The costs and benefits of batteries in the power system

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Samenvatting

Deze studie onderzoekt de effecten van batterijen op de integrale kosten van het Nederlandse energiesysteem van de toekomst voor een deel van de markten. De eerste batterijen leveren significante kostenvoordelen op voor het systeem. Wanneer de balanceringsmarkten verzadigd zijn, nemen de voordelen van extra batterijcapaciteit in sommige scenario's toe en in andere af. De ontwikkeling van zon- en windstroom, de elektriciteitsvraag, investeringskosten en brandstofprijzen hebben een sterke invloed op de systeemvoordelen. Nettarieven verslechteren de businesscase van batterijen, en kunnen een barrière voor verdere uitrol vormen in scenario's met positieve systeemvoordelen. Batterij-effecten verschillen per systeem actor maar zijn over het algemeen positief voor afnemers van elektriciteit.

Deze studie onderzoekt de effecten van batterijen op de integrale kosten van het Nederlandse energiesysteem van de toekomst voor een deel van de markten

Deze studie onderzoekt de systeemkosten en voordelen van grootschalige batterijen in lange termijn energiescenario's voor Nederland. We hebben een batterijmodel ontwikkeld dat gebruikmaakt van uurlijkse elektriciteitsprofielen uit een scenario gebaseerd op de Klimaat- en Energieverkenning voor 2030. Het model evalueert hoe de systeemkosten zich zouden ontwikkelen wanneer batterijen deelnemen aan de energiemarkt. Hierbij is gekeken naar de effecten op de day-ahead, FCR en aFFR-up markten. Markten die in deze analyse niet zijn meegenomen, betreffen: aFRR-down, mFRR, passieve onbalans, intraday, congestie management, blindstroom en blackstart voorzieningen. Daarmee beslaat deze analyse maar een deel van de mogelijke markten waar batterijen inkomsten kunnen genereren en besparingen kunnen opleveren.

Netkosten zijn in eerste instantie niet meegenomen, tenzij uitdrukkelijk vermeld. Andere flexibiliteitsoplossingen en de optie om elektriciteit te exporteren zijn uitgesloten. Dit stelt ons in staat om duidelijke systeemgrenzen te definiëren voor een grondige analyse van de systeemkosten, inclusief waardeoverdrachten binnen het systeem. Het uitsluiten van export uit de analyse verlaagt de gemiddelde elektriciteitsprijs, maar heeft slechts een geringe invloed op de prijsvolatiliteit. Dit resulteert in een lichte vermindering van de effectiviteit van batterijen, maar niet in een mate die de conclusies van deze studie wezenlijk beïnvloedt. Voor meer informatie, zie de technische documentatie.

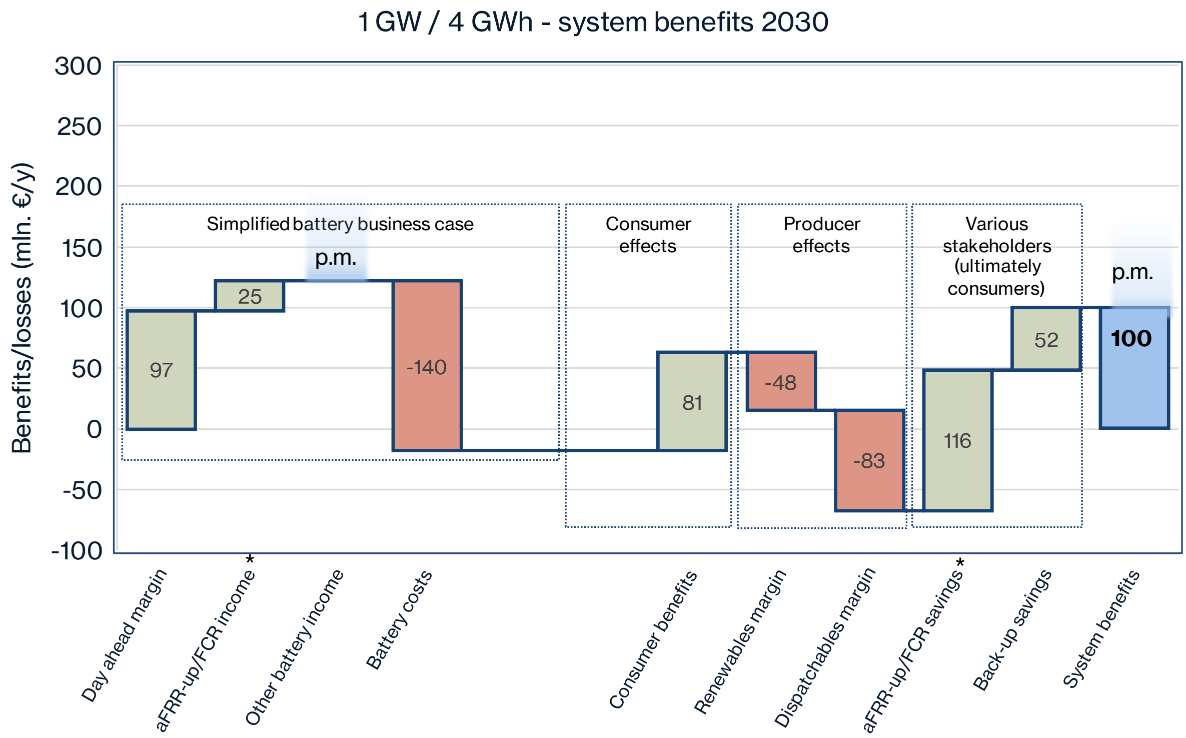
Door de grote impact van verschillende onzekerheden wordt vooral de samenhang van resultaten benadrukt en worden harde getallen beperkt genoemd

Uit deze studie blijkt dat de systeemvoordelen van batterijen zeer sterk afhangen van de gebruikte parameters zoals toekomstige batterijkosten, brandstofprijzen en overige veranderingen in de balancerings- en groothandelsmarkten. Bijna al deze parameters gaan gepaard met grote onzekerheden richting de toekomst.

Het is hierdoor niet nuttig om kwantitatieve resultaten uit doorrekeningen van specifieke varianten te noemen in de conclusies (een variant is een set aan aannames omtrent deze parameters). In plaats daarvan kan de samenhang van de verschillende resultaten uit alle doorgerekende varianten de lezer wel een gevoel geven van de effecten van batterijopslag op het energiesysteem in algemene zin. Zo kan worden geconcludeerd onder welke omstandigheden batterijen meer of minder positieve bijdragen kunnen leveren, en kan worden geleerd welke parameters de grootste invloed hebben op de effecten van batterijopslag.

