HyDelta 2

WP4 – Regional blending in the regional transmission (40 bar) pipelines to overcome congestion in the electricity grid

D4.2 – Cost-benefit analysis of various short-term supply-side E-grid flexibility options in local areas in comparison to conventional grid-expansion techniques

Status: complete

Dit project is medegefinancierd door TKI Nieuw Gas | Topsector Energie uit de PPS-toeslag onder referentienummer TKI2022-HyDelta.

Document summary

Corresponding author

Corresponding author	Salar Mahfoozi
Affiliation	New Energy Coalition (NEC)
Email address	s.mahfoozi@newenergycoalition.org

Document history

Version	Date	Author	Affiliation	Summary of main changes
1	Mar. 30 2023	SM, RvZ, CJ	NEC	80% draft
2	Apr. 15	SM, RvZ, CJ	NEC	100% draft
3	Jun. 01 2023	SM, RvZ, CJ	NEC	Additional editing and addressing of comments
4	Jun. 14 2023	SM	NEC	Cosmetic changes and finalized version

Dissemination level

PU	Public	X
RE	Restricted to • Project partners including Expert Assessment Group • External entity with whom a Non-Disclosure Agreement exists	

Document review

Partner	Name
GTS	Jelle Lieffering
Stedin	Iman Pishbin
Liander	Bart Vogelzang
NEC	Catrinus Jepma
NBNL, Gasunie, Kiwa, DNV, TNO, NEC, Hanze	HyDelta Supervisory Group

Executive summary

In order to move towards a renewable energy system in the Netherlands, an increasing capacity of renewables has to be connected to the electricity grid. This causes very serious e-grid congestion issues. Reinforcement of the e-grid can be very expensive if technologically and/or legally feasible at all, costs considerable time for various reasons and requires an electrotechnical workforce that often is not or scarcely available. So, Dutch electricity DSOs are facing growing congestion problems in providing grid connections in time for new renewable energy capacities. It is in fact likely that in the Netherlands e-grid congestion will be a reality and growing concern for at least the coming decade. This results in sometimes long connection waiting times for solar and wind farms (i.e., supply-side congestion) and similar adverse access conditions for the energy end-users (demand-side congestion), and also means that in the near future new solar and wind farms will not be able to deliver electricity to the grid at all times.

To determine the most cost-effective solutions for this issue from an energy system perspective covering different energy carriers and stakeholders involved, this study looked into alternative supply-side grid flexibility solutions provided by electrolyzers, batteries and their combinations alongside curtailment methods. The net costs of these options have then been compared with those of traditional grid expansion techniques. Such comparative economic analysis has been carried out via a case study in the context of a quasi-realistic setting in which a 38MWp solar park is introduced in a Netherlands' region facing serious supply-side e-grid congestion, Friesland.

The striking overall result of the case analysis of such newly added solar capacity in a rural e-grid-supply-congestion region, i.e. where electricity supply already exceeds demand during peak moments, is that under the current (2023) cost and energy price conditions considerable societal net benefits can be achieved by connecting the solar park to the market via the multiple flexibility options mentioned rather than by just reinforcing the local electricity grid.

Various sensitivities were explored to analyse the impact of parameter changes on the various flexibility components. For this purpose an impact assessment was made of changing: the distances between the solar park and a hydrogen refuelling station; the capacity of the solar park and electricity demand; hydrogen and electricity prices; the mode of transport of hydrogen via the RTL and tube trailers; the level of mobility demand, the CAPEX of electrolysers; and the way of sourcing the electricity from the grid. Of all sensitivities, especially changes in hydrogen and electricity prices turned out to have a large impact especially via their impact on returns on selling hydrogen to mobility. The impact of the option to sell hydrogen to mobility was anyhow important because its prices received per kg green hydrogen were assumed to be higher than those offered by industrial uptake.

Simulation results also showed that in the economic optimum large-scale batteries played a significant role in providing flexibility for dealing with supply-side congestion. Especially combinations of batteries and PtG proved effective in raising electrolyser use. Electrolysers and electrolyser/battery combinations were the optimal flexibility solution at the lower solar PV capacities, whereas battery solutions were at the higher end of the PV capacities considered.

All in all, our results suggest that from the overall energy system cost perspective it can be very promising to systematically assess costs and benefits of alternative ways to integrate new local renewable energy capacities into the energy system, especially in rural e-grid congestion regions. It should, however, be mentioned that the lowest cost energy system option can only be realised if somehow the stakeholders losing are at least compensated for their losses by the stakeholders gaining: one therefore somehow needs legislative framework that supports such compensation. This underlines the role that governmental policies and incentives on such planning issues will have to play

apart from their role e.g. with respect to the development and implementation of new technologies for greening energy production, etc. (see also Hydelta2 D4.3 on this).

Some assumptions and caveats about the research have been included below:

- Annualized costs and benefits methods was used for assessing the various scenarios in comparison to a Net Present Value (NPV) method (see section 3.3.3 for more information) this was done in order to fairly compare assets with different lifetimes with each other.
- This study considers the mutual costs and benefits of multiple stakeholders: renewable electricity producer, battery and/or electrolyser operator and the distribution grid operator. We acknowledge that under current market circumstances these actors will not operate their assets in a mutually optimal way. However, this methodology has been chosen to show what the societal optimum is when financial incentives of these actors would be aligned.
- Costs and benefits show the results for a pre-investment decision phase, taking into account both investment and planned operational considerations of a one year 4timeframe. Hence, the results are not yielded by the actual performance and differences over the years.
- Re-use of the RNB pipeline is considered for the transportation of hydrogen in most of the scenarios (RTL is not utilized). RNB gas pipeline of 8 bars is suitable for the level of output that is derived from the electrolyzer and serves the regional aspect of our study.
- Mobility demand of hydrogen – with a relatively high willingness-to-pay - is limited by regional demand constraints considered in our scenarios, the sensitivity of the results based on this demand has been evaluated. The industrial demand was not limited as it was perceived that any industrial offtaker would need to be connected to national hydrogen transport infrastructure in order to receive enough volume and security of supply.

Samenvatting

Om in Nederland naar een duurzaam energiesysteem over te gaan, moet steeds meer duurzame energie worden aangesloten op het elektriciteitsnet. Dit veroorzaakt zeer ernstige congestieproblemen op dit net. Versterking ervan: kan erg kostbaar zijn als het technologisch en/of juridisch al haalbaar is; kost om uiteenlopende redenen veel tijd; en vereist elektrotechnisch personeel dat vaak niet of nauwelijks beschikbaar is. Nederlandse distributiebedrijven op het gebied van elektriciteit worden dus geconfronteerd met toenemende congestieproblemen bij het op tijd leveren van netaansluitingen voor nieuwe capaciteit van hernieuwbare energie. Het is waarschijnlijk dat congestie op het elektriciteitsnet in Nederland in ieder geval de komende tien jaar een realiteit en groeiende zorg zal zijn. Dit leidt tot soms lange wachttijden voor de aansluiting van zonne- en windparken (d.w.z. congestie aan de aanbodzijde) en vergelijkbare ongunstige toegangsvoorwaarden voor de eindgebruikers van energie (congestie aan de vraagzijde). Dit betekent ook dat in de nabije toekomst nieuwe zonne- en windparken niet altijd elektriciteit aan het net zullen kunnen leveren.

Om te zoeken naar oplossingen en benaderingen om dit probleem aan te pakken, onderzocht deze studie alternatieve oplossingen voor netflexibiliteit aan de aanbodzijde, die worden geboden door opties met elektrolysers, batterijen en niet-levering te vergelijken met traditionele technieken om de capaciteit van het elektriciteitsnet uit te breiden. Deze bendering is toegepast in de context van een quasi-realistische setting waarin een zonnepark van 38 MWp wordt gevestigd in een regio met ernstige netcongestie aan de aanbodzijde. De kenmerken van de energiesituatie in de typische congestieregio Fryslân heeft daarbij als basis gediend. Door beide opties qua kosten en baten te vergelijken kon worden onderzocht hoe verschillende flexibiliteitsopties het economisch doen en wat dus de meest kosteneffectieve benadering is vanuit het perspectief van de totale kosten van het energiesysteem.

Het verrassende algemene resultaat van de casusanalyse is dat onder de huidige (2023) condities qua kosten- en energieprijzen er een significant netto kostenvoordeel voor de belanghebbenden kan worden behaald als men inzet op een benadering met een combinatie van flexibiliteitsopties (waterstof, batterijen en in extreme gevallen niet-levering) in plaats van de 'standaard-benadering' van het versterken van het lokale elektriciteitsnet.

Er werden ook verschillende andere gevoeligheden onderzocht om te zien hoe het gebruik van verschillende flexibiliteitsmiddelen verandert door diverse variabelen te wijzigen. Dit is gedaan door te kijken naar veranderingen: in de afstanden tussen het zonnepark en een waterstoftankstation, in de capaciteit van het zonnepark en de elektriciteitsvraag, in de waterstof- en elektriciteitsprijs, in de wijze van transport van waterstof via de RTL en tubetrailers, in de omvang van de mobiliteitsvraag, in het niveau van de CAPEX van elektrolyzers, en in het betrekken van elektriciteit van het net. Onder deze gevoeligheden speelden veranderingen in waterstofprijzen en elektriciteitsprijzen een prominente rol. Een toename van waterstofprijzen leidde tot hogere voordelen voor waterstof bij mobiliteitstoepassingen. Mobiliteitstoepassingen van waterstof waren in algemene zin belangrijk in de scenario's doordat in de mobiliteitsmarkt een hogere prijs per kg waterstof kon worden ontvangen dan bij afzet aan de industrie.

Modelresultaten toonden aan dat vooral grootschalige batterijen flexibiliteit voor aanbodcongestie leveren en naast de waterstoftechnologie een serieuze rol speelden in het optimum van de onderzochte scenario's. Vooral de combinaties van batterijen met PtG-eenheden bleken effectief bij het vergroten van het gebruik van de elektrolyse-eenheid. Electrolysers en electrolyser/batterijcombinaties zouden meer kosteneffectief kunnen worden gebruikt bij lagere zonne-PV-capaciteiten, terwijl batterijgerichte oplossingen grotere rol spelen bij hogere PV-capaciteiten.

Al met al suggereren onze resultaten dat het vanuit kostenperspectief belangrijk is om systematisch alternatieve manieren te onderzoeken om nieuwe lokale hernieuwbare energiecapaciteiten te integreren, vooral in landelijke regio’s met congestie op het elektriciteitsnet waar de geïnstalleerde capaciteit van zonne-opwekking regelmatig de relatief kleine vraag naar elektriciteit overtreft. De alternatieve manieren die we hebben geïdentificeerd, vereisen echter afstemming van de belangen van belanghebbenden en een wettelijk kader dat dit ondersteunt. Op basis hiervan is het belangrijk om de rol te benadrukken die overheidsbeleid en stimuleringsmaatregelen kunnen spelen voor het kiezen van de optimale oplossing voor de nieuwe inzet van hernieuwbare capaciteit (zie daarover ook HyDelta2 D4.3 – het rapport over de belangrijkste beleidsimplicaties van de onderzochte opties).

Enkele aannames en kanttekeningen bij het onderzoek zijn hieronder opgenomen:

- Geannualiseerde kosten-batenmethoden werden gebruikt voor het beoordelen van de verschillende scenario's in vergelijking met een Net Present Value (NPV)-methode (zie sectie 3.3.3 voor meer informatie). Dit werd gedaan om activa met verschillende levensduur eerlijk met elkaar te vergelijken.
- In deze studie worden de wederzijdse kosten en baten van meerdere belanghebbenden bekeken: producent van duurzame elektriciteit, batterij- en/of elektrolyserbeheerder en de distributienetbeheerder. We erkennen dat deze actoren onder de huidige marktomstandigheden hun activa niet op een wederzijds optimale manier zullen exploiteren. Er is echter voor deze methodiek gekozen om te laten zien wat het maatschappelijk optimum is als de financiële prikkels van deze actoren op elkaar worden afgestemd.
- Kosten en baten tonen de resultaten voor een pre-investeringsbeslissingsfase, rekening houdend met zowel investerings- als geplande operationele overwegingen voor een tijdsbestek van een jaar. De resultaten komen dus niet voort uit de werkelijke prestaties en verschillen over de jaren heen.
- Hergebruik van de RNB-leiding wordt in de meeste scenario's overwogen voor het transport van waterstof (RTL wordt niet benut). RNB-gaspijpleiding van 8 bar is geschikt voor het outputniveau dat wordt afgeleid van de elektrolyseur en dient het regionale aspect van ons onderzoek.
- De mobiliteitsvraag naar waterstof – met een relatief hoge betalingsbereidheid – wordt beperkt door regionale vraagbeperkingen die in onze scenario's worden overwogen, de gevoeligheid van de resultaten op basis van deze vraag is geëvalueerd. De industriële vraag was niet beperkt, aangezien werd aangenomen dat elke industriële afnemer aangesloten zou moeten zijn op de nationale transportinfrastructuur voor waterstof om voldoende volume en leveringszekerheid te krijgen.

Table of contents

1. Introduction and objectives of the research

Research activities from Deliverable 4.1 of the HyDelta2 project qualitatively specified several areas where the hosting of decentralized PtG (power-to-gas) activities for consumption by **1)** industry within the 6th industrial cluster and **2)** the mobility sector via hydrogen refuelling stations (HRS) could take place. These areas were determined based on the state of electricity grid congestion (e-grid congestion), the proximity of renewable energy production sites such as windfarm or solar-parks and the availability of a constellation of industrial off-takers from the 6th industrial cluster[1] who are connected to the 40-bar RTL gas pipeline and are end users who are decoupled from the built environment/public distribution system.

Modelling of D4.1 and subsequent scenario-analysis suggested that in such areas currently and on average from the energy suppliers' perspective the business case of PtG as a solution for e-grid congestion still is difficult given current assumed market prices of green hydrogen and demand levels from local industries. So, in most cases under current market conditions energy providers in such areas can gain more by directly selling electricity (current average price: ≈200 €/MWh) rather than introducing PtG and accepting hydrogen prices at levels which, in the absence of clear policy incentives, were assumed to be based on prices of natural gas and CO_2 allowances. It was also found in the PtG options that introducing utility-scale batteries increased the number of electrolyser running hours and contributed to dealing with e-grid congestion, but generally not enough to get to a proper business case from the energy suppliers' perspective.

The research from this deliverable (D4.2) will take the analysis a step further by taking an energy system perspective. Rather than, as in D4.1, assessing the economics of P2G from the perspective only of energy providers facing e-grid congestion, we will now take the economic perspective of all directly involved stakeholders combined facing such congestion: RES providers facing problems in supplying electricity to the grid and possibly other companies if P2G/battery activity is outsourced; DSO's facing issues via legal standards by insufficiently connecting customers and transmitting the produced electricity; and possibly the consumers of electricity – the local (cluster 6) industry in particular – having difficulties in acceding the grid for their power supply (see Table 1).

We will do so by a real-life case study comparing the costs and benefits of two basic options to deal with congesting: either reinforcing the grid such that new renewable electricity supply can be serviced, or making the (additional) energy suppliers to directly or indirectly invest in P2G and battery capacity to partly circumvent congestion. By comparing the net costs of both options one can assess from the overall energy system perspective what is the theoretically best option from the system perspective. Given the rapidly growing e-grid congestion problem in the Netherlands, such information obviously is crucial to minimize overall costs from an energy system perspective but is not necessarily decisive in practice because in order to be effective it assumes legal mechanisms e.g. for mutual compensation between energy providers and grid operators, etc. Moreover, the conclusion which option is economically optimal obviously will be case- and time-specific, and therefore requires systematic empirical assessment.

[1]These areas are unique because they will not directly be connected to the pure hydrogen backbone pipeline and are composed of a diverse group of industrial clusters who are facing serious demand-side congestion issues in the local e-grid and hence are an under-researched group.

Table 1: Main challenges from the perspective of the stakeholders involved in the electricity grid

Domain	Issue
Renewable Energy Supplier (RES)	• Facing challenges in gaining access and supplying renewable electricity to the grid.
Distribution Service Operator (DSO)	• Expansion of the grid is limited by high costs, lead times and scarce workforce. • Legally required to connect customers and the transmission of electricity.
Consumers (such as industry etc.)	• Difficulties in gaining access to the grid.

2. Electricity Grid Congestion

2.1 Effect of the energy transition on the current energy system

Ambitious decarbonization targets such as a CO_2 reduction of 49% by 2030 and 95% for 2050 compared to 1990 levels for the Netherlands is leading to an increased uptake and utilization of renewable energy sources. In fact, it is expected that by 2030, at least 70% of electricity generation in the Netherlands will originate from non-fossil fuel sources such as variable wind and PV [1]. Dutch energy policy is also pushing to rapidly reduce the role of natural gas in the energy system [1] and a shift towards an electrified energy system is underway.

Scaling up renewables to achieve these emission reduction targets is however challenging. The complexity of the energy supply system increases as the shares of variable renewable energy sources (VRES) grow [2]. Increasing the generation capacities of renewable electricity contribute to:

- Heightened intermittency within the grid (variability and uncertainty)
- Increasing electricity grid congestion at extra-high/high/intermediate/medium/low voltage grids (effects on locational distribution)

Traditionally transmission and distribution networks have been built to transport electricity from large-scale fossil-fuelled power plants towards different user groups such as industries, residential areas and businesses. This central generation and distribution facilitated the unidirectional flow of electricity within high-voltage grids. However, the increased “plugging” of variable renewable energy sources such as photovoltaics and wind unto the grid introduces uncertainties owing to their variable output. As a result of this integration, the direction in which electricity flows thru the grid increasingly shifts toward a bi-directional flow where the control and operation of the renewable energy fleets becomes increasingly challenging. **Figure 1** provides an illustration of what such a grid looks like.

The proliferation of renewable electricity production also leads to an increase of decentralized electricity production developments which increases the granularity of the electricity network. This effect can be seen in the enhancements being made to electricity infrastructures in rural areas. Originally, rural electricity grids contained grids with limited capacities due to the small population where electricity demand is largely for agricultural activities. Management of the grids for these areas involved low assets with a well-predictable growth over time [3]. However, in the past few years there has been an increase in power supply and demand in these regions. This is because these areas have large expanses of land where solar-farm and windfarm can be set up relatively quickly [3]. The expanding production capacity growth in these areas is an active security threat to grids which could occur by exceedances in the permissible amount of power through each cabling line and the permissible bound for the voltage level of each node [4]. Hence, the expansion of these grids to accommodate for these new electricity production sites is vital, the speed with which this transport capacity can be expanded will therefore be decisive for being able to connect new renewable electricity production sites.

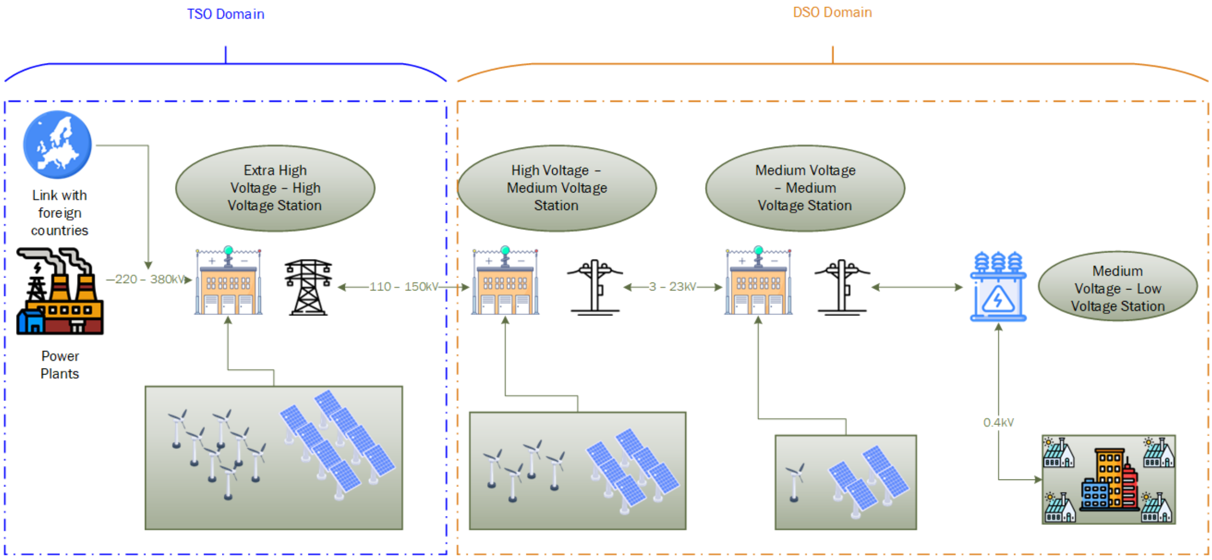


Figure 1: Overview of how electricity is distributed within the Netherlands. Handling and management of produced electricity at a transmission level is done by a national network operator (TSO); in the case of the Netherlands this is done by TenneT. Handling voltages for the transmission domain consist of 220 – 380kV and 110 – 150kV. Distribution of the electricity is done by a variety of regional network operators (DSO) who have jurisdiction over different regions of the country, these could be companies like Alliander, Enexis, Stedin etc. Handling voltages for the transmission domain consist of 50 kV, 3 – 23kV, and 0.4 kV. Electricity is also supplied through the low-voltage grid as well via rooftop solar PV and does contribute to e-grid congestion on the local grid. (Image is own illustration but inspired by [3])

The structural solution for integrating decentralized electricity production lies in expanding the high-voltage grid and the medium-voltage grid [3] and also the low-voltage grid. However, the process is both costly and time-consuming (sometimes lasting more than 10 years) and short-term grid balancing solutions need to be followed through. Hence, congestion management in distribution networks due to the increasing level of renewables lies in combining long-term structural expansion in combination with short-term solutions. Short-term solutions fall under two main categories: 1) network options and 2) instruments for reshaping grid users' generation and consumption patterns [5]. Network options involve reconfiguration of the grid, voltage regulation, and reactive power management. For reshaping of generation and consumption patterns the utilization of distributed flexibility resources (DFR's) such as electric vehicles, utility batteries and price-responsive loads [6] (e.g., electrolyzers and PtG system) could be effective. The technical efficiencies of these flexibility resources in reducing congestion and peak shaving in distribution grids have been studied in the past (see [7], [8]).

Of importance to this study is investigating the flexibility provided to medium-voltage grids by green hydrogen production via PtG system. Many governments, including the EU, give a prominent role to hydrogen as a provider of flexibility [9]. PtG plants can offer flexibility to the electricity grid via several ways [10]:

- The produced hydrogen can be stored for various time periods which gives hydrogen producers the freedom to adapt to the pricing situation of the electricity market while the produced hydrogen does not need to be immediately supplied to users i.e., **time flexibility**.
- Hydrogen can act as a medium to transfer renewable electricity in the form of molecules i.e., **end-use flexibility.**
- Hydrogen can offer renewable energy to locations where the electricity grid is less developed i.e., **locational flexibility**.

Emerging power-to-gas conversion system can also bring various opportunities for energy system such as flexibility [11] and decarbonisation [12]. Therefore, the assessment of how these technologies can be an economically efficient solution for energy system is necessary. Dealing with surplus generation in electricity distribution grids via comparing electrolyzers and expanding the grid capacity has been studied [13] where it was concluded in that study that the costs of grid expansion can be significantly reduced when electrolyzers come into the fold. The flexibility provided by these system affect not just electricity but also gas distribution networks and the effectiveness of sector coupling between electricity distribution grids and gas networks via power-to-gas conversion system on reducing the generation curtailment in the electrical grid has been investigated in [14] [15]. A visual example of flexibility achieved by such sector coupling is shown in **Figure 2**.

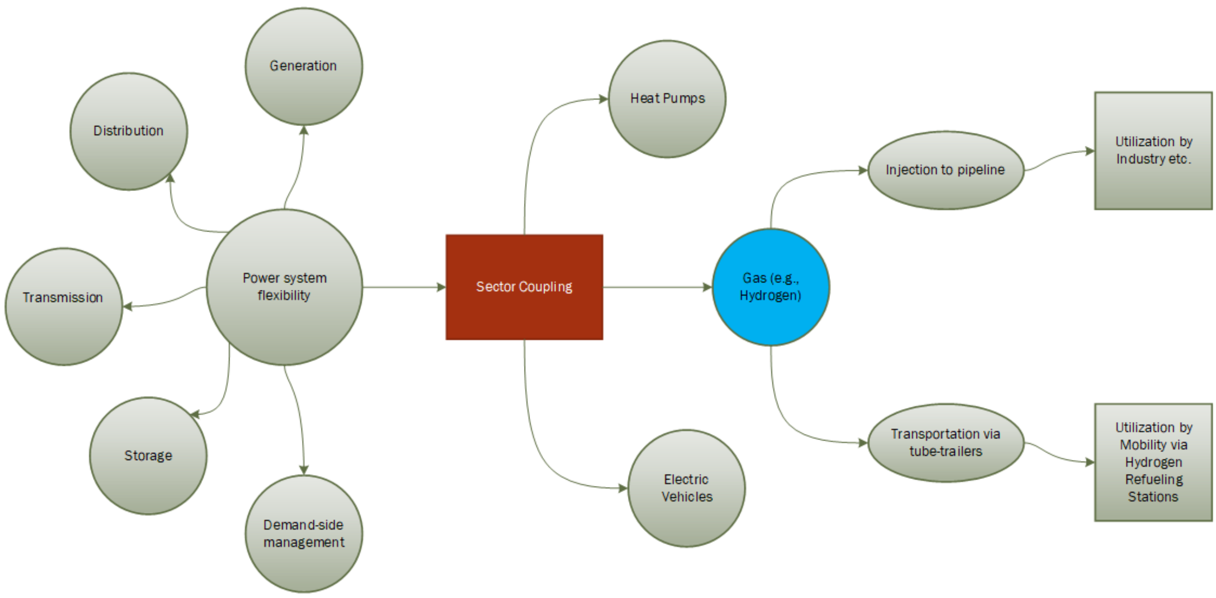


Figure 2: Representation of a flexible power system (inspired by [16]) where varied methods of generation, combined with stronger transmission and distribution networks, demand-side flexibility, storage and sector coupling techniques such as heat and hydrogen production help boost system flexibility and help with the decarbonization of the total energy system.

2.2 Exploring electricity grid congestion at specific areas

It would be beneficial to explore and provide actual examples of certain areas within the country that are afflicted with e-grid congestion and are in the process of expanding their grids in order to accommodate for new influxes of renewable electricity. A good case-study can be explored in the Friesland province in which the electricity grid is witnessing an increased feed-in of large-scale solar PV parks, solar panels on roofs, and windfarm. **Figure 3** provides a general overview of these additions.

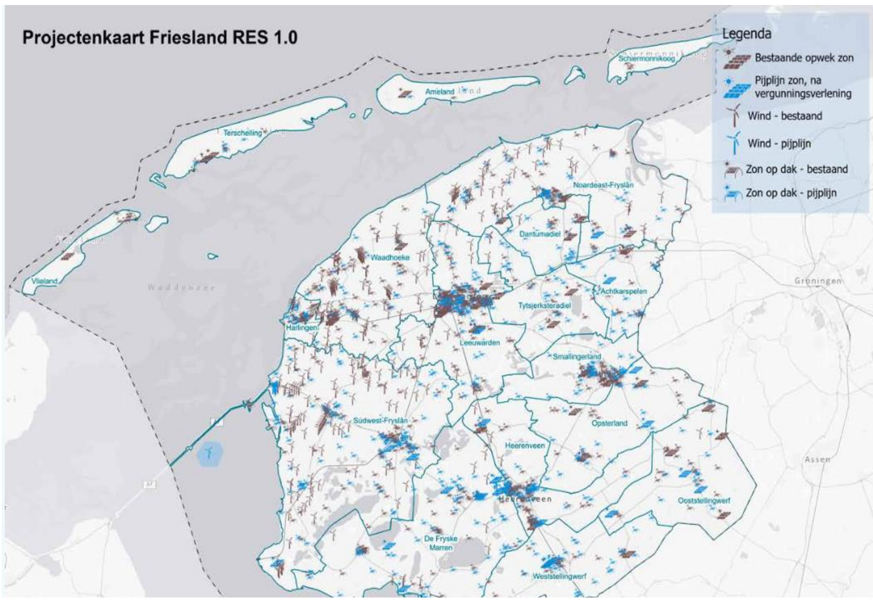


Figure 3: Existing (in brown) and anticipated (in blue) solar and wind installations in Friesland [56]

The level of supply-side congestion in the region can be clearly seen in **Figure 4** where virtually all areas of the region are afflicted by structural congestion and congestion management cannot be applied.

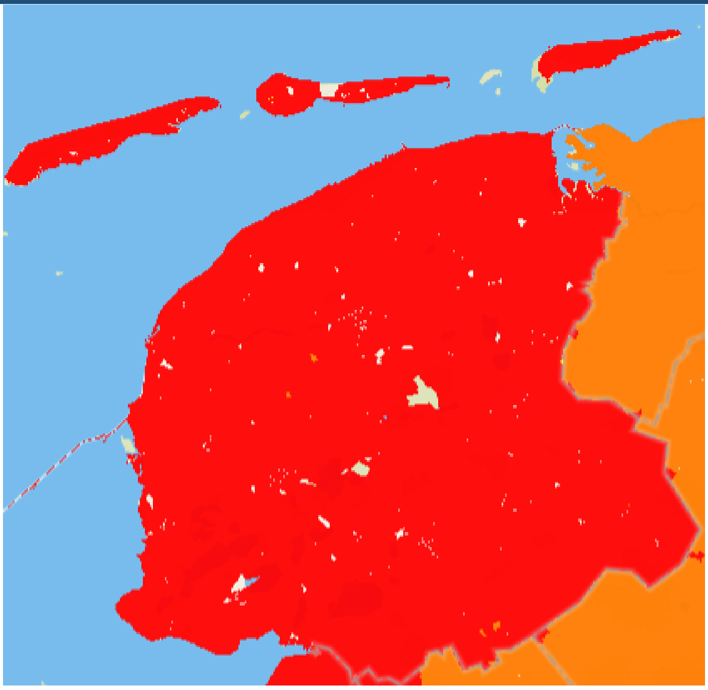


Figure 4: Supply-side congestion virtually affects the whole region of Friesland which is mostly driven by the enormous growth in feed-in from large-scale solar parks and solar on roofs. Date: 20/02/2023 [17].

Responsible for handling the produced electricity within the electricity grids in the province of Friesland are 15 HV/MV (High-Voltage/Medium-Voltage) stations (with 1 outside the region in Emmeloord) and 53 MV (Medium-Voltage) stations which function as control and switching stations (with 1 outside the region in Noordoostpolder) [18]. **Figure 5** displays the locations of where all of these stations are located. Insufficient capacities at certain stations prevent the connection of e.g., larger solar PV parks, thus if there is any chance for installing new solar farm in the area, congestion has to be managed from both the station level and medium voltage cables.

An actual example of a planned solar park is located at the 'De Ekers' business park in 'De Fryske Marren' municipality of Friesland close to the town of 'Joure' (**Figure 6**). This solar park is expected to have a production capacity of 13.5 MW and is close to the 'Oudehaske' high-voltage substation which based on reports from [19] is a station that will face an overreach in capacity by 2030. The distance between the solar field and the station is 2.5 km which potentially could be connected to the HV/MV station for distribution among other MV stations.

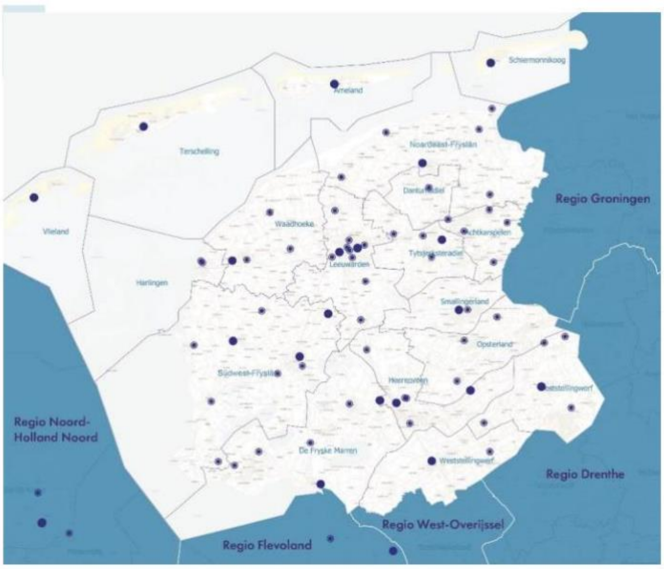


Figure 5: Currently 70 electricity stations exist within Friesland [18].

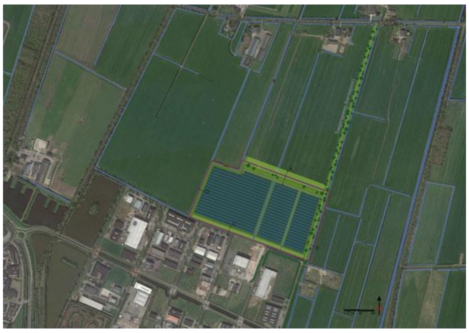


Figure 6: De Ekers solar park – example of a solar park that is in prospect of being connected to an already congested grid [20].

Figure 7 shows a map of where the aforementioned HV/MV station is but also gives an overview of what the state of congestion will be at various stations by the year of 2030 based on a series of simulations by RES Fryslan. The image clearly shows that there will be a significant number of HV and MV stations in the region that will require electricity grid capacity expansions.

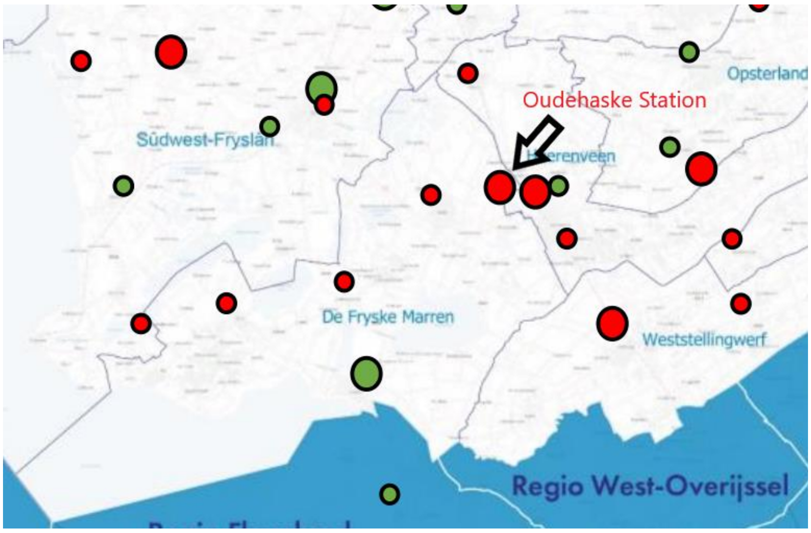


Figure 7: Stations in De Fryske Marren where maximum capacity will be overreached by 2030 [18].

