C) thermal buffering coupled with power-to-heat with a COP higher than 1 (heat pump).

Figure 42 shows that thermal buffers combined with e-boilers reduce system costs in all three scenarios by lowering hydrogen imports (due to higher utilisation of excess

[57] In the Direct Electrification scenario, low temperature power-to-heat accounts for 8% of total electricity demand, while non-hybrid high temperature power-to-heat accounts for 19% (also Table 4). By considering these percentages and the total electricity demand in the II3050 National Leadership (535 PJ) and International Trade (294 PJ) scenarios, we can approximate the electricity consumption and capacity of low temperature and non-hybrid high temperature power-to-heat.

[58] 1 MW_{th} of thermal buffering coupled to a heat pump will only result in power flexibility of 0.25 MW if the COP equals 4, while 1 MW_{th} of thermal buffering coupled to an electric boiler will result in 1 MW of flexible power if the efficiency is roughly 100%.

renewables) and by reducing the required capacity for H_2tP. However, thermal buffers combined with heat pumps increase system costs. This is due to the relatively high costs of excess thermal capacity for heat pumps and because it requires 1 kWh of thermal buffering capacity to absorb 1 kWh of electricity using a heat pump with a COP of 3.

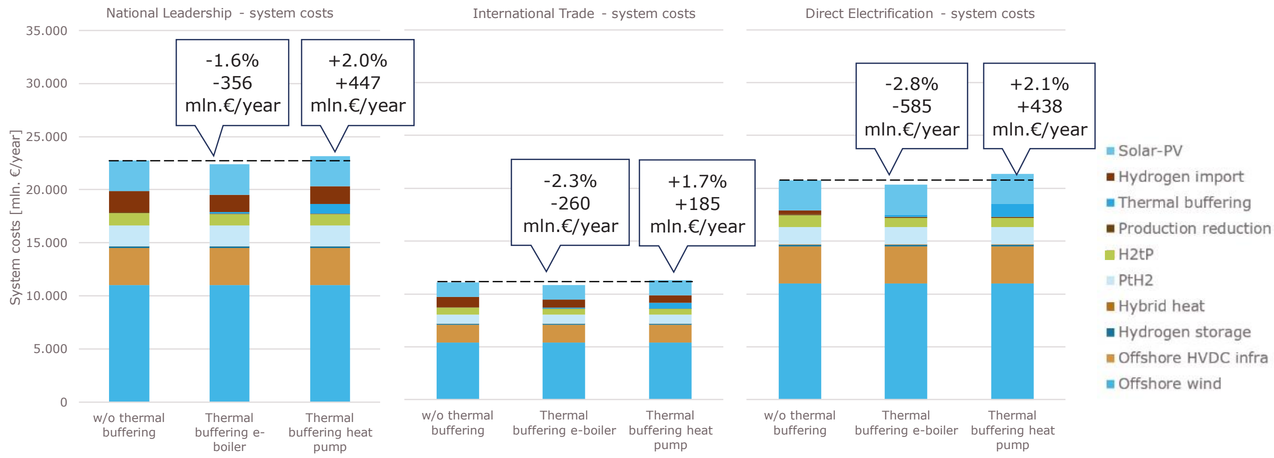

Figure 42. System costs with and without thermal buffering for the three scenarios.

Figure 43 and Figure 44 illustrate how thermal buffering utilises surplus renewable energy and discharges at moments of insufficient renewable energy. This reduces the need for H2tP flexible power production (see Figure 45) and, therefore, also for hydrogen demand. However, thermal buffering also 'competes' with PtH2, as it sometimes 'outbids' it in order to prepare periods of low renewable generation. This is illustrated in Figure 46. Furthermore, the application of industrial production is also reduced by thermal buffering.

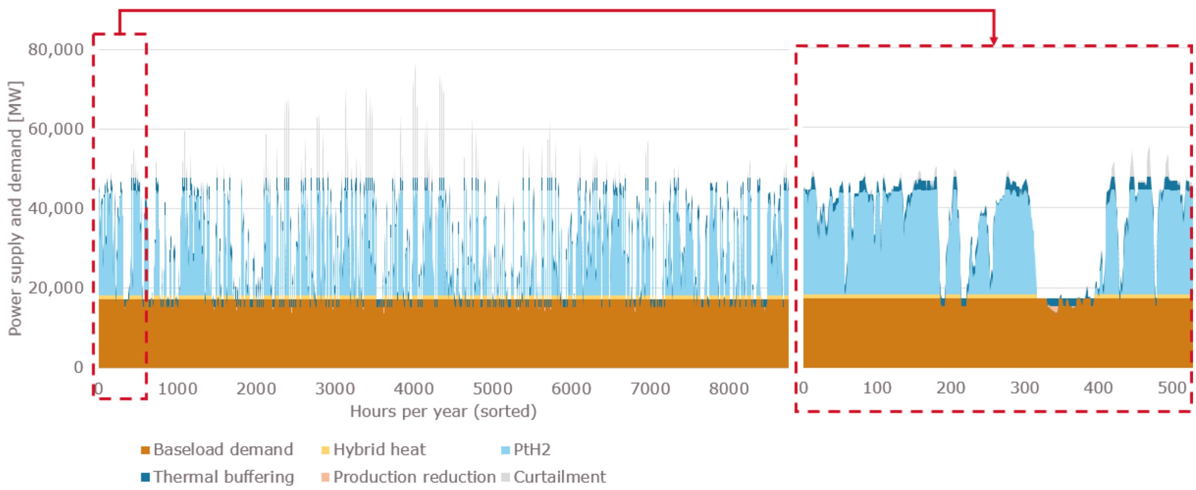

Figure 43. An unsorted time series depicting the frequency range during which thermal buffering is employed for the National Leadership scenario. The right figure zooms in on the first 500 hours to improve readability.