De eerste batterijen leveren significante kostenvoordelen op voor het systeem

We zien dat de eerste gigawatts (GW) aan batterijen leiden tot een aanzienlijke vermindering van systeemkosten (zie Figuur 1). De eerste GW's zullen waarschijnlijk vooral diensten leveren aan de balanceringsmarkten omdat daar de grootste besparingen vallen te realiseren doordat batterijen lagere biedingen kunnen doen dan veel van de huidige marktdeelnemers. Zodra de te realiseren besparingen in de balanceringsmarkten zijn behaald, zullen batterijen zich in toenemende mate richten op de groothandelsmarkten, waaronder de day-ahead markt.



Figuur 1. Uitsplitsing van systeemvoordelen voor de eerste GW aan batterijen in het referentiescenario van 2030, geclusterd naar verschillende systeemactoren. Omdat niet alle inkomsten van batterijen in deze studie meegenomen zijn, vallen deze en daarmee ook de systeembaten waarschijnlijk hoger uit (zie de p.m. post).

Toelichting

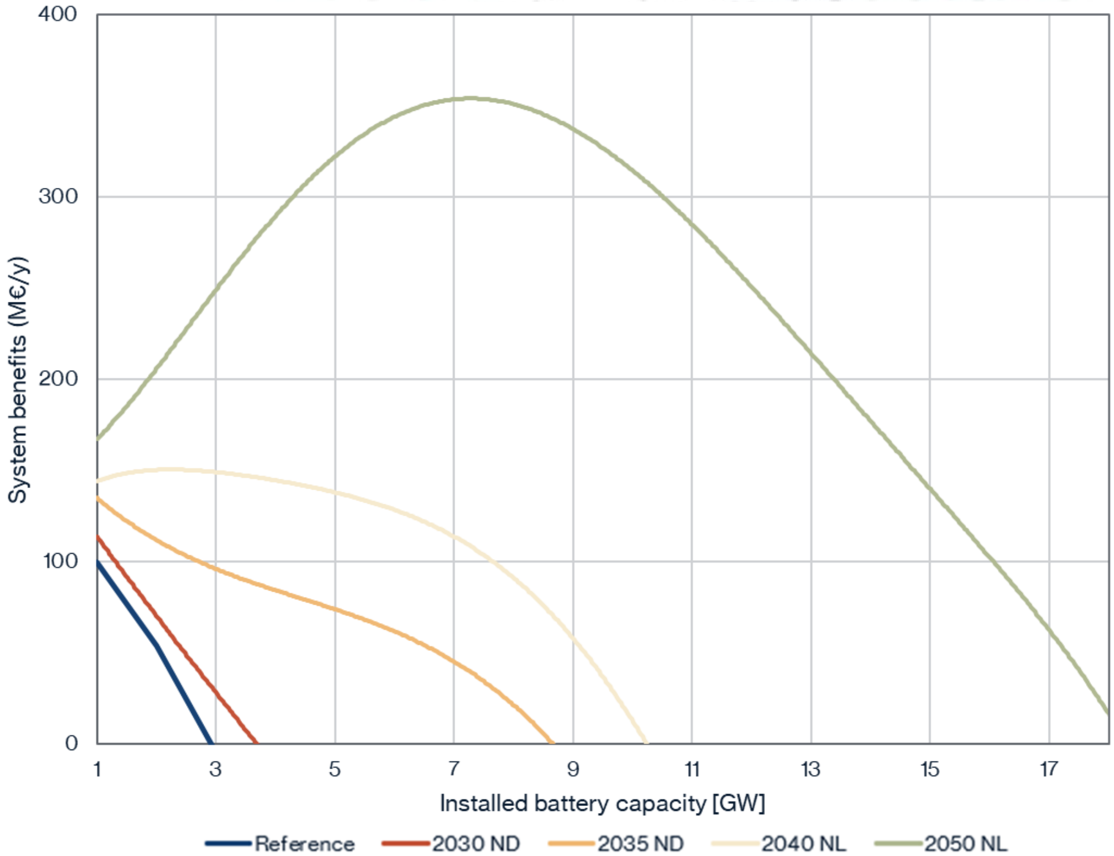
Het netto-effect, de totale systeembaten, is weergegeven als de blauwe balk uiterst rechts. Dit is de som van alle besparingen en herverdelingen in het energiesysteem. Van links naar rechts zien we: de marge die de batterij op de groothandelsmarkt maakt, de inkomsten uit de onbalansmarkten* en overige inkomsten, en de batterijkosten. Dit vormt een gesimplificeerde business case voor de batterij exploitant. Vervolgens zien we de besparingen op de elektriciteitsmarkt voor stroomverbruikers door verlaging van de stroomprijs; en als keerzijde daarvan, het margeverlies voor zowel van volatiele stroomproductie (zon en wind) als regelbare stroomproductie. Tot slot zien we de besparingen in onbalanskosten* en overbodig back-up vermogen door batterijen. Deze besparingen komen terecht bij verschillende stakeholders, waaronder netbeheer en consumenten.

****Het eurobedrag onder de besparing van onbalanskosten ('aFRR-up/FCR savings') kan ook deels bij batterijexploitanten terechtkomen ('aFRR-up/FCR income'), afhankelijk van de uitkomst van balanceringsmarkten.***

Wanneer de balanceringsmarkten verzadigd zijn, nemen de voordelen van extra batterijcapaciteit in sommige scenario's toe en in andere af

Wanneer de balanceringsmarkten grotendeels verzadigd zijn en additionele batterijcapaciteit voor inkomsten vooral is aangewezen op spreads die in de groothandelsmarkten zijn te verdienen, constateren we dat de ontwikkeling van de systeemkosten sterk zal afhangen van de batterijkosten en brandstofprijzen, evenals van de kenmerken van de energiemarkt.

Dit wordt geïllustreerd in Figuur 2. In dit figuur zijn de netto systeemvoordelen (system benefits) uit Figuur 1 voor verschillende scenario's als functie van batterijcapaciteit getoond. Omdat niet alle mogelijke inkomsten meegenomen zijn (zie p.m. posten in Figuur 1), vallen de werkelijke systeemvoordelen waarschijnlijk hoger uit.



Figuur 2. Systeemvoordelen als functie van batterijcapaciteit voor het referentie 2030 scenario en scenario's gebaseerd op de Nationale Drijfveren IP2024 en Nationaal Leiderschap II3050 scenario's voor 2030, 2035, 2040 en 2050.