Figure 8 provides a visual representation of what it means to connect a new solar park to the grid and how that translates to increased flows of electricity within an existing grid capacity. It can be seen that the grid capacity is surmounted due to the additional production by the addition of a solar PV park. In order to 'shave' these peaks, traditionally electricity providers opt for curtailment where production is cut in order to not compromise the safety of the grid but this also means that financial losses are incurred by not selling the electricity.

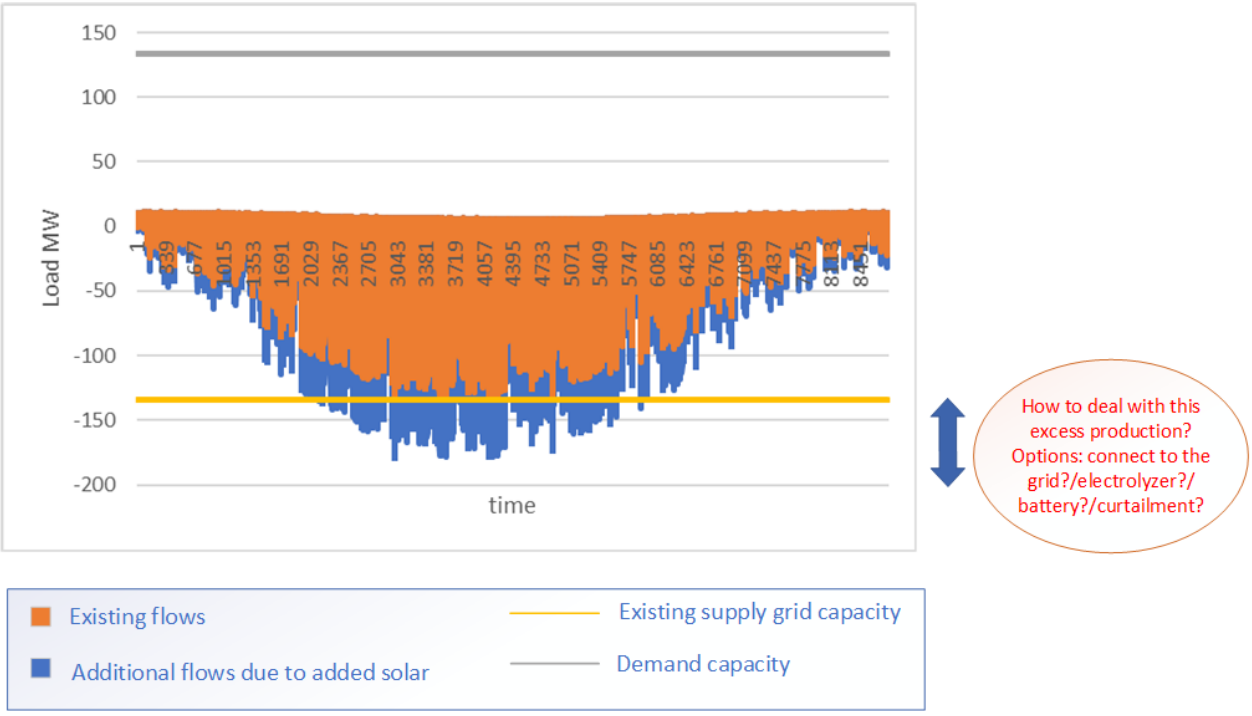


Figure 8: Effect of connecting a new solar farm to the electricity grid. Blue lines represent the extra electricity production via the new solar park. It can be seen that this additional capacity exceeds the existing grid capacity (yellow line) and that through certain times of the year the grids are prone to line exceedances.

As mentioned earlier, structural solutions for DSO's for integrating decentral electricity production involves expanding the HV/MV stations, MV stations, and MV cabling . These measures are taken if the benefits of these additional structural changes outweigh the costs. If the integration of such solar parks is to occur then alterations need to be made to both electricity capacity stations and cabling lines if there are capacity shortages within the lines and the transformer stations or if the grid faces complications from voltage overshoots. A brief overview will be given in order to understand which elements undergo expansion and what the average costs of such upgrades.

Electricity from power plants and abroad is transported to energy consumers via overhead lines and underground cables. Electricity is converted to lower voltage levels at various points in the grid. This occurs at electricity stations where each station is known to transform and convert various voltages depending on their placement to the grid. Table 2 below shows the types of transformer stations of interest to us that undergo expansion but also their handling capacities and potential costs of erecting new transformer stations while Table 3 lists an indicative cost of cables in regional distribution grids.

Table 2: Types of regional power stations that undergo expansion costs in order to accommodate for new regional capacities [3].

Station Type	Handling Voltage	Connection Capacity for Renewable Energy Sources	Space requirements – Lead Time and costs
HV-MV Station 	From 110 – 150 to 3-23kV	Sun: 4 – 49MW Wind: <4 pieces of 3MW	15,000 – 40,000 m^2 – 5 to 7 years - >€25,000,000
MV-MV Station 	3-23 kV	Sun: 1-3 MW Wind: <1 piece of 1MW	200 – 4,000 m^2 – 2.5 – 3 years – €1,300,000 – €6,500,000

MV-LV Station 	10-23 kV – 0.4 kV	N/A	10-35m² – 0.5 – 1 years - €35,000 – €250,000

Table 3: Types of cabling used in regional distribution grids [3].

Connection type	Width – Lead time – costs
HV cable	± 10m – 5-7 years – 1,000 – 5,000 €/m
MV cable	1 - 10m – 0.5-3 years – 100 – 400 €/m
LV cable	± 1m – 0.5-1 year – 70 – 150 €/m

An example of the costs of expansion activities due to congestion can be explored in the region of Eindhoven. Based on **Figure 9** there are currently 2 bottlenecks[2] and are a result of limited capacity occurring at the HV/MV stations or on TenneT's high-voltage grid[3] [21]. Two stations (Hapert and Aarle-Rixtel) need to be expanded (in this case the available capacity on the Enexis grid can only be used after expansion of TenneT's high voltage grid) [21]. 7 station bottlenecks are expected to occur in 2025 or earlier and 2 others will occur in 2025. New HV/MV stations are also being realized which are shown by the pink figures with a grid image in addition to the investments that will go into expanding the grid. It is estimated that more than €50,000,000 will be required to install 2 HV-MV transformation stations in which 30,000 – 90,000 m^2 will be occupied and a timescale of 5 – 7 years will be needed. On the other hand, the cost of extending existing HV-MV stations is within the range of €35,000,000 - €50,000,000 and the required area is situation dependent with a timescale of 4 – 6 years (**Figure 10**).

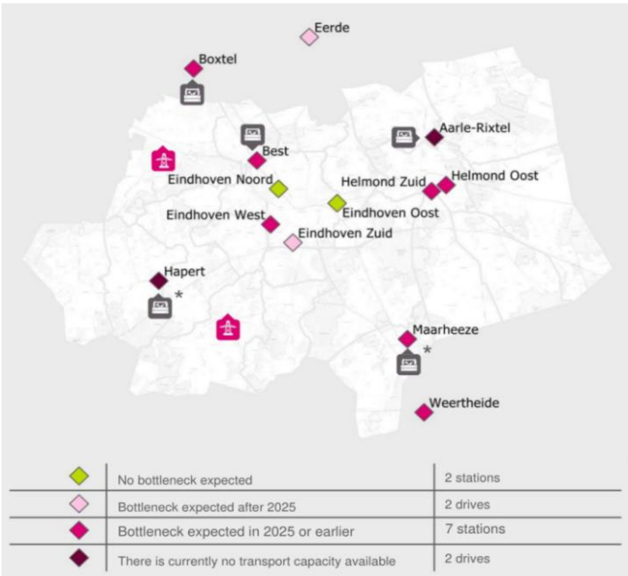


Figure 9: Electricity stations within the vicinity of Eindhoven and their state of congestion [21].

[2] This information is from 2020

[3] It's important to be mindful of the fact that high-voltage grids and extra-high voltage stations and grids all are operated by TenneT which is the Transmission Service Operator of electricity within the Netherlands.

Figure 10: Total impact on time, space and costs based on necessary expansions and new stations [21].

2.3 Exploring grid flexibility options provided by the production of green hydrogen and other distributed flexibility resources such as batteries

It was mentioned earlier how compared to the established tradition of solving grid congestion issues via expanding the grid, grid balancing and congestion management could also occur via the integration of distributed flexibility resources or DFR's. These involve an array of assets that are increasingly implemented for short-term management in time scales of real-time to day-ahead planning. DFR's offered by market parties to TSOs and DSOs can be used by TSO's in form of balancing capacity or balancing energy bids, and by TSOs and DSOs in the congestion management process [22]. In essence, any consumers that have demand management capabilities such as operators of renewable energy sources, large-scale utility battery operators, operators of distributed heat networks, power-to-gas operators could act as load bearing entities.

The applicability of DFR's can be understood in the context of the electricity supply curve that was shown in **Figure 8**. The excess peaks generated by the installation of the new solar park can be 'shaved' by employing a variety of solutions (see **Figure 11**).

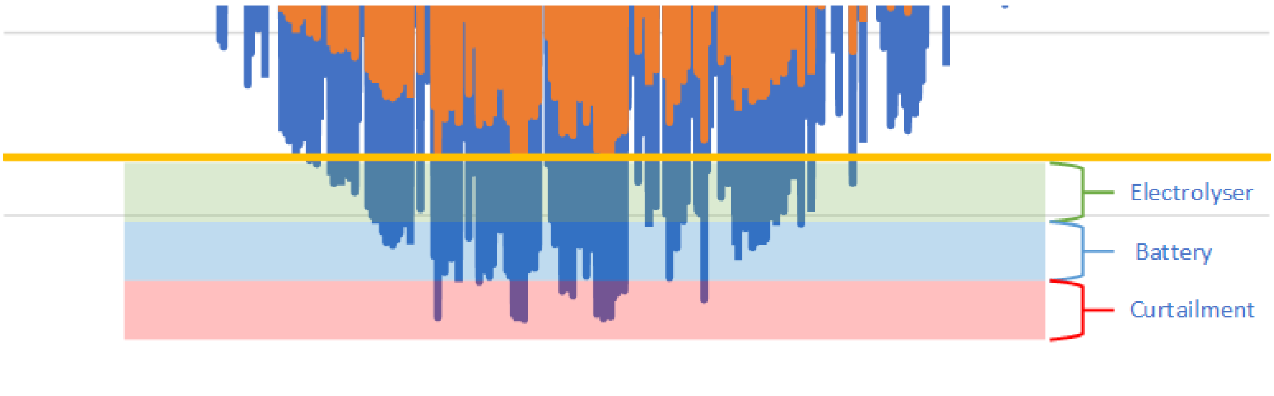


Figure 11: A potential mix of solutions can be employed in order to deal with exceedances in grid capacities

The order of implementing the various congestion management techniques shown above is hypothetical and is only used to indicate which sections of the peaks can be shaved with which flexibility providing resource. The operating strategy of utilizing these flexibility solutions is complex and is dependent on economic drivers which are influenced by the design of the energy market, regulatory aspects and the design of grid ancillary services **(Figure 12)**. These economic drivers then influence system operations of the grid which is composed of the operating strategy, forecast accuracies and aggregation concepts. Social drivers consisting of user behaviours and acceptance also play a role. Important to mention is that flexibility solutions are restricted by technical constraints within their operation. These operational characteristics can consist of efficiency, ramping, response and recovery time. Hence all of these considerations come into play when determining the order of implementing these flexibility solutions [23].

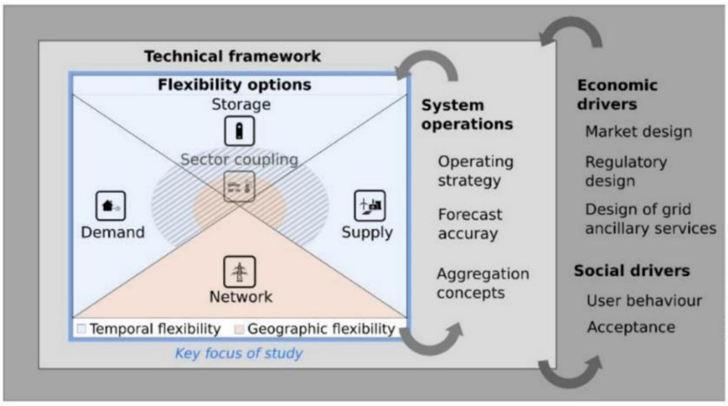


Figure 12: Various drivers that affect the utilization of flexibility options [23]

What can be said is that a mix of solutions will be required; for example, initial parts of the surplus production can be shaved via an electrolyser if there are enough peak hours and there is local demand for hydrogen (e.g., to industry or mobility). Higher peaks can be for example stored via battery and consumed at a later stage. The highest peaks which occur sporadically can be curtailed seeing how the implementation of assets to utilize them would be a waste of resources **(Figure 13)**.

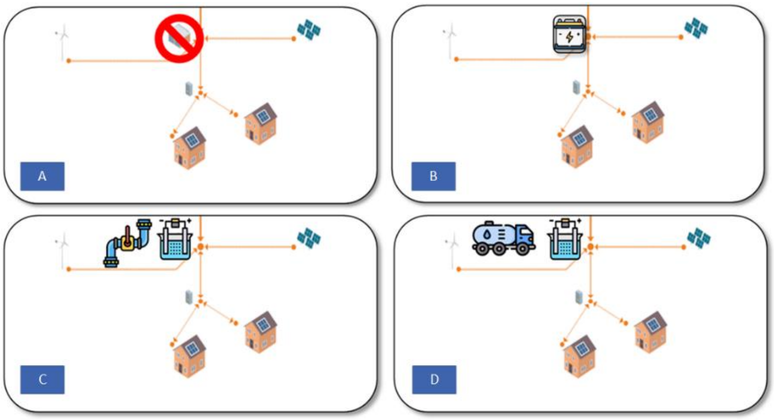


Figure 13: Flexibility techniques considered: A) Curtailment B) Battery Utilization C) Producing hydrogen via electrolyzers and injecting into the hydrogen network D) Producing hydrogen via electrolyzers and utilization by the mobility sector

Within the context of the aforementioned congestion management techniques, we will specifically look into how new additional capacities generated by a hypothetical solar farm could be integrated into the grid and what the congestion management techniques mean in terms of economic feasibility. This feasibility will be explored through a cost-benefit analysis approach where the various cost elements involved in these grid expansion activities will be calculated and an optimized solution will be given incorporating the different flexibility measures: hydrogen production via PtG, utility batteries, curtailment and grid expansion.

3.Methodology: Cost benefit analysis

3.1 Definition of a CBA and cost categories considered

In order to derive costs for the various short-term grid flexibility options and conventional grid expansion costs, a financial Cost Benefit Analysis in combination with optimization will be undertaken in this study. Cost–benefit analysis (CBA) provides an overview of the effects, risks and uncertainties of a measure and the resulting costs and benefits to society[4] as a whole [24]. By quantifying these advantages and disadvantages as much as possible and assigning values to them, CBA provides insights into the social-welfare effects of the measure, expressed as the balance in euros of the benefits minus the costs [24].

At the highest and simplest level, CBA has three major components (**Figure 14**) and can fit into the context of the objectives of this research via these steps [25]:

- **Estimation of the benefits** of the various grid flexibility techniques.
- **Estimation of the costs** of the various grid flexibility techniques.
- **Comparison of costs and benefits** for the various grid flexibility techniques.

Figure 14: General approach of a CBA study

The outcome of the CBA is a stacked bar-chart where categories of costs and benefits are classified and summed in order to yield the final costs and benefits for various categories. **Figure 15** provides a sample representation of what the results from a CBA calculation looks like.

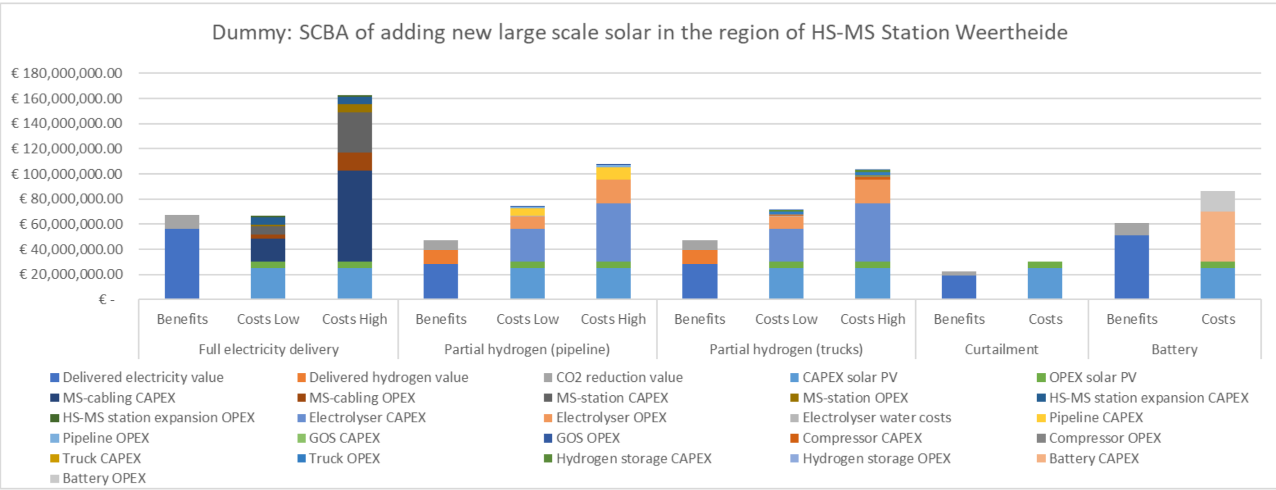


Figure 15: Sample outcome of a CBA (The results presented here are dummy results used for illustrative purposes)

For the purpose of this study, several cost and benefit categories were determined and classified and are presented in Table 4 and Table 5.

[4] The analysis done in this study does not focus on the social costs and benefits and is solely a financial CBA considering the costs and benefits for the DSO

Table 4: Various cost categories considered

Costs Categories			
RES and Electricity Infrastructure	**Hydrogen**	**Battery**	**Others**
• CAPEX of Solar PV • OPEX of Solar PV • CAPEX of MV Station • OPEX of MV Station • CAPEX of MV Cable • OPEX of MV Cable • CAPEX of HV-MV station expansion • OPEX of HV-MV station expansion	• CAPEX of Electrolyzer • OPEX of Electrolyzer • Water costs • CAPEX of compressor • OPEX of compressor • CAPEX of hydrogen storage tank • OPEX of hydrogen storage tank • CAPEX of RTL • OPEX of RTL • CAPEX of RNB • OPEX of RNB • CAPEX of trucks • OPEX of trucks	• CAPEX of Battery • OPEX of Battery	• Costs of land-use

Electricity and hydrogen are the commodities that are derived from the operation of implementing a solar farm and will serve as the benefit indicators of the CBA study. The benefits derived from the selling of hydrogen can be differentiated into hydrogen being provided to industry and the other to mobility.

Table 5: Benefits examined, consisting of the electricity and hydrogen sold to users.

Benefits Categories	
Electricity	Hydrogen
• Electricity provided by the solar PV park	• Hydrogen provided to industry • Hydrogen provided to mobility

3.2 Basis for the location of the study and design characteristics considered for the expansion of the grid

The CBA will be investigated by introducing a hypothetical decentralized 38MWp solar PV park. The details behind the selection of this capacity is mentioned in the next section. A conventional implementation of the solar farm would require a new connection to be made between the solar park and a MV transformer station. Unutilized MV cable capacities need to exist in order to transmit the electricity from the MV station to a HV-MV transformer station where incoming electricity from the HV grid is also introduced and stepped down in order to be distributed via the MV cable network. A figure of such an incorporation is represented in **Figure 16**.

Introduction of the solar farm evidently involves the expansion of the grid at certain points in order to accommodate for the increased capacities being transmitted. This expansion is signified by the "+" sign in **Figure 16** and these additional upgrades are considered within the green oval borders. This could potentially mean that either an existing MV station close to the solar park needs to be expanded, a new MV transformer unit needs to be installed or cable capacities need to be expanded. It's important to emphasize that the model used in our study does not determine whether the additional capacities for the expansion of the MV station should result in the building of a new MV station or expansion of the station and that this is to be interpreted based on standard practices that DSO's take to make these decisions, the same story applies to the additional capacities for the cables.

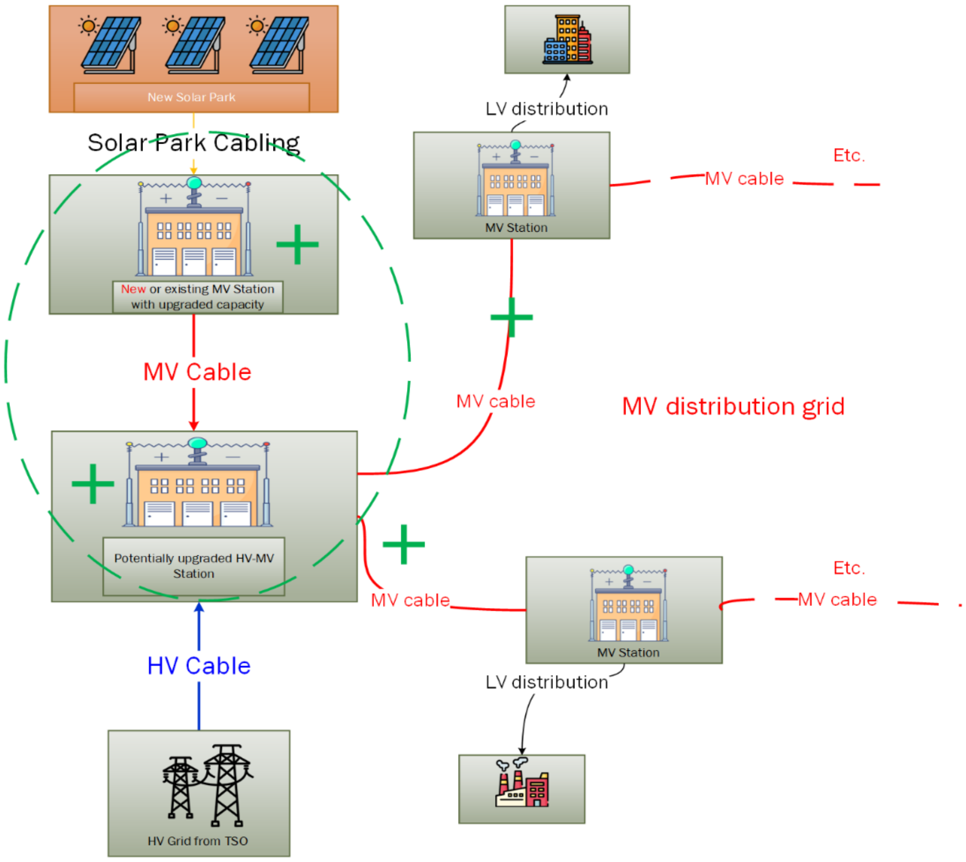


Figure 16: Expansion of the MV grid in order to accommodate for a new solar park due to a shortage of transmission capacity on the grid involves the expansion of HV/MV stations and/or the installation/expansion of new/existing MV stations and MV cables.

It is also of interest to see how various large-scale load bearing sources such as electrolyzers and utility-scale batteries can be accommodated right next to the installation of the new solar PV park and what that introduction means for the expansion activities of the grid in terms of costs and benefits. The involvement of these flexibility options could reduce the required MV-station and MV-cable capacity upgrades and potentially circumvent capacity upgrades required for HV-MV stations. Ideally this could lead to a reduction in grid expansion costs and an increased utilization of PtG system. **Figure 17** provides an illustration of what such a network. The expansions are signified by the "+" sign and affect the MV stations and also the additional cable capacities that need to be installed. These additional upgrades are considered within the green oval borders.

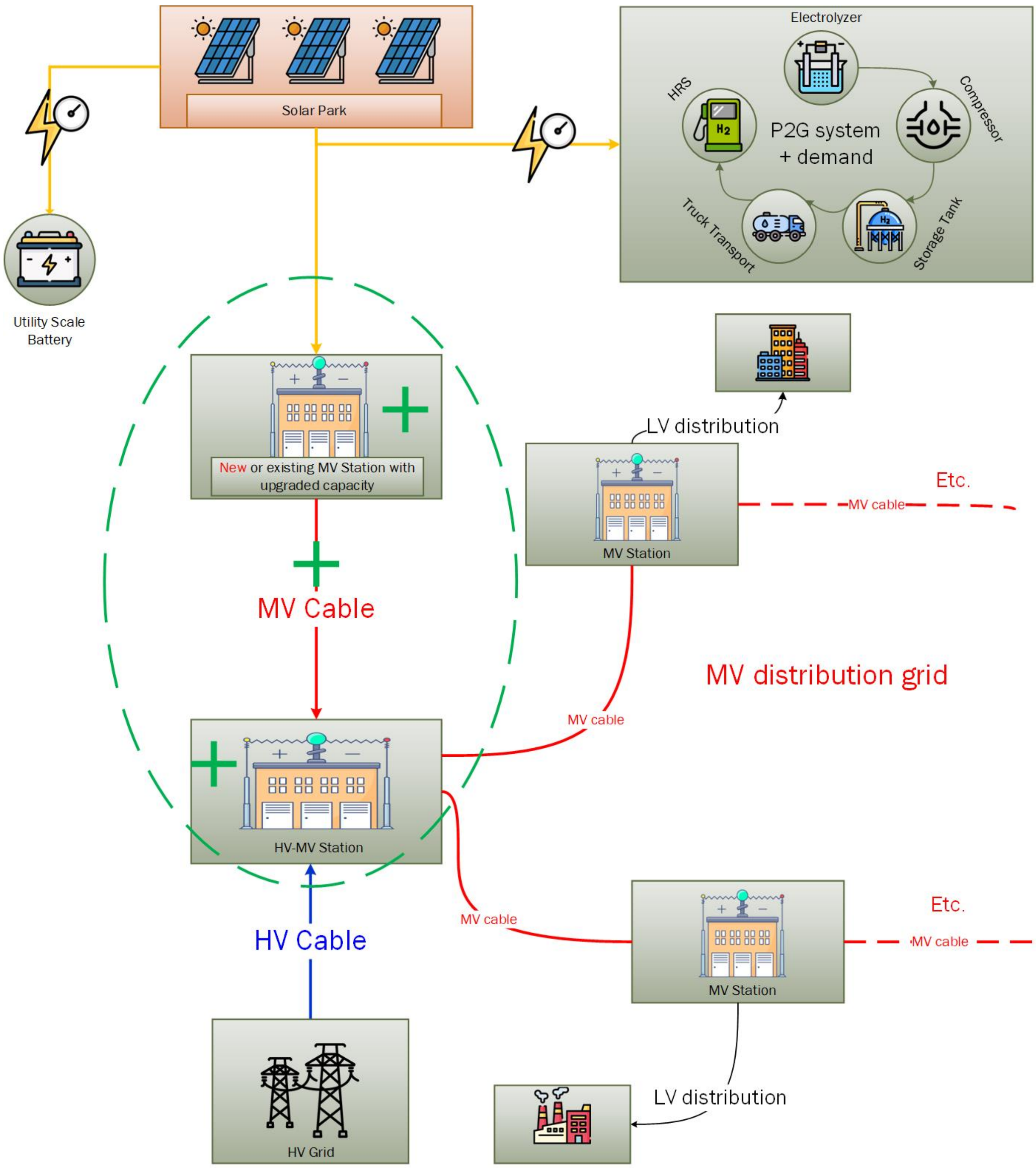


Figure 17: Introduction of a mix of solutions to deal with the congestion introduced via the installation of a new solar farm.

3.3 Model description

A model has been developed to investigate the costs and benefits of connecting a new solar park in the range of 5-50 MW using a combination of different options. The model is an MILP model that makes decisions on how to connect the new solar field maximizing the annualized net benefits. Two versions of the model have been created: one in which the new solar park can only be connected by expanding the local electricity grid (similar to the current obligation of grid operators to connect new customers) and one in which more freedom is given to consider multiple options next to expanding the grid, such as a combination of curtailment, installing a battery, or installing an electrolyser to serve demand for hydrogen.

First, it will be explained what calculations are made in the model. Secondly, the input data will be described. Finally, the decision variables and objective function are explained.

3.3.1 General explanation of calculations

The model assumes that the new solar park is connected via a MV-station and MV-cable to the HV-MV station (as shown in **Figure 17**). Scaling the MV-station and MV-cable is quite straightforward. However, the significant HV-MV station expansion depends on the degree in which the new solar park contributes to additional 'exports' of electricity from the regional distribution grid to the national high voltage transmission grid. Therefore, regional electricity supply and demand patterns are used to simulate how much electricity is imported or exported from and to the national electricity transmission grid. **Figure 18** shows two indicative examples of how the local electricity supply and demand patterns determine the power requirements of the HV-MV station for each hour during the year, and thereby the required station capacity[5]. The left side of the figure shows an indicative situation in which the station capacity is sufficient to import and export electricity from and to the national transmission grid anytime. The right side of the figure shows an indicative situation after a very large solar park would have been connected without expanding the HV-MV station capacity. For these types of situations the model decides if it is beneficial in terms of overall stakeholders costs and benefits to expand the HV-MV station or apply (a combination of) alternative solutions to integrate the new solar park into the local energy system.

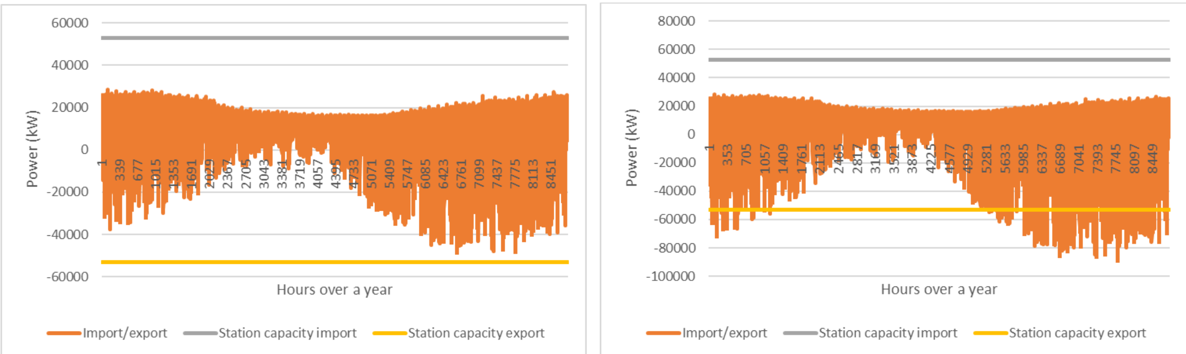


Figure 18: Example of the regional electricity supply and demand on the HV-MV stations' required capacity

3.3.2 Parameters and input data

Three types of input parameters are used inside the model: input data on regional characteristics, (such as installed PV, electricity demand, HV-MV station capacity, etc.), hourly input data for the one year time period and techno-economic parameters of the technical equipment. In this order the assumed input data is discussed.

As discussed in section 3.2, the regional characteristics were based on a typical situation of a local electricity grid in which a relatively large solar field was planned to be installed. Due to the lack of specific data on future cases in which this could take place, we based the expansion situation on Oosterwolde region in 2019. In this region a large scale solar PV park of 50 MWp was planned [26]. The HV-MV station in this region had to be expanded to connect this new solar park. This region initially

[5] In reality the DSO scales the station capacity on a risk analysis based on historical experience of consumer and producer behaviour in the region. Since we do not have this data, the model scales the station based on the simulated production and consumption patterns. As we do this equally for scaling the required electrolyser, battery and grid capacities, a fair comparison can be made between the different solutions.

contained 37.2 MWp of solar capacity and a HV-MV station of 53 MVA[6] [27]. Since in practice the electricity grid capacity is based on contracted capacity and a risk analysis, instead of the actual required capacity (which is the assumption in our model in order to compare grid expansions equally with the alternative solutions) we changed the initial capacities of the existing HV-MV station to 29 MVA and the initial solar capacity to 49.2 MW. This would be the existing HV-MV station capacity without any risk analysis and the solar capacity that makes this station ''full'' but not overloaded. Hence, in this situation the HV-MV station capacity was fully utilized. For the remaining new 38 MWp of solar capacity, we left it open to the model on how to integrate the electricity generated by this solar capacity (by either expanding the electricity grid, installing a battery or electrolyser, or curtailing the electricity). In the baseline scenario we assume an equal distance from the solar park to the HV-MV station as from the solar park to the hydrogen demand.

Table 6: Overview input data on regional characteristics assumed

Parameter	Unit	Value	Remark
Initial solar PV capacity	MWp	49.2	Existing solar capacity [28] plus new solar capacity that could be integrated without expanding the HV-MV station
New added solar PV capacity	MWp	38	Remaining solar capacity from the new 50 MWp solar park to be integrated [26]
Initial HV-MV station capacity	MVA	29	Based on maximum used HV-MV station capacity under assumed initial PV capacity and demand
Annual electricity demand of small users (KVB) connected to the distribution grid	GWh	65	Based on the 2020 standard annual usage (SJV) of small user connections in this area [29]
Annual electricity demand of large users (GVB) connected to the distribution grid	GWh	53	Unknown for Oosterwolde in 2019, based on contracted demand in similar sized region: Wolvega [30]
Potential annual local hydrogen demand for mobility applications (HRS)	Tonnes	109.5	Based on annual delivery of one HRS with capacity of 400 kg/day, utilized for 75% [31]
Distance solar park to HV-MV station	km	10	General assumption
Distance solar park to hydrogen demand/grid connection	km	10	General assumption

The hourly data consists of: hourly electricity and hydrogen prices; solar generation pattern; electricity demand patterns for small users (KVB) and larger users (GVB); and maximum (local) hydrogen demand. The data and sources are summarized in Table 7.

Table 7: Overview input data with hourly interval

Parameter	Unit	Indicative value	Source
Solar generation	Load factor	815 full load hours	Based on KNMI weather data
Electricity day ahead price projection 2030	€/kWh	Avg. 0.67 €/kWh	NSE4 [32]
Water costs	€/m^3	Always 0.728 €/m^3	OASEN

[6] VA: volt-ampere. 1 VA = 1W.