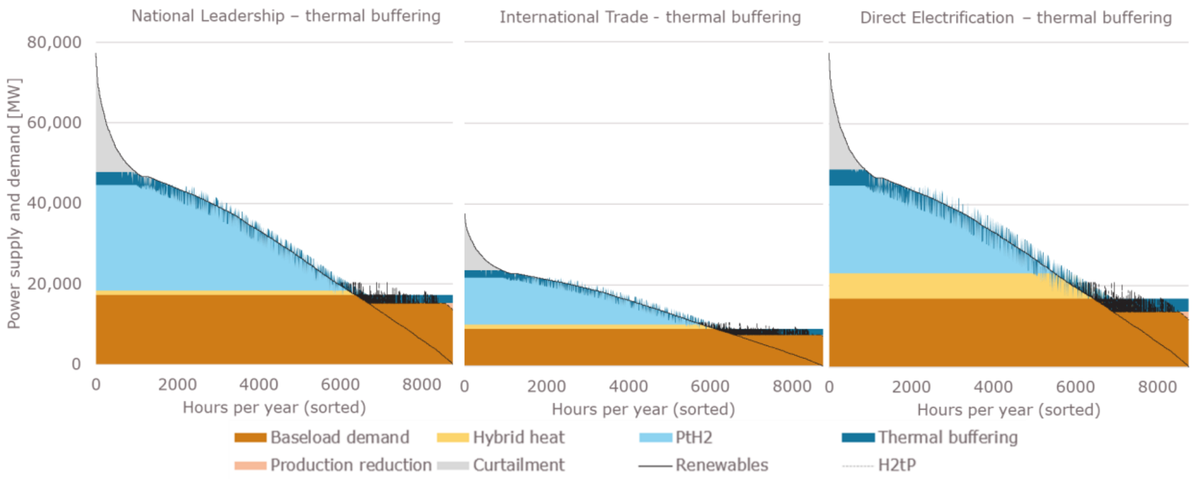

Figure 44. Illustration of how thermal buffering can both absorb surplus renewables and reduce the need for H2tP backup capacity.

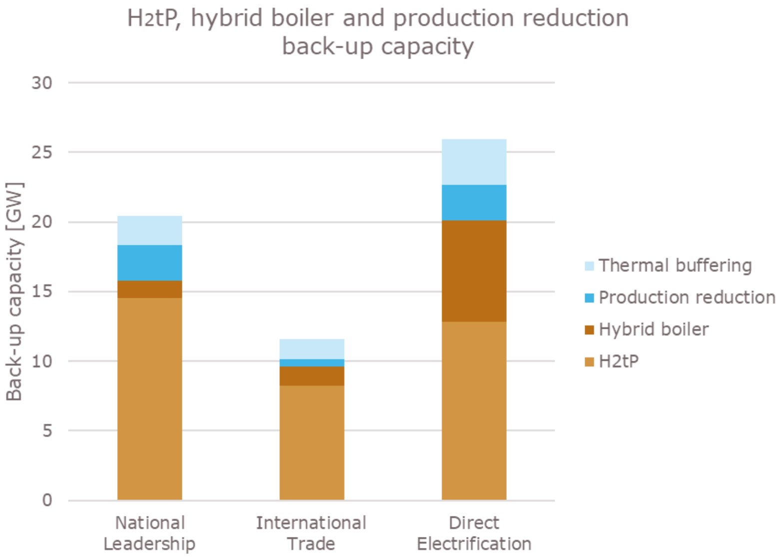

Figure 45. Backup capacity provided by H2tP, hybrid boilers, industrial production reduction and thermal buffering for the three scenarios.

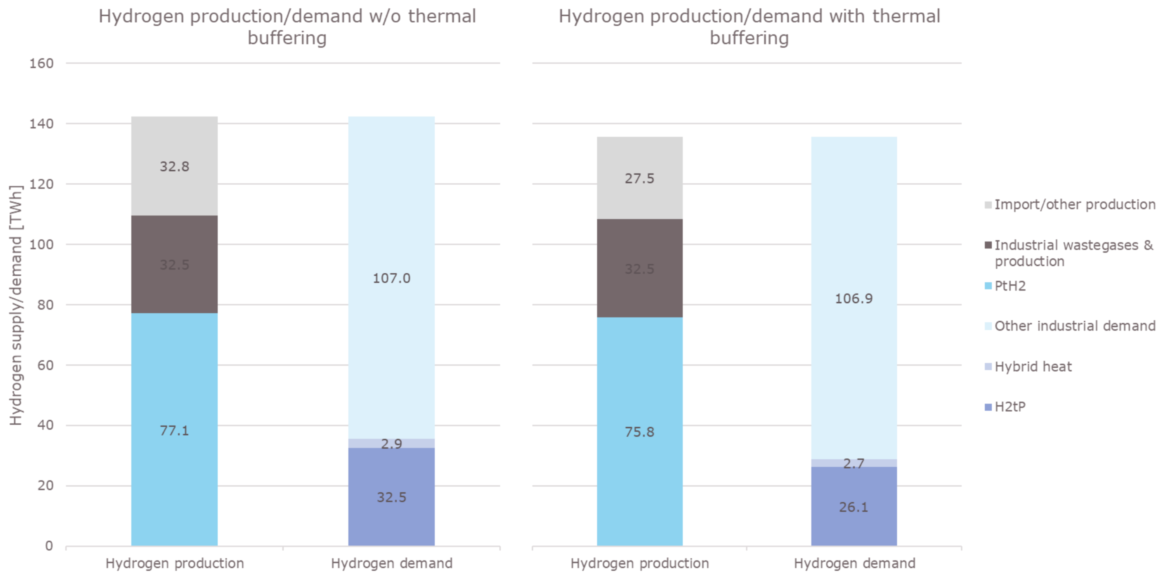

Figure 46. Production and demand without and with thermal buffering for the National Leadership scenario.

Volume and land usage for thermal buffering

The energy density of thermal buffering ranges from roughly 50-200 kWh/m3, depending on the type of buffering technology and the operating temperature range.59 In the National Leadership scenario, roughly 78 GWh of thermal buffering is implemented. Using 100 kWh/m3, 780.000 m3 of thermal buffering volume would be required. If a thermal buffer has a height of 10 meters, this translates to 7.8 hectares of land area.

This is a relatively small land area compared to the land area used by a large oil refinery in Rotterdam (150 to 300+ hectares) or the land area of Tata Steel of roughly 750 hectares[60]. However, the land and volume requirements can be a limitation for industrial sites that lack land area for expansion, as thermal buffering must be close to the production process.