Let op: gegeven de vele onzekerheden achter belangrijke inputparameters (zoals batterij- en brandstofkosten) en de grote impact die deze parameters hebben op de resultaten en ook als gevolg van methodologische simplificaties, kan op basis van deze grafiek niet worden geconcludeerd hoeveel batterijvermogen optimaal is in een gegeven scenario.

Als we bijvoorbeeld de verwachte referentiekosten en vraag- en opwekprofielen voor 2030 nemen (blauwe en oranje lijnen in Figuur 2), zijn de systeemvoordelen positief voor de eerste batterijen tot het punt dat de balanceringsmarkten verzadigen. Wanneer additioneel batterijvermogen wordt toegevoegd dat hoofdzakelijk zal zijn aangewezen op de day-ahead markt dalen de systeemvoordelen naar nul bij 3 tot 4 GW.

Voor het 2050 scenario stijgen de systeemvoordelen wél door additioneel batterijvermogen dat hoofdzakelijk actief is op de day-ahead markt (groene lijn in Figuur 2). Deze stijging zet door tot 7 GW aan geïnstalleerd batterijvermogen. Daarna nemen de marginale voordelen af voor additionele batterijen om vervolgens tot nul te dalen bij 18 GW.

De ontwikkeling van zon- en windstroom, de elektriciteitsvraag, investeringskosten en brandstofprijzen hebben een sterke invloed op de systeemvoordelen

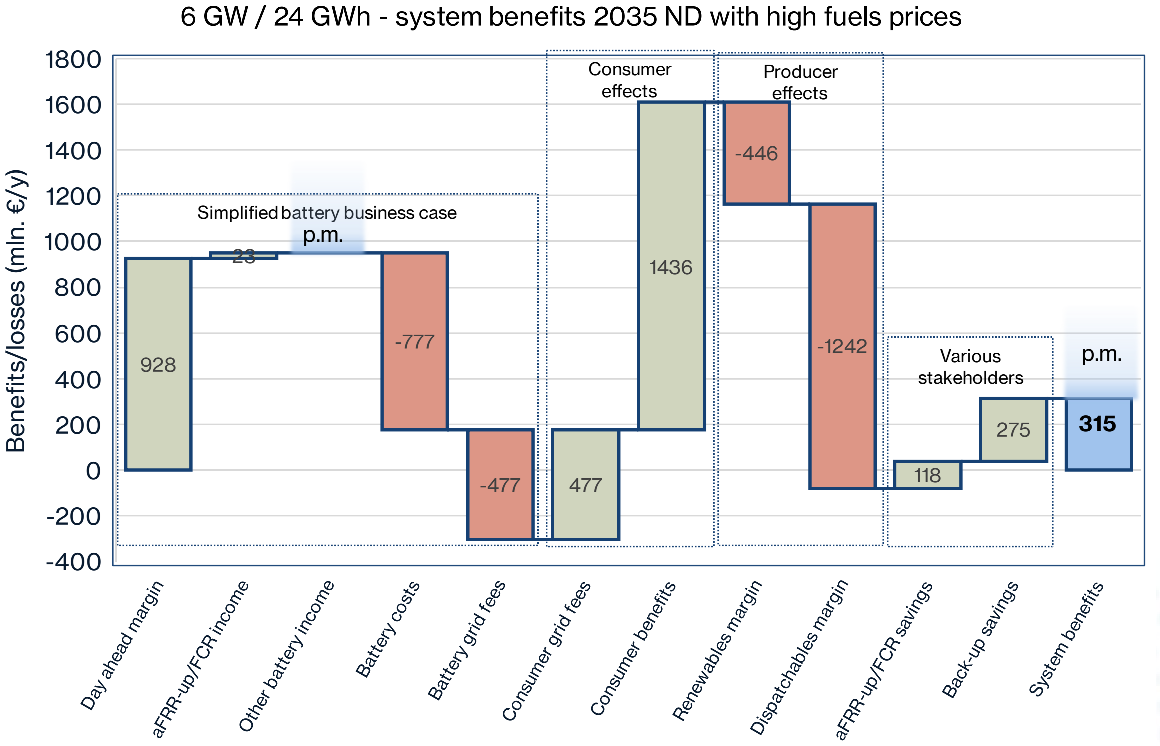
In het algemeen zien we dat de systeemvoordelen hoger zijn en blijven bij hogere batterijcapaciteiten als de kosten van batterijen dalen, brandstofprijzen stijgen en de vraag naar elektriciteit en het volatiele aanbod toenemen. Waar in 2030 de systeemvoordelen aan de geanalyseerde markten vanaf 1 GW afnemen, stijgen ze in 2040 en 2050 eerst en geven ze tot veel hogere capaciteiten positieve waarden (zie Figuur 2). De belangrijkste verschillen tussen deze scenario's betreffen de absolute en relatieve toename aan variabele elektriciteitsproductie, de toenemende vraag naar elektriciteit, en de afnemende investeringskosten voor batterijen.

Een gevoeligheidsanalyse toont aan dat hogere brandstofprijzen en lagere investeringskosten voor batterijen de piek in systeemvoordelen verder verhogen, met positieve resultaten bij hogere batterijvermogens. Bij 25% lagere investeringskosten voor batterijen nemen de maximale systeemvoordelen bijvoorbeeld toe met meer dan 50% in 2050. Verder resulteren hogere onbalansvergoedingen in significant hogere systeemvoordelen bij de eerste GW's aan batterijen, aangezien de balanceringsmarkten al snel verzadigd raken.

Nettarieven verslechteren de businesscase van batterijen, en kunnen een barrière voor verdere uitrol vormen in scenario's met positieve systeemvoordelen

De resultaten die eerder besproken zijn, bevatten nog niet de effecten van nettarieven. Wanneer batterijen opereren onder het ATR85 transporttariefregime, zouden ze in theorie geen hogere piekbelastingen op het elektriciteitsnet moeten veroorzaken en dus niet leiden tot extra investeringen in het net. Daarom komen de netvergoedingen die van batterijen worden geïnd neer op een waardeoverdracht aan andere netgebruikers.

Zoals afgebeeld in de onderstaande illustratieve uitsplitsing van systeemkosten, is het mogelijk om positieve systeemvoordelen te vinden, maar toch een potentieel negatieve bedrijfscase door nettarieven die een barrière kunnen vormen voor hun commerciële uitrol. De nettarieven verdienen daarom nader onderzoek, die de wenselijkheid van batterijen versus andere flexibiliteitsoplossingen moet afwegen, met voldoende ondersteuning om hun installatie te faciliteren.



Figuur 3. Systeemvoor- en nadelen breakdown voor het 2035 Nationale Drijfveer II3050/IP2024 scenario met 50% hogere brandstofprijzen.