Hydrogen 2030 wholesale price projection supply to backbone and/or industry	€/kg	Avg. 2 €/kg	NSE4 [32]
Hydrogen willingness-to-pay mobility	€/kg	Always 7 €/kg	Assumption based on costs/km driving with diesel price of 1.35 €/l
Local electricity demand small users (KVB)	kWh	Seasonal pattern	Based on average household usage [33]
Local electricity demand large users (GVB)	kWh	Weekly pattern	Industry pattern [31]
Maximum hydrogen demand industry	kg	Constant 10 kg/h	350 TJ/y gas demand
Maximum hydrogen demand mobility	kg	Weekly pattern	Mobility pattern [31]

An overview of the techno-economic assumptions of the involved assets is provided in Table 8. The techno-economic data on the installations within the model are as much as possible retrieved from the expert and literature assumptions used by the Dutch SDE++ subsidies and the Dutch grid operators, as these values are assessed to be representative for the current situation in the Netherlands. If costs are in kW or kg, the total CAPEX per unit is calculated for the assumed size of a single unit. As a linear model is used, no scaling factor for installations is applied.

Table 8: Overview of input data for installations

Installation	Capacity (unit)	CAPEX (unit)	Fixed OPEX (% of CAPEX/y)	Lifetime (years)	Spatial usage (m^2/unit)	Source
Solar panel	0.31 kWp	€ 131	2.1%	25	3.33	[34]
Electrolyser + BOP + grid connection	100 kW	€ 180,000	2.1%	15	53	[34]
Compressor (to 200 bars)	100 kW	€ 267,700	5%	15	24	[35]
Compressed H2 storage tank (200 bars)	250 kg	€ 135,000	2%	25	30	[35]
Tube trailer filling facility	335 kg/h	€ 100,000	2%	10	220	[36]
Battery	100 kW	€ 20,000	1.4%	20	15	[34] [37]
MV cable	1000 kW/m	€ 12.5	2%	30	0.5	[3] [38]
MV station	1000 KVA	€ 300,000	2%	30	84	[39] [3]
HV-MV station	1000 KVA	€ 250,000	2%	30	275	[3]
RTL pipeline (re-purposed)	4100 kg_H2/h/m	€ 150	5.6%	40	1.75	[39] [40]
RNB pipeline	220 kg_H2/h/m	€ 13.5	62%	40	1.75	[41] [40]
Truck + gH2 trailer	670 kg_H2/trip	€ 710,000	4.5%	10	0	[42]

Next to the data provided in the table, the following aspects should be mentioned:

- The electrolyser and balance of plant already includes compression capacity; additional compression capacity to 200 bars is only installed if hydrogen has to be stored and transported via tube trailers.
- For the electrolyser and balance of plant system 57.8 kWh of electricity and 0.01 m^3 water is required to produce 1 kg of hydrogen [34]. The additional compressor uses 2 kWh of electricity and 0.001 m^3 of water to compress the hydrogen to 200 bars.
- The tube trailer filling facility is equal to a dispenser that enables the hydrogen to be released from the storage into the tube trailer.
- For the battery, the assumption is made that a 100kW battery could store 200kWh of electricity. Hence, that full storage capacity can be achieved in 2 hours which is typical for batteries available in the market [34]. For charging and discharging each an efficiency of 95% is assumed and the self-discharge is assumed to be 5% per month [37].
- Sizes of 1000 KVA or 1000 kW are not typical for HV-MV stations (20-300 MVA) or MV cables (5-20 MW). We use these unit size such that capacities can be scaled close to optimal sizes. This makes our results less dependent on available unit sizes (e.g. if we would assume a unit size of 20 MW per cable, the model must install 40 MW of capacity in a situation when only 21 MW is needed. While in reality an option of a 10 MW and 11 MW cable might also be an option).
- For the RTL and RNB pipelines techno-economic characteristics of re-used pipeline sections are assumed. In the calculation of the RTL pipeline capacity a diameter of 20 cm, hydrogen transport at 40 bars and a velocity under 20 m/s was considered. In the calculation of the RNB pipeline capacity a diameter of 11 cm, hydrogen transport at 8 bars and a velocity under 7 m/s was considered. Given the use of existing pipelines there is no flexibility in scaling the diameter of the pipes.
- KIWA investigated that if 37% of the distribution grid would be converted to hydrogen, the conversion would cost 678 M€ and 422 M€ of annual costs to maintain it [41]. Based on these numbers, and given the total length of the Dutch distribution grid of 134 thousand kilometres, we estimated the costs to convert one meter of distribution grid on €13.5 and 62% of annual maintenance costs.
- For hydrogen transport by truck, additional assumptions are made on the average driving speed (40 km/hour), (un)loading time (1.5 hours), utilization of the truck (50%), fuel price (€1.35/litre diesel), fuel consumption (0.35 litre/km) and driver wage costs (€35/hour) [42].
- The baseline scenario assumes that all hydrogen transport options are available (e.g. pipe sections available for re-use). The implications on the results will be discussed if certain location specific options for re-use are not available.

3.3.3 Decision variables and objective function

Based on the parameter values and the constraints, the model determines several capacity and operational decisions in order to maximize the net annual benefits from an overall stakeholder perspective. An overview of the decision variables is shown in Table 9. The hourly decision variables are the operational decisions, for example what to do with the generated kilowatt hours of electricity at any given moment: is it stored in the battery, used for hydrogen conversion, transported via the electricity grid or curtailed? **The constraints in the model do determine that for example no more hydrogen can be sold than is demanded at any moment**; that the amount of hydrogen produced should be equal to the right amount of electricity utilized at the same period and to balance all the flows throughout the installations. The capacity decision variables determine the optimal amount of capacity to be installed for each type of installation and infrastructure, such as the electricity grid (cables, stations) the electrolyser and hydrogen transport modes and the battery. **Constraints determine that the installed capacities cannot be exceeded**, for example that the electrolyser cannot utilize more electricity than capacity is installed.

An important note is that since we do analyse the involvement of the electrolyser as alternative for electricity grid expansion from a multiple stakeholder cost-benefit perspective, in our baseline scenario we consider that the electrolyser uses electricity from the solar park only and not from the grid. In one of the sensitivities we show what happens if the electrolyser is also allowed to use grid electricity.

Table 9: Overview of decision variables of the model used

Hourly decision variables ***(for t=1:8760 hours, continuous and non-negative values)***
1. The amount of generated solar electricity (kWh) transported via the electricity grid in hour *t* 2. The amount of generated solar electricity (kWh) curtailed in hour *t* 3. The amount of electricity (kWh) utilized in the electrolyser in hour *t* 4. The amount of electricity (kWh) utilized in the additional compressor (200 bars) in hour *t* 5. The amount of electricity (kWh) used to charge the battery in hour *t* 6. The amount of electricity (kWh) discharged from the battery in hour *t* 7. The amount of electricity (kWh) stored in the battery during hour *t* 8. The amount of electricity (kWh) from the battery transported to the electricity grid in hour *t* 9. The amount of electricity (kWh) from the battery utilized in the electrolyser in hour *t* 10. The amount of water (m^3) utilized in the electrolyser in hour *t* 11. The amount of water (m^3) utilized in the additional compressor (200 bars) in hour *t* 12. The amount of hydrogen (kg) produced by the electrolyser in hour *t* 13. The amount of hydrogen (kg) compressed by the compressor in hour *t* 14. The amount of hydrogen (kg) stored in the compressed tank 1 (at electrolyser location) during hour *t* 15. The amount of hydrogen (kg) transported via the RNB pipeline section during hour *t* 16. The amount of hydrogen (kg) transported via the RTL pipeline section during hour *t* 17. The amount of hydrogen (kg) starting to be transported via the truck during hour *t* 18. The number of trucks (#) returning from its previous trip during hour *t* 19. The amount of hydrogen (kg) stored in the compressed tank 2 (at truck destination location) during hour *t* 20. The amount of hydrogen (kg) delivered to industry/the backbone in hour *t* 21. The amount of hydrogen (kg) delivered to mobility in hour *t*
Capacity decision variables ***(for k=1:12 types of installations, integer and non-negative values)***
1. The amount of units installed for installation *k* 2. Opening decision variable for installation *k* (especially to facilitate the constraints for the transportation options: if a certain cable or pipeline capacity is installed, it should be done over the whole required transport distance)

The objective of the model is to maximize the net annual benefits, which are obtained by subtracting the total annualized costs from the total annualized benefits. The annualized costs and benefits metric is used instead of the net present costs and benefits for two reasons:

1. Using the Capital Recovery Factor (CRF) makes possible to retrieve the annualized costs of deploying one specific unit of an asset. This is necessary, because in this way both the operational and investment decisions can be considered during the optimization of the costs and benefits. The discounting function is non-linear and therefore would ask for a non-linear model instead of the linear modelling approach that was used. Using the annualized costs provides the opportunity to take discounting into account before we start the optimization.

Box 1: Background information on calculating the annualized capital costs

The annuity of each asset is determined by multiplying the capital recovery factor (CRF) with the total investment costs. The total investment costs are the amount of units installed for a specific type of installation *k* (x_k) multiplied by the investment costs for a single unit of *k* (see Table 9). The CRF can be calculated by the second part of the formula, where *i* is the interest rate and *n* is the number of annuities (i.e. the lifetime of installation *k*). In this study an interest rate of 2% is used.

$$Annuity_k = x_k \times investmentcosts_k \times \frac{i(1+i)^n}{(1+i)^n - 1}$$

2. The scope of our cost-benefit analysis involves multiple stakeholders that have different investment cycles and types of assets. In other words, we compare two situations in which multiple stakeholders make investment and operational decisions together for the sake of maximizing the mutual costs and benefits. Using the annualized costs and benefits approach makes it possible to equally compare costs related to the different asset lifetimes and investment cycles [43].

Box 2: Example illustration of how annualized cost cash flows equal the actual cost cash flows that are typically used to calculate a NPC or NPV

In order to show how the annualized costs and benefits relate to the NPV or NPC, and how investment costs of assets with different lifetimes can be compared, a simple illustration is presented in Table 10. The table shows the cash flows of the CAPEX and fixed OPEX for 1 MW electrolyser capacity (using similar techno-economic assumptions as in our study). The column of the actual cash flow costs shows the CAPEX in year 0 and the fixed OPEX in year 1 until 15. The equivalent cash flow shows the cash flow using annualized costs: the capital investments are already spread out equally over the lifetime (by the Capital Recovery Factor) in such a way that if we discount these costs, we get the same NPC at the predefined period. Using the annualized costs makes us able to compare assets with different characteristics (long/short lifetime, low/high capital or operational costs) fairly while still including the hourly operational aspects.

Table 10: Representation of the actual cash flow of the CAPEX and fixed OPEX of a 1 MW electrolyser under our techno-economic assumptions, and the equivalent cash flow using the annualized costs

		Actual cash flow of costs		**Equivalent cash flow using annualized costs**	
Year (*n*)	**Discount factor (*i*=0.02)**	**Nominal**	**Discounted**	**Nominal**	**Discounted**
0	1	€ 1,800,000	€ 1,800,000	€ -	€ -
1	0.980	€ 38,000	€ 37,255	€ 178,086	€ 174,594
2	0.961	€ 38,000	€ 36,524	€ 178,086	€ 171,171
3	0.942	€ 38,000	€ 35,808	€ 178,086	€ 167,814
4	0.924	€ 38,000	€ 35,106	€ 178,086	€ 164,524
5	0.906	€ 38,000	€ 34,418	€ 178,086	€ 161,298

6	0.888	€ 38,000	€ 33,743	€ 178,086	€ 158,135
7	0.871	€ 38,000	€ 33,081	€ 178,086	€ 155,034
8	0.853	€ 38,000	€ 32,433	€ 178,086	€ 151,995
9	0.837	€ 38,000	€ 31,797	€ 178,086	€ 149,014
10	0.820	€ 38,000	€ 31,173	€ 178,086	€ 146,092
11	0.804	€ 38,000	€ 30,562	€ 178,086	€ 143,228
12	0.788	€ 38,000	€ 29,963	€ 178,086	€ 140,419
13	0.773	€ 38,000	€ 29,375	€ 178,086	€ 137,666
14	0.758	€ 38,000	€ 28,799	€ 178,086	€ 134,967
15	0.743	€ 38,000	€ 28,235	€ 178,086	€ 132,320
NPC			**€ 2,288,272**		**€ 2,288,272**

The objective function covering the financial costs and benefits related to the scope of this research is presented below:

$$Annual\ net\ benefits = annualized\ benefits - annualized\ costs$$

The annualized benefits represent the value for the delivered electricity to the grid, the delivered hydrogen to users connected to the centralized hydrogen system (a national hydrogen network and local industrial users connected to this infrastructure) and hydrogen delivered to local mobility end users decoupled from the central hydrogen network.

$$\begin{aligned} Annualized\ benefits & \\ &= total\ benefits\ of\ additional\ delivered\ electricity \\ &+\ total\ benefits\ of\ additional\ delivered\ hydrogen \end{aligned}$$

The annualized costs represent all the additional costs that have to be made by stakeholders to deliver the additional electricity and hydrogen to the electricity grid or hydrogen grid/end users. This includes the annualized investment costs in the assets, fixed maintenance costs and the costs of land. Also, some assets include variable OPEX such as the water usage for the electrolyser and the compressors; and the fuel used if trucks are used to transport hydrogen. The electricity used in the electrolyser, batteries and the compressors is used directly from the additional solar capacity, and therefore does not generate costs from the overall stakeholder perspective, but decreases the potentially delivered electricity (and so decreases the potential benefits from delivering electricity).

$$Annualized\ costs = total\ annualized\ investment\ costs + total\ fixed\ maintenance\ costs + total\ water\ costs + total\ fuel\ costs\ for\ truck\ transport + total\ costs\ of\ spatial\ use$$

4. Results

4.1 Annual costs and benefits by traditionally expanding the grid

Figure 19 presents the annualized costs and benefits derived from expanding the grid through the incorporation of new solar capacity (additional 38MWp) onto the grid while Table 11 details the costs and benefits for each of the assets. It can be clearly seen that the derived benefits are less than the costs; benefits derived only consist of the annual electricity that is sold since it is the only energy commodity that is generated under this scenario and 100% of it is sent to the grid. A significant portion of the costs are related to the capital and operational expenditures of the solar PV park while the CAPEX and OPEX of MV station expansion and capacity expansions to the HV-MV grid also importantly contribute to the share of costs. Land-use costs also contribute significantly and consist of the spatial impact of the solar park and the electricity grid infrastructure such as the stations and the cables, this is shown in **Figure 20**.

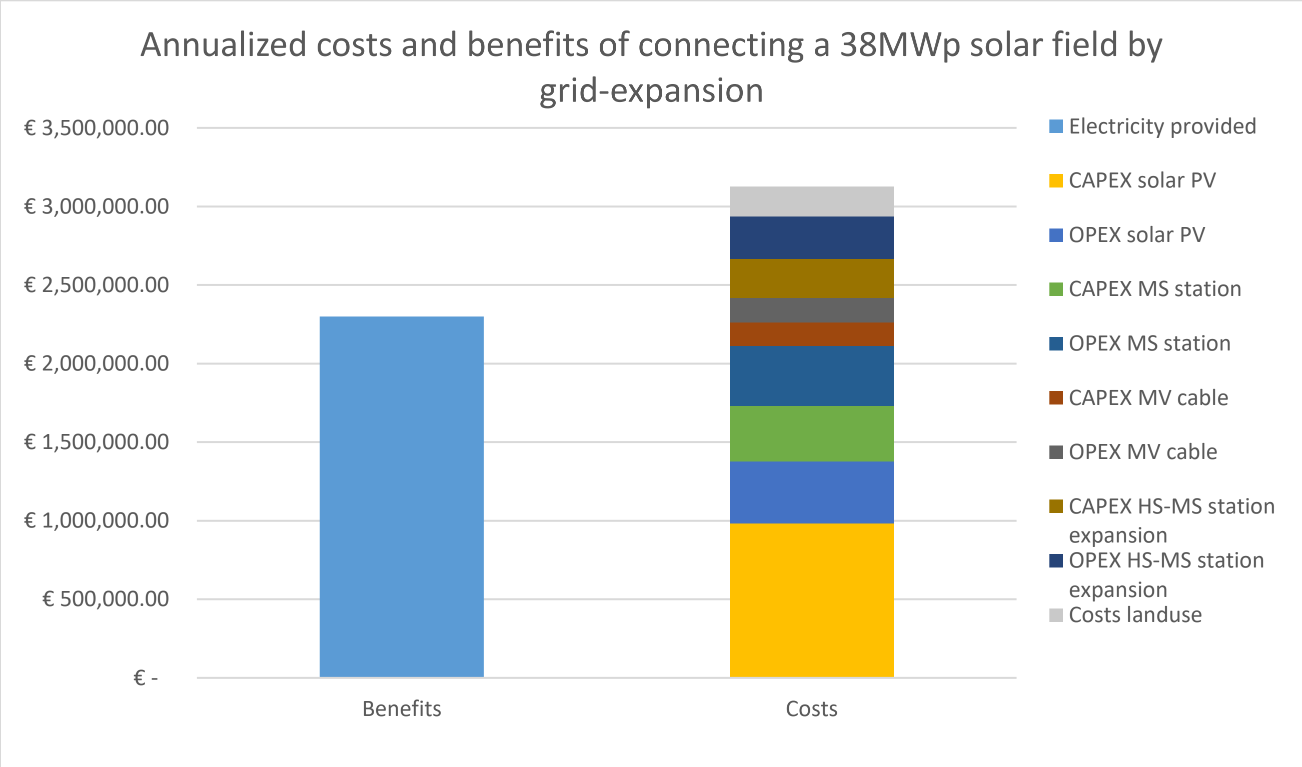


Figure 19: Annualized costs and benefits of connecting a 38MWp solar park by traditionally expanding the grid

Table 11: Infrastructure costs per asset and overall Costs and Benefits of expanding the grid

Category	Benefits	Costs	Δ: B - C
Electricity provided	€ 2,298,167.27	€ -	
CAPEX solar PV	€ -	€ 982,915.04	
OPEX solar PV	€ -	€ 395,387.92	
CAPEX MV station	€ -	€ 350,935.18	
OPEX MV station	€ -	€ 384,000.00	
CAPEX MV cable	€ -	€ 146,222.99	
OPEX MV cable	€ -	€ 160,000.00	

CAPEX HV-MV station expansion	€ -	€ 246,751.30	
OPEX HV-MV station expansion	€ -	€ 270,000.00	
Costs land-use	€ -	€ 189,895.23	
Total	**€ 2,298,167.27**	**€ 3,126,107.66**	**€ - 827,940.39**

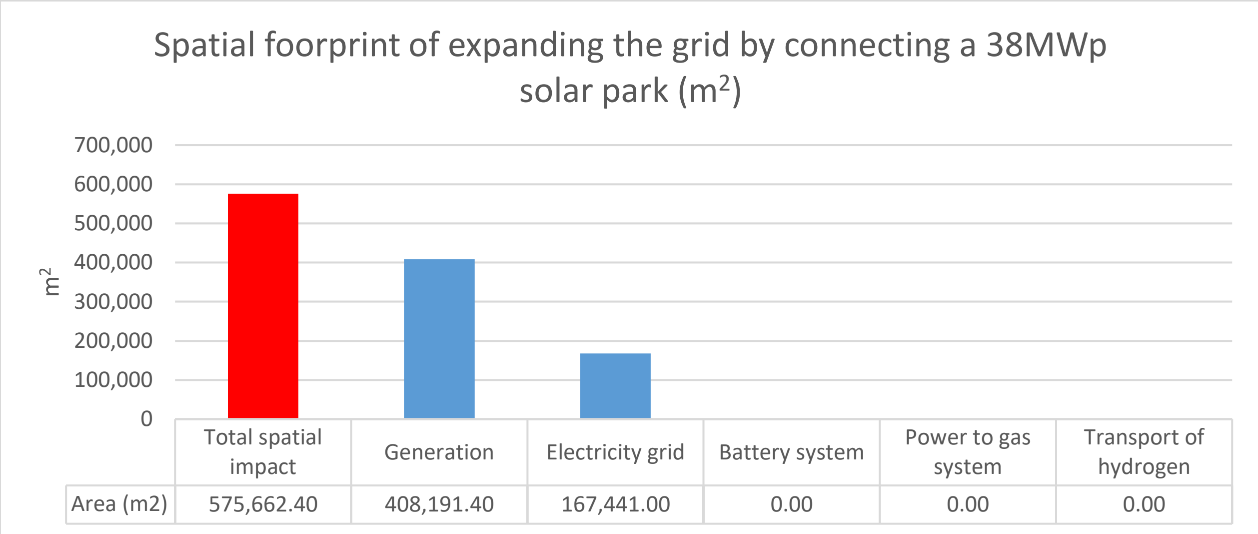


Figure 20: Spatial footprint of traditionally expanding the grid

4.2 Annual costs and benefits related to the implementation of various grid flexibility solutions

Figure 21 represents the annualized costs and benefits of incorporating the solar PV park into the electricity infrastructure via a mix of solutions. We can see that the difference between the annualized costs and benefits are significantly reduced; this is due to the increased benefits achieved by the selling of hydrogen to the mobility sector. The measure of benefits derived from hydrogen usage is based on the 7€/kg willingness-to-pay price for mobility applications, utilization of hydrogen for industrial purposes is not considered since less benefits would be derived from the conversion of electricity to hydrogen for this purpose and hence the model chooses the most optimal financial outcome. Transportation of hydrogen to the hydrogen refuelling station is done via the 8-bar RNB pipeline. In this case the pipeline is re-used and refurbished however the costs of re-purifying the hydrogen via transmission through a re-purposed grid for mobility usage at an HRS station is not considered.

Table 12 lists the various costs for each asset reflected in the expansion. Costs presented in this condition consist of the many categories involved in our mix of grid flexibility solutions such as CAPEX and OPEX of electrolyzers, compressors for the compression of hydrogen, utilization of hydrogen in storage tanks and costs related to the transport of hydrogen via the RNB grid. **Figure 22** represents the spatial impacts of this combination of solutions in which the total spatial impact is roughly 100,000 m^2 compared to the spatial footprint of traditionally expanding the grid.

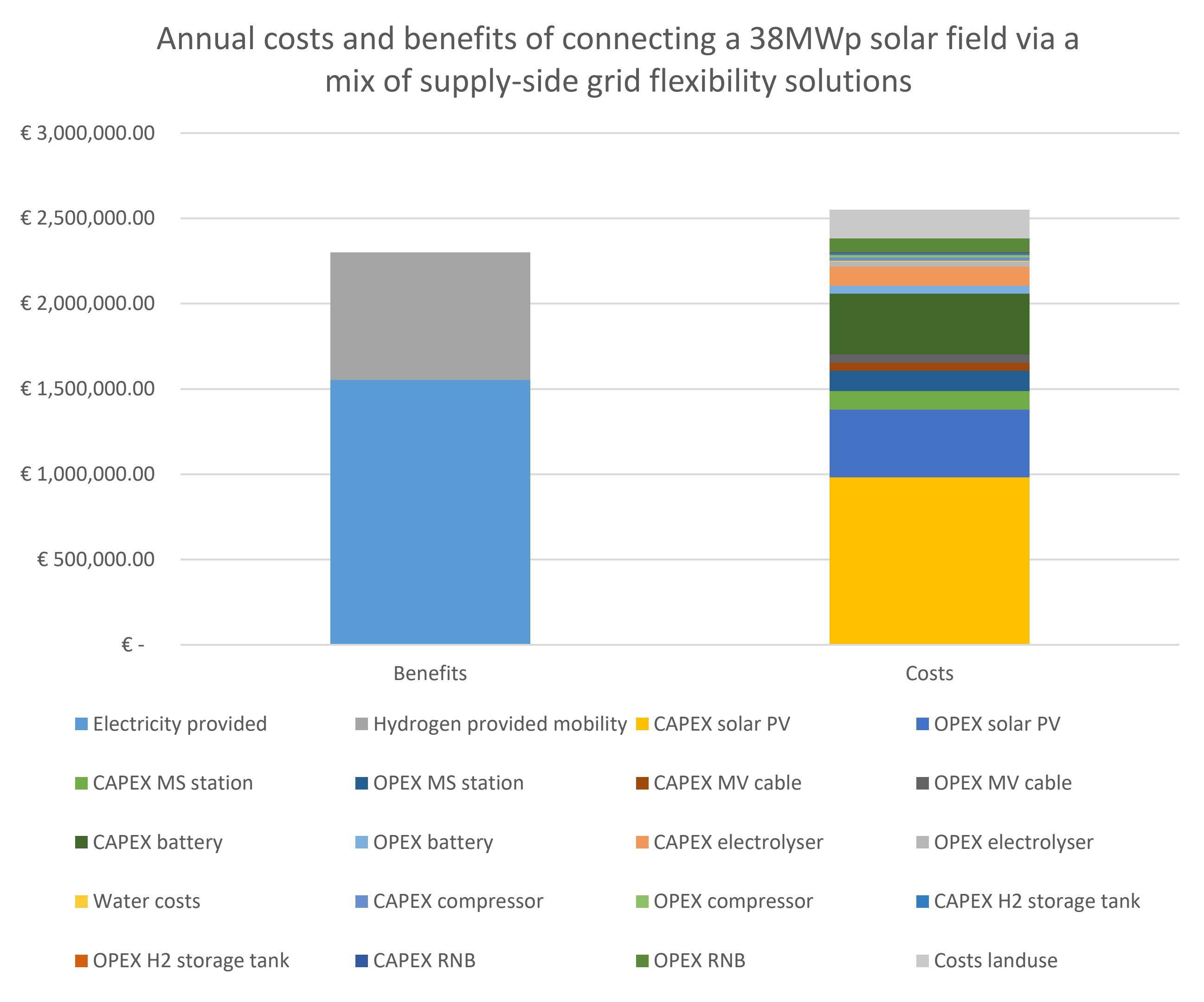


Figure 21: Annualized costs and benefits of connecting a 38MWp solar park by implementing a mix of grid flexibility options

Table 12: Infrastructure costs per asset and overall Costs and Benefits of expanding the grid via a mix of grid flexibility options

Category	Benefits	Costs	Δ: B - C
Electricity provided	€ 1,552,838.95	€ -	
Hydrogen provided mobility	€ 746,923.67	€ -	
CAPEX solar PV	€ -	€ 982,915.04	
OPEX solar PV	€ -	€ 395,387.92	
CAPEX MV station	€ -	€ 109,667.24	
OPEX MV station	€ -	€ 120,000.00	
CAPEX MV cable	€ -	€ 45,694.68	
OPEX MV cable	€ -	€ 50,000.00	
CAPEX battery	€ -	€ 356,244.89	
OPEX battery	€ -	€ 45,120.00	
CAPEX electrolyzer	€ -	€ 112,068.68	
OPEX electrolyzer	€ -	€ 30,400.00	
Water costs	€ -	€ 4,351.44	
CAPEX compressor	€ -	€ 20,833.88	

OPEX compressor	€ -	€ 13,385.00	
CAPEX H2 storage tank	€ -	€ 6,914.76	
OPEX H2 storage tank	€ -	€ 2,700.00	
CAPEX RNB	€ -	€ 4,935.03	
OPEX RNB	€ -	€ 83,700.00	
Costs land use	€ -	€ 165,966.85	
Total	**€ 2,299,762.62**	**€ 2,550,285.41**	**€ -250,522.78**

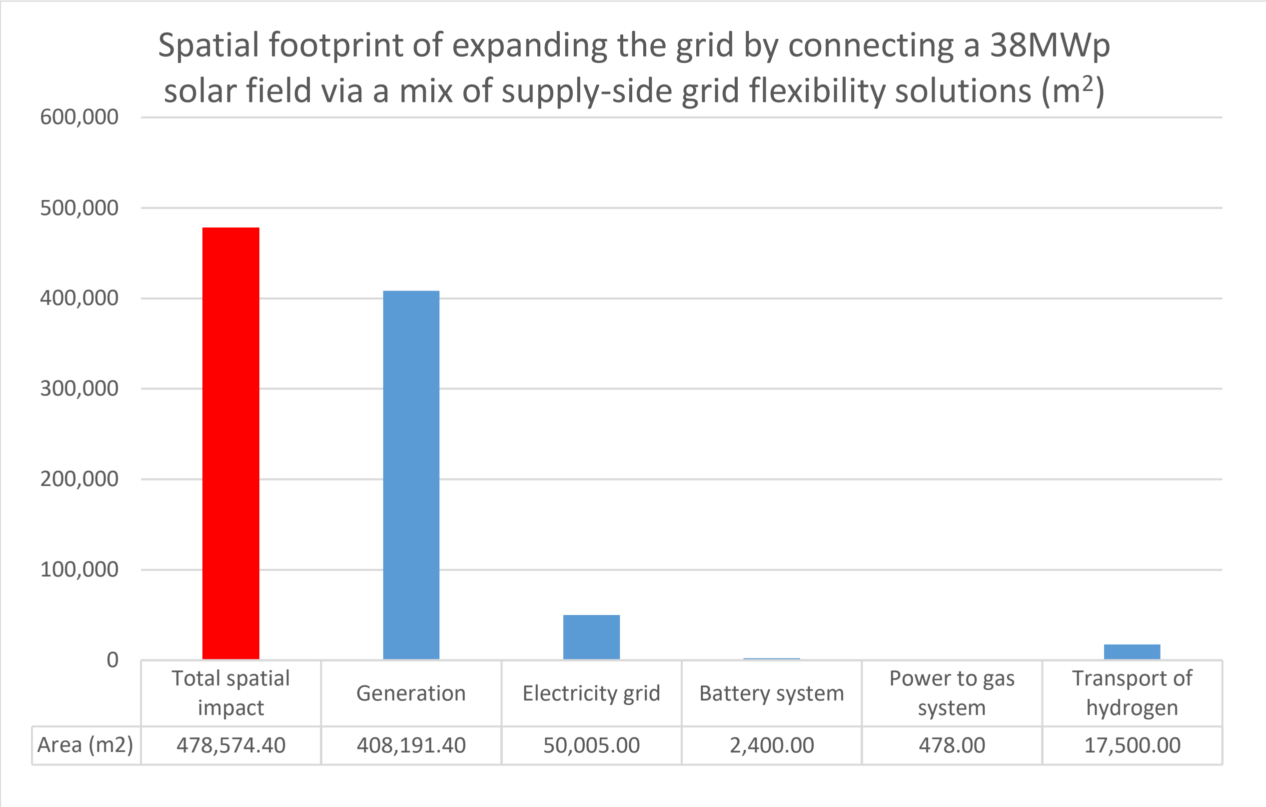


Figure 22: Spatial footprint of each activity in a mixed solution approach

With a mix of grid flexibility solutions implemented, it is also of interest to see the share of electricity provided for each of these solutions. **Figure 23** displays the utilization percentage for each of these components: 20% of electricity is curtailed, 15% is sent to the electricity grid, 30% is stored via battery, 18% is converted by the electrolyzer for hydrogen production while 17% is employed by the electrolyzer in combination with a battery; hence with a battery in the process the electrolyzer is utilized 35% of the time.

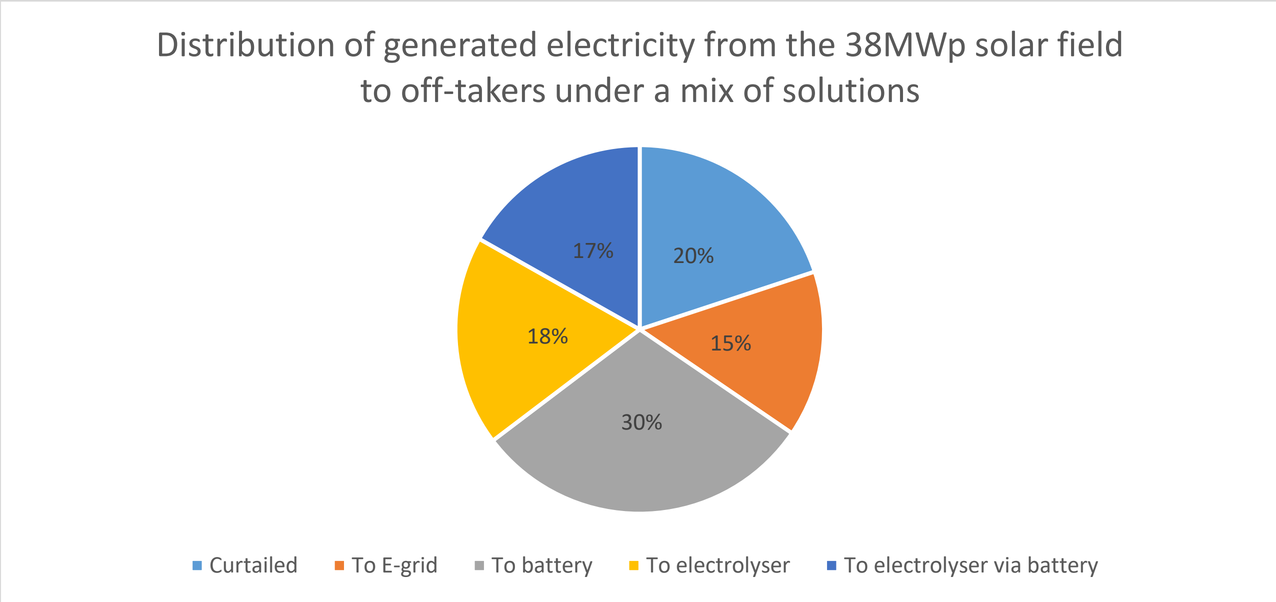
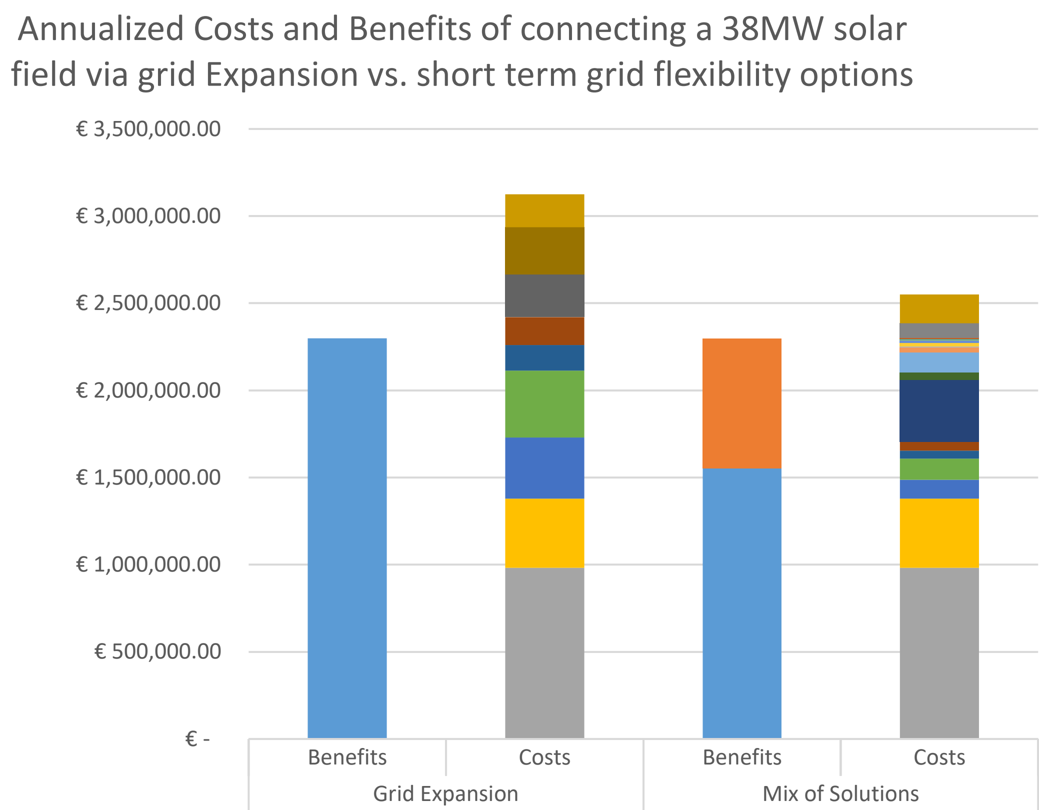


Figure 23: Distribution of electricity utilization thru the utilization of a variety of congestion management techniques.