Required capacity and costs for hydrogen buffering

Due to the intermittency of green hydrogen production and the flexible hydrogen usage by hybrid heat and H2tP backup plants, significant amounts of hydrogen buffering are required to match supply and demand. Table 12 shows the required hydrogen capacity and the equivalent number of salt caverns that would be required in each scenario. The Direct Electrification and National Leadership scenarios require a significantly higher hydrogen buffer capacity compared to the International Trade scenario. This is due to the green hydrogen production capacities and hydrogen demand being higher in these two scenarios. Note that empty natural gas fields can also be used for hydrogen buffering, effectively reducing the amount of salt caverns required.

[59] IRENA (2020). Innovation Outlook: Thermal Energy Storage.

[60] Tata Steel. Op bezoek bij Tata Steel in IJmuiden.

Table 12. Required hydrogen buffer capacity in terms of energy volume (GWh), number of salt caverns and annualised costs for the three scenarios.

	Direct Electrification (Roadmap Electrification in the Industry)	**National Leadership** (II3050)	**International Trade (II3050)**
Required hydrogen buffer capacity	8832 GWh	8674 GWh	4391 GWh
Number of salt caverns (based on 193 GWh per cavern[61])	46	45	23
Costs onshore	117 M€/year	115 M€/year	58 M€/year
Costs offshore	179 M€/year	176 M€/year	89 M€/year

3.2.6 Battery storage: batteries appear less promising when only the needs for industry are considered

Finally, battery storage is integrated into the system. For the National Leadership and Direct Electrification scenarios, 5 GW (6-hour battery determined on battery characteristics and an energy-power ratio of 6:30 GWh) is added, while for the International Trade scenario, 2.5 GW (15 GWh) is added. Figure 47 shows that system costs increase for all scenarios even though the round-trip efficiency of battery storage is typically higher than that of thermal buffering (90% vs 80% in this analysis). The cost increase is simply due to the high CAPEX of battery storage. Furthermore, due to the relatively low storage volume of battery storage (6 hours compared to 25 hours for thermal buffering), it is not effective in reducing the H2tP backup capacity.

While battery storage installed specifically for industrial power demand does not reduce system costs, battery storage that is ‘freely available’ from other sectors does reduce system costs. In the II3050 National Leadership and International Trade scenarios, 6.3 GW (27 hours → 170 GWh) and 4.4 GW (27 hours → 119 GWh) of battery storage, respectively, is available through electric vehicles. Figure 47 shows how system costs are reduced if half of that battery capacity is available to the industry (without additional costs).

[61] TNO & EBN (2022). Haalbaarheidsstudie offshore ondergrondse waterstofopslag (average based on a range of 135-250 GWh operational volume per cavern).

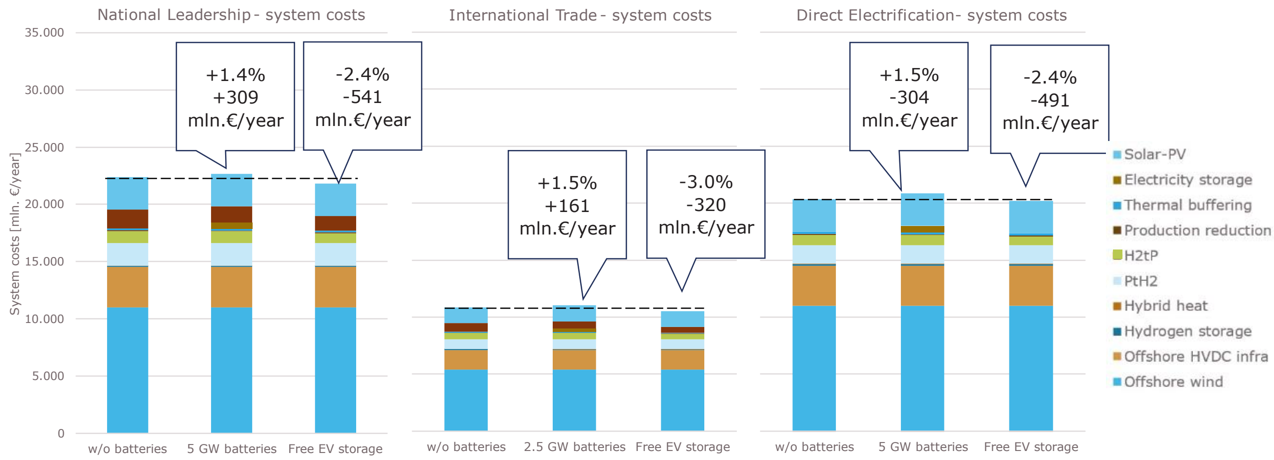

Figure 47. System costs with and without battery storage or 'freely available' battery storage from electric vehicles (EVs) for the three scenarios.

Figure 48 illustrates how battery storage fulfils a function that is comparable to thermal buffering (albeit at higher costs for dedicated battery storage). More renewable surpluses are absorbed, and industrial production reduction is applied less often. However, as explained above, investing in additional battery storage for industrial purposes does not reduce system costs.

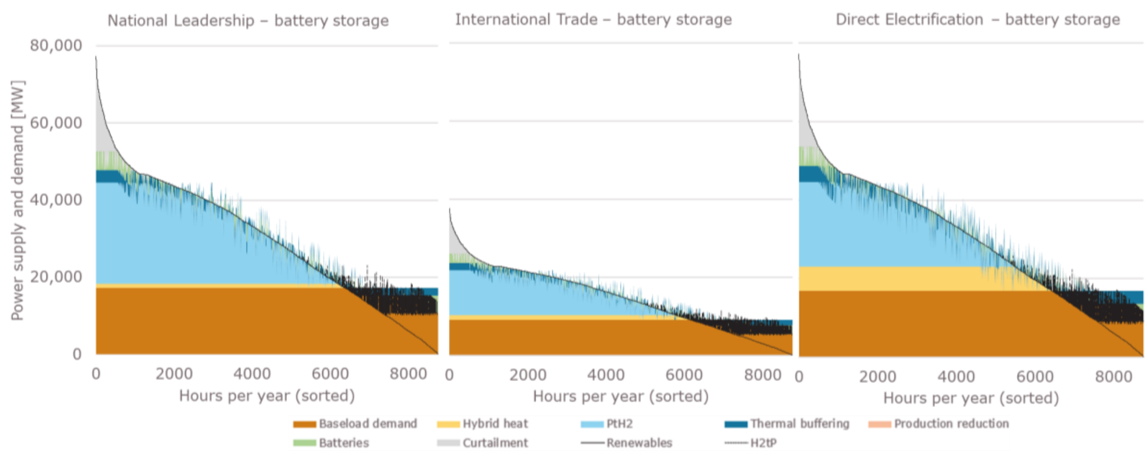

Figure 48. Illustration of how battery storage can both absorb surplus renewables and reduce the use of industrial production reduction for 5 GW battery storage (National Leadership and Direct Electrification scenarios) and 2.5 GW (International Trade scenario).