Batterij-effecten verschillen per systeem actor, en zij zijn over het algemeen positief voor afnemers van elektriciteit

Bovenstaande uitspraken hebben betrekking op algemene systeemeffecten. Voor actoren binnen het systeem zullen de uitkomsten anders zijn.

- *Batterij exploitanten* hebben een positieve business case
- In het algemeen profiteren *elektriciteitsverbruikers* doordat dankzij batterijen de (gemiddelde) elektriciteitsprijs daalt. Meer in het bijzonder verlagen batterijen de piekprijzen en maken ze de elektriciteitsmarkt minder volatiel en robuuster tegen schokken (hoge brandstofprijzen, extreem weer).
- *Netbeheerders* profiteren doordat hun inkoopkosten voor balancering dalen, welke voordelen in de vorm van lagere nettarieven aan eindgebruikers worden doorgegeven.
- *Elektriciteitsproducenten* ondervinden over het algemeen een margeverlies omdat batterijen hun verkoopprijzen verlagen. Batterijen verminderen ook de vollasturen voor regelbare centrales, terwijl ze die voor hernieuwbare energiebronnen verhogen door minder curtailment. Dit bouwt voort op een trend waarbij hernieuwbare energiebronnen met nul marginale kosten duurdere regelbare centrales uit de markt drukken.
- Tot slot profiteert de *samenleving als geheel* van een vermindering van de CO_2-uitstoot wanneer fossiele brandstoffen nog steeds worden gebruikt voor de opwekking van elektriciteit.

Kalavasta
Climate Neutral Strategies

Summary

This study looks at the system benefits of batteries in a select set of markets for the Dutch energy system. The first batteries result in significant system benefits. Once balancing markets are saturated, the system benefits of additional battery capacity increase in some scenarios and decrease in others. Battery investment costs, fuel prices and the development of volatile electricity production and demand strongly influence battery system benefits. Grid fees worsen the business case for batteries, and could be a barrier for commercial rollout in scenarios with positive system benefits. Battery effects vary per system actor, and are generally positive for consumers

This study looks at the system benefits of batteries in a select set of markets for the Dutch energy system

This study investigates the costs and benefits of large scale batteries in long-term energy scenarios for the Netherlands. We built a custom model using hourly electricity profiles from a 2030 climate policy scenario. It evaluates how system costs would evolve upon the introduction of batteries that could take part in the energy market. We focused on the day-ahead, FCR and aFRR-up markets. Markets not included in this analysis are the aFRR-down, mFRR, passive balancing, intraday, congestion management and reactive power. This analysis therefore only considers some of the possible markets in which batteries could generate revenues and reduce system costs.

Grid costs were not taken into account initially, except were explicitly noted. Other flexibility solutions and the option to export of electricity were excluded. This allowed us to define firm system boundaries for a firm system costs analysis including value transfers within. Excluding exports from the analysis reduces the average electricity price but only slightly affects price volatility. This results in a slight decrease the effectiveness of batteries but not to an extent that meaningfully affects the conclusions that can be drawn from this study. For more information see the technical documentation.

Due to the high impact of several uncertainties, the coherence and emergent picture of the results is more important than the individual quantitative scenario outcomes

This study shows that the system benefits of batteries strongly depend on parameters such as future battery costs, fuel prices, and other changes in balancing and wholesale markets. Almost all of these parameters are associated with great uncertainties looking forward.

Therefore, it is not useful to mention quantitative results from specific variant analyses in the conclusions (a variant is a set of assumptions about these parameters). Instead, the coherence of the various results from all analysed scenarios can give the reader a sense of the effects of battery storage on the energy system. This allows one to draw conclusions about the conditions in which batteries can make more or less positive contributions, and uncover which parameters have the greatest influence on battery storage performance.

The first batteries result in significant system benefits

We find that the first gigawatts (GWs) of batteries lead to a sizeable system cost reduction. The first GWs will likely focus on the balancing markets as the largest benefits are to made there because batteries can bid lower than many of the current market participants. Once these benefits have been attained, batteries will increasingly turn to the wholesale electricity markets, and specifically the day-ahead market.

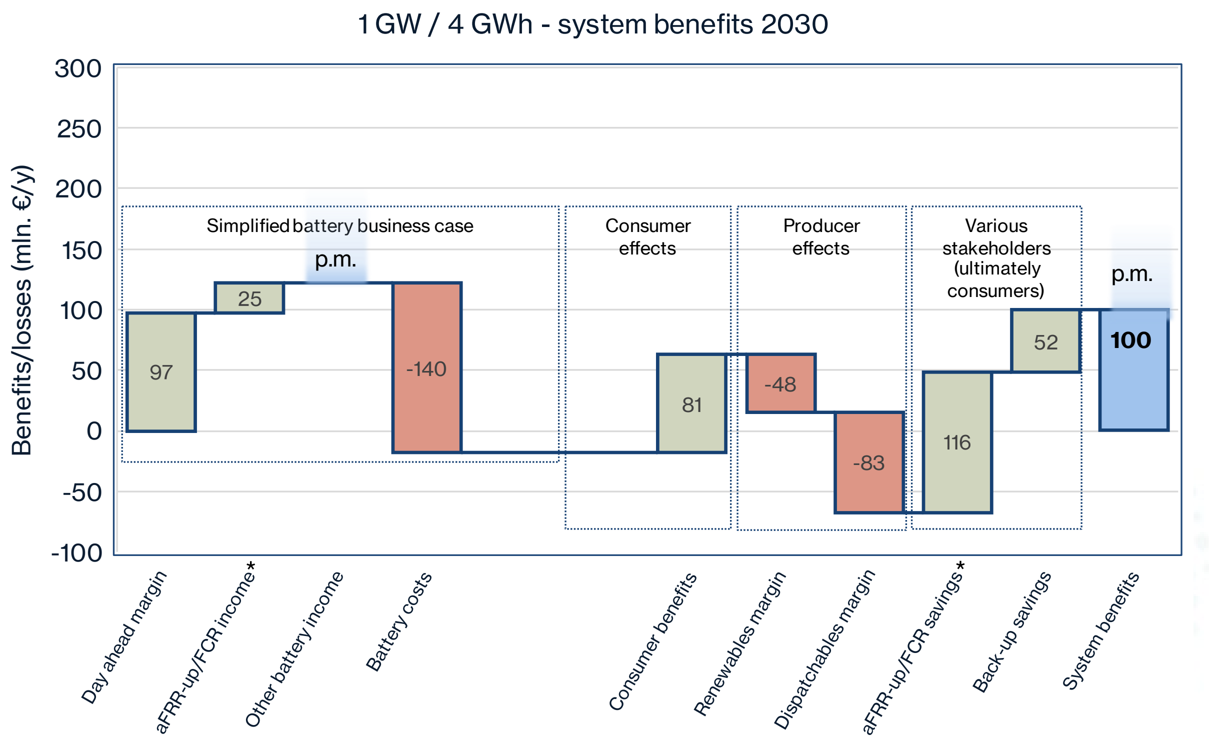


Figure 4. System benefits breakdown for the first GW of batteries in the 2030 reference scenario, as well as the angles through which various actors experience the effects. Because not all battery revenues are included, system benefits are likely higher than show here, denoted with a p.m. post.