For a better visual comparison, **Figure 24** depicts the costs and benefits for the two main scenarios. Annual asset costs prove to be less by applying a mix of grid flexibility solutions while the benefits for both methods are the same; this is however coincidental in this case and is dependent on factors affecting demand and the willingness-to-pay for hydrogen that exists.



	Grid Expansion – Benefits	Grid Expansion – Costs	Mix of Solutions – Benefits	Mix of Solutions – Costs
Costs landuse	€ -	€ 189,895.23	€ -	€ 165,966.85
OPEX RNB	€ -	€ -	€ -	€ 83,700.00
CAPEX RNB	€ -	€ -	€ -	€ 4,935.03
OPEX H2 storage tank	€ -	€ -	€ -	€ 2,700.00
CAPEX H2 storage tank	€ -	€ -	€ -	€ 6,914.76
OPEX compressor	€ -	€ -	€ -	€ 13,385.00
CAPEX compressor	€ -	€ -	€ -	€ 20,833.88
Water costs	€ -	€ -	€ -	€ 4,351.44
OPEX electrolyser	€ -	€ -	€ -	€ 30,400.00
CAPEX electrolyser	€ -	€ -	€ -	€ 112,068.68
OPEX battery	€ -	€ -	€ -	€ 45,120.00
CAPEX battery	€ -	€ -	€ -	€ 356,244.89
OPEX HS-MS station expansion	€ -	€ 270,000.00	€ -	€ -
CAPEX HS-MS station expansion	€ -	€ 246,751.30	€ -	€ -
OPEX MV cable	€ -	€ 160,000.00	€ -	€ 50,000.00
CAPEX MV cable	€ -	€ 146,222.99	€ -	€ 45,694.68
OPEX MS station	€ -	€ 384,000.00	€ -	€ 120,000.00
CAPEX MS station	€ -	€ 350,935.18	€ -	€ 109,667.24
OPEX solar PV	€ -	€ 395,387.92	€ -	€ 395,387.92
CAPEX solar PV	€ -	€ 982,915.04	€ -	€ 982,915.04
Hydrogen provided mobility	€ -	€ -	€ 746,923.67	€ -
Electricity provided	€ 2,298,167.27	€ -	€ 1,552,838.95	€ -

Figure 24: Comparison of annualized costs and benefits of a traditional grid expansion method versus a mix of grid-flexibility solutions

4.3 Sensitivity analysis

Based on the two costs and benefit values that have been determined so far, it would also be of value to consider how changing certain parameters impact these costs and benefits and whether in some circumstances the benefits could outweigh the costs. These parameters could consist of:

- The role that altering distances could play:
    - Between the solar PV park and the HV/MV station (via increasing and decreasing the kilometres of cable laying)
    - Hydrogen transport from production site to Hydrogen Refuelling Station (via increasing and decreasing the length of the RNB pipeline or trucking distances)
- Changes in the local electricity supply and demand
    - Increasing and decreasing the supply capacity of the solar PV park
    - Increasing and decreasing the electricity demand
- Alterations in the electricity and hydrogen prices
    - Increasing and decreasing the hydrogen price
    - Increasing and decreasing the electricity price
- Changing the mode of hydrogen transport
    - No utilization of the RNB gas pipeline
    - No utilization of the RNB and RTL gas pipelines – Trucks only
- Doubling the demand of hydrogen for mobility
- Decreasing the CAPEX of electrolyzers
    - CAPEX reduction of 50%
    - No CAPEX (not realistic but only done for theoretical purposes)
- Sourcing the electricity of the electrolyzer from the e-grid instead of the solar PV park

The chosen values for these parameters are shown in Table 13.

Table 13: List of altered parameters for the sensitivity analysis

Sensitivity case	Changed value A	Changed value B
Sensitivity 1: Distance (locational aspect)		
1a) Hydrogen close by, electricity far	Hydrogen distance = 0 km (i.e., hydrogen refueling onsite of the PtG facility)	Electricity distance (i.e., distance of solar PV park to HV/MV station) = 20 km
1b) Electricity close by, hydrogen far	Hydrogen distance = 20 km	Electricity distance = 1 km
Sensitivity 2: Local electricity supply & demand (locational aspect)		
2a) High supply, low demand	New PV capacity = +500%	E-demand = -50%
2b) Low supply, high demand	New PV capacity = -50%	E-demand = +500%
Sensitivity 3: value of electricity and hydrogen (market aspect)		
3a) Hydrogen valued higher, electricity lower	Hydrogen price = +25%	Electricity price = -25%
3b) Electricity valued higher	Hydrogen price = -25%	Electricity price = +25%
Sensitivity 4: Transport Options of Hydrogen (No RNB pipelines – No RTL pipelines – Only truck transport)		
Sensitivity 5: 2x mobility demand of hydrogen		
Sensitivity 6: Electrolyzer cost reduction (50% electrolyser CAPEX reduction (€900/kW) – No electrolyzer CAPEX)		
Sensitivity 7: Electrolyzer and battery can use electricity from the grid		

Some of the results of the sensitivities related to the distribution of the produced electricity from the solar PV park to the various sources and also their spatial footprints are included in the appendix section of the report.

4.3.1 Sensitivity: Changes in distances

This section represents the cost and benefits derived from altering the distances between the PtG facility to the hydrogen refueling station and the HV/MV station.

4.3.1.1 Sensitivity 1A: HRS Station: 0km – Distance to HV/MV station: 20 km

Here, it is assumed that the HRS station is at the same location of the PtG facility while the distance between the PtG facility and the HV/MV station is 20km. **Figure 25** shows the costs and benefits derived from such a comparison.

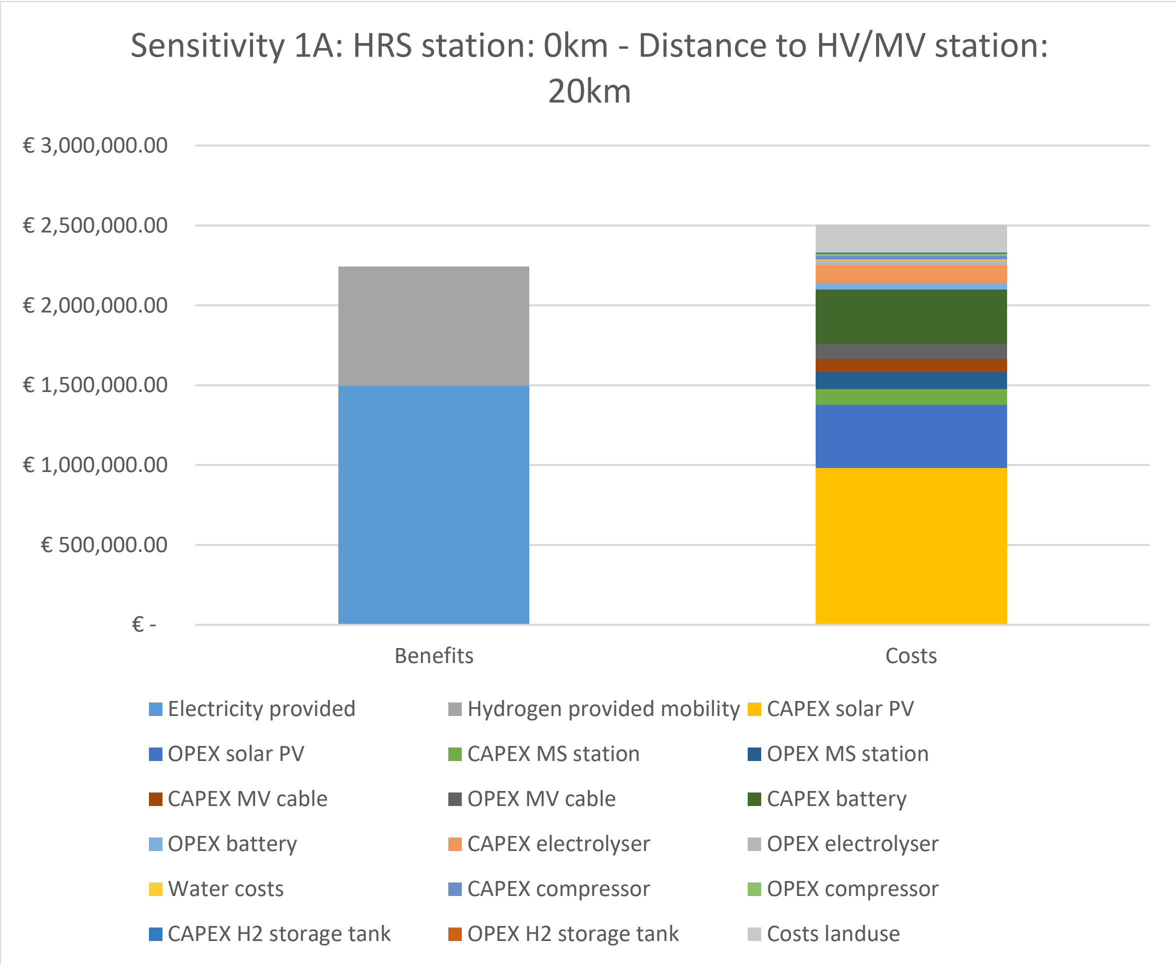


Figure 25: Annualized costs and benefits involved in Sensitivity 1A where the hydrogen refuelling station is considered to be on-site of the PTG facility and the distance to the HV/MV station is 20km

Compared to the baseline mix of solutions scenario there are not much differences, only slight increases in the costs of MV cabling due to the increased distance. Table 14 shows the detailed costs and benefits per asset for this sensitivity.

Table 14: Infrastructure costs per asset and overall Costs and Benefits of expanding the grid for sensitivity 1A

Category	Benefits	Costs	Δ: B - C
Electricity provided	€ 1,495,135.92	€ -	
Hydrogen provided industry	€ -	€ -	
Hydrogen provided mobility	€ 746,126.98	€ -	
CAPEX solar PV	€ -	€ 982,915.04	
OPEX solar PV	€ -	€ 395,387.92	
CAPEX MV station	€ -	€ 98,700.52	
OPEX MV station	€ -	€ 108,000.00	
CAPEX MV cable	€ -	€ 82,250.43	
OPEX MV cable	€ -	€ 90,000.00	
CAPEX battery	€ -	€ 340,659.18	
OPEX battery	€ -	€ 43,146.00	
CAPEX electrolyzer	€ -	€ 112,068.68	
OPEX electrolyzer	€ -	€ 30,400.00	
Water costs	€ -	€ 4,346.95	
CAPEX compressor	€ -	€ 20,833.88	
OPEX compressor	€ -	€ 13,385.00	
CAPEX H2 storage tank	€ -	€ 6,914.76	
OPEX H2 storage tank	€ -	€ 2,700.00	
Costs land-use	€ -	€ 171,621.03	
Total	**€ 2,241,262.90**	**€ 2,503,329.39**	**-€ 262,066.49**

4.3.1.2 Sensitivity 1B: HRS Station: 20 km – Distance to HV/MV station: 1 km

It was also of interest to look into the reverse case, where the distance between the PtG facility to the hydrogen refuelling is 20km and the distance to the HV/MV station is 1km. Under this scenario, no hydrogen production is considered and the model solely opts for electricity production. Transportation of hydrogen from the PtG facility to the farther HRS station lead to higher costs and therefore the utilization of the RNB gas infrastructure is not considered. In response to this, a question that may arise is that as a rule of thumb isn't the transportation per pipeline cheaper than cable? Then why aren't pipelines used? This has to do with the assumptions of the model with regard to the costs per meter of the cables vs pipelines and also their carrying capacity. The costs per cable is 12.5 €/m per MW of cable capacity while for the pipeline it is 13.5 €/m of a re-purposed RTL pipeline that has a capacity of 220kg of hydrogen per hour per meter which is equivalent to 7333 kW/m[7] or 7.3MW/m of energy (see Table 8).

Figure 26 and Table 15 provide the cost-benefit graph and the detailed annualized costs respectively. **Figure 27** shows how the produced electricity from the solar park is distributed under this sensitivity, 50% of the electricity is sent to batteries for storage and release into the grid, while 29% is sent to the grid, 21% is curtailed.

[7] 220kgH2/h/m × 33.33kWh/kg (this is the lower heating value of hydrogen) = 7333kW/m = 7.3MW/m

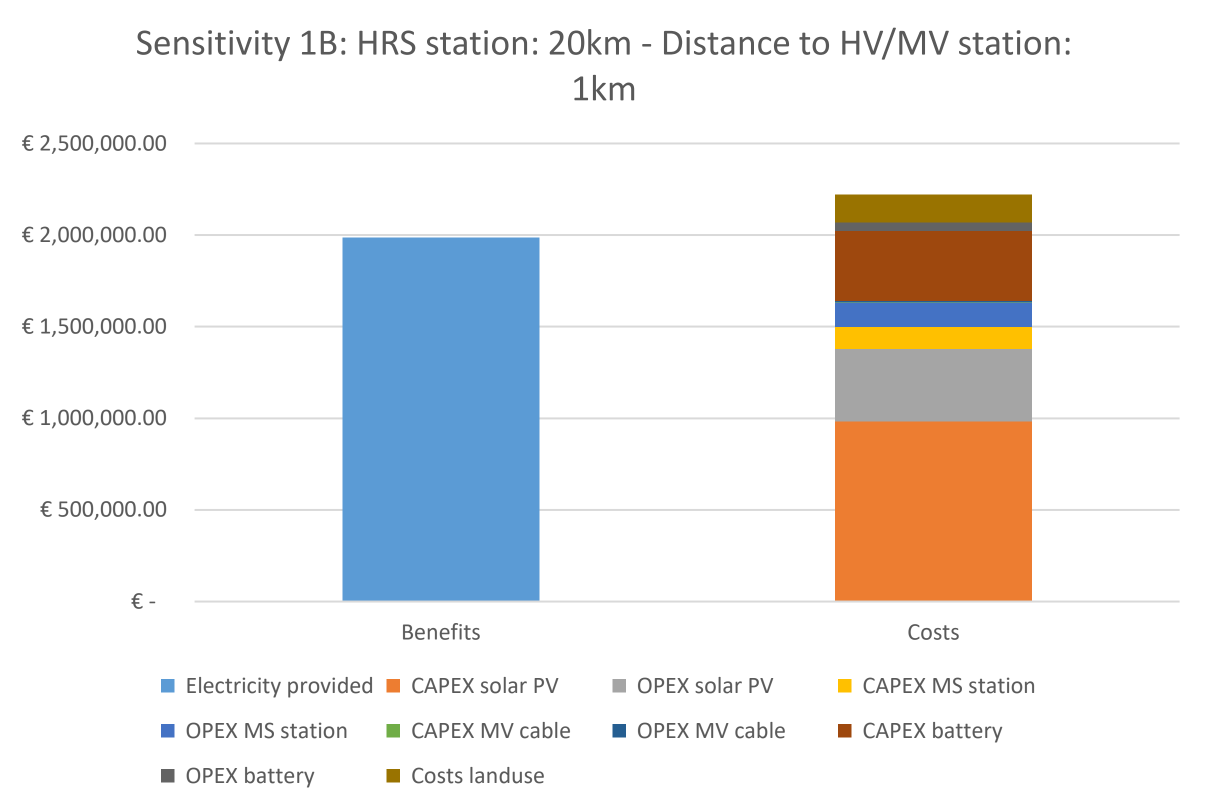


Figure 26: Annualized costs and benefits involved in Sensitivity 1B where the hydrogen refuelling station is considered to be 20km away from the PtG facility and the distance to the HV/MV station is 1km

Table 15: Infrastructure costs per asset and overall Costs and Benefits of expanding the grid for sensitivity 1B

Category	Benefits	Costs	Δ: B - C
Electricity provided	€ 1,987,044.10	€ -	
CAPEX solar PV	€ -	€ 982,915.04	
OPEX solar PV	€ -	€ 395,387.92	
CAPEX MV station	€ -	€ 120,633.97	
OPEX MV station	€ -	€ 132,000.00	
CAPEX MV cable	€ -	€ 5,026.42	
OPEX MV cable	€ -	€ 5,500.00	
CAPEX battery	€ -	€ 380,736.73	
OPEX battery	€ -	€ 48,222.00	
Costs land-use	€ -	€ 150,007.69	
Total	**€ 1,987,044.10**	**€ 2,220,429.76**	**-€ 233,385.65**

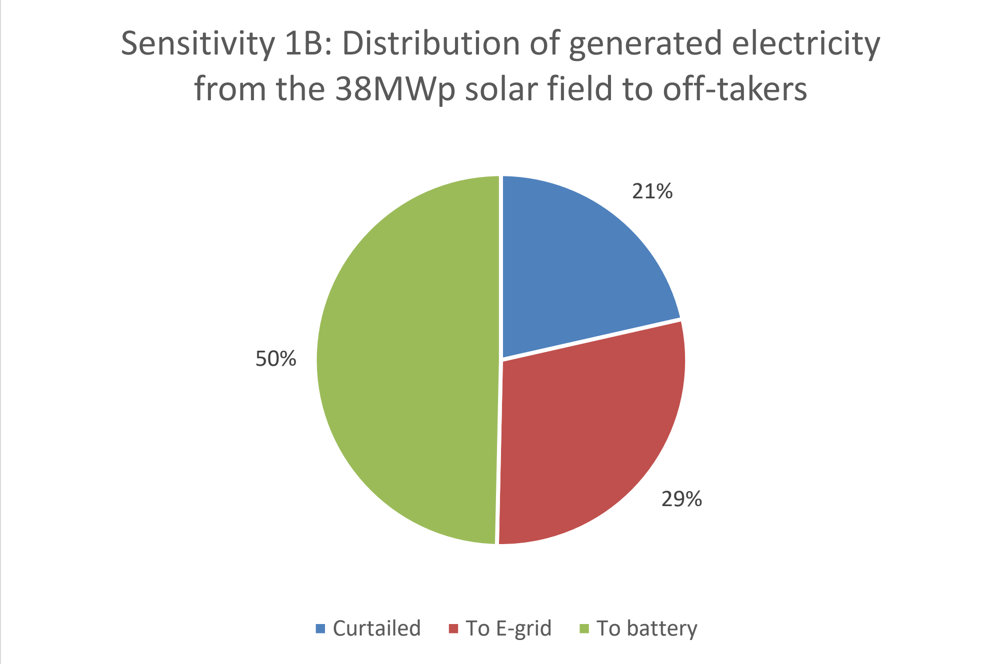


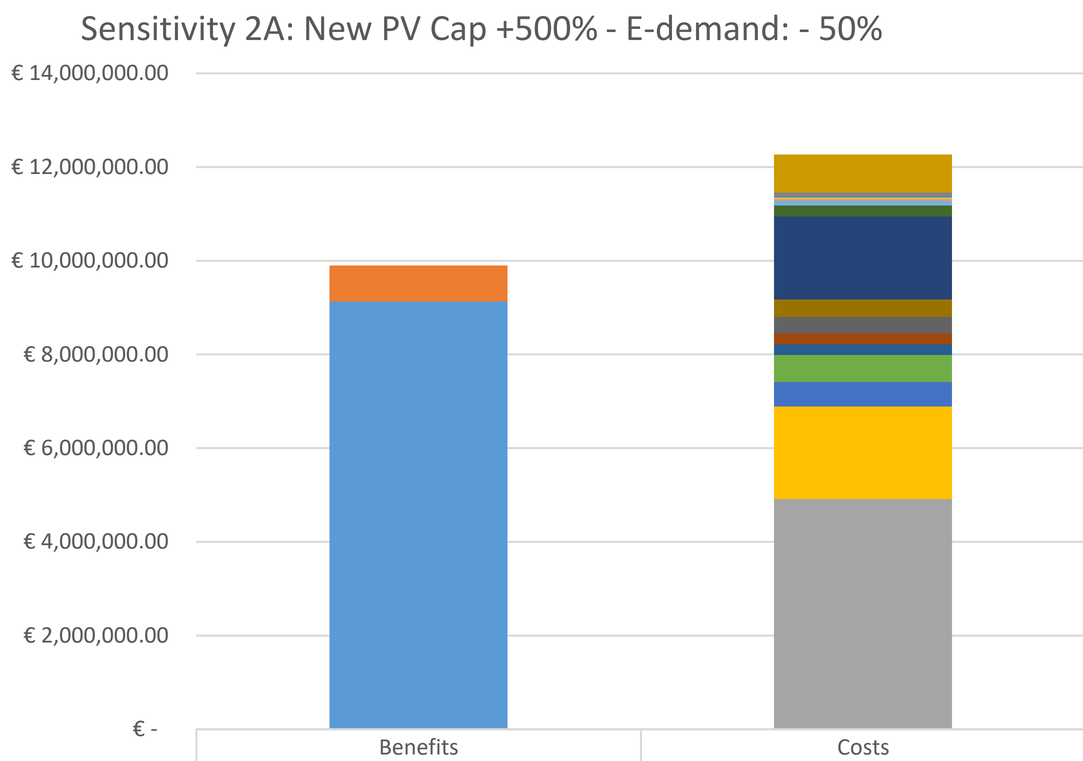
Figure 27: Distribution of generated electricity from the 38MWp solar field to the various sources for sensitivity 1B

4.3.2 Sensitivity: Changes in the supply and demand of electricity

Another sensitivity of interest was to see how changes in the supply and demand of electricity could play a role in changing the cost and benefits. These scenarios are quite extreme and was used to replicate solar PV parks where installed capacities are above 150MWp.

4.3.2.1 Sensitivity 2A: New PV Capacity +500% - Electricity Demand – -50%

This sensitivity looked into increasing the installed PV capacity by 500% (i.e., 228 MW) and reducing the electricity demand by 50%. Naturally, much higher benefits can be gained by the increased amount of electricity that is produced and sold under higher capacities. For hydrogen sold to mobility applications very little change is seen compared to the baseline mix of solutions scenario. **Figure 28** displays the costs and benefits for this scenario with the costs per asset, the actual table with the differences in costs and benefits is shown in the appendix (Table 27). **Figure 29** displays the distribution of the produced electricity to the various sources, 44% of the electricity is stored in batteries and sold to the grid, 21% is sent to the e-grid and a sizeable 27% is curtailed. In total, only 8% is utilized by the electrolyzer. Also of interest is to see what the spatial footprint of such a scenario is, **Figure 30** gives an approximation where clearly more than 2 million square meters of land are needed for the solar park.



	Benefits	Costs
Costs landuse	€ -	€ 810,931.59
OPEX RNB	€ -	€ 83,700.00
CAPEX RNB	€ -	€ 4,935.03
OPEX H2 storage tank	€ -	€ 2,700.00
CAPEX H2 storage tank	€ -	€ 6,914.76
OPEX compressor	€ -	€ 13,385.00
CAPEX compressor	€ -	€ 20,833.88
Water costs	€ -	€ 4,471.55
OPEX electrolyser	€ -	€ 30,400.00
CAPEX electrolyser	€ -	€ 112,068.68
OPEX battery	€ -	€ 224,472.00
CAPEX battery	€ -	€ 1,772,318.32
OPEX HS-MS station expansion	€ -	€ 380,000.00
CAPEX HS-MS station expansion	€ -	€ 347,279.60
OPEX MV cable	€ -	€ 240,000.00
CAPEX MV cable	€ -	€ 219,334.49
OPEX MS station	€ -	€ 576,000.00
CAPEX MS station	€ -	€ 526,402.77
OPEX solar PV	€ -	€ 1,976,949.27
CAPEX solar PV	€ -	€ 4,914,599.26
Hydrogen provided mobility	€ 766,500.00	€ -
Electricity provided	€ 9,133,884.76	€ -

Figure 28: Annualized costs and benefits involved in Sensitivity 2A where the capacity of the solar field is increased by 500% (i.e., 228MW) and the electricity demand of the region for users is reduced by 50%.

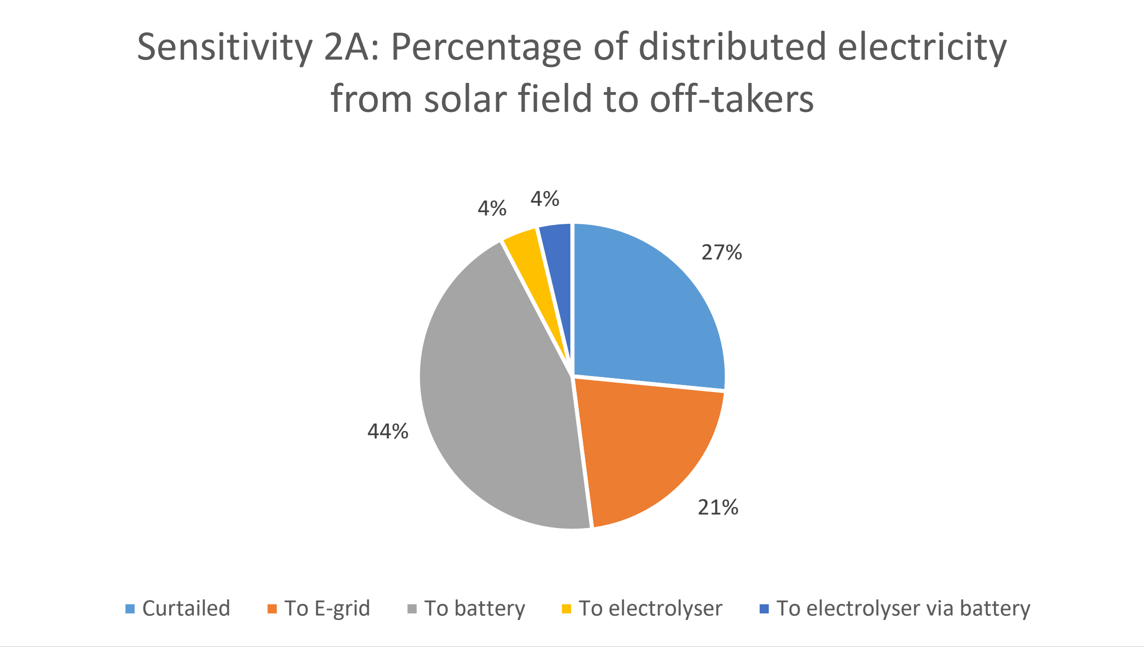
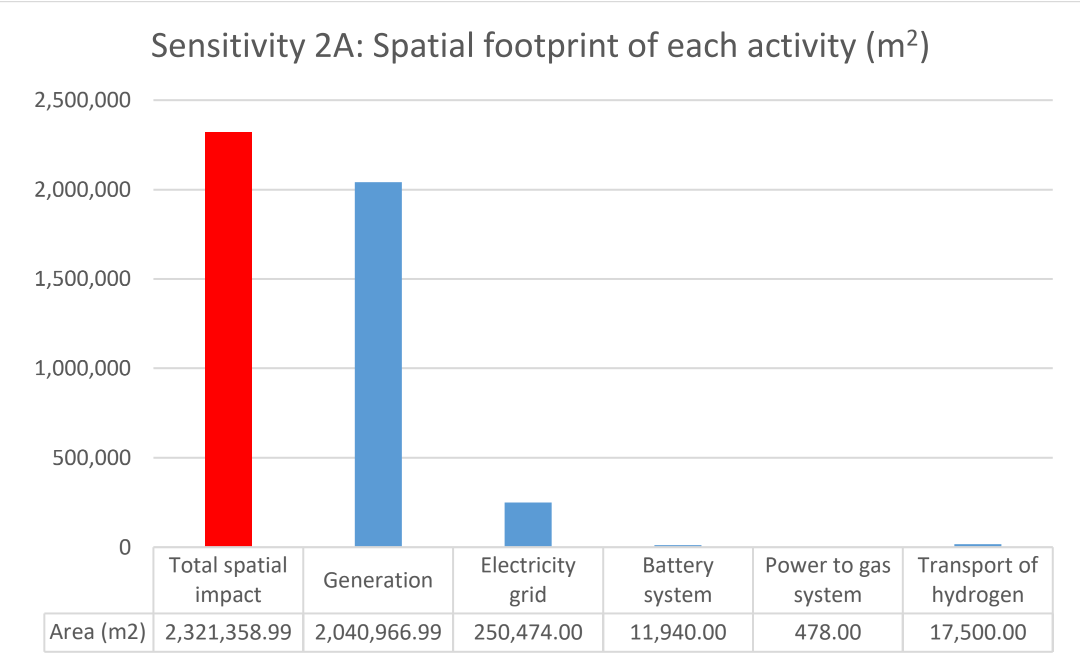


Figure 29: Distribution percentage of electricity from the solar park to the various off-takers for sensitivity 2A

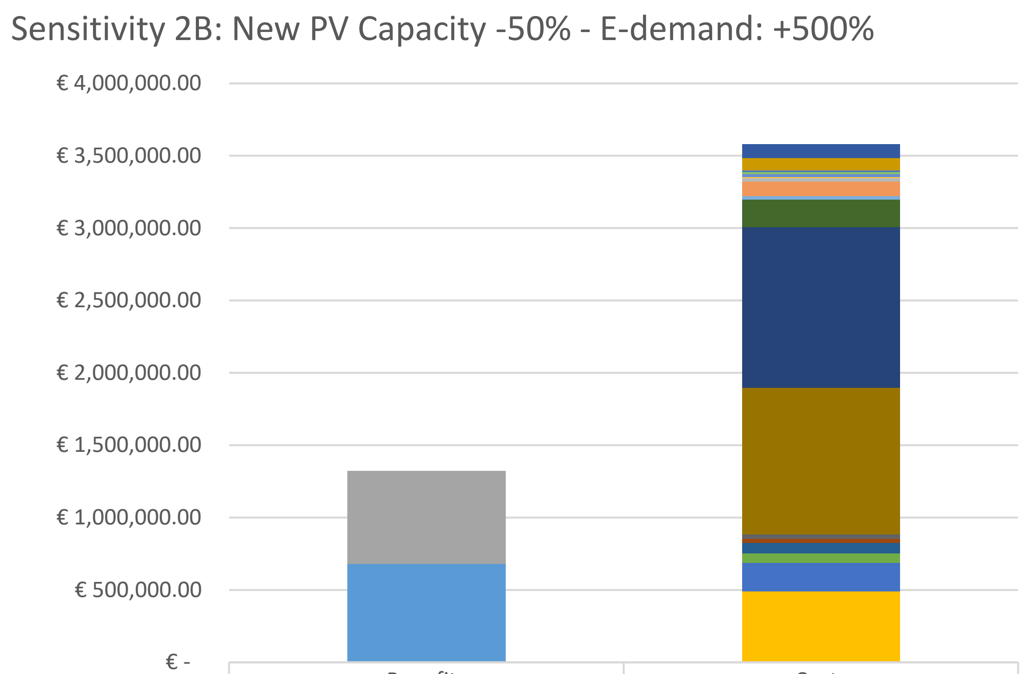


	Total spatial impact	Generation	Electricity grid	Battery system	Power to gas system	Transport of hydrogen
Area (m2)	2,321,358.99	2,040,966.99	250,474.00	11,940.00	478.00	17,500.00

Figure 30: Spatial footprint for sensitivity 2A

4.3.2.2.Sensitivity 2B: New PV Capacity -50% - Electricity Demand +500%

Figure 31 provides the costs and benefits where solar PV capacity is decreased by 50% and electricity demand is increased by 500%. What stands out significantly is costs incurred for expanding the HV-MV stations due to the increased demand. The actual table with the differences in costs and benefits is shown in the appendix in Table 28.



	Benefits	Costs
Costs landuse	€ -	€ 94,503.15
OPEX RNB	€ -	€ 83,700.00
CAPEX RNB	€ -	€ 4,935.03
OPEX H2 storage tank	€ -	€ 2,700.00
CAPEX H2 storage tank	€ -	€ 6,914.76
OPEX compressor	€ -	€ 13,385.00
CAPEX compressor	€ -	€ 20,833.88
Water costs	€ -	€ 3,736.97
OPEX electrolyser	€ -	€ 26,600.00
CAPEX electrolyser	€ -	€ 98,060.10
OPEX battery	€ -	€ 24,252.00
CAPEX battery	€ -	€ 191,481.63
OPEX HS-MS station expansion	€ -	€ 1,110,000.00
CAPEX HS-MS station expansion	€ -	€ 1,014,422.00
OPEX MV cable	€ -	€ 30,000.00
CAPEX MV cable	€ -	€ 27,416.81
OPEX MS station	€ -	€ 72,000.00
CAPEX MS station	€ -	€ 65,800.35
OPEX solar PV	€ -	€ 197,693.96
CAPEX solar PV	€ -	€ 491,457.52
Hydrogen provided mobility	€ 642,485.23	€ -
Hydrogen provided industry	€ 0.44	€ -
Electricity provided	€ 678,570.74	€ -

Figure 31: Annualized costs and benefits involved in Sensitivity 2B where the capacity of the solar field is reduced by 50% (i.e., 14MW) and the electricity demand of the region for users is increased by 500%.