3.2.7 Sensitivity analysis

The assumptions regarding the forecasted costs of various technologies and the import price of hydrogen for 2050 are highly uncertain but also have a large impact on the results of the system cost analyses. Using a sensitivity analysis, the effects of the uncertainties of the most important parameters can be explored.

The results for the National Leadership scenario are evaluated against a diverse set of technology cost assumptions. Sensitivity analyses for other scenarios have been omitted. Even though the exact results may differ among scenarios, the trends triggered by alterations in cost data are anticipated to be consistent across all scenarios.

Figure 49 presents the primary analysis results and acts as a reference for the sensitivity analysis. The fluctuation in system costs following each technological step is illustrated in the blue textboxes within the figure. A negative percentage indicates a reduction in system costs with respect to the previous step, whereas a positive percentage signifies an increase.

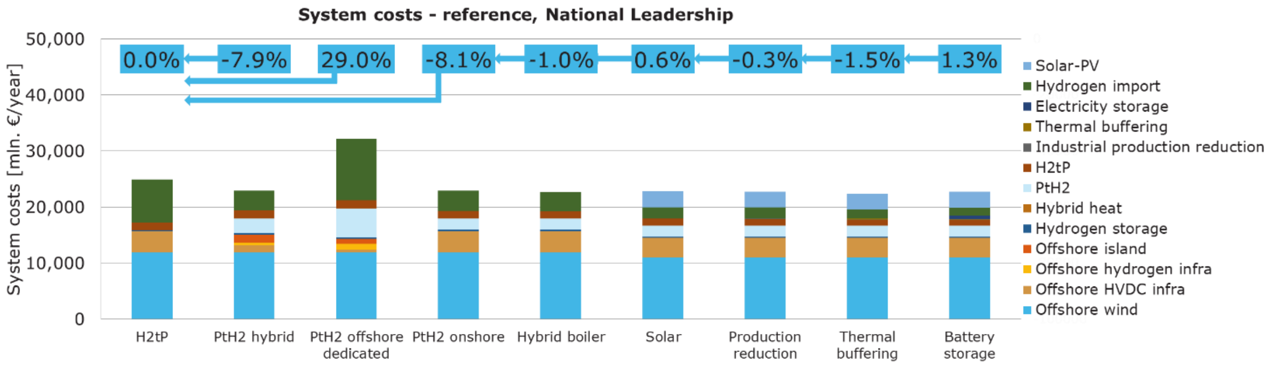

Figure 49. Primary analysis results acting as a reference for the sensitivity analysis.

Figure 50 up to Figure 54 show the effects of varying hydrogen import prices, offshore HVDC costs, offshore island costs, thermal buffering costs, H_2tP costs and offshore solar PV costs. These parameters are especially important for deciding whether or not the different technological solutions increase or decrease system costs. For example, in deciding between offshore, hybrid, or onshore PtH_2, the infrastructure costs play an important role (offshore island costs for offshore PtH_2, HVDC costs for onshore PtH_2). Furthermore, industrial production reduction is in competition with flexibility by backup capacity, which means that the costs of H_2tP are a pivotal parameter. The sensitivity analyses focus on the following parameters.

- **A higher hydrogen import price** leads to a stronger decrease in system costs for each technology that reduces hydrogen demand (hybrid boiler, thermal buffering and offshore solar PV) or increases hydrogen production (hybrid or onshore PtH_2, offshore solar PV). As offshore solar PV both reduces hydrogen demand for H_2tP backup power and increases hydrogen production via increased load hours of PtH_2, system costs decrease significantly. This is in contrast with the slight increase in system costs in the reference results.
- **A lower hydrogen import price** leads to the exact opposite as a higher import price. All the technologies, except for hydrogen boiler, production reduction and thermal buffering, actually increase system costs. For PtH_2, the economically viable capacity is lowered drastically, as many more annual load hours are required to offset the capital expenditures. Therefore, PtH_2 would only reduce system costs at a significantly lower capacity.
- **At 25% lower CAPEX for offshore solar PV**, system costs actually decrease instead of increase. Thus, either lower offshore solar PV CAPEX or higher hydrogen import prices make offshore solar PV worthwhile (apart from technical feasibility).
- Since the system costs for onshore and hybrid PtH_2 are comparable, any changes in either offshore hydrogen or electricity infrastructure makes one variant more attractive than the other. **Increased costs of offshore islands** makes the hybrid PtH_2 option more expensive, and **increased costs of offshore HVDC** makes onshore PtH_2 more expensive. Given the uncertainty of these cost figures, no unequivocal conclusion can be drawn other than 100% dedicated offshore PtH_2 being more expensive.

- **Thermal buffering** leads to decreased system costs in all variants, even when CAPEX are doubled or if hydrogen import prices increase or decrease.
- **A substantial reduction in CAPEX for H_2tP** makes it more economically viable than using industrial production reduction for backup capacity. Very cheap open-cycle gas turbines (OCGTs) might thus be more cost-effective than most types of industrial production reduction.