Explanation

The net effect, the total system benefits, is shown as the blue bar on the far right. This represents the sum of all savings and redistributions in the energy system. From left to right, we see: the margin that the battery makes on the wholesale market, the income from the balancing markets*, other income not analysed in this study, and the battery costs. This forms a simplified business case for the battery operator. Next, we see the savings on the electricity market for consumers through lower electricity prices; and at the other side, the margin loss for both volatile electricity production (solar and wind) and flexible electricity production. Finally, we see the savings in imbalance costs* and redundant backup capacity due to batteries. These savings benefit various stakeholders, including the grid operator and consumers.

****The euro amount under the savings from imbalance costs ('aFRR-up/FCR savings') can also partly go to battery operators ('aFRR-up/FCR income'), depending on the outcome of balancing markets.***

Once balancing markets are saturated, the system benefits of additional battery capacity increase in some scenarios and decrease in others

When the balancing markets are saturated and additional battery capacity for its revenues is largely confined to spreads on the day-ahead market, we find that the system costs development strongly depends on battery investment costs and fuel costs as well energy market characteristics.

This is illustrated in Figure 5. In this figure, the net system benefits from Figure 4 are shown for different scenarios as a function of battery capacity. Since not all possible revenue streams are included (see p.m. items in Figure 4), the actual system benefits are likely to be higher.

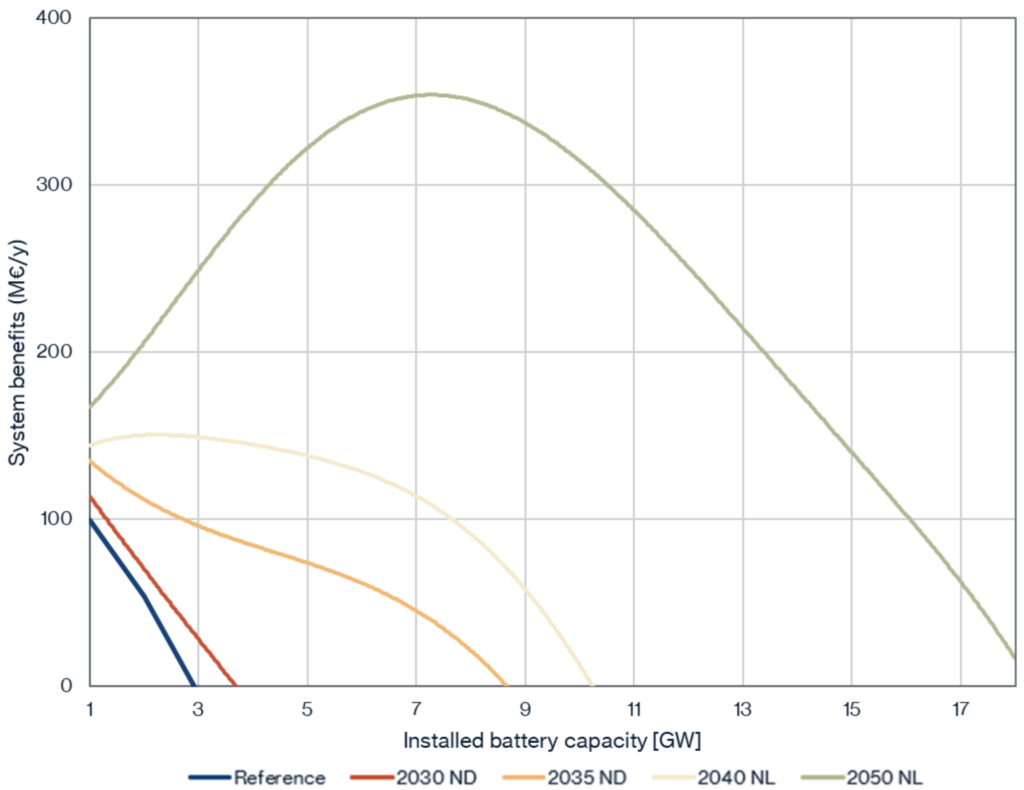


Figure 5. System benefits as a function of battery capacity for the reference 2030 and based on the National Drivers IP2024 and National Leadership II3050 scenarios for 2030, 2035, 2040 and 2050.

Please note: given the many uncertainties behind important input parameters (such as battery and fuel costs) and the major impact these parameters have on the results and also as a result of methodological simplifications, it cannot be concluded from this graph how much battery power is optimal is in a given scenario.

If we take the expected reference costs and demand and generation profiles for 2030 (blue and orange lines in Figure 5), the system benefits are positive for the first batteries until the balancing markets saturate. When additional battery capacity is added that is mainly dependent on the day-ahead market, the system benefits drop to zero at 3 to 4 GW.

For the 2050 scenario, however, the system benefits increase when adding battery capacity that is mainly active in the day-ahead market (green line in Figure 5). This increase continues up to 7-8 GW of installed battery capacity. After that, the marginal benefits decrease for additional batteries, eventually dropping to zero at 18 GW.

Battery investment costs, fuel prices and the development of volatile electricity production and demand strongly influence battery system benefits

In general we see that system benefits are higher and remain higher at higher battery capacities as battery costs go down, fuel prices go up and electricity demand and volatile supply increase. While in 2030 system benefits (for the markets analysed) decline from 1 GW onwards, in 2040 and 2050 they go up first to give a peak and more sustained benefits (see Figure 5). The main differences between these scenarios are the absolute and relative increase in volatile electricity production and electricity demand and a decrease in battery investment costs.

A sensitivity analysis shows that higher fuel prices and lower battery investment costs further increase peak system benefits, with positive results up to higher capacities. For example, with 25% lower investment costs for batteries, the maximum system benefits increase by more than 50% in 2050. Furthermore, higher imbalance fees result in significantly higher system benefits for the first GW of batteries, as the balancing markets quickly become saturated.