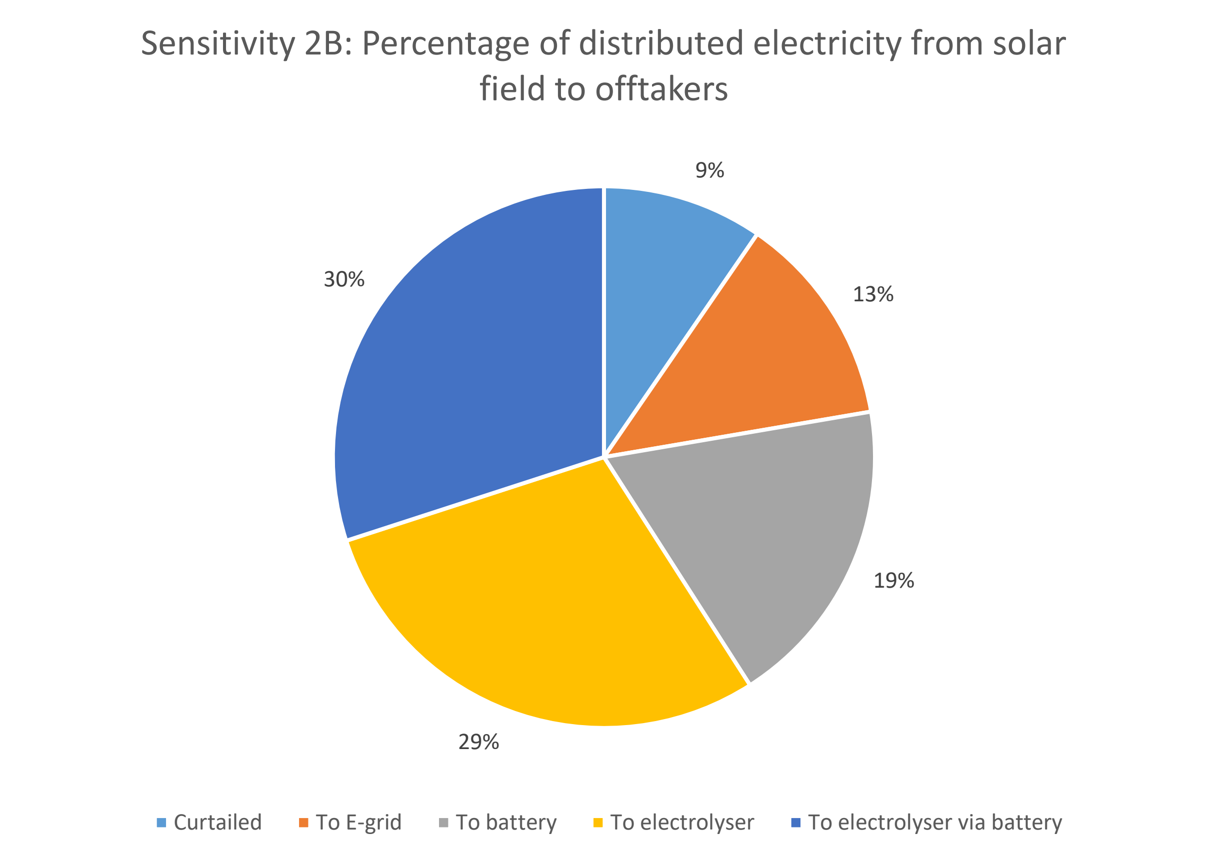


Figure 32: Distribution percentage of electricity from the solar park to the various off-takers for sensitivity 2B

Figure 32 provides the electricity distribution from the solar field under this scenario, to maximize profits via the selling of hydrogen 30% of the produced electricity is stored via battery and then utilized by the electrolyzer while 29% is utilized directly by the electrolyzer. 19% is stored by batteries and then distributed to the electricity grid and only 13% is sent directly to the grid, 9% is curtailed.

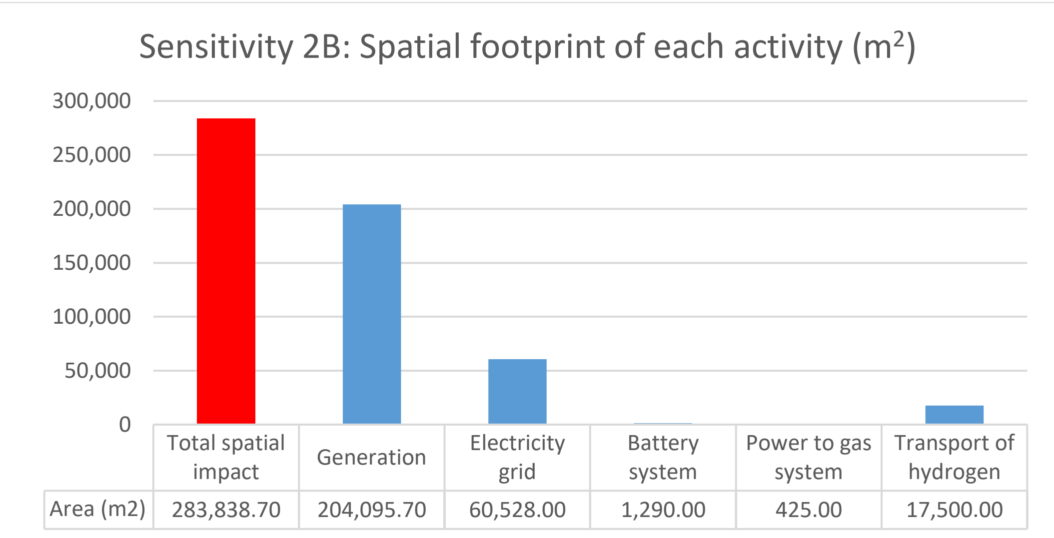


Figure 33: Spatial footprint for sensitivity 2B

Figure 33 shows the spatial footprint of such a scenario. Under this case, the spatial footprint is clearly less compared to scenarios with higher PV capacities.

4.3.3 Sensitivity: changes in the market price of electricity and hydrogen

Another impactful effect would be to study the effect of changing hydrogen and electricity prices and investigating the outcome of the outcome of the results.

4.3.3.1 Sensitivity 3A: Hydrogen price decreased by 25% and electricity price increased by 25%

As was seen from the benefits derived from the mix of solutions scenario, hydrogen provided additional benefits by acting as a revenue source for mobility applications. Alterations in the price charged for hydrogen could certainly affect cost and benefits from the perspective of the PtG operator. **Figure 34** displays the annualized costs and benefits where the hydrogen market price is decreased by 25% and electricity prices are increased by 25%. Under this circumstance the benefits outweigh the costs and lead to significant net gains for the electricity provider. However, electricity is the only commodity that is sold under this scenario and does not lead to any utilization of hydrogen. This is grounded on the higher level of demand that exists for electricity consumption compared to hydrogen and the enhanced profits that could be gained from the selling of electricity as opposed to hydrogen. The demand for hydrogen is easily influenced by price fluctuations, any slight reduction in its price reduces the profit margins for the producer and deems it as unprofitable. Table 16 lists the detailed costs for each of the asset categories[8]. Batteries play an influential role in acting as an arbitrager in the electricity market by storing the electricity when the price is low and selling the electricity when it is high. Visualised in **Figure 35** is the share of electricity distributed, a substantial amount of the electricity is sent to the utility battery where 18.6 MW of capacity is installed. The spatial footprint here is very similar to the baseline mix of solutions and is included in the appendix in **Figure 52**.

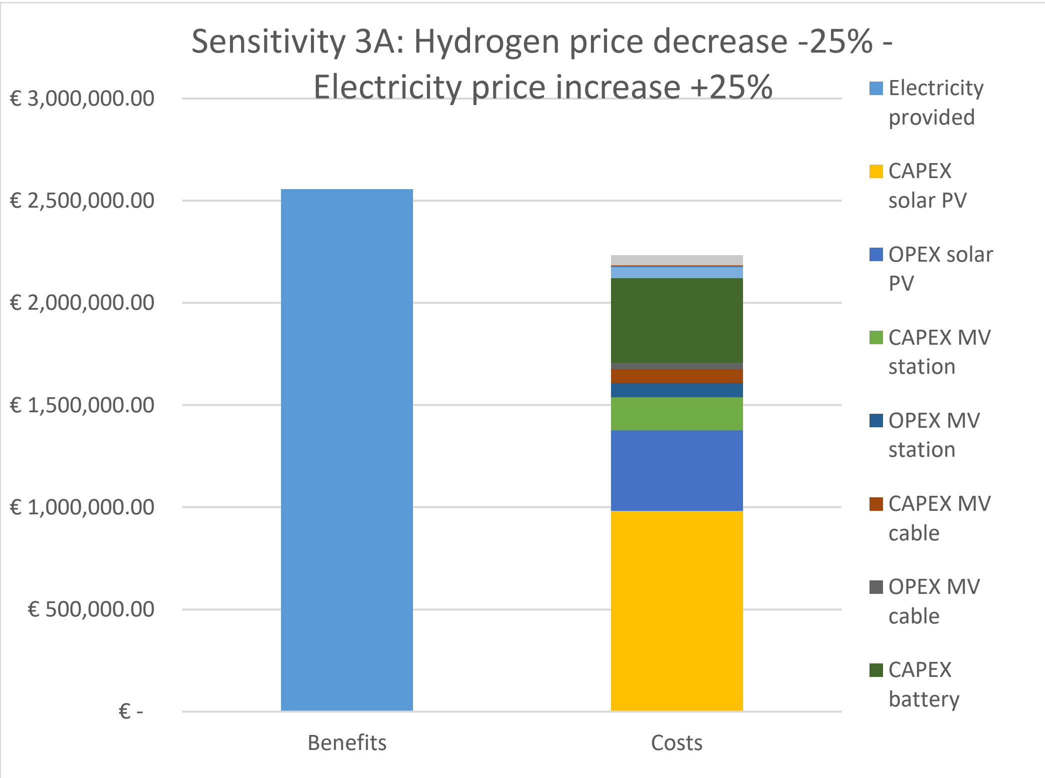


Figure 34: Annualized costs and benefits involved in sensitivity 3A where hydrogen price is decreased by 25% and electricity price is increased by 25%

[8] Assets are included for the CAPEX and OPEX of hydrogen storage however these costs reflect the given baseline hydrogen storage levels that must exist in order for the model to run

Table 16: Infrastructure costs per asset and overall Costs and Benefits for sensitivity 3A

Category	Benefits	Costs	Δ: B - C
Electricity provided	**€ 2,516,511.69**	**€ -**	
Hydrogen provided industry	€ -	€ -	
Hydrogen provided mobility	€ -	€ -	
CAPEX solar PV	€ -	€ 982,915.04	
OPEX solar PV	€ -	€ 395,387.92	
CAPEX MV station	€ -	€ 120,633.97	
OPEX MV station	€ -	€ 132,000.00	
CAPEX MV cable	€ -	€ 50,264.15	
OPEX MV cable	€ -	€ 55,000.00	
CAPEX HV-MV station expansion	€ -	€ -	
OPEX HV-MV station expansion	€ -	€ -	
CAPEX battery	€ -	€ 405,228.56	
OPEX battery	€ -	€ 51,324.00	
CAPEX electrolyser	€ -	€ -	
OPEX electrolyser	€ -	€ -	
Water costs	€ -	€ -	
CAPEX compressor	€ -	€ -	
OPEX compressor	€ -	€ -	
CAPEX H2 storage tank	€ -	€ 6,914.76	
OPEX H2 storage tank	€ -	€ 2,700.00	
CAPEX RTL	€ -	€ -	
OPEX RTL	€ -	€ -	
CAPEX RNB	€ -	€ -	
OPEX RNB	€ -	€ -	
CAPEX Trucks	€ -	€ -	
OPEX Trucks	€ -	€ -	
Costs land-use	€ -	€ 162,802.78	
Total	**€ 2,516,511.69**	**€ 2,365,171.18**	**€ 151,340.51**

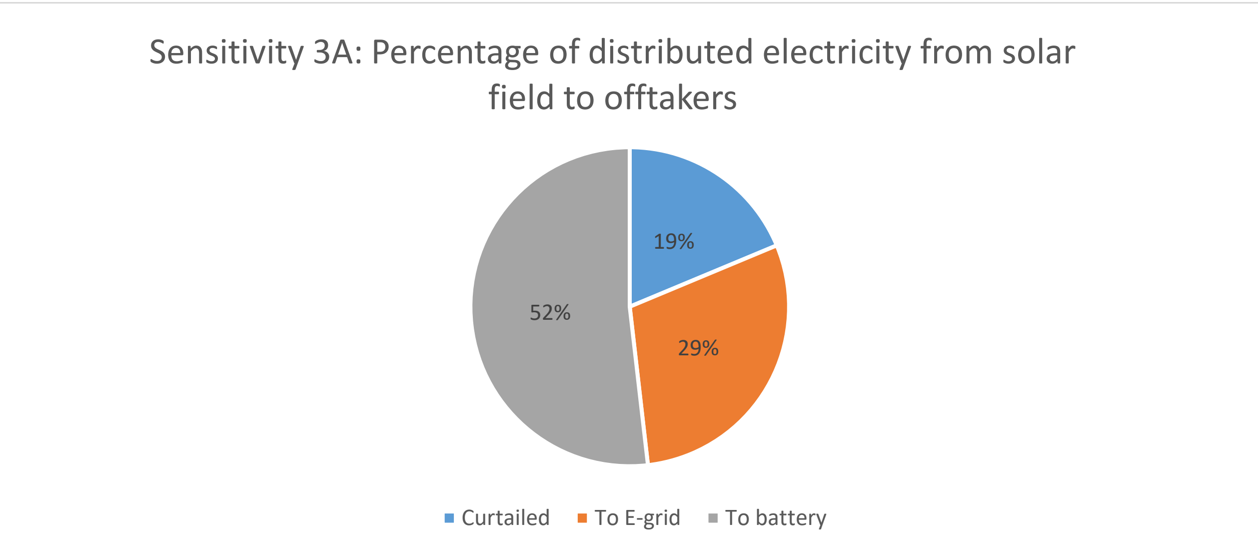


Figure 35: Distribution percentage of electricity from the solar park to the various off-takers for sensitivity 3A

4.3.3.2 Sensitivity 3B: Hydrogen price increased by 25% and electricity price decreased by 25%

Attention should be given to a vice-versa scenario where the market hydrogen price is increased by 25% and the electricity price is reduced by 25% (**Figure 36**). While the benefits are less than the costs, we clearly see that the benefits derived from the selling of hydrogen is higher compared to the other scenarios.

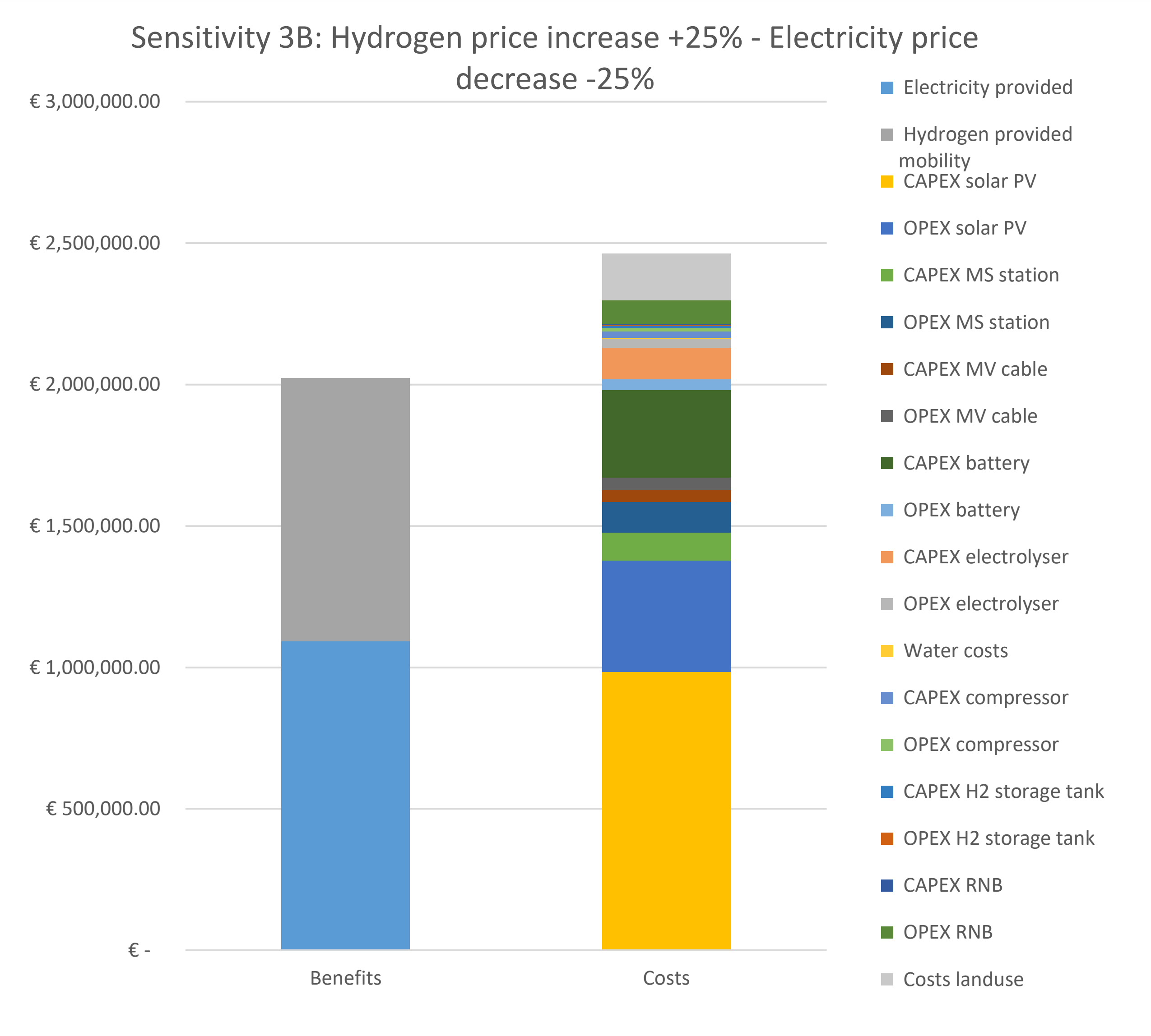


Figure 36: Annualized costs and benefits involved in sensitivity 3B where hydrogen price is increased by 25% and electricity price is decreased by 25%

Table 17 lists the costs and benefits per asset for this sensitivity while **Figure 37** shows the distribution of electricity per the various flexibility measures. The electricity distribution is quite different from the baseline mix of solutions scenario, here 28% of the electricity is curtailed since less benefits are gained from selling the electricity, 12% is distributed directly to the grid and 26% is stored in the battery and sold at higher prices, 18% of the electricity is utilized by the electrolyser and 16% is used later by the electrolyzer via the battery.

Table 17: Infrastructure costs per asset and overall Costs and Benefits for sensitivity 3B

Category	Benefits	Costs	Δ: B - C
Electricity provided	€ 1,092,142.04	€ -	

Hydrogen provided industry	€	0.00	€	-	
Hydrogen provided mobility	€	930,658.79	€	-	
CAPEX solar PV	€	-	€	982,915.04	
OPEX solar PV	€	-	€	395,387.92	
CAPEX MV station	€	-	€	98,700.52	
OPEX MV station	€	-	€	108,000.00	
CAPEX MV cable	€	-	€	41,125.22	
OPEX MV cable	€	-	€	45,000.00	
CAPEX HV-MV station expansion	€	-	€	-	
OPEX HV-MV station expansion	€	-	€	-	
CAPEX battery	€	-	€	309,487.75	
OPEX battery	€	-	€	39,198.00	
CAPEX electrolyser	€	-	€	112,068.68	
OPEX electrolyser	€	-	€	30,400.00	
Water costs	€	-	€	4,337.81	
CAPEX compressor	€	-	€	20,833.88	
OPEX compressor	€	-	€	13,385.00	
CAPEX H2 storage tank	€	-	€	6,914.76	
OPEX H2 storage tank	€	-	€	2,700.00	
CAPEX RTL	€	-	€	-	
OPEX RTL	€	-	€	-	
CAPEX RNB	€	-	€	4,935.03	
OPEX RNB	€	-	€	83,700.00	
CAPEX Trucks	€	-	€	-	
OPEX Trucks	€	-	€	-	
Costs land-use	€	-	€	164,420.41	
Total	**€**	**2,022,800.83**	**€**	**2,463,510.01**	**-€ 440,709.17**

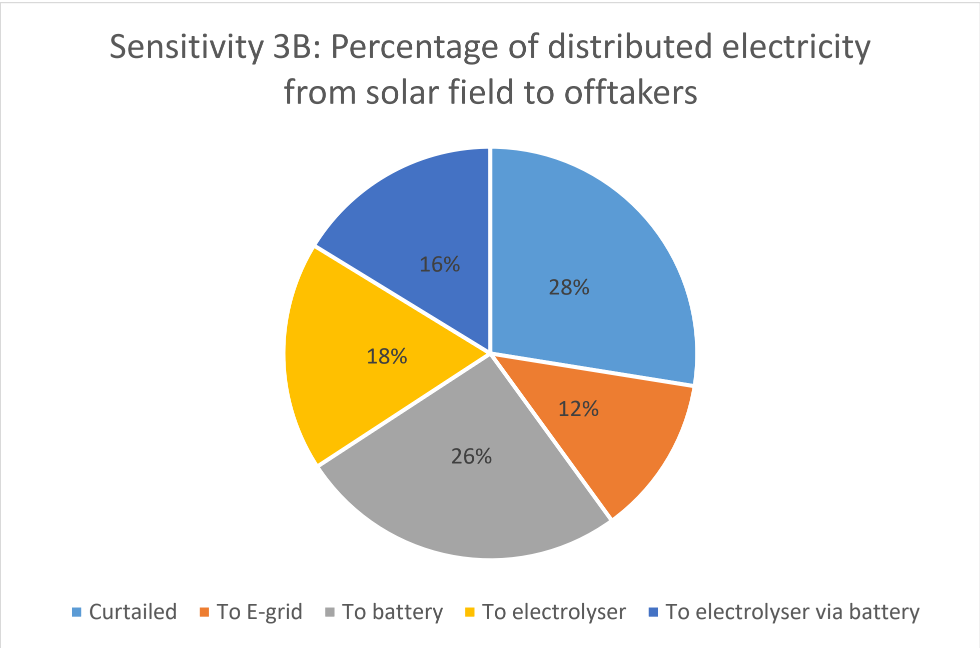


Figure 37: Distribution percentage of electricity from the solar park to the various off-takers for sensitivity 3B

4.3.4 Sensitivity: Transport Options of Hydrogen (No RNB pipelines – No RTL pipelines – Only truck transport)

4.3.4.1 Sensitivity 4A: No RNB

In all the results so far, the model opts for utilizing the RNB pipeline (i.e., regional distribution pipeline) for the transportation of hydrogen from source to sink. This is simply due to the lower costs involved in re-using the RNB pipelines instead of installing new pipelines, however it was also of interest to look into the option of not using RNB's but only considering tube trailer transport of hydrogen and/or the RTL.

Figure 38 provides the costs and benefits of this scenario, the RTL is utilized over the usage of trucks since the costs involved for truck transport is considerably high compared to the re-use of the RTL. Implementation of the RTL is only feasible if the output capacity of the PtG system is large enough to be utilized via an RTL, the capacities of the utilized PtG system in this sensitivity does provide a high enough yield to make connection to an RTL pipeline feasible. Table 18 provides the costs and benefits of each asset.

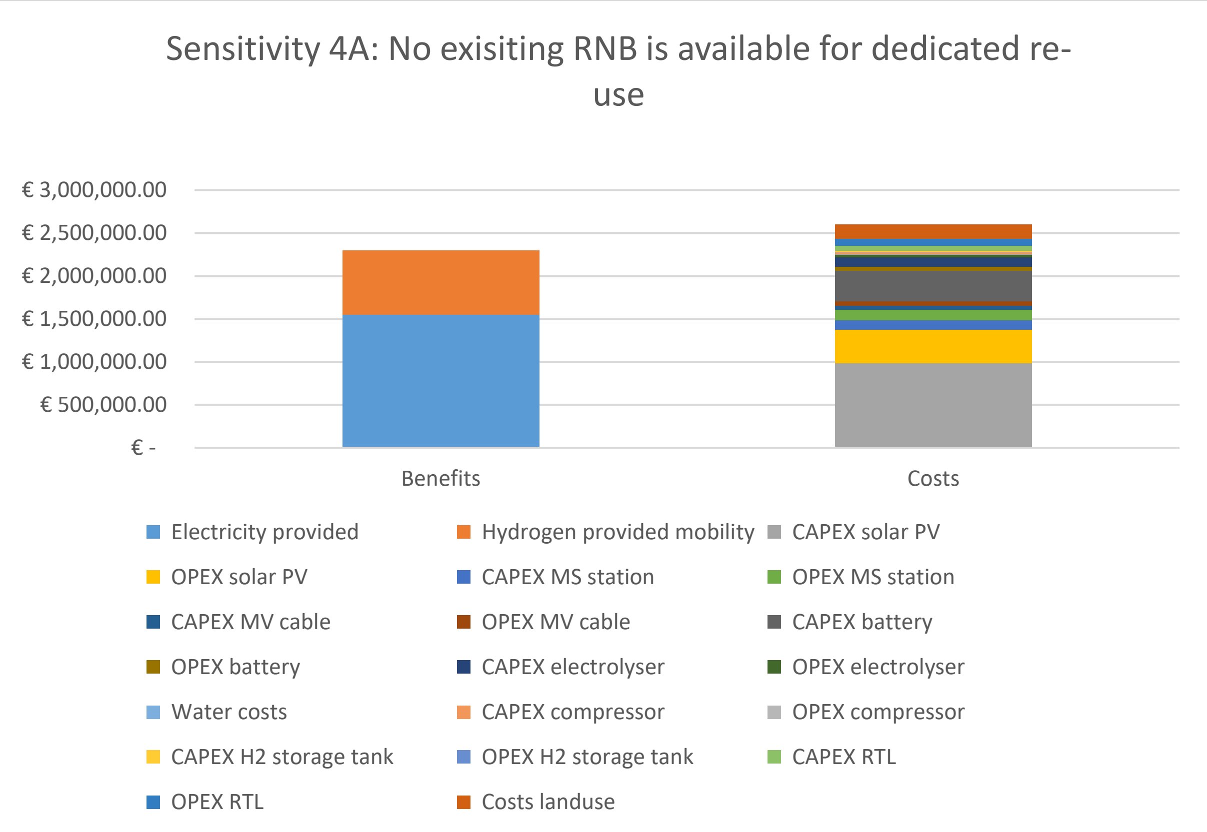


Figure 38: Annualized costs and benefits involved in sensitivity 4A where utilization of the RTL is not an option

Table 18: Infrastructure costs per asset and overall Costs and Benefits for sensitivity 4A

Category	Benefits	Costs	Δ: B - C
Electricity provided	€ 1,552,838.95	€ -	
Hydrogen provided mobility	€ 746,923.67	€ -	
CAPEX solar PV	€ -	€ 982,915.04	
OPEX solar PV	€ -	€ 395,387.92	
CAPEX MV station	€ -	€ 109,667.24	
OPEX MV station	€ -	€ 120,000.00	

CAPEX MV cable	€	-	€	45,694.68	
OPEX MV cable	€	-	€	50,000.00	
CAPEX battery	€	-	€	356,244.89	
OPEX battery	€	-	€	45,120.00	
CAPEX electrolyzer	€	-	€	112,068.68	
OPEX electrolyzer	€	-	€	30,400.00	
Water costs	€	-	€	4,351.44	
CAPEX compressor	€	-	€	20,833.88	
OPEX compressor	€	-	€	13,385.00	
CAPEX H2 storage tank	€	-	€	6,914.76	
OPEX H2 storage tank	€	-	€	2,700.00	
CAPEX RTL	€	-	€	54,833.62	
OPEX RTL	€	-	€	84,000.00	
Costs land-use	€	-	€	165,966.85	
Total	**€**	**2,299,762.62**	**€**	**2,600,484.00**	**-€ 300,721.38**

4.3.4.2 Sensitivity 4B: No RNB No RTL – Trucks only

So far, all results have never opted for the utilization of trucks in order to transport the hydrogen to a hydrogen refuelling station. It was worth investigating if the model would still opt for truck transportation of hydrogen if it had no other option but trucks. Interestingly enough the model doesn't opt for producing hydrogen at all and only opts for the production of electricity. Under this scenario, hydrogen conversion is not a part of the optimal solution mix. The trucking of hydrogen is financially feasible when involving small amounts of hydrogen being transported over long distances but as soon as volumes are increased large fleets of trucks will be needed for the transportation; added to that is the high wages for truck drivers.

Seeing how hydrogen production does not take place, utility batteries however do play a significant role, this is shown in **Figure 57** in the appendix where 50% of the electricity produced by the solar field are utilized by batteries and this leads to higher benefits derived from the selling of electricity. **Figure 39** and Table 19 provide the costs and benefits for this scenario. **Figure 56** in the appendix provides the spatial footprint of this sensitivity.

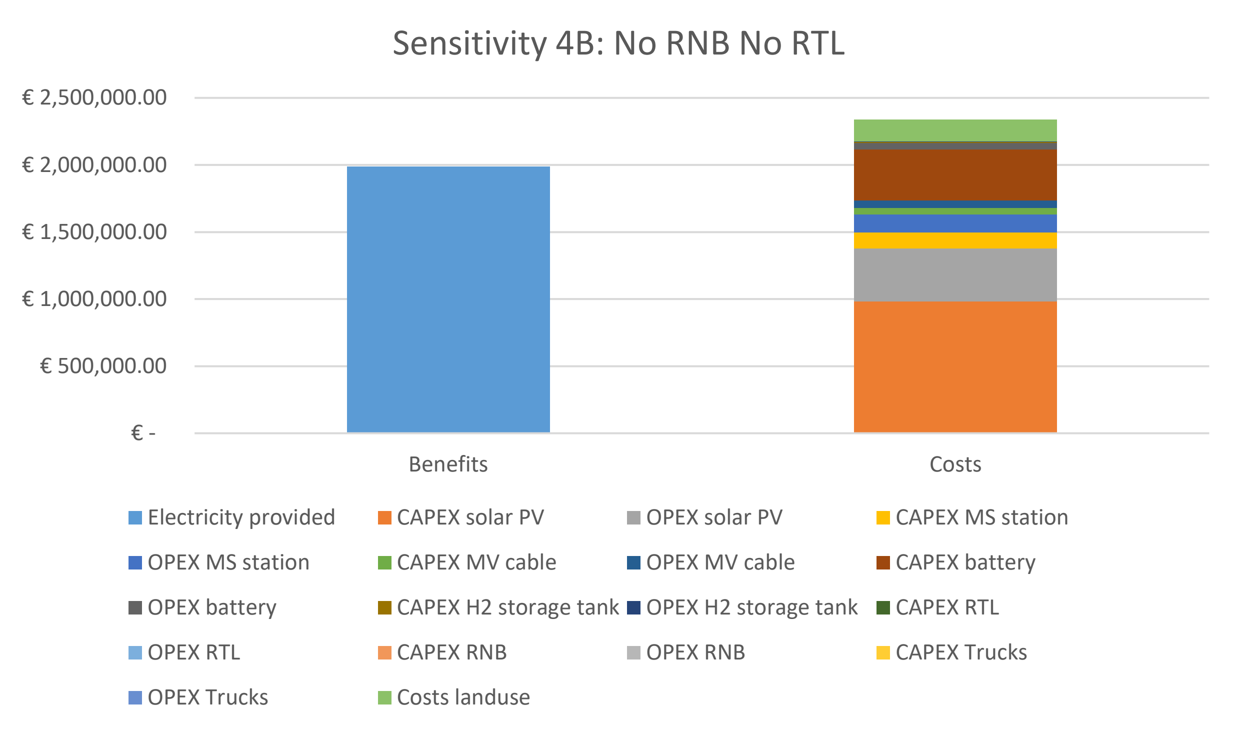


Figure 39: Annualized costs and benefits involved in sensitivity 4B where no RNB and no RTL pipeline is considered.

Table 19: Infrastructure costs per asset and overall Costs and Benefits for sensitivity 4B

Category	Benefits	Costs	Δ: B - C
Electricity provided	€ 1,988,373.02	€ -	
CAPEX solar PV	€ -	€ 982,915.04	
OPEX solar PV	€ -	€ 395,387.92	
CAPEX MV station	€ -	€ 120,633.97	
OPEX MV station	€ -	€ 132,000.00	
CAPEX MV cable	€ -	€ 50,264.15	
OPEX MV cable	€ -	€ 55,000.00	
CAPEX battery	€ -	€ 380,736.73	
OPEX battery	€ -	€ 48,222.00	
CAPEX H2 storage tank	€ -	€ 6,914.76	
OPEX H2 storage tank	€ -	€ 2,700.00	
CAPEX RTL	€ -	€ -	
OPEX RTL	€ -	€ -	
CAPEX RNB	€ -	€ -	
OPEX RNB	€ -	€ -	
CAPEX Trucks	€ -	€ -	
OPEX Trucks	€ -	€ -	
Costs land use	€ -	€ 162,674.26	
Total	**€ 1,988,373.02**	**€ 2,337,448.82**	**-€ 349,075.80**

4.3.5 Sensitivity 5: 2x Mobility Demand

Seeing how results indicate that the mobility demand of hydrogen is the dominating form of hydrogen utilization (industrial utilization of hydrogen by the model is very limited) it was of interest to see how the benefits derived from doubling the demand for the mobility sector would change compared to the domineering benefits from selling electricity. Under this scenario, higher profits from the selling of hydrogen are derived compared to selling the electricity to the grid. **Figure 40** and Table 20 provide the costs and benefits for each of the assets. **Figure 41** shows that for this sensitivity the distribution of electricity from the solar PV park directly to the electrolyzer but also to electrolyzer and battery combinations is very significant. Only 9% of the produced electricity is sent to the grid while 16% is stored by the battery for later utilization on the e-grid.