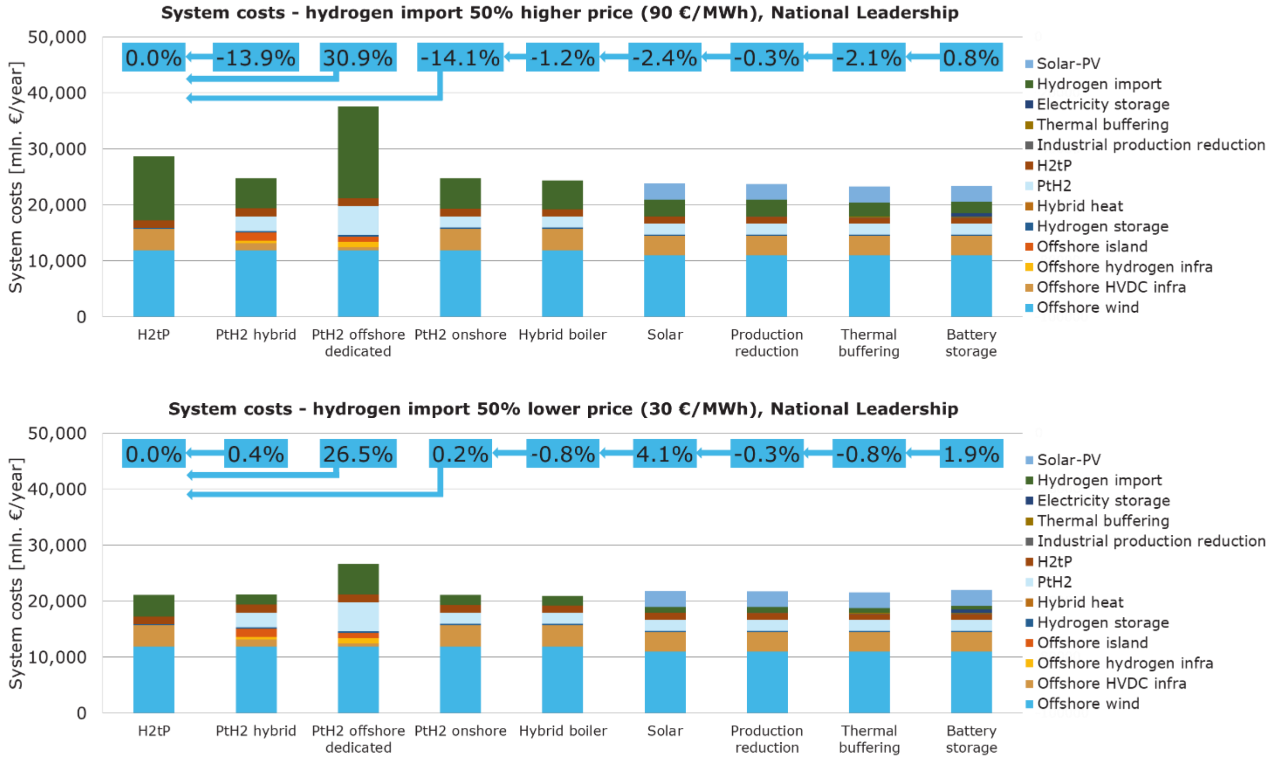

Figure 50. System costs with a 50% lower (30 €/MWh) and higher (90 €/MWh) hydrogen import price for the National Leadership scenario.

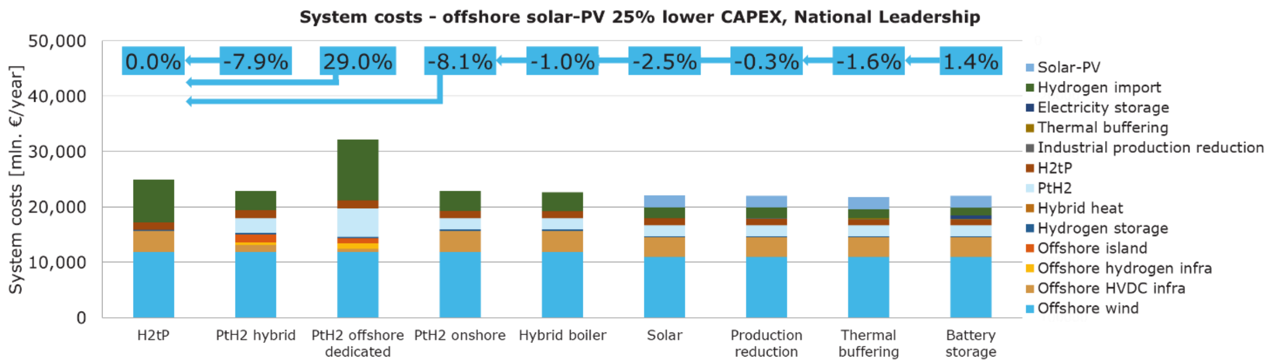

Figure 51. System costs with 25% lower solar PV CAPEX for the National Leadership scenario.