Grid fees worsen the business case for batteries, and could be a barrier for commercial rollout in scenarios with positive system benefits

The results discussed before do not yet include the effects of grid fees. When batteries operate under the ATR85 transport fee regime, they should (in theory) not cause higher peak loads on the electricity grid and would thus not lead to additional grid investments. Hence the grid fees collected from batteries amount to a value transfer to other grid users.

As depicted in the illustrative system costs breakdown below, it is possible to find positive system benefits, yet a potentially negative business case due to grid fees which may prove prohibitive for their commercial roll-out. The grid fees thus deserve further study which should balance the desirability of batteries vs other flexibility solutions with enough support to facilitate their installation.

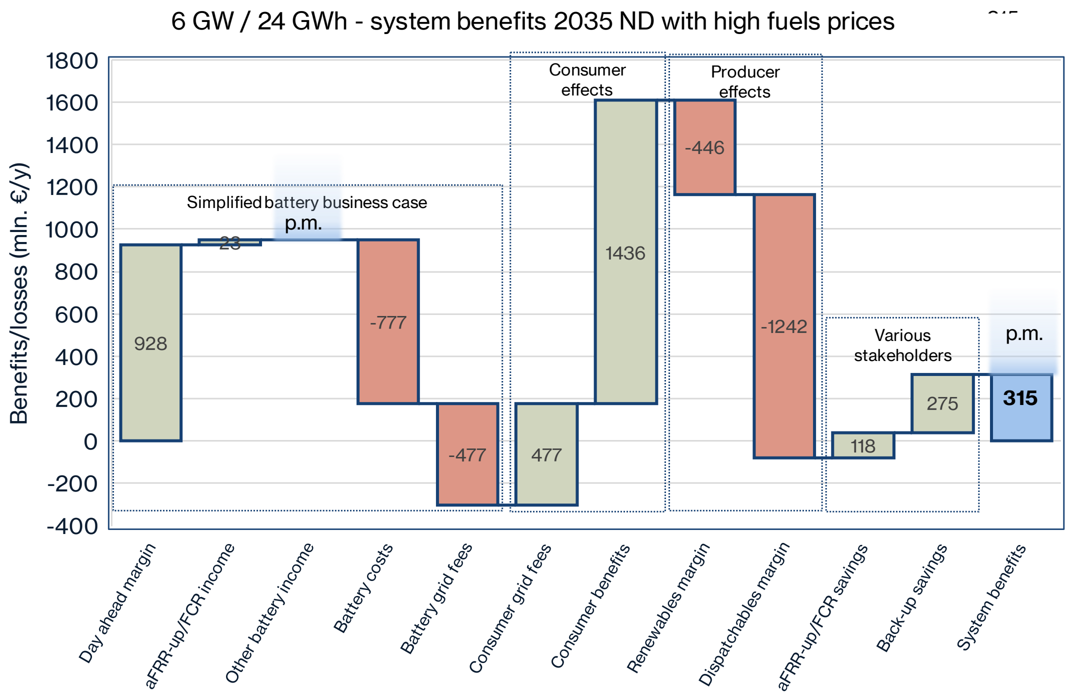


Figure 6. System benefits breakdown for the 2035 National Drivers II3050 scenario (illustrative).

Battery effects vary per system actor, and are generally positive for consumers

The statements above pertain to overall system effects. For actors within the system, the outcomes will be different.

- *Battery operators* have a positive business case
- *Electricity consumers* in general profit as batteries reduce the (average) electricity price. More specifically, batteries reduce peak prices and also make the overall electricity market less volatile and more robust against shocks (high fuel prices, extreme weather).
- *Grid operators* profit as grid balancing costs decrease, which in result would lower grid fees and be a benefit extended to electricity consumers.
- *Electricity producers* do generally experience a margin loss as batteries reduce their sales prices. Batteries also reduce the load hours for dispatchable plants, while they increase them for renewables due to less curtailment. This builds on a trend as zero marginal cost renewables push more expensive dispatchable plants out of the market.
- And finally, *society at large* benefits from a reduction in CO_2 emissions when fossil fuels are still used for power generation.

Contents

I. Introduction

A challenge often found in climate-neutral scenarios is to balance a volatile electricity supply from solar and wind with a demand which is shaped differently. On the one hand it is desirable to have ways of absorbing excess supply, while on the other hand it is important to have backup solutions to still provide electricity when demand exceeds supply.

There are various technologies and strategies to deal with this intermittency, ranging from demand side response, dispatchable power plants, power-to-X and many more. One technology that can help on both sides of the equation is large scale battery storage. Batteries can charge at times of excess production and discharge at times of shortages. In addition, batteries can also help stabilise the grid in the balancing markets and help resolve congestion.

One set of climate-neutral scenarios for the Netherlands that serves as a major reference are the grid operators' Integrale Infrastructuur Verkenning 2030-2050 (II3050) scenarios[1]. These scenarios aim to

- give insight into which routes exist to a climate neutral energy system in the Netherlands in 2050
- give insight into the urgency of choices to be made
- deliver input for the outlook which underpins the Ministry of Economic Affairs and Climate programmes NPE2050, PES, PEH, PIDI and VAWOZ
- ultimately deliver the foundations on which the grid operators' long term grid planning and investment decisions will be based.

The II3050 scenarios are made with the Energy Transition Model (ETM) for the aggregated energy system and the Carbon Transition Model (CTM) for the industrial sector within. The ETM and CTM are both simulation models that describe the entire energy system and industrial system respectively. The grid operators have developed four storylines which differ primarily in their levels of autonomy, cooperation, market dependency, and governmental involvement, presenting paths towards a CO_2-neutral 2050.

> The 'Decentral Initiatives' storyline emphasizes local solutions and community autonomy, supporting diverse sustainable initiatives but struggling with industry sustainability due to unstable renewable sources. The 'European Integration' storyline focuses on European integration, coordinating energy policies across nations to boost self-sufficiency and enhance renewable energy and CCS use. The 'International Trade' storyline leverages global markets to optimize economic benefits, becoming a central hub for hydrogen while relying heavily on imports. The 'National Leadership' storyline features a government-directed strategy, mandating technologies and investments to maximize local renewable energy and centralize control.

The most recent edition of II3050 (developed in 2022-2023) differs in many ways from the previous edition (developed in 2019-2020). For instance, the industry has been covered in much more detail with the CTM, leading to a deeper understanding of how industrial sites may develop and what differences may emerge within and between sectors. Another striking difference is that

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[1] Netbeheer Nederland (2023): Het energiesysteem van de toekomst: de II3050-scenario's. Integrale energiesysteemverkenning 2030-2050

while the former edition of II3050 contained many dozens of GWs of backup power plants to ensure a security of supply, this newest edition has up to 41 GW of large scale batteries in 2050 instead[2].