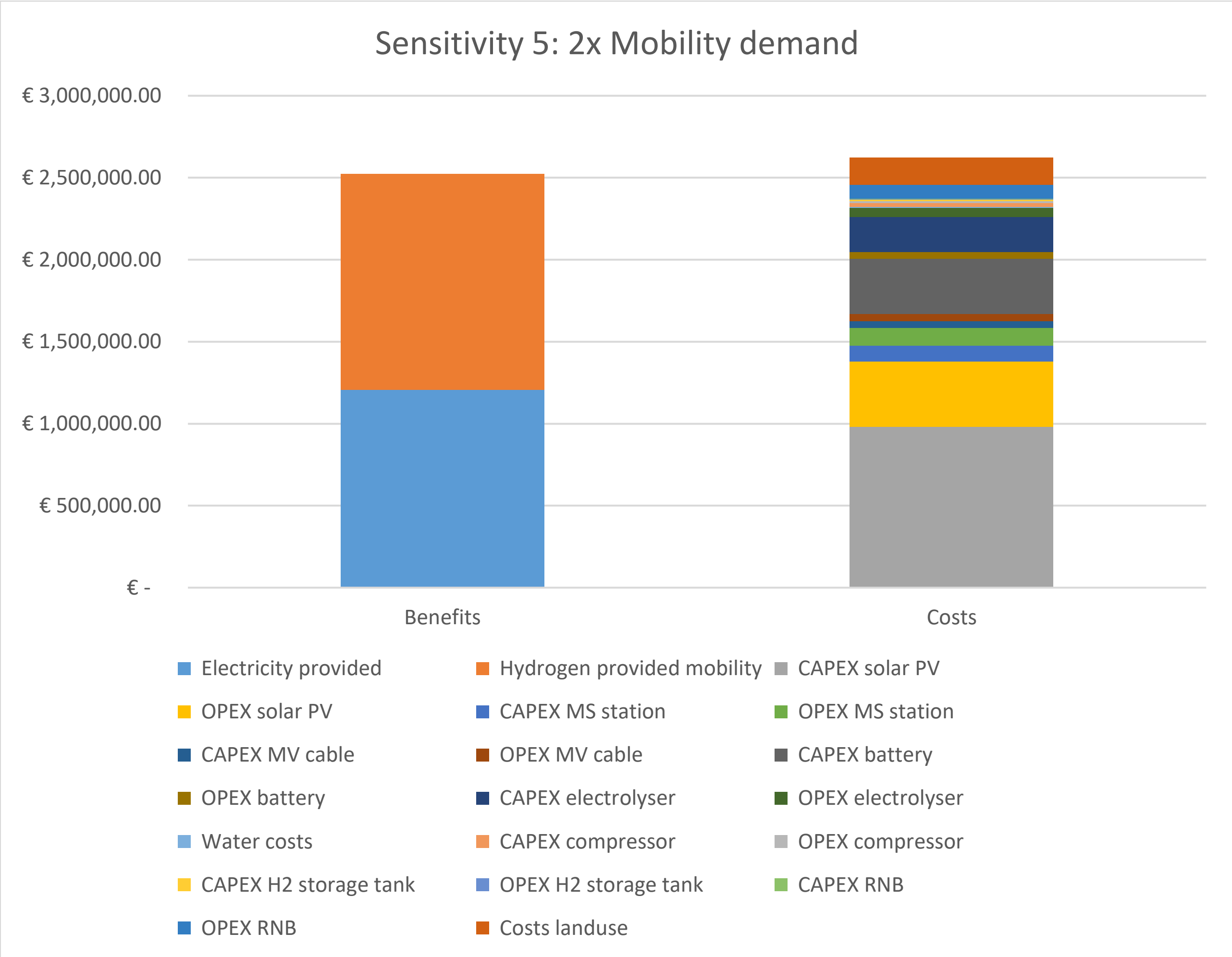


Figure 40: Annualized costs and benefits involved in sensitivity 5 where mobility demand is doubled

Table 20: Infrastructure costs per asset and overall Costs and Benefits for sensitivity 5

Category	Benefits	Costs	Δ: B -C
Electricity provided	€ 1,205,087.85	€ -	
Hydrogen provided mobility	€ 1,318,172.55	€ -	
CAPEX solar PV	€ -	€ 982,915.04	
OPEX solar PV	€ -	€ 395,387.92	
CAPEX MV station	€ -	€ 98,700.52	
OPEX MV station	€ -	€ 108,000.00	
CAPEX MV cable	€ -	€ 41,125.22	

OPEX MV cable	€ -	€ 45,000.00	
CAPEX battery	€ -	€ 336,206.11	
OPEX battery	€ -	€ 42,582.00	
CAPEX electrolyser	€ -	€ 210,128.78	
OPEX electrolyser	€ -	€ 57,000.00	
Water costs	€ -	€ 7,670.16	
CAPEX compressor	€ -	€ 20,833.88	
OPEX compressor	€ -	€ 13,385.00	
CAPEX H2 storage tank	€ -	€ 6,914.76	
OPEX H2 storage tank	€ -	€ 2,700.00	
CAPEX RNB	€ -	€ 4,935.03	
OPEX RNB	€ -	€ 83,700.00	
Costs landuse	€ -	€ 164,762.78	
Total	**€ 2,523,260.39**	**€ 2,621,947.18**	**-€ 98,686.79**

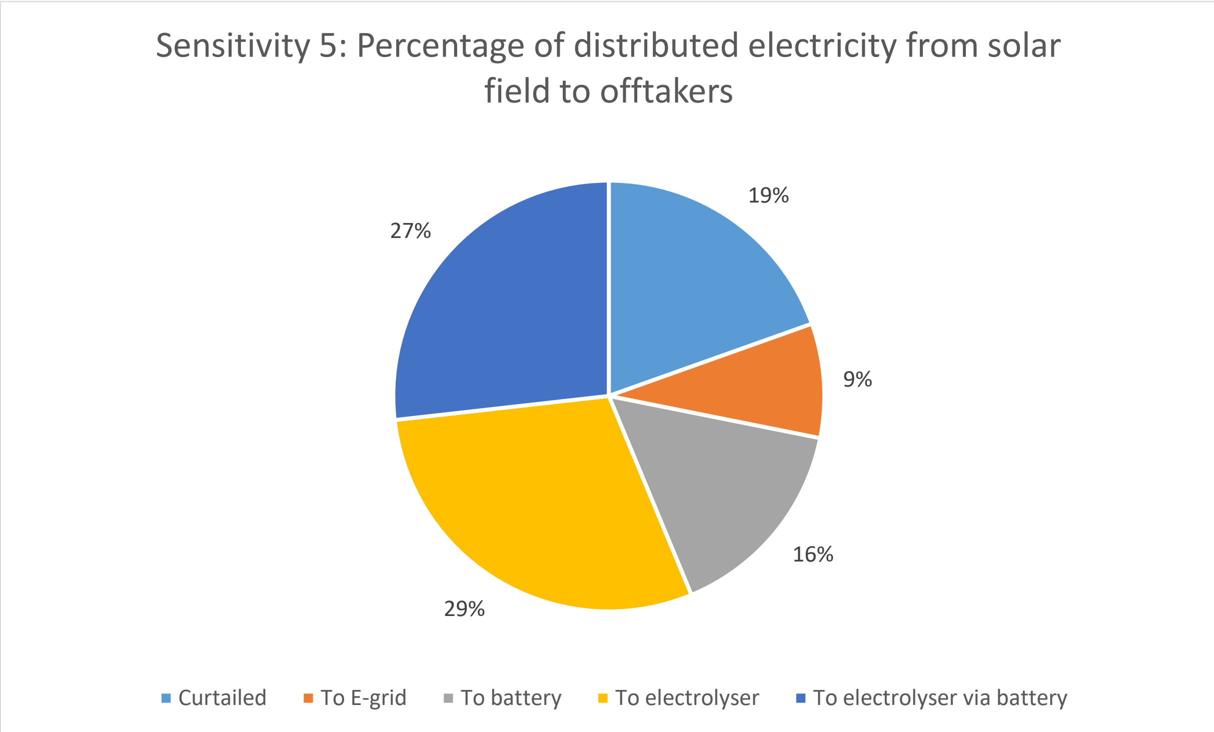


Figure 41: Distribution percentage of electricity from the solar park to the various off-takers for sensitivity 5

4.3.6 Sensitivity: Electrolyzer cost reduction (50% electrolyser CAPEX reduction (€900/kW) – No electrolyzer CAPEX)

Another important factor affecting the utilization of electrolyzers for the production of green hydrogen is the high CAPEX of the electrolyzer. It was of interest to see how this would change if the electrolyzer CAPEX was reduced by 50% and also one in a purely theoretical case of no CAPEX to see how results would be affected.

4.3.6.1 Sensitivity 6A: 50% Electrolyzer cost reduction

Here the CAPEX of the electrolyzer is assumed to be €900/kW compared to the default electrolyzer CAPEX of €1800/kW. The distribution of electricity per source is not too different compared to the mix of scenarios but the electrolyzer is utilized 2% more compared to the percentages in the mix of solutions (18% vs. 20%), hence it could be said that reduction in electrolyzer CAPEX only has a small role in increasing the utilization (see **Figure 59** in appendix).

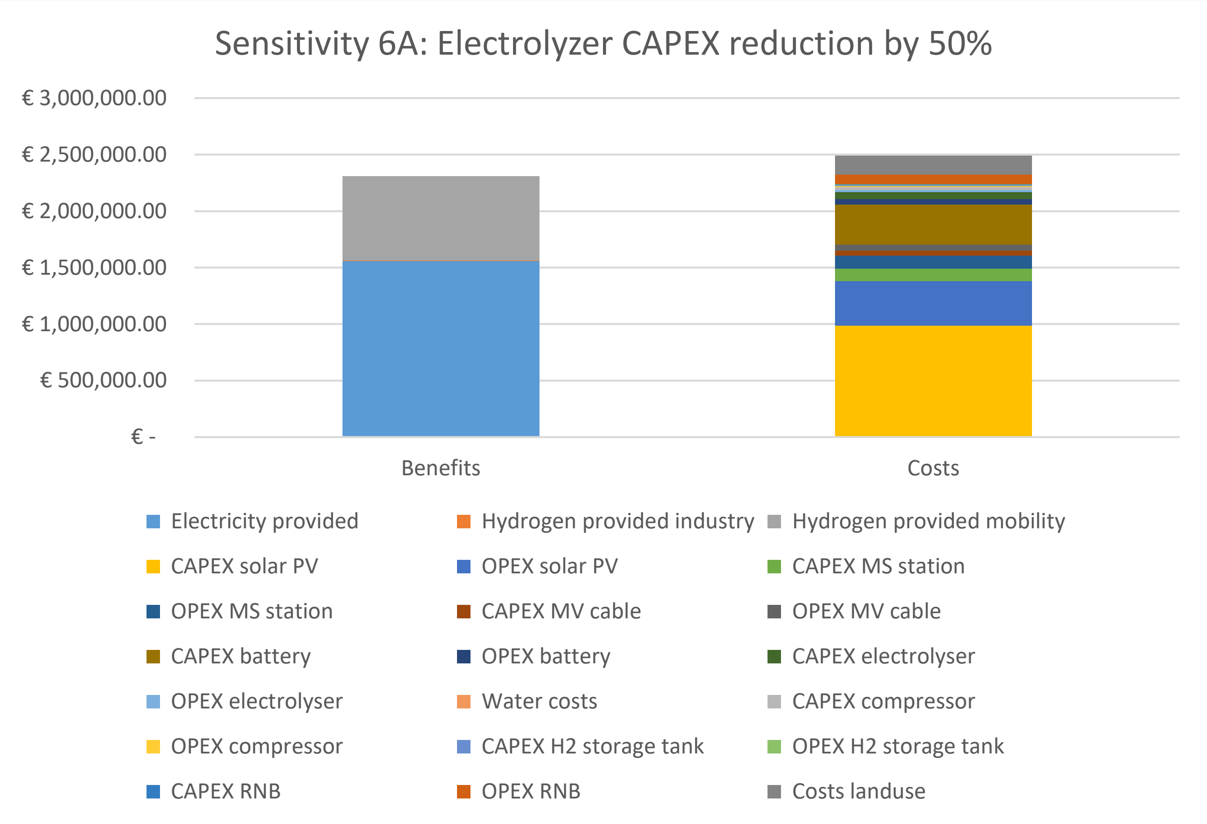


Figure 42: Annualized costs and benefits involved in sensitivity 6A where electrolyzer CAPEX is reduced by 50%

Table 21: Infrastructure costs per asset and overall Costs and Benefits for sensitivity 6A

Category	Benefits		Costs		Δ: B - C
Electricity provided	€	1,559,807.21	€	-	
Hydrogen provided industry	€	233.71	€	-	
Hydrogen provided mobility	€	748,559.47	€	-	
CAPEX solar PV	€	-	€	982,915.04	
OPEX solar PV	€	-	€	395,387.92	
CAPEX MV station	€	-	€	109,667.24	
OPEX MV station	€	-	€	120,000.00	
CAPEX MV cable	€	-	€	45,694.68	
OPEX MV cable	€	-	€	50,000.00	
CAPEX battery	€	-	€	356,244.89	
OPEX battery	€	-	€	45,120.00	
CAPEX electrolyser	€	-	€	63,038.63	
OPEX electrolyser	€	-	€	17,100.00	
Water costs	€	-	€	4,365.91	
CAPEX compressor	€	-	€	20,833.88	
OPEX compressor	€	-	€	13,385.00	
CAPEX H2 storage tank	€	-	€	6,914.76	
OPEX H2 storage tank	€	-	€	2,700.00	
CAPEX RNB	€	-	€	4,935.03	

OPEX RNB	€ -	€ 83,700.00	
Costs landuse	€ -	€ 165,995.69	
Total	**€ 2,308,600.38**	**€ 2,487,998.68**	**-€ 179,398.29**

4.3.6.2 Sensitivity 6B: Electrolyzer CAPEX at 0 €/kW

This sensitivity involves setting the CAPEX of the electrolyzer at 0 €/kW and is only done for indicative purposes. Interestingly enough, it is only under this scenario that hydrogen is also utilized for industrial usage but deriving only very minimal benefits. Under this scenario the benefits outweigh the costs by a slight margin due to the lack of any expenditures for the electrolyzer assets. **Figure 43** and Table 22 provide the detailed costs and benefits under this scenario. **Figure 44** shows the electricity distribution for this sensitivity, utilization of the electrolyzer is not surprisingly the highest among all the results (38% of the electricity is sourced directly to the electrolyzer) while only 1% is sourced to the electrolyzer via battery. 28% is stored in the battery and then sent to the grid while only 18% is utilized directly by the grid. **Figure 60** in the appendix shows the spatial footprint of such a sensitivity.

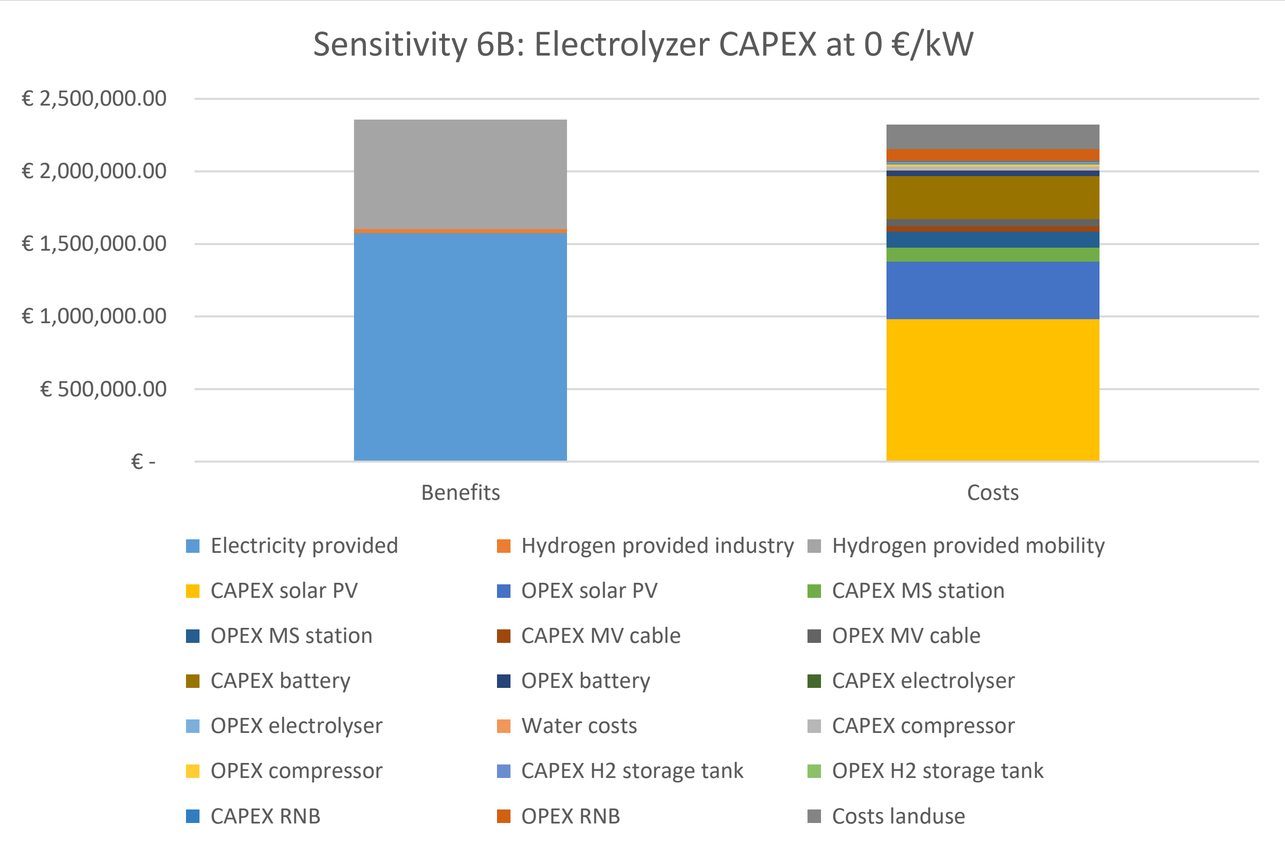


Figure 43: Annualized costs and benefits involved in sensitivity 6B where electrolyzers have a 0 €/kW CAPEX

Table 22: Infrastructure costs per asset and overall Costs and Benefits for sensitivity 6B

Category	Benefits	Costs	Δ: B - C
Electricity provided	€ 1,576,854.08	€ -	
Hydrogen provided industry	€ 26,824.96	€ -	
Hydrogen provided mobility	€ 755,085.19	€ -	
CAPEX solar PV	€ -	€ 982,915.04	
OPEX solar PV	€ -	€ 395,387.92	

CAPEX MV station	€ -	€ 98,700.52	
OPEX MV station	€ -	€ 108,000.00	
CAPEX MV cable	€ -	€ 41,125.22	
OPEX MV cable	€ -	€ 45,000.00	
CAPEX battery	€ -	€ 298,355.09	
OPEX battery	€ -	€ 37,788.00	
CAPEX electrolyser	€ -	€ -	
OPEX electrolyser	€ -	€ -	
Water costs	€ -	€ 5,146.00	
CAPEX compressor	€ -	€ 20,833.88	
OPEX compressor	€ -	€ 13,385.00	
CAPEX H2 storage tank	€ -	€ 13,829.52	
OPEX H2 storage tank	€ -	€ 5,400.00	
CAPEX RNB	€ -	€ 4,935.03	
OPEX RNB	€ -	€ 83,700.00	
Costs landuse	€ -	€ 165,527.67	
Total	**€ 2,358,764.24**	**€ 2,320,028.88**	**€ 38,735.36**

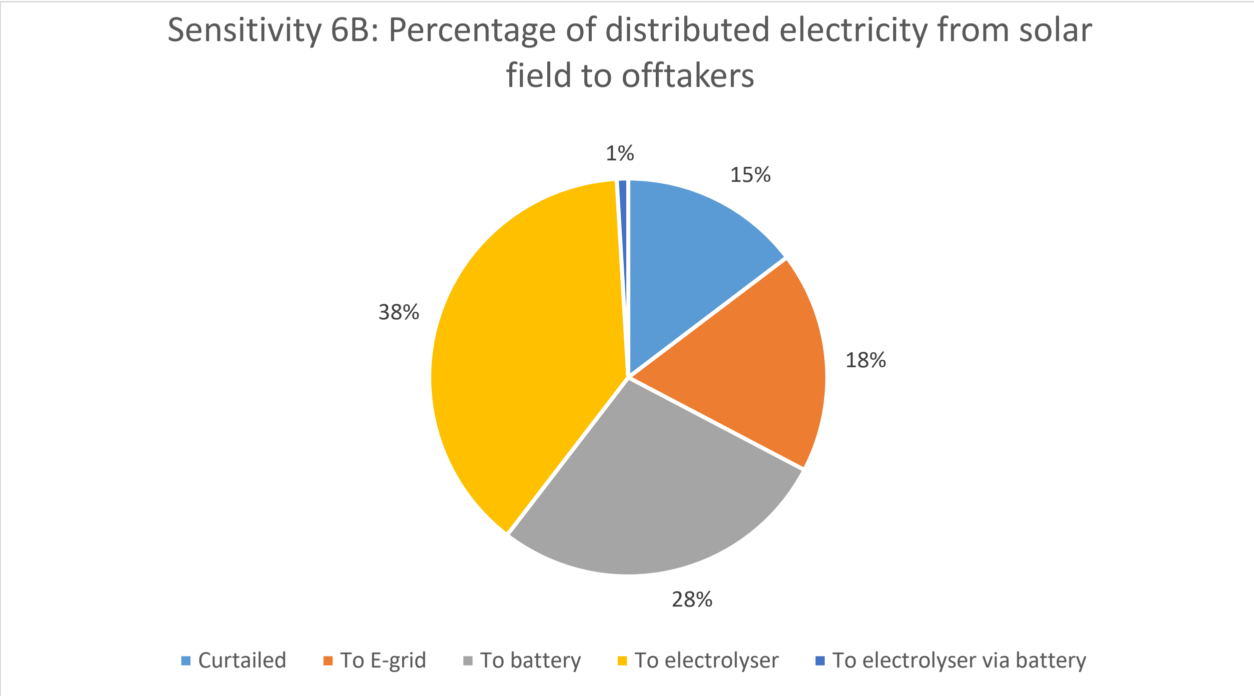


Figure 44: Distribution percentage of electricity from the solar park to the various off-takers for sensitivity 6B

4.3.7 Sensitivity 7: Electrolyzer and battery can use electricity from the grid

This final sensitivity examines how costs and benefits would change if the electrolyzer would utilize electricity from the grid. This approach however only makes sense if the electricity from the grid is of renewable origin - otherwise utilizing grey electricity for the production of hydrogen via electrolysis would be unreasonable - hence it is assumed that the electricity fed into the electrolyzer from the grid is of renewable origin. Under this scenario, slightly more hydrogen is sold to the mobility sector compared to the baseline mix of solutions scenario. **Figure 45** and Table 23 provide the detailed costs and benefits.

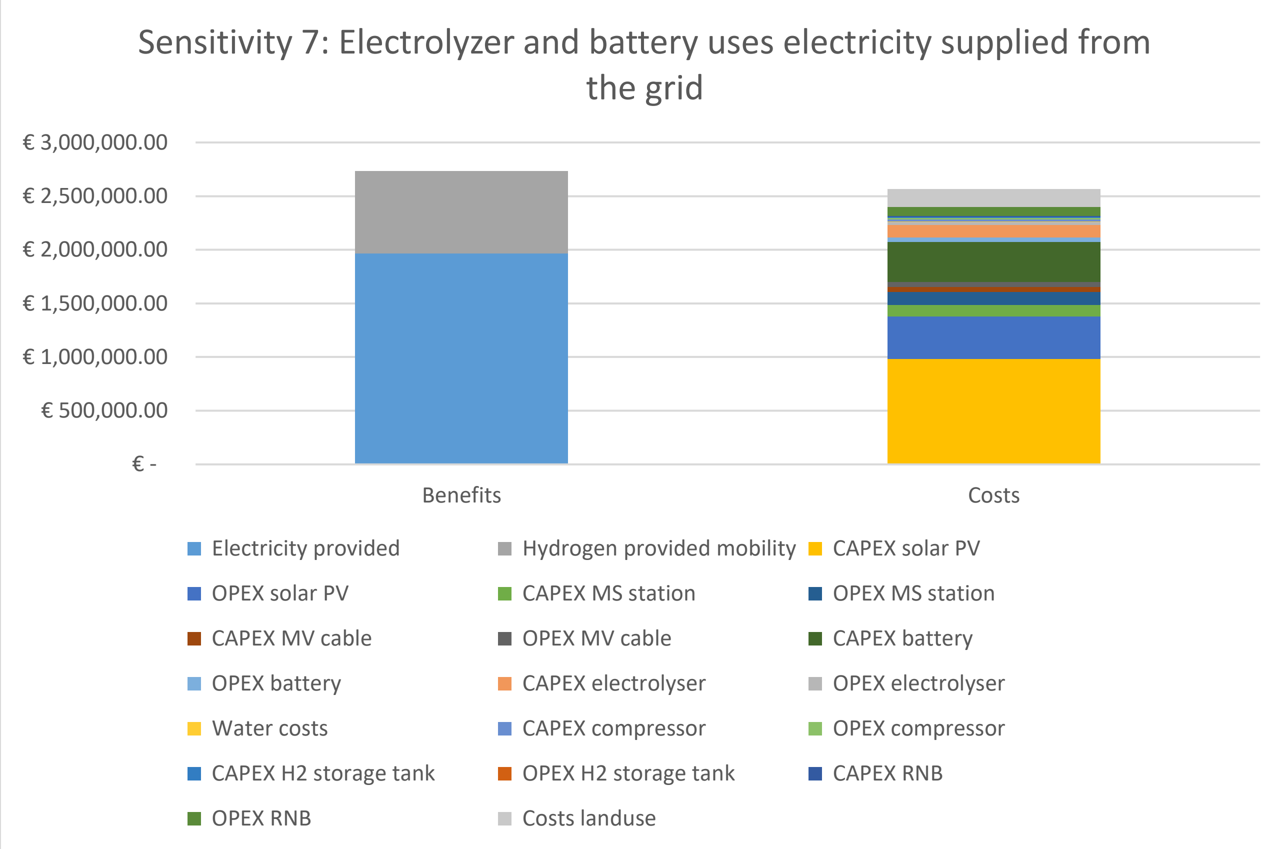


Figure 45: Annualized costs and benefits involved in sensitivity 7 where the electrolyzer and battery can source electricity from the grid

Table 23: Infrastructure costs per asset and overall Costs and Benefits for sensitivity 7

Category	Benefits	Costs	Δ: B - C
Electricity provided	€ 1,965,637.15	€ -	
Hydrogen provided mobility	€ 766,500.00	€ -	
CAPEX solar PV	€ -	€ 982,915.04	
OPEX solar PV	€ -	€ 395,387.92	
CAPEX MV station	€ -	€ 109,667.24	
OPEX MV station	€ -	€ 120,000.00	
CAPEX MV cable	€ -	€ 45,694.68	
OPEX MV cable	€ -	€ 50,000.00	
CAPEX battery	€ -	€ 367,377.54	
OPEX battery	€ -	€ 46,530.00	
CAPEX electrolyser	€ -	€ 112,068.68	
OPEX electrolyser	€ -	€ 30,400.00	
Water costs	€ -	€ 4,476.91	
CAPEX compressor	€ -	€ 20,833.88	
OPEX compressor	€ -	€ 13,385.00	
CAPEX H2 storage tank	€ -	€ 6,914.76	
OPEX H2 storage tank	€ -	€ 2,700.00	
CAPEX RNB	€ -	€ 4,935.03	
OPEX RNB	€ -	€ 83,700.00	
Costs landuse	€ -	€ 166,025.30	
Total	**€ 2,732,137.15**	**€ 2,563,011.98**	**€ 169,125.16**

Figure 46 depicts the distribution of electricity under this scenario. Compared to the mix of solutions explored in the baseline results, less electricity is curtailed in this situation (14% vs 20%) but the same amount of electricity is sent to the e-grid. There is an increased percentage of electrolyzer utilization compared to the baseline mix of solutions (25% vs 18%). There is a significant increase in battery utilization (44% vs 30%) while utilization of the battery via the electrolyzer stands at only 2% compared to 17%. Battery utilization is significant because higher yields of electricity can be sourced and stored from the grid compared to the yields from the solar field therefore it is used more. Combined usage of the battery and electrolyzer is significantly lower, since there are few moments where it would be optimal for the electrolyzer to store the electricity from the solar field at a lower electricity price compared to the prices of electricity on the grid in order to sell hydrogen. The spatial footprint of this scenario is in **Figure 61** in the appendix section.

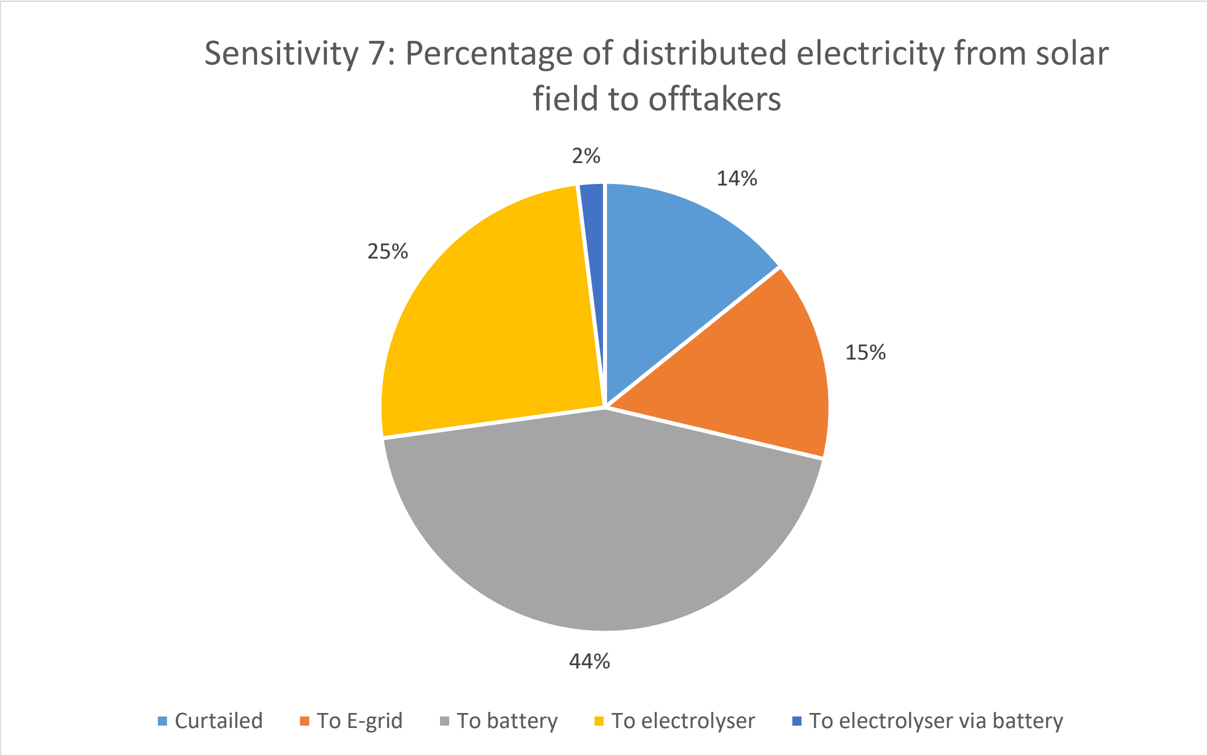


Figure 46: Distribution percentage of electricity from the solar park to the various off-takers for sensitivity 7

4.4 Overview results

As on overview of the various results shared, Table 24 provides a comparison of the costs and benefits for the presented results while Table 25 provides the electricity distribution profile for each of the presented scenarios.