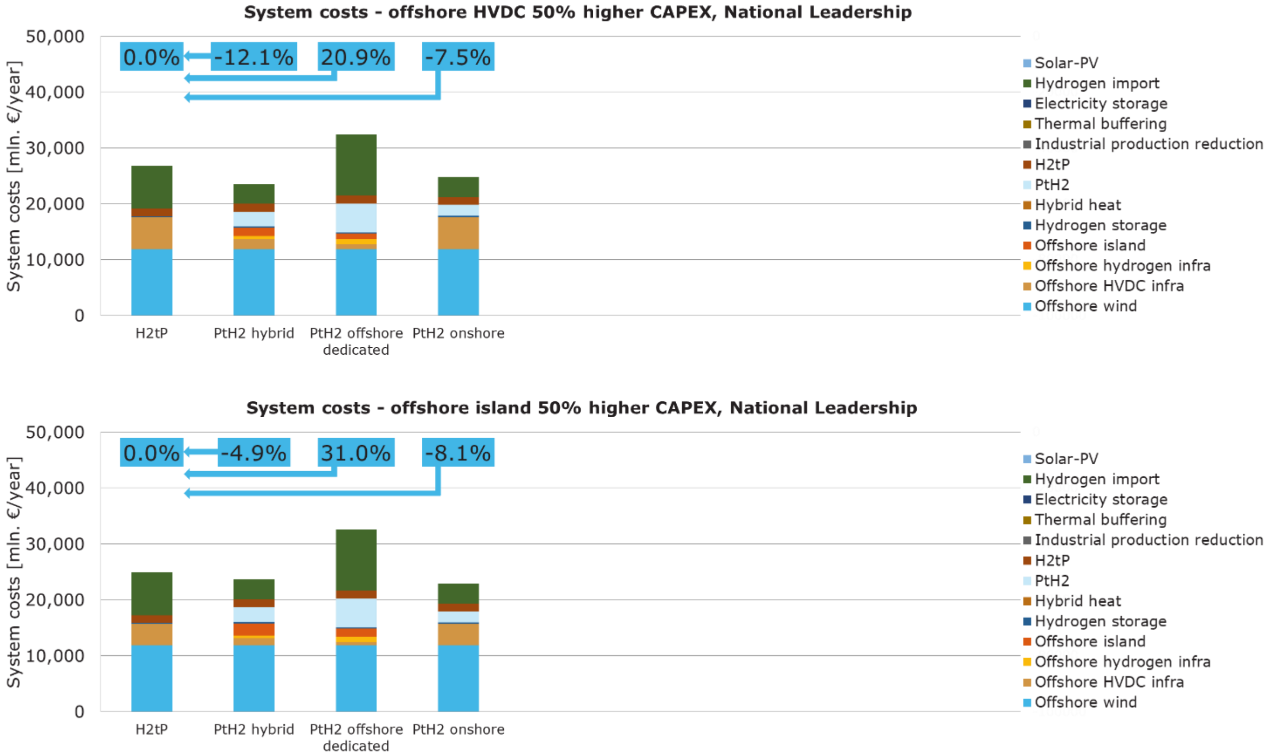

Figure 52. System costs with 50% higher offshore HVDC CAPEX and 50% higher offshore island CAPEX for the National Leadership scenario.

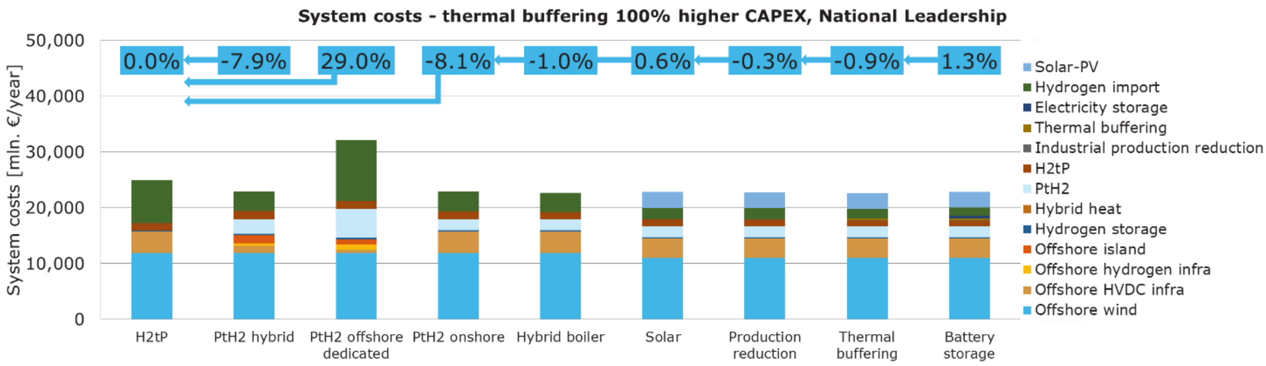

Figure 53. System costs with 100% higher thermal buffering CAPEX for the National Leadership scenario.

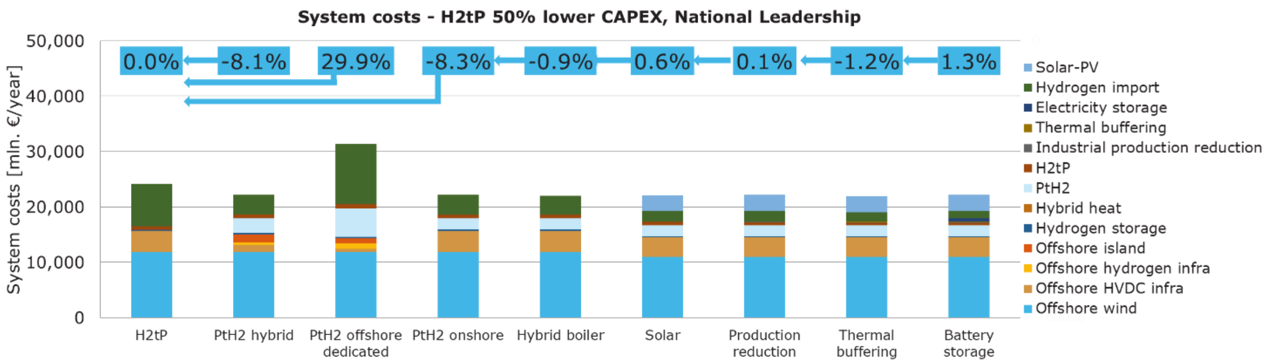

Figure 54. System costs with 25% lower H2tP CAPEX for the National Leadership scenario

4 Conclusions

In this chapter, we discuss the conclusions of this research. The chapter starts with the general conclusions. In the second section, we give the techno-economic conclusions. Followed in the third section with the policy considerations. In section 4.4, the goal is to demystify common misconceptions surrounding the concept of flexibility to improve the discussion around flexibility.

4.1 General conclusions

For filling the valley, the part of the curve with a shortage of renewables, a combination of backup power plants, thermal buffering and temporary industrial production reduction leads to the lowest system costs. Within a simplified scope consisting solely of industry and offshore wind/solar PV, roughly one-quarter of backup capacity can be reduced by a combination of thermal buffering and industrial production reduction. The use of battery storage appears less promising when only the needs for the industry are considered. However, the use of backup capacity for industrial baseload demand could potentially be further reduced when considering other parts of the energy system that lie outside the scope of this study, such as battery storage from electric vehicles, solar farms or households.

The economic perspectives for offshore solar PV are uncertain. Systems with offshore solar PV only lead to reduced system costs if future hydrogen import prices turn out higher than expected and/or if the costs of offshore solar PV are reduced further than is currently forecasted. However, it is likely that there will be plenty of solar capacity available elsewhere in the system to provide electricity to the industry during periods with less wind. Furthermore, the ability of solar PV to replace backup capacity is very limited.

For lowering the peak, the part of the curve with excess renewables, hybrid power-to-heat is the first option to be used by the industry to use surpluses of offshore wind, as it converts electricity to heat with high efficiency. However, the capacity of this option is limited for most scenarios in 2050. The remaining surplus can be utilised by both electrolysis and power-to-heat combined with thermal buffering.

Regarding the location of power-to-gas, there appears to be no significant preference between on- and offshore from both a financial and spatial perspective. The extra costs of offshore islands are compensated to a large extent by the decreased infrastructure costs. However, system costs significantly increase when using dedicated offshore power-to-gas coupled to offshore wind, where all power generated is directly converted. This is due to a decrease in overall system efficiency as, during hours with a shortage of renewables, power is being converted into hydrogen offshore while simultaneously backup power plants onshore are converting it back into electricity.