These batteries have been placed in the scenarios following an analysis the grid operators have done with in-house tools to evaluate the capacities and volumes needed to ensure the stability of the grid. This analysis has been done after the demand and supply side of these scenarios have been developed. These quantities and capacities of batteries can hence been seen as the 'technically required' capacities for these energy scenarios.

While the grid operators installed these batteries for grid stabilisation purposes, they did not look into their costs and benefits. We therefore do not know if alternative solutions would result in higher or lower system costs, nor if batteries in these scenarios are profitable on a business case level. This therefore raises the question what the costs and benefits of large scale batteries are in long term low carbon and climate-neutral scenarios and whether the (financial) conditions are there to expect such capacities to be installed.

This study aims to answer this question. We will both look at shorter (2030, 2035) and longer (2040, 2050) time horizons when analysing the system costs effects of battery storage. We will also consider the sensitivity of the system cost effects to several key parameters, such as fuel prices, battery prices and balancing market developments.

The rest of this report is structured as follows. We present a brief summary of our methods, the results, and then our conclusions. An extensive documentation of our methods (model, data used and assumptions) can be found in the technical documentation attached.

[2] 41 GW large scale (li-ion and flow) batteries in the Decentral Initiatives 2050 scenario. In addition there are also household and EV batteries. See also https://energytransitionmodel.com/saved_scenarios/14552

II. Methods

This section details the methods used in this study. It is a high-level summary of the technical documentation, which can be found in the last chapter of this report and will be useful to those trying to develop a more detailed understanding of our methods.

Since our aim is to understand the system effects of batteries, we will look at the effects of batteries upon their introduction in an energy system which does not contain any batteries yet. This allows us to compare system parameters like system costs, emissions and curtailment directly between a reference system and a system with batteries.

We use the 2030 Climate and Energy Outlook as our reference 2030 scenario

As a reference energy system we take the Climate and Energy Outlook 2022 scenario for the year 2030 (hereinafter referred to as KEV 2030) in the Energy Transition Model (ETM)[3]. The KEV 2030 scenario is a representation of the Climate and Energy Outlook ("Klimaat- en Energieverkenning") of 2022 carried out by PBL, a yearly study which looks at the effects of current climate and energy policies. This scenario for 2030 thus describes the energy system of 2030 expected based on current policies. It provides us with a very good relevant reference point since it is founded on actual policies and 2030 as a year can be seen at the start of the window 'long term' and 'large scale capacity'. According to CBS at the end of 2022 there was 142 megawatt of battery capacity installed in the Netherlands [4][5] – the Dutch high voltage grid operator TenneT expects/requires several gigawatts of battery capacity by 2030[6].

By having the KEV 2030 scenario incorporated in the ETM, we gain access to a wealth of simulation and analysis options facilitated by the ETM. The ETM is an open source and open data model which describes the energy system of a region (country, province, municipality). It features a demand and supply side, as well as an extensive flexibility module at their intersection, which are matched on an hourly basis for electricity according to a merit order principle. These hourly profiles are calculated bottom up. They thus already incorporate changes like heat pump adoption in the built environment, electric vehicle uptake and charging strategies in mobility, industrial electrification and much more.

We use the profiles of this scenario as input for a custom-built battery model

The ETM has the option to introduce large-scale batteries, but we chose not to work with this module. The battery behaviour in the ETM tracks the residual load curve (which has no direct notion of the electricity price curve) and thus gives poor performance in the day-ahead market. The ETM also does not cover some of the other important markets the battery is active in (notably balancing markets).

We therefore built a custom model, and import the hourly demand profiles, import curves, generation capacities and marginal costs from the ETM 2030 scenario. We have made three adjustments to the original KEV 2030 scenario:

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[3] https://energytransitionmodel.com/saved_scenarios/15969

[4] CBS (nov. 2023): Grote batterijen voor opslag van elektriciteit, 2022

[5] Most of this capacity is small scale (size: few MW) and short duration (< 2h)

[6] https://www.tennet.eu/nl/batterijopslag

1. we set the export availability to zero to create a closed system
2. we increase solar-PV capacity to a more realistic number for 2030[7]
3. we delete all flexibility technologies (storage and conversion) present to create a scenario stripped of batteries and with no competing interaction.

Excluding exports from the analysis reduces the average electricity price but only slightly affects price volatility. This results in a slight decrease the effectiveness of batteries but not to an extent that meaningfully affects the conclusions that can be drawn from this study. For more information see the technical documentation.

We use the resulting profiles from the ETM in duo: once as reference curves, and once as curves subject to interaction with battery system. Next, we analyse both curves to calculate differences in activities of plants, cost effects of that, curtailment and emissions and much more.

In this model the battery can be active in various markets, but not all

The battery activity is instructed by an algorithm which is described in detail in the technical documentation. In our model the battery has three markets it can be active in: the FCR, aFFR-up and day-ahead markets. In reality there are more markets, including aFFR-down, intraday, passive imbalance, mFRR, congestion management and ancillary services. Hence our model does not consider all potential revenue batteries can generate, however it does consider the largest markets. Furthermore, the model does not take into account ATR85 transport right restrictions, which would reduce the actual battery income. Se the technical documentation for more information.

It is important to emphasize that a battery can be active in several markets at the same time. However, reserving some battery capacity for one market might prevent that capacity to be used in other markets. The challenge of finding the best use of battery power (MW) and battery capacity (MWh) given market conditions is sometimes referred to as 'value stacking'. Within the scope of our analysis, the battery will in general opt for the FCR and aFRR markets if conditions allow as revenues generally are higher than on the day-ahead market. One would expect the aFRR margins to approach those of the day-ahead market as the former market saturates. In our battery model, battery power and capacity is first reserved for FCR. The remainder of the capacity is first used for aFRR-up combined with day-ahead trading. Activation in these two markets is efficiently combined using perfect foresight. This is an optimistic approach, however battery operators will likely attempt to combine several markets in the most optimal way using sophisticated algorithms.