Table 24: Overview of annualized costs and benefits for the different scenario's

Scenario	Benefits - €	Costs - €	Δ: B – C
Conventional Grid Expansion	2,298,167.27	3,126,107.66	-827,940.39
Mix of solutions	2,299,762.62	2,550,285.41	-250,522.78
Sensitivity 1A: Distance to HRS: 0km Distance to HV/MV Station: 20 km	2,241,262.90	2,503,329.39	-262,066.49
Sensitivity 1B: Distance to HRS: 20km Distance to HV/MV Station: 1 km	1,987,044.10	2,220,429.76	-233,385.65
Sensitivity 2A: PV Capacity: +500% E-demand: -50%	9,900,384.76	12,267,696.20	-2,367,311.44
Sensitivity 2B: PV Capacity: -50% E-demand: +500%	1,321,056.41	3,579,893.15	-2,258,836.74
Sensitivity 3A: Hydrogen price: +25% Electricity price: -25%	2,022,800.83	2,463,510.01	-440,709.17
Sensitivity 3B: Hydrogen price: -25% Electricity price: +25%	2,516,511.69	2,365,171.18	+151,340.51
Sensitivity 4A: No RNB	2,299,762.62	2,600,484.00	-300,721.38
Sensitivity 4B: No RNB – No RTL – Trucks only	1,988,373.02	2,337,448.82	-349,075.80
Sensitivity 5: 2x Mobility Demand	2,523,260.39	2,621,947.18	-98,686.79
Sensitivity 6A: Electrolyzer CAPEX: -50%	2,308,600.38	2,487,998.68	-179,398.29
Sensitivity 6B: Electrolyzer CAPEX: 0	2,358,764.24	2,320,028.88	+38,735.36
Sensitivity 7: Electrolyzer with grid-electricity	2,732,137.15	2,563,011.98	+69,125.16

Table 25: Electricity distribution profiles for each of the scenario's

Scenario	**Percentage of distribution**				
	Curtailed	*E-grid*	*Battery*	*Electrolyzer*	*Electrolyzer via battery*
Conventional Grid Expansion	-	100%	-	-	-
Mix of solutions	20%	15%	30%	18%	17%
Sensitivity 1A: Distance to HRS: 0km Distance to HV/MV Station: 20 km	24%	13%	29%	18%	16%
Sensitivity 1B: Distance to HRS: 20km Distance to HV/MV Station: 1 km	21%	29%	50%	-	-
Sensitivity 2A: PV Capacity: +500% E-demand: -50%	27%	21%	44%	4%	4%
Sensitivity 2B: PV Capacity: -50% E-demand: +500%	9%	13%	19%	29%	30%
Sensitivity 3A: Hydrogen price: +25% Electricity price: -25%	28%	12%	26%	18%	16%
Sensitivity 3B: Hydrogen price: -25% Electricity price: +25%	19%	29%	52%	-	-
Sensitivity 4A: No RNB	20%	15%	30%	18%	17%
Sensitivity 4B: No RNB – No RTL – Trucks only	21%	29%	50%	-	-
Sensitivity 5: 2x Mobility Demand	19%	9%	16%	29%	27%
Sensitivity 6A:	19%	16%	30%	20%	15%

Electrolyzer CAPEX: -50%					
Sensitivity 6B: Electrolyzer CAPEX: 0	15%	18%	28%	38%	1%
Sensitivity 7: Electrolyzer with grid-electricity	14%	15%	44%	25%	2%

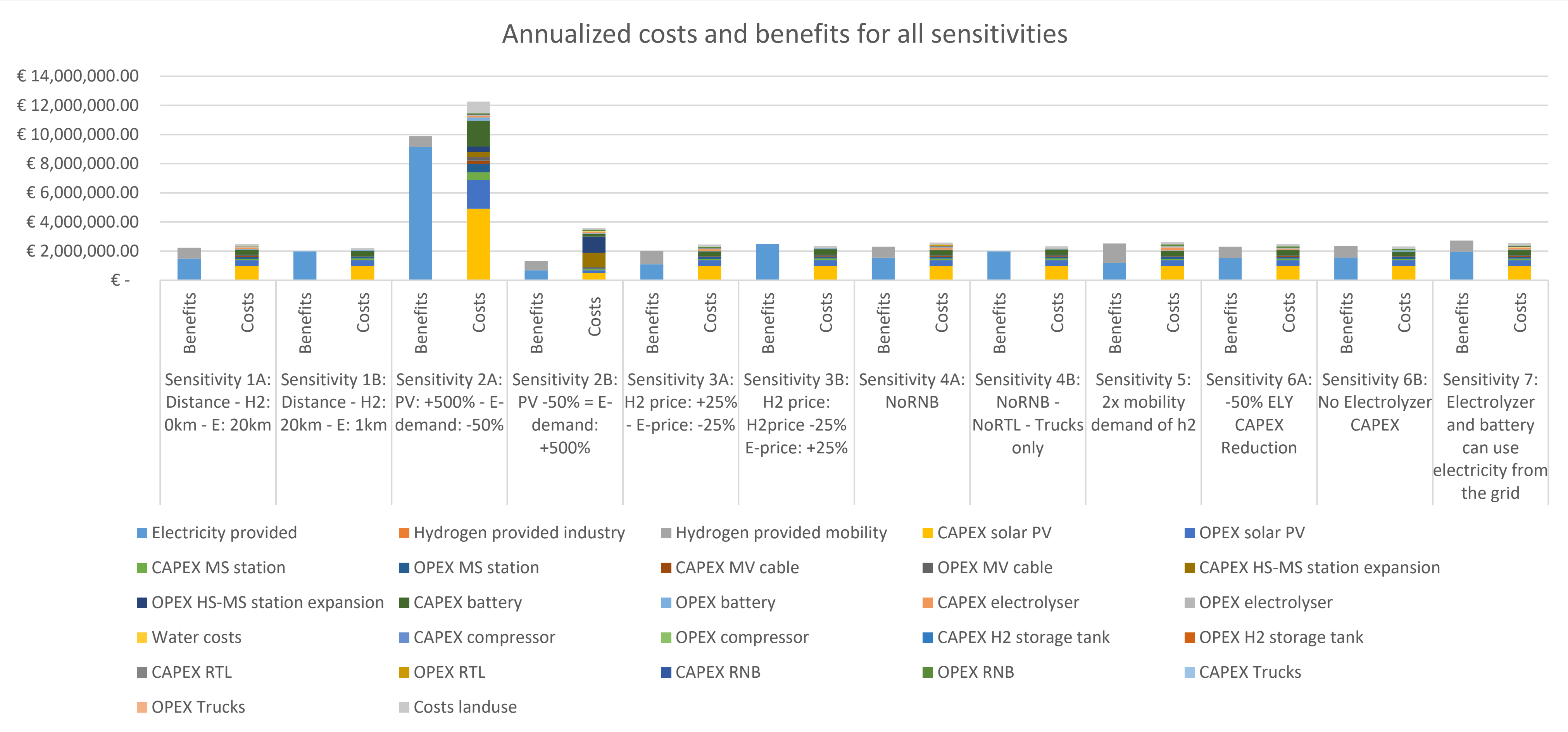


Figure 47: All annualized costs and benefits for the sensitivity scenarios

Figure 47 combines all the annualized costs and benefits for each of the sensitivities. For all the graphical data such as the spatial footprint of all scenarios and the distribution of electricity from the solar park to various resources more detailed graphs and costs are included in the appendix.

5. Implications of Results

The results of this study show that newly added solar parks in rural regions where electricity supply exceeds demand already during peak moments, higher mutual stakeholder net benefits can be achieved if we would connect the solar parks via multiple options rather than solely reinforcing the local electricity grid.

It should be mentioned that the proposed mix of solutions is not likely to be seen in practise, among others due to current legislation and market regulations. Distribution grid operators are obligated to facilitate all parties that are willing to get a grid connection: local energy producers, consumers but also potential flexibility providers through batteries and electrolysers. All such parties will manage the operation of their assets to maximize their own profits. In HyDelta WP2[9] we saw for example that the electrolyser running only by market prices will not be able to reduce grid investments without any additional measures. Therefore, our results are not applicable directly under the existing legislative framework, but indicate that a mix of solutions can reduce electricity grid investments significantly if legislation will support these options to be aligned according to the local grid its needs.

We noticed that each solution has a different role in the mix:

- Grid reinforcements help to inject the bulk of produced electricity as we are used to in the traditional way of connecting solar PV parks;
- Curtailment helps to limit large grid investments that are only required to facilitate injection of the highest solar generation overshoots for a very small number of hours during the year;
- The batteries help to optimize the utilization of electricity grid capacity and increases the local match between generation and demand;
- The power-to-gas system potentially can help to match local supply and demand of energy better, if there are more structural overshoots of electricity generation in the region. It turns out that it is more effective to use this electricity to serve demand of other energy carriers in the region than to invest in the equipment to export the electricity to the transmission grid.

The first three solutions are part of the mix for most of the researched cases. By performing sensitivity analysis, we identified the main conditions under which the hydrogen option can be beneficial to integrate additional large solar parks in a specific region:

- Mainly regions with relatively a lot of solar electricity generation compared to the regional electricity demand (e.g. rural area's with relatively a lot of space compared to buildings and industrial activity);
- A precondition for the hydrogen option is that a good hydrogen price is received compared to electricity. The assumed price of 7 €/kg hydrogen for mobility applications was sufficient in most of the cases. An industrial price of 2 €/kg was not sufficient;
- The degree in which electricity is converted to hydrogen depends also on the availability of renewable hydrogen demand for applications that are willing to pay a sufficient price (e.g. we saw more PtG was applied if two instead of one HRS was assumed in the region);
- An RNB pipeline section should be made available for re-use in order to enable cost-efficient transport of the hydrogen to the demand location; or the demand location should be next to the solar PV park (e.g. HRS located near the newly installed solar field). Since we have seen

[9] See HyDelta 2 D2.2 (to be published)

that transport by trucks is too expensive and the RTL is cost efficient but the volumes were relatively low in our examples compared to the transport capacity of an average RTL pipeline.

Next to these preconditions, also the regional transport distances of hydrogen and electricity determined to a lesser extent the applicability of the region. Moreover, a reduction in electrolyser CAPEX (as expected towards 2030) will make the hydrogen option more favourable.

Another important aspect worth mentioning is about how the utilization of large-scale supply-side batteries played a significant role in balancing the fluctuating supply from the solar park and played the largest role in terms of providing flexibility for most of the scenarios and sensitivities we looked into. This is because batteries can provide relief from grid congestion, and solar PV parks combined with batteries require smaller grid connections. In addition they provide their worth by offering protection against price risks because electricity no longer needs to be supplied at the same time that is generated [38].

The business case for batteries will improve in the coming years. This is because batteries will quickly become cheaper in the future, while revenues will increase due to greater fluctuations in electricity prices. The network tariffs for charging the battery from the grid will remain the same over time. Due to the decrease in other costs, the share of the network tariffs in the total costs will therefore increase from about 25% now to 35% in 2030 [38].

The size of battery storage in the Netherlands is expected to grow from about 70 MW now to about 1 to 1.5 GW in 2030 [38]. This increase is due to batteries becoming profitable in new markets and the size of some markets growing. Battery operators can already profitably make their battery system available to TenneT to maintain the grid frequency. Around 2030, batteries will also become profitable on the imbalance market [38]. Parties on the imbalance market can voluntarily contribute to maintaining the system balance. Finally, batteries can already earn good income by solving network operators' congestion problems on the congestion market.

However, batteries at solar parks will not become profitable before 2030 without additional policy. Policy must therefore be designed that has additional conditions to only stimulate the intended type of batteries in the intended application, for example an investment subsidy with strict preconditions [38] (for more information on policy recommendations on implementing large-scale batteries for dealing with supply-side congestion see [38]).

For most of the scenarios involving the mix of proposed solutions, the direct uptake of generated electricity from the solar field to the electrolyzer proved to have considerable utilization but it was in combination with large-scale batteries where the utilization potential of electrolyzers is significantly increased. Adding battery capacity, electricity from the congestion hours could be stored for the short term and be released in a spread fashion over time to the electrolyzer. This way the electrolyzer can absorb more - otherwise curtailed - electricity with a lower installed capacity and increased utilization rate. This can also have great potential behind the meter at companies who want to produce and consume their own hydrogen.

Table 26: Percentage of Electrolyzer and Electrolyzer via large-scale battery utilization

Scenario	*Electrolyzer*	*Electrolyzer via battery*	*Total Electrolyzer Utilization*	*Electrolyzer Capacity (MW)*	*Battery Capacity (MW)*
Conventional Grid Expansion	-	-			
Mix of solutions	18%	17%	35%	0.8	16
Sensitivity 1A: Distance to HRS: 0km Distance to HV/MV Station: 20 km	18%	16%	34%	0.8	15.3
Sensitivity 1B: Distance to HRS: 20km Distance to HV/MV Station: 1 km	-	-	-		
Sensitivity 2A: PV Capacity: +500% E-demand: -50%	4%	4%	8%	0.8	79.6
Sensitivity 2B: PV Capacity: -50% E-demand: +500%	29%	30%	59%	0.7	8.6
Sensitivity 3A: Hydrogen price: +25% Electricity price: -25%	18%	16%	34%	0.8	13.9
Sensitivity 3B: Hydrogen price: -25% Electricity price: +25%	-	-	-		
Sensitivity 4A: No RNB	18%	17%	35%	0.8	16
Sensitivity 4B: No RNB – No RTL – Trucks only	-	-	-		
Sensitivity 5: 2x Mobility Demand	29%	27%	56%	1.5	15.1
Sensitivity 6A: Electrolyzer CAPEX: -50%	20%	15%	35%	0.9	16
Sensitivity 6B: Electrolyzer CAPEX: 0	38%	1%	39%	4.8	13.4

Sensitivity 7: Electrolyzer with grid-electricity	25%	2%	27%	0.8	16.5

Table 26 shows how the utilization percentages of electrolyzers and electrolyzer + battery combinations changed per sensitivity and what the corresponding capacities of the electrolyzers and batteries were. One trend that was seen among the various results for the sensitivities was that in the mixed solution cases where the photo-voltaic capacity of the solar field was lower compared to the default 38MWp capacity, higher utilization of electrolyzers, batteries and combined electrolyzers and batteries were achieved. This effect was highlighted in sensitivity 2B where the capacity of the solar field was reduced by 50%, conversely, the opposite effect was gained when the photo-voltaic capacity was increased by 500% in sensitivity 2A. This lead to a much lower utilization of electrolyzers and electrolyzers in combination with batteries while singular utilization of batteries increased significantly where in the case of sensitivity 2B this was 44% (see Table 25). Based on this trend, it can be suggested that electrolyzers and electrolyzer + battery combinations could be utilized more sufficiently and strategically under lower solar PV capacities where their contribution as a grid flexibility asset is more significant whereas their contribution in much higher PV capacities takes a back seat and supply-side battery solutions play a much more robust role in providing supply-side flexibility. All of this is rooted in the influential role that electricity prices play and the higher reapable profit margins that electricity achieves over green hydrogen. When there is a limited pool of profit from the selling of electricity at disposal (due to a smaller solar field capacity) and a mix of grid flexibility solutions are implemented (e.g., electrolyzers, batteries etc.), the model opts for including hydrogen as a means of revenue but in cases where the cumulative yield of electricity production via a solar field with a high capacity is available batteries dominate and electricity as a revenue stream stands out boldly.

This aforementioned effect is shown in sensitivity 3B where the electricity price is increased by 25% and hydrogen price is reduced by 25%. Simply no hydrogen is produced and the revenues from the selling of electricity are significantly increased, here, batteries play an important role in increasing these revenues due to the effects of arbitrage. Hence what could be said is that supply-side batteries have potential to provide significant flexibility and profits to RES providers.

Another important factor is that transportation of hydrogen via tube-trailers was not an attractive option at all. This is due to the higher expenses of purchasing the trucks, labour costs, operational expenditures of the truck. RNB pipeline were the preferred mode of transporting hydrogen to HRS stations, however the model did not calculate the costs involved in re-purifying the hydrogen via RNB pipelines if they are to be used in an HRS station. Re-used pipelines do have the potential to impurify the hydrogen, hence if this route is taken, special components need to be installed to maintain the purity of hydrogen suitable for use at a hydrogen refuelling site. RNB pipelines could be less cost-effective in comparison to trucks under his scenario but this requires a more thorough investigation.

Very limited benefits were derived of hydrogen usage in industries, and this only occurred in sensitivity 6B where the electrolyzer CAPEX was set to 0€/kW. Electrolyzer utilization was the highest under this scenario which is expected. What can be said is that reduced electrolyzer CAPEX can increase electrolyzer utilization.

6. Conclusions

In order to move towards a renewable energy system in the Netherlands, an increasing capacity of renewables has to be connected to the electricity grid. This causes very serious e-grid congestion issues. Reinforcement of the e-grid can be very expensive if technologically and/or legally feasible at all, costs considerable time for various reasons and requires an electrotechnical workforce that often is not or scarcely available. So, Dutch electricity DSOs are facing growing congestion problems in providing grid connections in time for new renewable energy capacities. It is in fact likely that in the Netherlands e-grid congestion will be a reality and growing concern for at least the coming decade. This results in sometimes long connection waiting times for solar and wind farms (i.e., supply-side congestion) and similar adverse access conditions for the energy end-users (demand-side congestion), and also means that in the near future new solar and wind farms will not be able to deliver electricity to the grid at all times.

As a means of looking for solutions and approaches to tackle this issue, this study looked into alternative supply-side grid flexibility solutions provided by electrolyzers, batteries and their combinations alongside curtailment methods in comparison to traditional grid expansion techniques. These methods were investigated within the context of a quasi-realistic setting where a 38MWp solar park is established in a region dealing with serious supply-side grid congestion, the electricity demand characteristics of e-grid users of a region in Friesland served as the basis. This similitude allowed us to look into the costs and benefits of how various e-grid flexibility options would fare under decentral production areas.

Comparisons were made between the annualized costs and benefits of traditional grid expansion measures and a mix of solutions and is shown **Figure 48**.

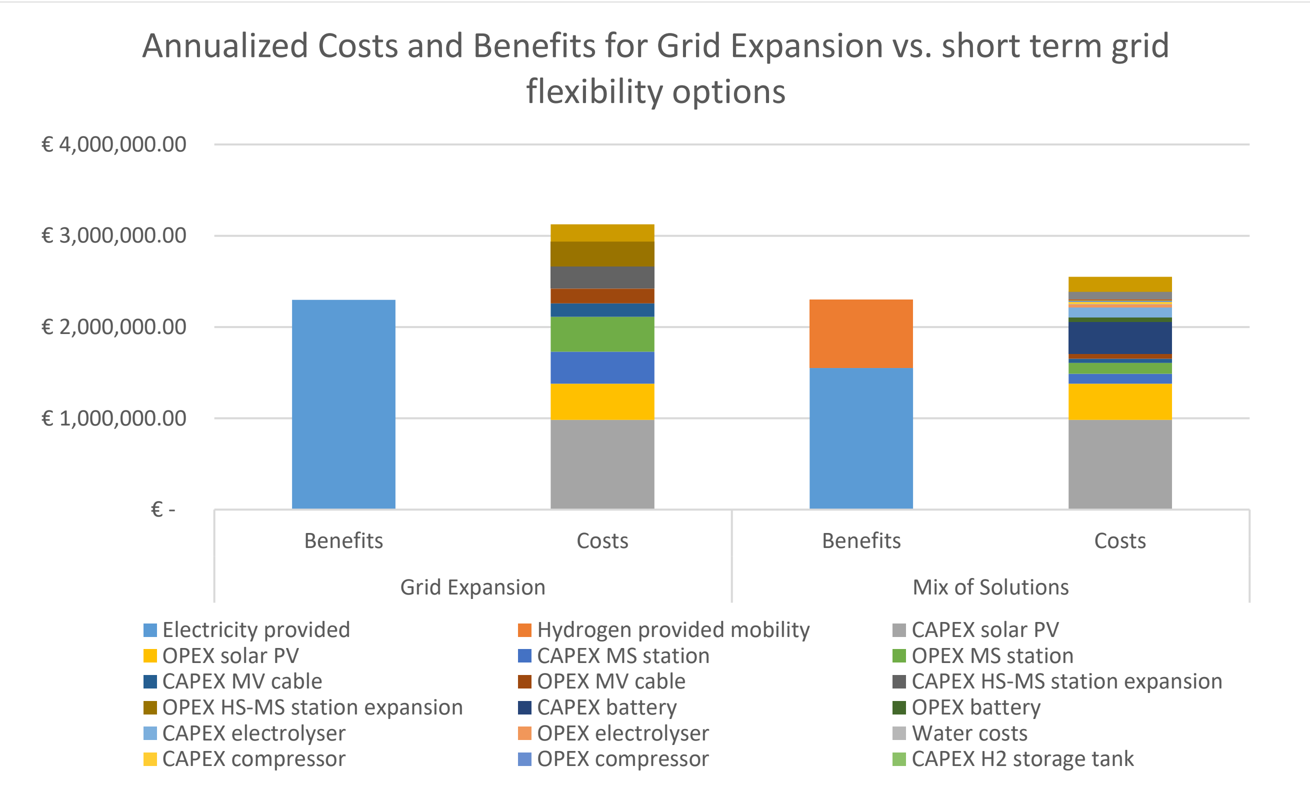


Figure 48: Annualized costs and benefits for grid expansion vs a mix of solutions

The overall result of the case analysis of newly added solar capacity in a rural supply-congestion region, i.e. where electricity supply already exceeds demand during peak moments, is that under the current (2023) cost and energy price conditions higher stakeholder net benefit can be achieved by connecting the solar park to the market via multiple flexibility options rather than by just reinforcing the local electricity grid.

Various other sensitivities were also explored to see how utilization of different flexibility assets changes by altering different variables. These were done by looking into changing the distances between the solar park and a hydrogen refuelling station, changes in the capacity of the solar park and electricity demand, changes in hydrogen and electricity price, changes in the mode of transport of hydrogen via the RTL and tube trailers, doubling the mobility demand, changing the CAPEX of electrolyzers and also sourcing the electricity from the grid. Among these sensitivities, changes in hydrogen prices and electricity prices played a prominent role and increases in hydrogen prices lead to higher benefits being gained by selling hydrogen to mobility applications. This was even higher when the demand for mobility was doubled. Mobility applications of hydrogen dominated since in the optimum, green hydrogen demand from local mobility was much higher than from local decentralized industry because a higher price is received per kg of hydrogen in the mobility market compared to industry.

Model results showed that large-scale batteries also proved to show great potential as a provider of flexibility for supply-side congestion since they were utilized significantly for scenarios involving a mix of solutions. Combinations of batteries with PTG units proved to be effective in increasing the utilization of the electrolyzer unit, hence combinations of these two warrants more investigations.

All in all, our results suggest that it is promising to investigate alternative ways to integrate new local renewable energy capacities, especially in rural regions where large installed capacities of solar generation regularly exceed the relatively small demand for electricity. However, the alternative ways that we identified do require alignment of stakeholders interests and a legislative framework that supports this. Based on this, it is important to emphasize the role that governmental policies and incentives can play next to the development of new technologies in the expansion of cheaper renewable sources of energy. Therefore, two directions of further investigations are required to bring these findings forward. A short supplementary deliverable (D4.3 – Report on the main policy implications of the blending options researched) has been created to provide a more detailed policy recommendation based on the findings derived from this study, it is recommended that the reader also refer to that document for more detailed insights.

References

[1] International Energy Association - IEA, "The Netherlands 2020 Energy Policy Review," IEA, 2020.

[2] H. Kondziella and T. Bruckner, "Flexibility requirements of renewable energy based electricity systems – a review of research results and methodologies," *Renewable and Sustainable Energy Reviews,* vol. 53, pp. 10-22, 2016.

[3] Netbeheer Nederland, "Basisdocument over energie infrastructuur," 24 May 2019. [Online]. Available: https://www.netbeheernederland.nl/_upload/Files/Basisdocument_over_energie-infrastructuur_143.pdf. [Accessed 22 November 2022].

[4] S. Ghaemi, X. Li and M. Mulder, "Economic feasibility of green hydrogen in providing flexibility to medium-voltage distribution grids in the presence of local-heat systems," *Applied Energy,* 2023.

[5] L. Hirth and S. Glismann, "Congestion Management: From physics to Regulatory Instruments," *EconStor Preprints,* 2018.

[6] K. Poplavskaya, M. Joos, V. Krakowski, K. Knorr and L. de Vries, "Redispatch and balancing: Same but different. Links, conflicts and solutions," in *17th International Conference on the European Energy Market (EEM)*, Sweden, 2020.

[7] X. Yan, C. Gu, X. Zhang and F. Li, "Robust optimization-based energy storage operation for system congestion management.," *IEEE Trans Power Syst,* vol. 14, no. 2, pp. 2694 - 2702, 2020.

[8] F. Shen, Q. Wu, X. Jin, B. Zhou, C. Li and Y. Xu, "ADMM-based market clearing and optimal flexibility bidding of distribution-level flexibility market for day-ahead congestion management of distribution networks," *Internation Journal of Electric Power Energy Systems,* vol. 123, 2020.

[9] European Commission, "EU Hydrogen Strategy," 8 July 2020. [Online]. Available: https://ec.europa.eu/commission/presscorner/detail/en/FS_20_1296. [Accessed 25 January 2023].

[10] X. Li and M. Mulder, "Value of power-to-gas as a flexibility option in integrated electricity and hydrogen markets," *Applied Energy,* vol. 304, 2021.

[11] A. Lewandowska-Bernat and U. Desideri, "Opportunities of power-to-gas technology in different energy systems architectures," *Applied Energy,* vol. 228, pp. 57 - 67, 2018.

[12] M. Berger, D. Radu, R. Fonteneau, T. Deschuyteneer, G. Detienne and D. Ernst, "The role of power-to-gas and carbon capture technologies in cross-sector decarbonisation strategies," *Electric Power Systems Research,* vol. 180, 2020.

[13] M. Robinius, T. Raje, S. Nykamp, T. Rott, M. Müller, T. Grube, B. Katzenbach, S. Küppers and D. Stolten, "Power-to-Gas: Electrolyzers as an alternative to network expansion – An example from a distribution system operator," *Applied Energy,* pp. 182 - 197, 2018.

[14] A. De Corato, I. Saedi, S. Riaz and P. Mancarella, “Aggregated flexibility from multiple power-to-gas units in integrated electricity-gas-hydrogen distribution systems,” *Elecric Power Systems Research,* vol. 212, 2022.

[15] S. Henni, P. Staudt, B. Kandiah and C. Weinhardt, “Infrastructural coupling of the electricity and gas distribution grid to reduce renewable energy curtailment,” *Applied Energy,* vol. 288, 2021.

[16] IRENA, “Making powersystems more flexible as global energy transition accelerates,” IRENA, 13 November 2018. [Online]. Available: https://www.irena.org/news/articles/2018/Nov/Making-power-systems-more-flexible-as-global-energy-transition-accelerates. [Accessed 23 November 2022].

[17] Netbeheer Nederland, “Capaciteitskaart invoeding elektriciteitsnet,” Netbeheer Nddelrand, 20 February 2023. [Online]. Available: https://capaciteitskaart.netbeheernederland.nl/. [Accessed 27 February 2023].

[18] Regiegroep Regionale Energue Strategie RES Fryslan, “Fryslan Regionale Energie Strategie,” 2021.

[19] Liander, Netbeheer Nederland, “Impact van concept RES scenario's op de elektriciteits- en gasinfrastructuur RES regio Fryslan,” Liander, Netbeheer Nederland, 2021.

[20] Vollmer + partners, “Zonnepark De Ekers, inpassingsplan,” Vollmer + partners, [Online]. Available: https://www.vp.nl/zonnepark-de-ekers-ruimtelijke-inpassingsplan.html. [Accessed 27 February 2023].

[21] Enexis Netbeheer, Tennet, Netbeheer Nederland, “Grid Impact Report,” 2020.

[22] ENTSOE, “Distributed Flexibility and the value of TSO/DSO cooperation,” ENTSOE, ?.

[23] A. Heider, R. Reibsch, P. Blechinger, A. Linke and G. Hug, “Flexibility options and their representation in open energy modelling tools,” *Energy Strategy Reviews,* vol. 38, 2021.

[24] G. Romijn and G. Renes, “General Guidance for Cost-Benefit Analysis,” CPB Netherlands Bureau for Economic Policy Analysis; PBL Netherlands Environmental Assessment Agency.

[25] IRENA, “Smart Grids and Renewables: A cost-benefit analysis guide for developing countries,” International Renewable Energy Agency, 2013.

[26] Groenleven, “Zonnepark Oosterwolde,” Groenleven, [Online]. Available: https://groenleven.nl/projecten/zonnepark-oosterwolde/. [Accessed 15 12 2022].

[27] Liander, “Vooraankondiging verwachte congestie verdeelstation Oosterwolde,” Liander, 2019.

[28] Liander, “Beschikbare data - Decentrale opwek Zon Kleinverbruik,” 24 11 2020. [Online]. Available: https://www.liander.nl/partners/datadiensten/open-data/data. [Accessed 29 11 2022].

[29] Liander, “Beschikbare data - Kleinverbruiksdata per jaar,” 01 01 2020. [Online]. Available: https://www.liander.nl/partners/datadiensten/open-data/data. [Accessed 29 11 2022].

[30] Liander, “Congestiegebied Wolvega,” Liander, 2022.

[31] v. Z. R., K. J., J. C., v. S. M. and M. S., “D7A.2 - Techno-economic analysis of hydrogen value chains in the Netherlands: value chain design and results,” HyDelta, 2022.

[32] S. Hers, B. Koirala, Y. Melese, S. Blom and F. Taminiau, “Energy System and Market Analysis,” North Sea Energy, 2022.

[33] Liander, “Beschikbare data - Verbruiksprofielen,” [Online]. Available: https://www.liander.nl/partners/datadiensten/open-data/data. [Accessed 23 11 2022].

[34] TNO, DNV, “Eindadvies Basisbedragen SDE++ 2022,” Planbureau voor de Leefomgeving, Den Haag, 2022.

[35] G. Janssen, “Technology factsheet - Compressed hydrogen storage,” TNO, 2020.

[36] N. Rustagi, A. Elgowainy and J. Vickers, “DOE Hydrogen and Fuel Cells Program Record,” DOE, 2018.

[37] S. Lamboo, “Technology factsheet - Lithium-ion battery for power applications,” TNO, 2019.

[38] CE Delft, “Omslagpunt grootschalige batterijopslag,” CE Delft, 2021.

[39] Netbeheer Nederland, “Bijlagen Het Energiesysteem van de Toekomst: Integrale Infrastructuurverkenning 2030-2050,” Netbeheer Nederland, 2021.

[40] Stedin, “Criteria Kabels en Leidingen,” Stedin.

[41] KIWA, “Toekomstbestendige gasdistributienettenq,” Netbeheer Nederland, 2018.

[42] M. Reuß, T. Grube, M. Robinus, P. Preuster, P. Wasserscheid and D. Stolten, “Seasonal storage and alternative carriers: A flexible hydrogen supply chian model,” *Applied energy,* no. 200, pp. 290-302, 2017.

[43] Homer Pro 3.11, “Annualized Costs,” Homer Energy, [Online]. Available: https://www.homerenergy.com/products/pro/docs/3.11/annualized_cost.html. [Accessed 23 01 2023].

[44] IRENA, “Power System Flexibility for the Energy Transition,” International Renewable Energy Agency , Abu Dhabi, 2018.

[45] D. Möst, S. Schreiber and M. Jakob, “Introduction,” in *The Future European Energy System: renewable energy, flexibility options and technological progress*, D. Möst, Ed., Cham, Springer, 2021, pp. 3-7.

[46] Liander, [Online]. Available: https://www.liander.nl/sites/default/files/20190924%20Vooraankondiging%20verwachte%20congestie%20verdeelstation%20Oosterwolde%20v1.0.pdf . [Accessed 03 February 2023].

[47] Phase to Phase, “Netten voor distributie van elektriciteit,” Phase to Phase, 01 January 2023. [Online]. Available: https://phasetophase.nl/boek/boek_1_2.html. [Accessed 08 February 2023].

[48] R. van Zoelen, “Flexible hydrogen production from the perspective of the electrolyzer and storage operator,” 2020.

[49] Investing.com, “Dutch TTF Natural Gas Historische data,” 12 8 2022. [Online]. Available: https://nl.investing.com/commodities/dutch-ttf-gas-c1-futures-historical-data. [Accessed 12 8 2022].

[50] EEX, “EU ETS Auctions,” 12 8 2022. [Online]. Available: https://www.eex.com/en/markets/environmental-markets/eu-ets-auctions.

[51] Windturbinemodels.com, “Nordex N100 Delta,” [Online]. Available: https://en.wind-turbine-models.com/turbines/438-nordex-n100-delta. [Accessed 01 08 2022].

[52] Enexis, “Tarieven,” [Online]. Available: https://www.enexis.nl/tarieven. [Accessed 01 08 2022].

[53] O. Ruhnau, “How flexible electricity demand stabilizes wind and solar market values: The case of hydrogen electrolyzers,” *Applied Energy,* 2022.

[54] CE Delft, “Kernrapport Beleid voor grootschalige batterijsystemen en afnamenetcongestie,” CE Delft, 2023.

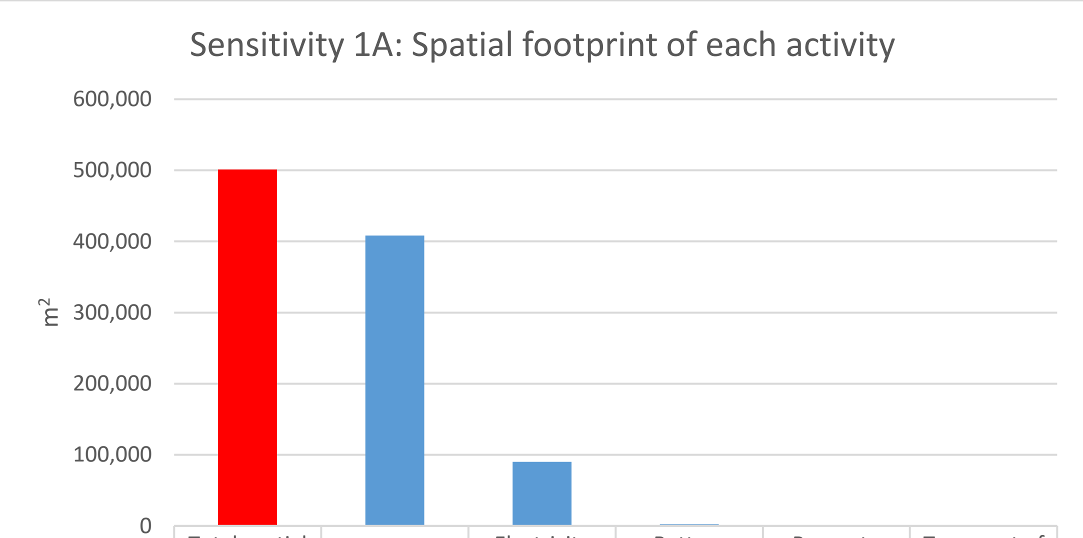
[55] L. van Cappellen, J. Vendrik and C. Jongsma, “Omslagpunt grootschalige batterijopslag,” CE Delft, 2022.

[56] RES Fryslan, “Regionale Energie Strategie Fryslan,” 2021.