4.2 Techno-economic conclusions

4.2.1 Supply-side

Power-to-gas (electrolysis) proves to be a cost-effective solution for utilizing surplus energy across all scenarios. Generally, onshore flexible electrolysis is the most cost-effective approach for operating the electrolyser. However, a hybrid model incorporating offshore flexible hydrogen production and electrical landing is also economically viable, yielding similar results to the onshore electrolysis alternative.

High capacity of dedicated offshore hydrogen production can lower transport and infrastructure costs but lead to higher costs on a system level. This is because it can cause double conversion (electricity to hydrogen and hydrogen to electricity) and consequently reduce efficiency. When opting for offshore power-to-gas, all baseload electricity demand should be supplied by electricity directly in order to avoid double conversion as much as possible. It may, however, be difficult to determine what the future baseload demand of the industry will be, as it depends on choices by current and future industrial activity, which are always surrounded by uncertainty.

However, in specific cases, it may be beneficial to use dedicated offshore hydrogen production. When a large part of the baseload demand is already supplied by other offshore wind farms, and the farm is further away from the coast or is difficult to connect using HVDC infrastructure, it can be cost-effective to use a limited amount of dedicated offshore hydrogen production and transport the hydrogen instead of the electricity. This does not follow directly from the analysis because an average distance is assumed, and offshore wind is allocated based on the demand.

Batteries can flatten the curve, but they increase system costs when used for of the profile of offshore wind and offshore solar PV. Using existing battery storage capacity elsewhere in the electricity system (e.g., from electric vehicles, solar farms and households) is an option that could reduce system costs and the need for backup power plants in general, and therefore also for the industry. When these batteries are available, they can flatten the curve and lower the total system costs.

Innovation in wind turbine designs has the potential to flatten the curve, but these technologies are not market-ready. There are developments in designs of wind turbines with lower maximum capacity but an increased amount of full load hours. However, the technology readiness level of these wind turbines is low, which is why the economic impact of this technology could not be determined in this analysis. In potential, this technology could fill a large part of the valley of the curve. Therefore, we suggest focusing innovation on this new design of wind turbines.

4.2.2 Conclusions industry

Hydrogen backup power plants are the most cost-effective way to provide the majority of electricity during moments when renewable electricity is scarce. When hydrogen backup is compared to demand side response (DSR), the potential of demand side response is limited. Temporary industrial production reduction can reduce the required backup capacity slightly. However, the cost savings are minimal as it is an expensive option. The alternative of industrial production shift, instead of production reduction, has not been analysed and requires further research.

Hybrid heat can reduce the system costs significantly. When hybrid heat capacity is available, electricity can be used during hours of excess renewable generation, which reduces fuel consumption. However, a critical note needs to be placed with this conclusion, as onshore infrastructure costs for hybrid heat are not considered in this study. The potential of hybrid heat in the form of hybrid boilers is limited, namely between 2 and 5 GW, depending on the scenario. Hybrid steam cracking furnaces may also be technically feasible. However, due to the high costs of additional furnaces, the cost savings are nullified. Only the life extension of readily depreciated conventional furnaces combined with new electric furnaces could reduce costs on a system level.

Thermal buffering can reduce system costs and flatten the curve by utilizing excess renewables and storing these for hours when there is a shortage of renewables. However, as additional power-to-heat capacity is required for incorporating thermal buffering, only relatively inexpensive power-to-heat technologies such as e-boilers are suitable for thermal buffering. Using thermal buffering with expensive options such as heat pumps actually increases system costs. Furthermore, due to the high coefficient of the performance of heat pumps, much more thermal buffering capacity is required to shift one unit of electricity demand in time. However, because of its potential, we advise more research on the thermal buffering of heat pumps.

4.3 Policy considerations

In this section, we suggest policy considerations based on our analysis and the conclusions drawn in the previous section. The policy considerations consist of the implementation of new pricing mechanisms to fund backup plants, assuring that the majority of offshore wind tenders will be connected at least partially via electricity infrastructure and the focus on research and innovations on gas-to-power backup solutions.

1 Develop and implement fitting pricing mechanisms for backup power plants

This research highlights the pressing need for backup power plants. However, it should be noted that the future requirements for backup capacity are uncertain and that a significant share of these plants will only generate electricity for a limited number of hours each year. The business model for these power plants relies on hours where electricity is scarce with corresponding (very) high scarcity prices. This might lead investors to be conservative in investing in backup capacity as overcapacity eliminates scarcity prices.

The use of temporary industrial production reduction to lessen the need for backup capacity can lead to minor cost savings, but only if just the right amount of industrial production reduction is used. If too little backup capacity is available and industrial production must be excessively reduced, system costs significantly increase. This asymmetry between potential cost savings and cost increase might lead to a preference for slight overcapacity in backup power as the future backup requirements might be difficult to predict.

The business model for backup plants based on scarcity prices might make investors prefer a little less backup capacity over a little too much, while from a system costs perspective, it is more desirable to have a little too much backup capacity. It thus appears that the current business model for backup plants does not lead to sufficient backup capacity. Therefore, it is essential to develop alternative market mechanisms that enhance the profitability of backup power plants.

One potential solution to improve the business case of backup plants is the implementation of an insurance fee or capacity mechanism. In this proposed system, an industrial party would pay an insurance fee in exchange for access to backup capacity. This means that the energy provider would receive payment even without operating the backup power plant. Such an arrangement significantly strengthens the economic viability of a power plant, making it a more attractive investment opportunity.

2 Ensure that the majority of offshore wind tenders will be at least partially connected to land via offshore electricity infrastructure

This report does not provide conclusive evidence for or against the cost-effectiveness of offshore hydrogen production in general. However, *dedicated* offshore hydrogen production does appear to result in elevated system costs. If the baseload electricity demand is not fulfilled through direct offshore wind electricity, hydrogen backup power plants come into play. This could lead to an ineffective situation where offshore hydrogen production and onshore use of hydrogen in a power plant occur simultaneously. Consequently, this leads to significant cost escalations, as energy is lost with each conversion process.

However, when looking at other factors, there can be reasons to opt for offshore electrolysis. When hydrogen is produced offshore, it is advisable to transport a certain proportion of energy produced by wind farms in the form of electricity. This minimal amount of electrical landing is determined by the baseload demand and all hybrid technologies in the energy system (see Figure 55).