Appendix

A. Additional graphical and tabular data for each of the sensitivities:

A.1 Sensitivity 1A: Distance to HRS Station: 0km – Distance to HV/MV Station: 20km



	Total spatial impact	Generation	Electricity grid	Battery system	Power to gas system	Transport of hydrogen
Area (m2)	500,968.90	408,191.40	90,004.50	2,295.00	478.00	0.00

Figure 49: Spatial footprint of the different energy infrastructures for Sensitivity 1A where distance to HRS Station: 0km – Distance to HV/MV Station: 20km

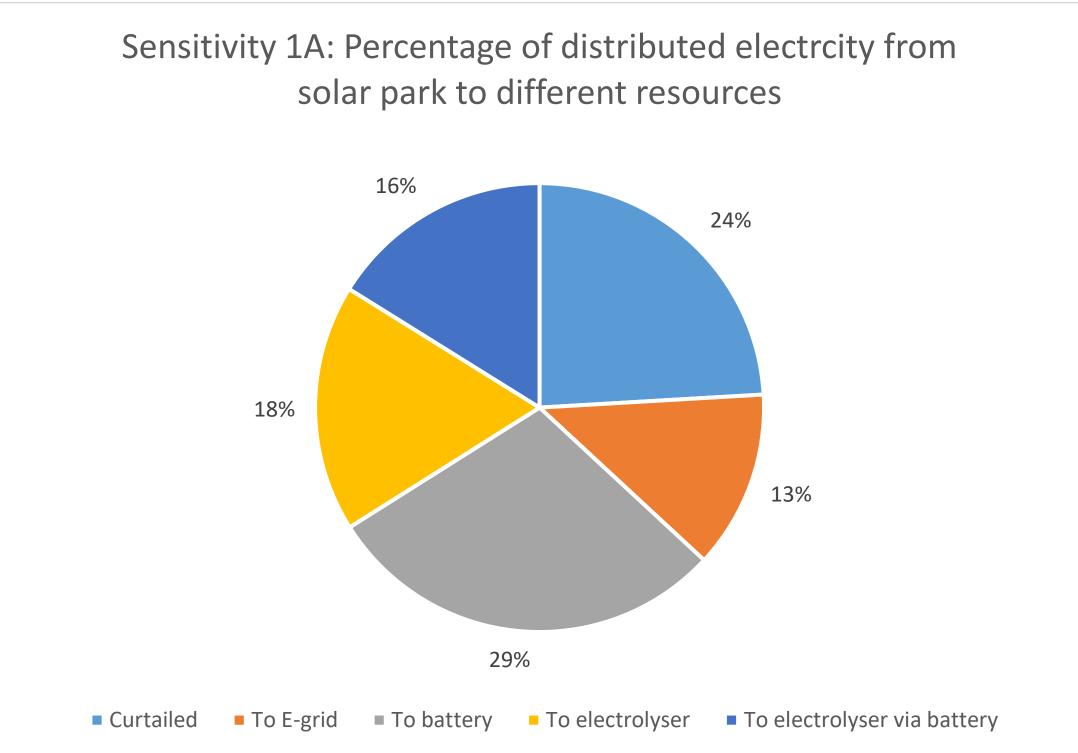


Figure 50: Distribution of electricity from the solar park to the various flexibility resources

A.2 Sensitivity 1B: Distance to HRS Station: 20km – Distance to HV/MV Station: 1km

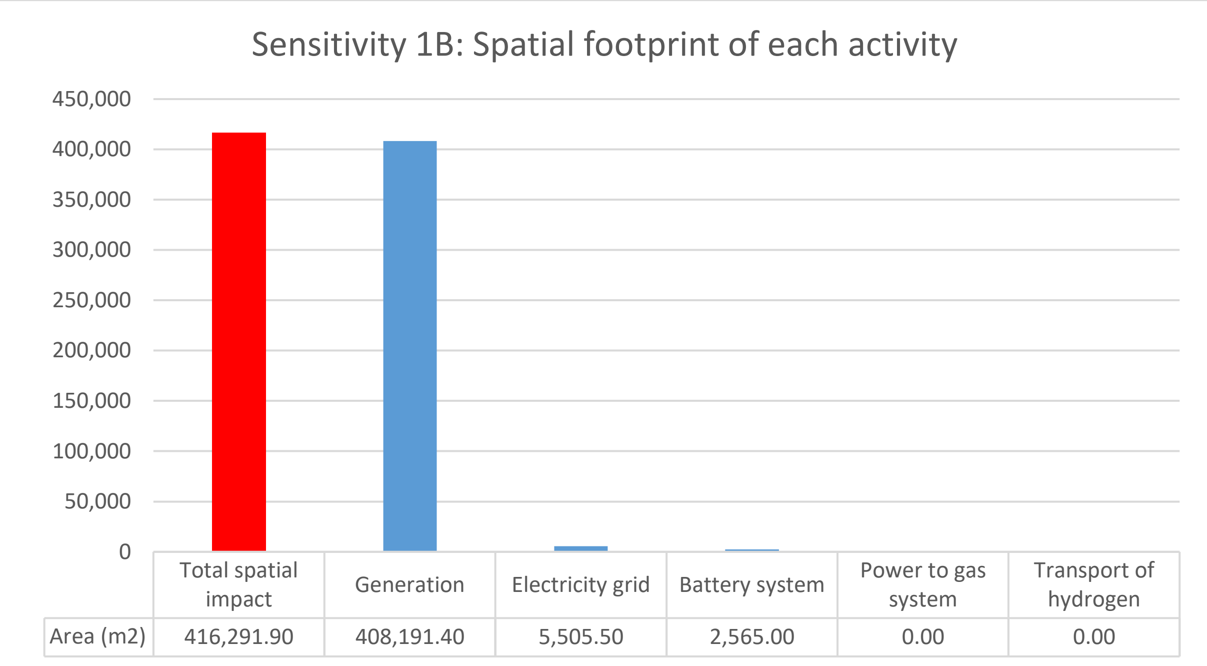


Figure 51: Spatial footprint of the different energy infrastructures for Sensitivity 1B where distance to HRS Station: 20km – Distance to HV/MV Station: 1km

A.3 Sensitivity 2A: PV Capacity +500% - Electricity Demand: -50%

Table 27: Annualized costs and benefits for each of the assets for Sensitivity 2A where the PV capacity of the installed solar park is in increased by 500% and the electricity demand is reduced by 50%

Category	Benefits	Costs	Δ: B - C
Electricity provided	€ 9,133,884.76	€ -	
Hydrogen provided mobility	€ 766,500.00	€ -	
CAPEX solar PV	€ -	€ 4,914,599.26	
OPEX solar PV	€ -	€ 1,976,949.27	
CAPEX MV station	€ -	€ 526,402.77	
OPEX MV station	€ -	€ 576,000.00	
CAPEX MV cable	€ -	€ 219,334.49	
OPEX MV cable	€ -	€ 240,000.00	
CAPEX HV-MV station expansion	€ -	€ 347,279.60	
OPEX HV-MV station expansion	€ -	€ 380,000.00	
CAPEX battery	€ -	€ 1,772,318.32	
OPEX battery	€ -	€ 224,472.00	
CAPEX electrolyser	€ -	€ 112,068.68	
OPEX electrolyser	€ -	€ 30,400.00	
Water costs	€ -	€ 4,471.55	
CAPEX compressor	€ -	€ 20,833.88	
OPEX compressor	€ -	€ 13,385.00	
CAPEX H2 storage tank	€ -	€ 6,914.76	
OPEX H2 storage tank	€ -	€ 2,700.00	

CAPEX RNB	€ -	€ 4,935.03	
OPEX RNB	€ -	€ 83,700.00	
Costs landuse	€ -	€ 810,931.59	
Total	**€ 9,900,384.76**	**€ 12,267,696.20**	**-€ 2,367,311.44**

A.4 Sensitivity 2B: PV Capacity -50% - Electricity Demand: +500%

Table 28: Annualized costs and benefits for each of the assets for Sensitivity 2B where the PV capacity of the installed solar park is decreased by 50% and the electricity demand is increased by 500%

Category	Benefits	Costs	Δ: B - C
Electricity provided	€ 678,570.74	€ -	
Hydrogen provided industry	€ 0.44	€ -	
Hydrogen provided mobility	€ 642,485.23	€ -	
CAPEX solar PV	€ -	€ 491,457.52	
OPEX solar PV	€ -	€ 197,693.96	
CAPEX MV station	€ -	€ 65,800.35	
OPEX MV station	€ -	€ 72,000.00	
CAPEX MV cable	€ -	€ 27,416.81	
OPEX MV cable	€ -	€ 30,000.00	
CAPEX HV-MV station expansion	€ -	€ 1,014,422.00	
OPEX HV-MV station expansion	€ -	€ 1,110,000.00	
CAPEX battery	€ -	€ 191,481.63	
OPEX battery	€ -	€ 24,252.00	
CAPEX electrolyser	€ -	€ 98,060.10	
OPEX electrolyser	€ -	€ 26,600.00	
Water costs	€ -	€ 3,736.97	
CAPEX compressor	€ -	€ 20,833.88	
OPEX compressor	€ -	€ 13,385.00	
CAPEX H2 storage tank	€ -	€ 6,914.76	
OPEX H2 storage tank	€ -	€ 2,700.00	
CAPEX RNB	€ -	€ 4,935.03	
OPEX RNB	€ -	€ 83,700.00	
Costs landuse	€ -	€ 94,503.15	
Total	**€ 1,321,056.41**	**€ 3,579,893.15**	**-€ 2,258,836.74**

A.5 Sensitivity 3A: Hydrogen price increase by 25% - Electricity price decrease by 25%

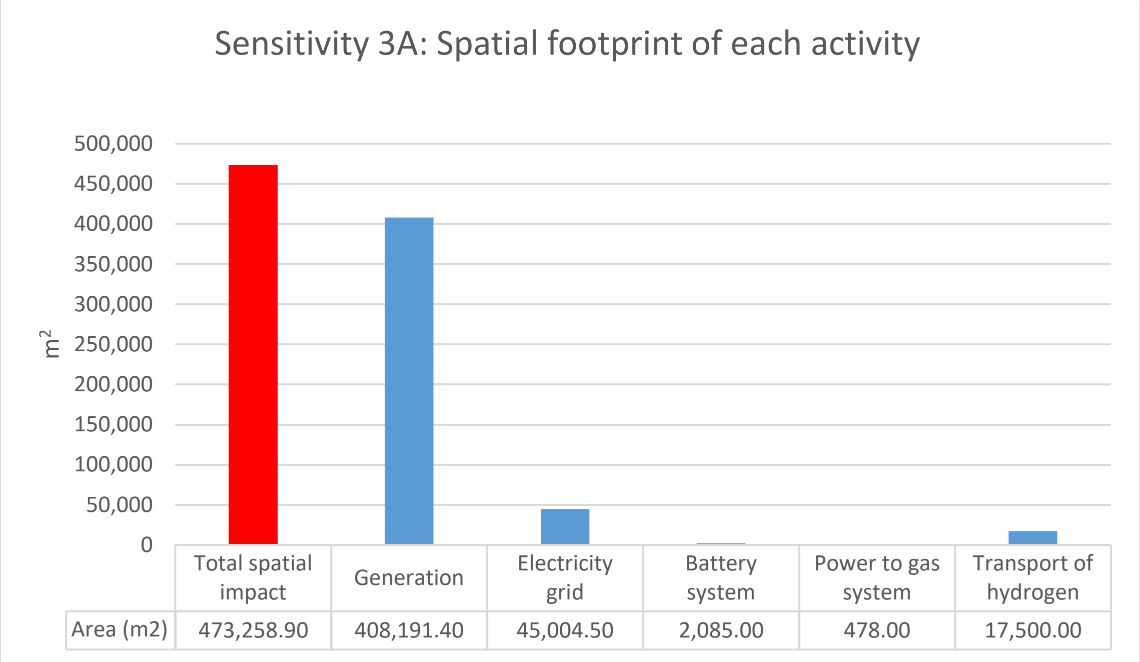


Figure 52: Spatial footprint of the different energy infrastructures for Sensitivity 3A where hydrogen price is increased by 25% and electricity price is decreased by 25%

A.6 Sensitivity 3B: Hydrogen price decrease by 25% - Electricity price increase by 25%

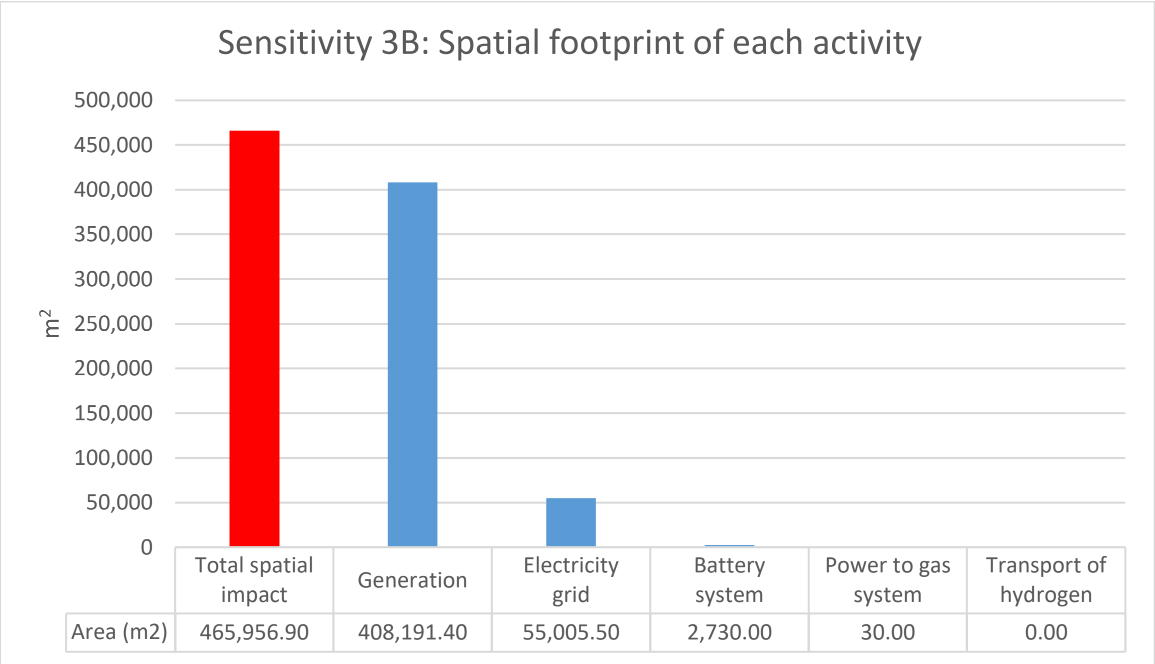


Figure 53: Spatial footprint of the different energy infrastructures for Sensitivity 3B where hydrogen price is decreased by 25% and electricity price is increased by 25%

A.7 Sensitivity 4A: No RNB

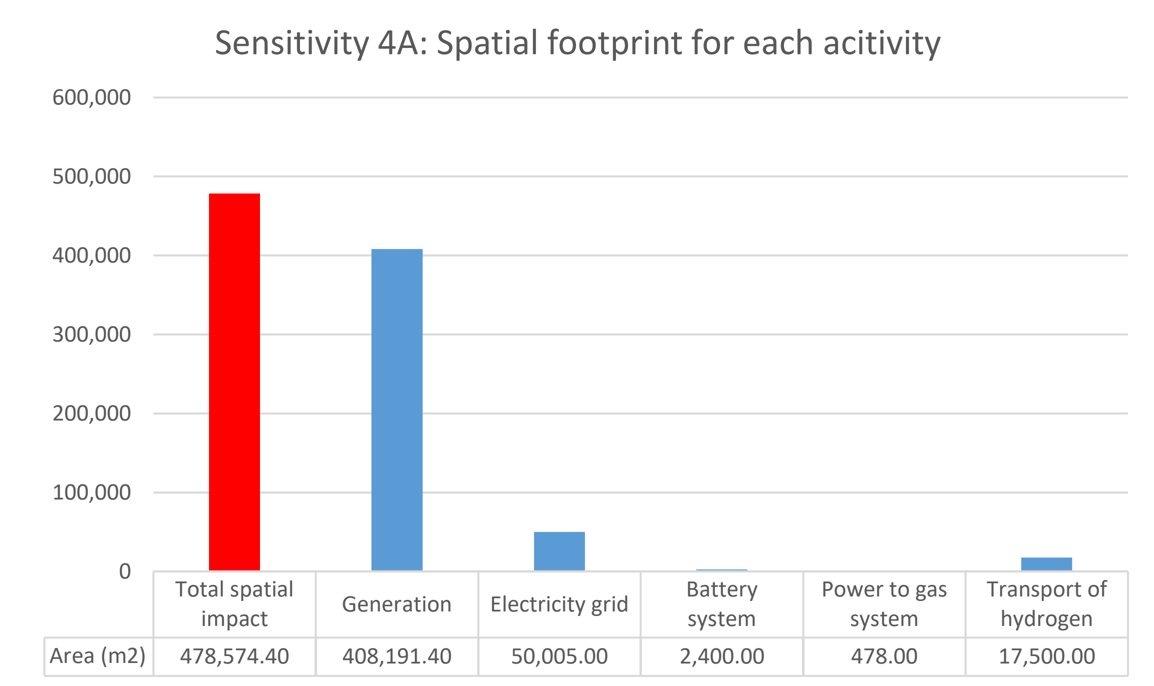


Figure 54: Spatial footprint of the different energy infrastructures for Sensitivity 4A where no RNB pipeline is used for the transportation of hydrogen

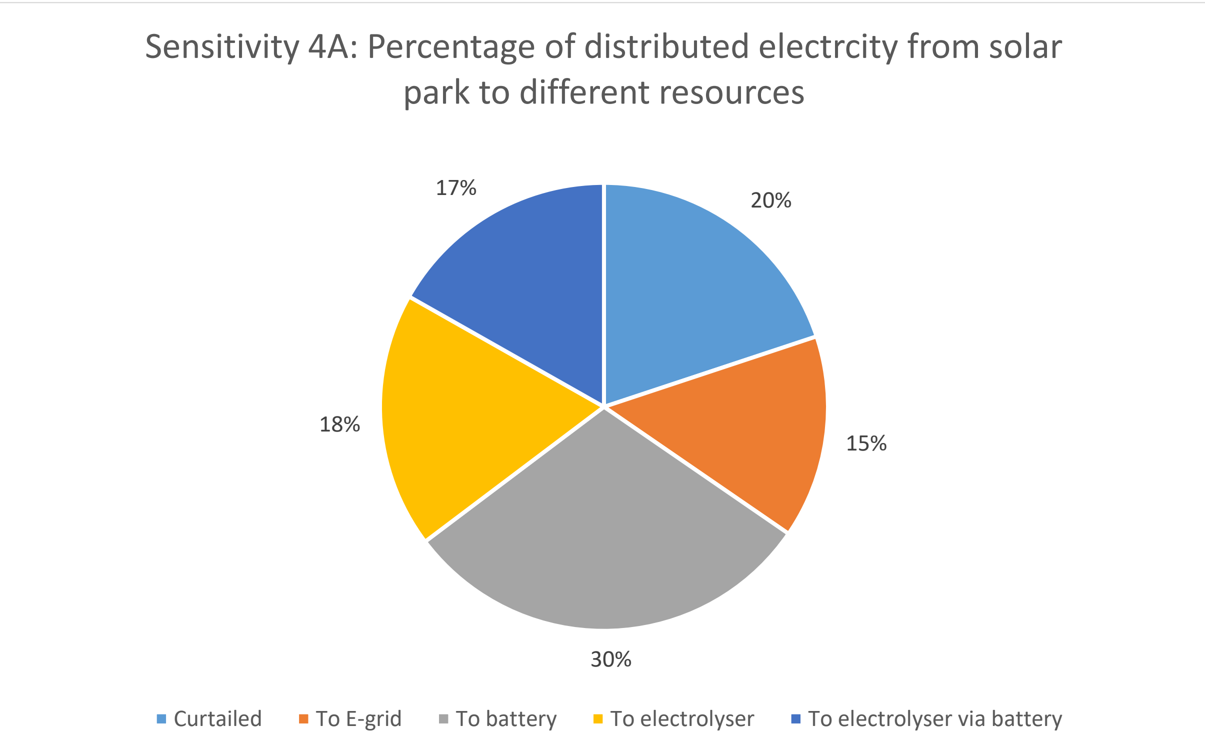


Figure 55: Distribution of electricity from the solar park to the various flexibility resources for the No RNB sensitivity

A.8 Sensitivity 4B: No RNB No RTL – Trucks only

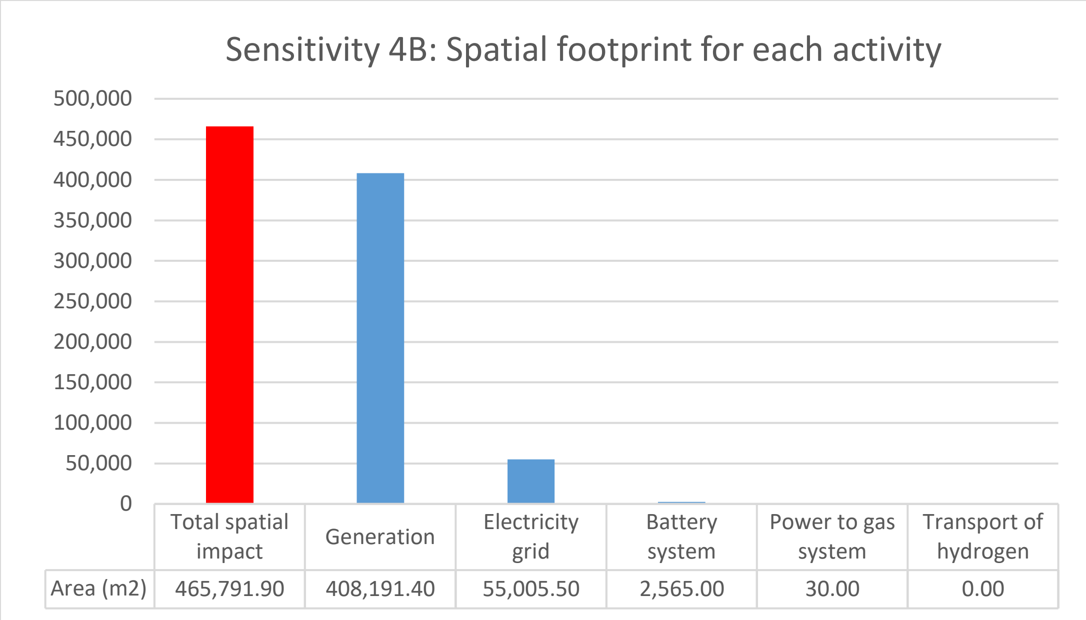


Figure 56: Spatial footprint of the different energy infrastructures for Sensitivity 4B where no RNB, no RTL pipeline and only truck transport of hydrogen are considered

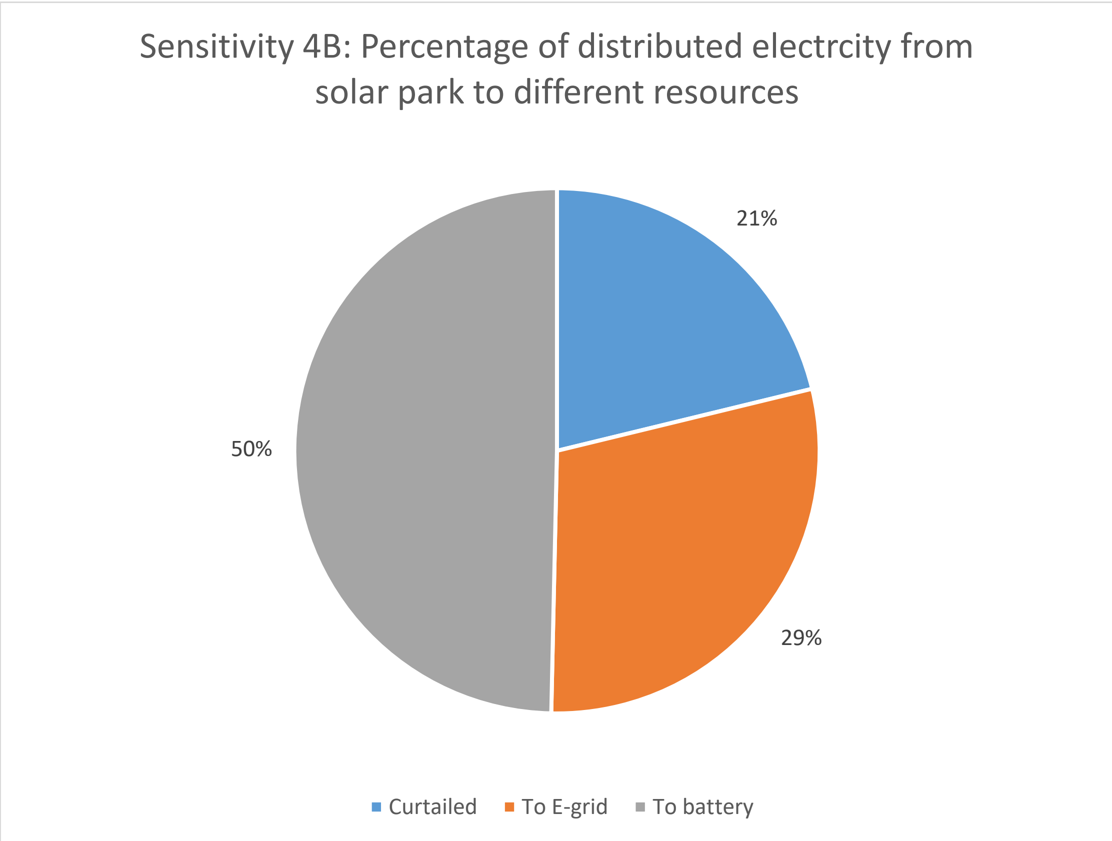


Figure 57: Distribution of electricity from the solar park to the various flexibility resources for the No RNB, No RTL and Truck Transport sensitivity

A.8 Sensitivity 5: 2x mobility demand of hydrogen

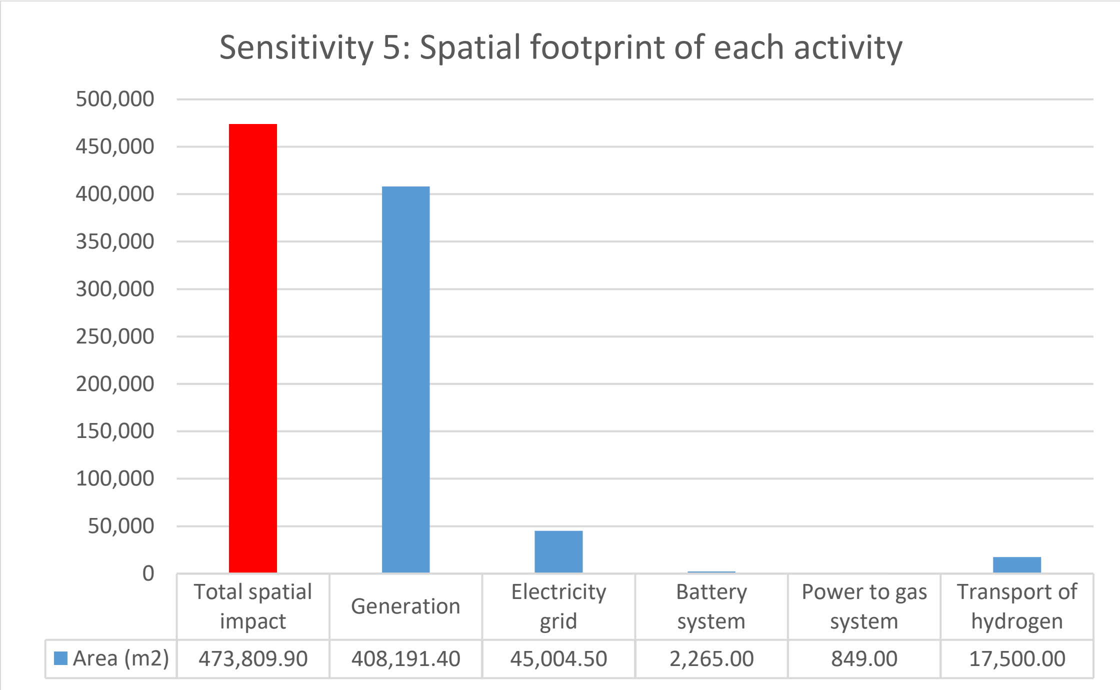


Figure 58: Spatial footprint of the different energy infrastructures for Sensitivity 5 where mobility demand of hydrogen is doubled

A.9 Sensitivity 6A: -50% CAPEX reduction of electrolyzers

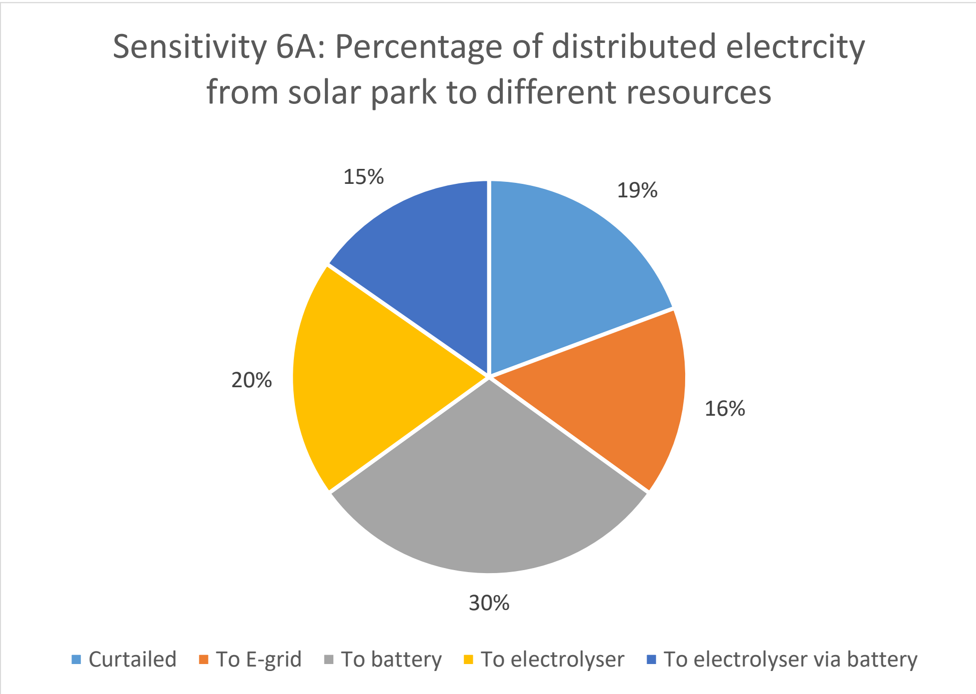


Figure 59: Distribution of electricity from the solar park to the various flexibility resources when electrolyzer CAPEX is reduced by 50%

A.10 Sensitivity 6B: No electrolyzer CAPEX

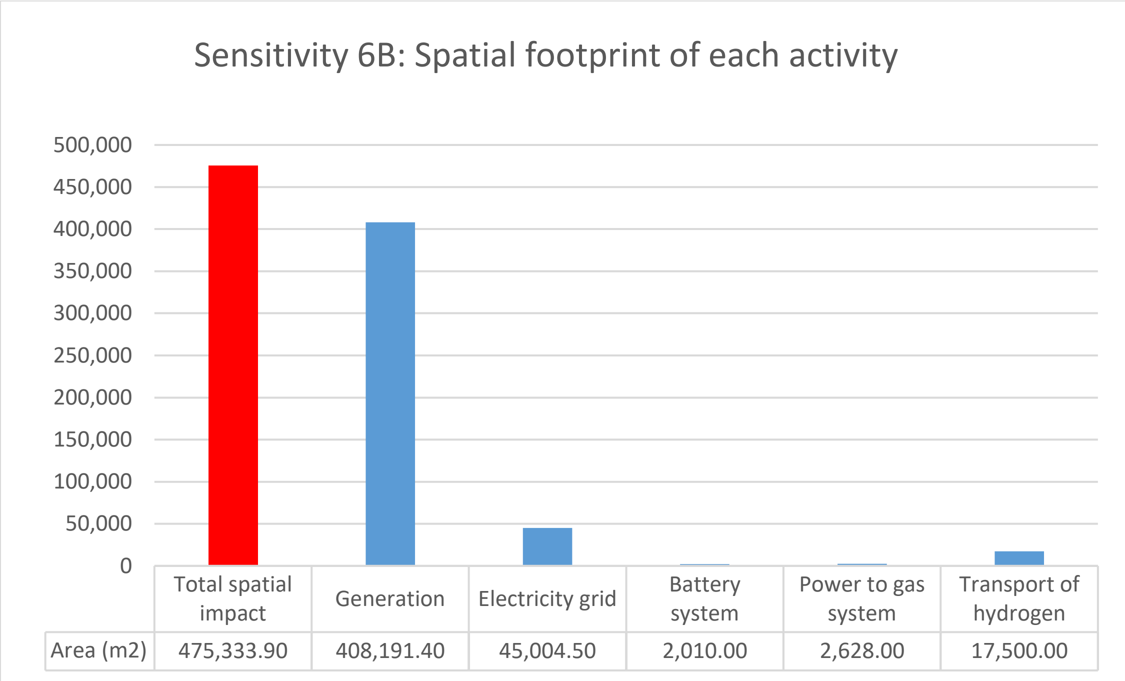


Figure 60: Spatial footprint of the different energy infrastructures for Sensitivity 6B where no electrolyzer CAPEX is considered

A.11 Sensitivity 7: Electrolyzer and battery can use electricity from the grid

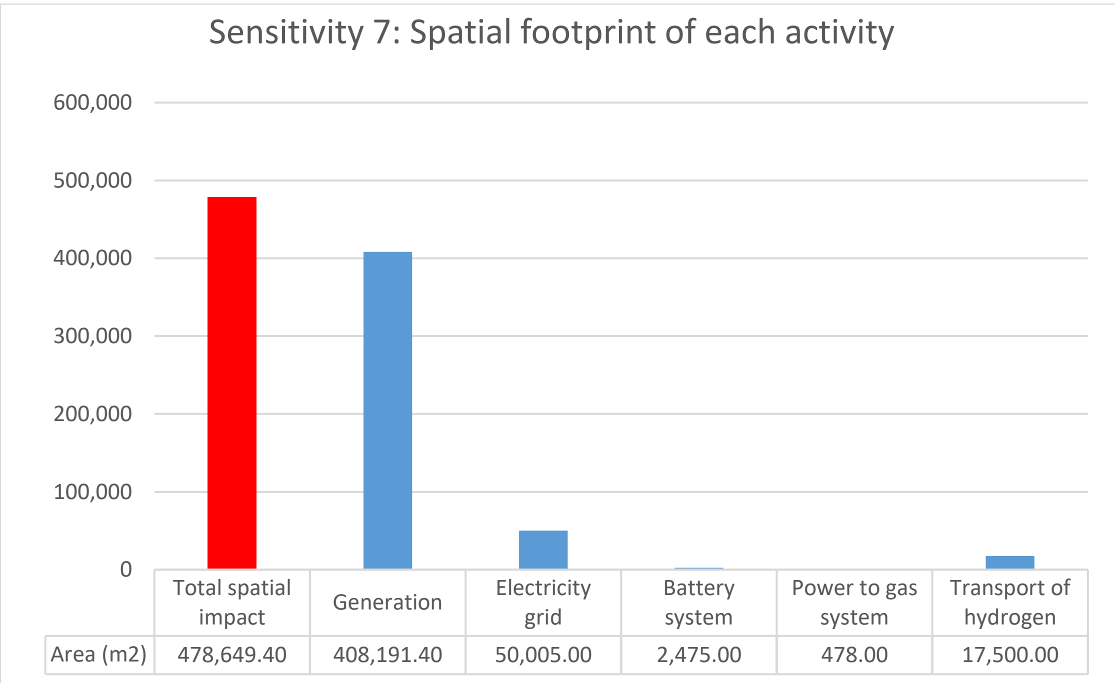


Figure 61: Spatial footprint of the different energy infrastructures for Sensitivity 7 where the electrolyzer and battery source electricity from the grid