This can be addressed by ensuring that the majority of offshore wind farms are at least partially connected to land via offshore electricity infrastructure in future offshore wind tenders.

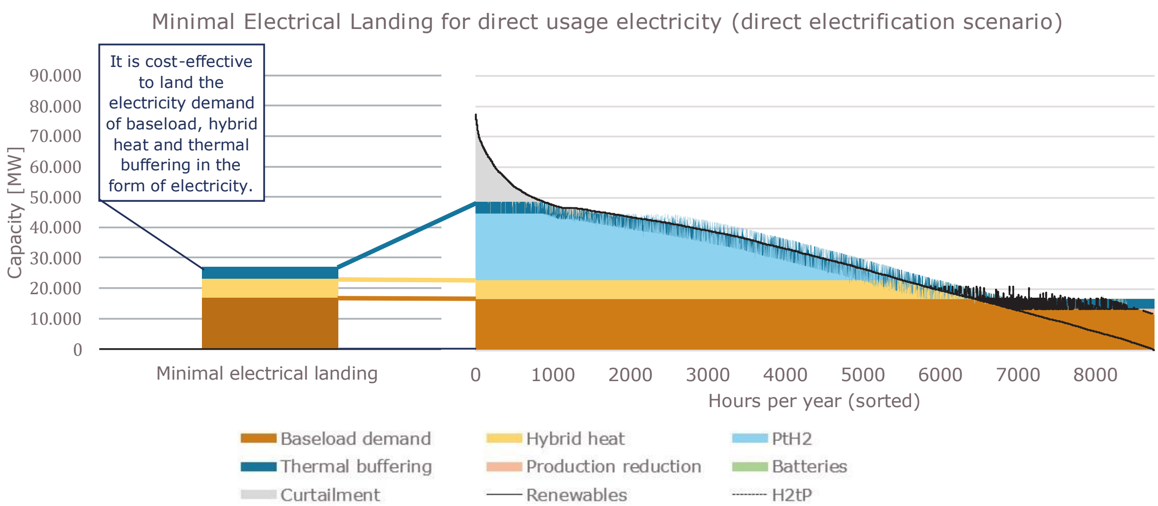

Figure 55. Minimal electrical landing for the Direct Electrification scenario.

3 Focus research and innovation on gas-to-power backup solutions

Our research findings indicate the necessity of large-capacity backup power plants to provide electricity during periods of limited offshore wind production. The significant numbers required can be attributed to the lack of cost-effective, flexible alternatives available on a large scale. While our research assumes hydrogen power plants as the backup solution, it is worth considering that large-scale fuel cells can also serve as sources of backup electricity.

To enhance the effectiveness and affordability of backup power generation, this research proposes allocating research and innovation budgets specifically for this purpose. For hydrogen power plants, it is crucial to prioritize low investment costs, even if it means sacrificing some efficiency. Although this approach may lead to higher operational costs, the limited deployment of these plants mitigates any concerns.

Another promising alternative for backup power is reversible electrolysis. Technologies like solid oxide cells enable the production of hydrogen through the addition of electricity, and they can also reverse the process of generating electricity using hydrogen. Implementing this technology on a large scale could allow a portion of the electrolysis capacity to be used as electricity backup, reducing the reliance on traditional backup plants. While this technology is currently at a low technology readiness level, its promising potential warrants investment in research and development.

4.4 Demystifying assumptions and misconceptions around flexibility in offshore wind and industrial demand

In this section, we dive deeper into common assumptions of topics around flattening the curve. We use our analysis to objectively clarify common assumptions and misconceptions and aim to improve the societal discussion around these subjects.

Assumption: the industry has a large demand side response (DSR) potential and can, therefore, contribute to flattening the curve

In our analysis, we found that the technical potential to temporarily decrease production of the industry is subsector-dependent. Most sectors can decrease production to a certain level before shutting down completely. On average, we found this technical potential to be around 80% for the energy-intensive industries and include ‘new’ industries. This means that facilities could decrease production to 80% without negative consequences. However, in terms of system costs, the potential of demand side response (DSR) is significantly lower. The underlying factor behind this is the comparatively higher cost of temporary production reduction compared to backup power plants. The cost-effective industrial DSR potential is between 0.5 GW and 2.5 GW, depending on the scenario, but this barely reduces system costs.

Assumption: to reduce costs, energy should be transported from offshore farms to the coast in the form of hydrogen

To reduce the costs of offshore electricity infrastructure, energy can be transported via pipelines in the form of hydrogen. This means offshore wind farms need to be directly connected to dedicated offshore hydrogen production. The electrolysers can be placed on (artificial) islands, platforms or within the turbine. Even though this reduces infrastructure costs, it results in higher total system costs due to lower system efficiency. This is because this inevitably leads to hours in which hydrogen is produced offshore and hydrogen is used onshore to produce electricity at the same time.

It is important to emphasise that with this analysis and the underlying assumptions, it is impossible to decide the most cost-optimal configuration for one specific wind farm. This means that for a specific wind farm further offshore, it could be cost-effective to use (partly) dedicated hydrogen production. The dedicated hydrogen configuration will become more interesting when there is no baseload electricity demand. But in general, it is advisable to be hesitant with high volumes of dedicated offshore hydrogen production.

Appendix 1 Consulted parties

Table 13. Sounding board.

Name	Company
Andreas ten Cate	TKI Energy and Industry
Bert den Ouden	HyXchange
Bob Meijer	TKI Offshore energy
Bram van der Wees	TKI Offshore energy
Cornelis Biesheuvel	Dow Chemicals
Erik Klooster	Vemobin
Julia Peerenboom	Tennet
Jurre Honkoop	Ørsted
Marc van Dijk	Cosun
Marijn Pronk	RWE
Remko Ybema	HyCC

Table 14. Interviews.

Name	Company
Anouk van Loon & Bart van der Meulen	Tata Steel
Astrid Schilderman	SynKero
Bob Meijer	TKI Offshore energy
Cornelis Biesheuvel	Dow Chemicals
David Molenaar	Siemens Gamesa
Jeroen van Hooijdonk	Shell Pernis
Cyriel Pieters	BP
Jurre Honkoop	Ørsted
Marc van Dijk	Cosun
Marijn Pronk	RWE

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