We calculate system benefits by comparing a scenario with batteries to one without

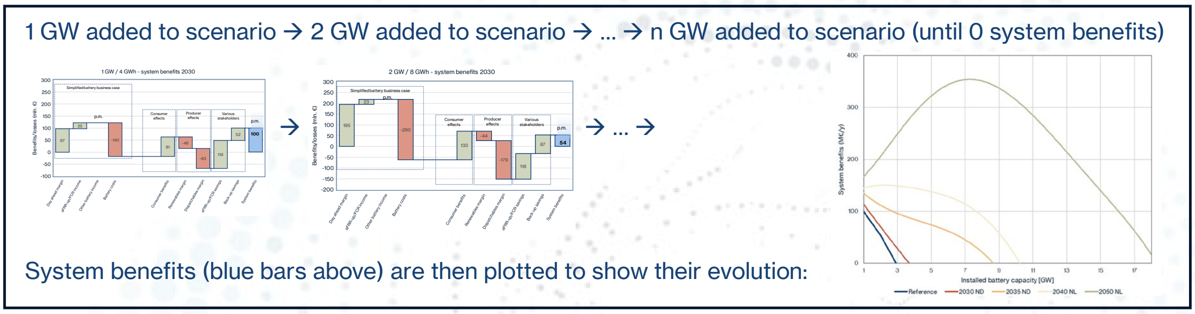
When it comes to system benefits in a closed system like ours, we can sum the change in producer margins, costs and savings to find the net system cost effects. On the margin side there is a positive margin for the batteries for both the FCR, aFRR-up and day-ahead markets (revenues minus marginal costs for charging). We then also have battery costs (investment costs depreciation and fixed operational costs). The combination of these two, along with grid fees, effectively constitutes a simplified business case (excluding some revenue streams, as indicated before). Grid fees are set to zero initially. Regarding the system effects, there can be cost

[7] The solar-PV capacity in the KEV2030 scenario is 26 GW, while 24 GW was already present at the end of 2023 (CBS). Solar-PV capacity in the scenario is upped to 34 GW based on the IP2024 Climate Ambition scenario from the Dutch grid operators

savings in both the FCR and aFRR-up markets and an electricity price reduction which benefits consumers. On the flip side of that however, there can also be a reduced margin for producers. Lastly, there can be savings in backup power (fixed costs) as the batteries effectively reduce the peak capacity of dispatchable plants required.

III. Results

In this chapter we present the results of our analysis. First we show how we calculate the system benefits for 1 GW of batteries in the reference 2030 scenario. Then we illustrate what happens when we add another GW of batteries and how we can in this way evaluate how system benefits develop for increasing amounts of battery capacity. Consequently, we use this method and apply it to the II3050 National Drivers/National Leadership scenarios for 2030, 2035, 2040 and 2050. Fourth, we perform a sensitivity analysis of some key parameters (especially fuel prices and battery investment costs due to high uncertainty) in the 2035 and 2050 scenarios. And last, we quantify some other benefits batteries yield which follow from our model.



System benefits breakdown

Below in Figure 7 we show how the system benefits, shown in blue, are calculated from its various components for our reference 2030 scenario, as also described in the Methods section. While the exact numbers vary between scenarios, the components of the system benefits calculation remain the same.

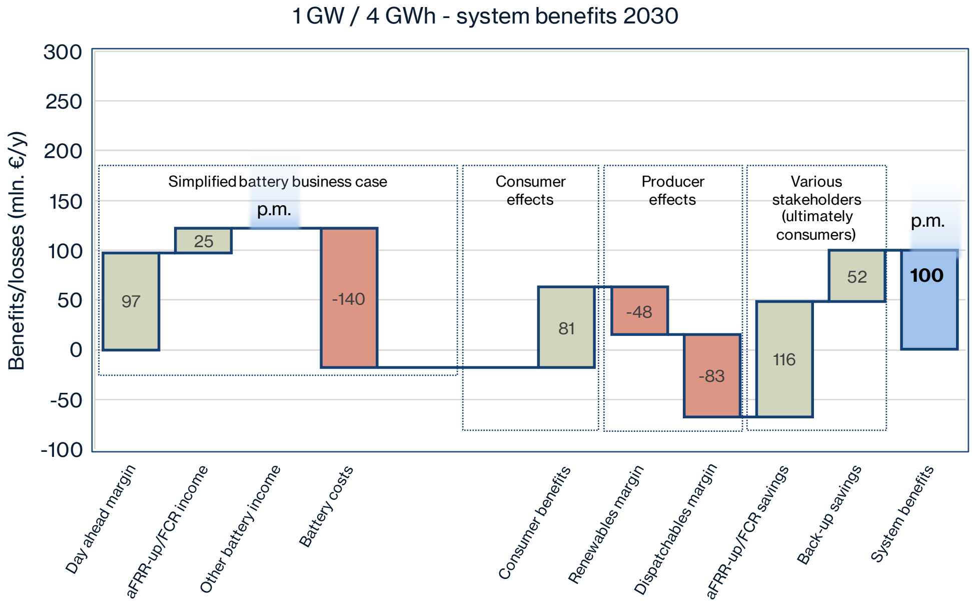


Figure 7. System benefits breakdown excl. grid fees for the first GW of batteries in the 2030 reference scenario, clustered for the perspectives of various system actors. Since we have not covered all battery revenues, total revenues and hence system benefits are likely higher, as denoted by the p.m. posts.

The simplified net battery earnings include day-ahead margin, income from FCR and aFRR-up markets, and battery costs, excluding grid fees and some other revenues

The first component (starting on the left of the waterfall in the figure) are the margins the battery makes on the day-ahead market (revenues – electricity purchased, including efficiency). This generally constitutes a major benefit. The second component is income generated from the FCR and aFRR-up markets (both capacity and bids). This constitutes a small revenue stream as the size of balancing markets are limited and we assume that batteries will bid based on opportunity costs from the day-ahead market as balancing markets become saturated. Third, we find the battery costs (fixed operation and maintenance costs as well as depreciation of capital costs). These three together constitute the simplified net battery earnings, which excludes grid fees and some revenue streams from other markets.

In this case we find the battery business case to be slightly negative, but there are two important remarks to be made on this. First, not all battery revenue streams are included. It is likely the business case would be positive if we were to included intra-day, aFFR-down, mFFR, passive balancing and ancillary services revenues. Second, there is also a trade-off between aFFR income and aFFR consumer benefits (which we will come to later). A battery can bid higher prices, generating higher income but lower cost reductions for TenneT, or lower prices, giving smaller battery income but higher benefits for TenneT. Here we follow the second route as it is likely the markets get saturated soon. On a system level the benefits are the same, but not to individual parties involved.

Batteries reduce electricity prices and balancing costs, benefiting consumers, but reduce margins for producers and lessen the need for backup plants, resulting in net system benefits

Next we go into the effects beyond the battery business case. On the day-ahead market batteries reduce (peak) electricity prices, yielding significant benefits for electricity consumers. This comes at the expense of the margin of both renewable and dispatchable plants. This happens because batteries can push certain plants outside the merit order and reduce scarcity prices, lowering the compensation all plants receive in a given hour. Next, the aFRR income from batteries also leads to general savings for TenneT and balancing responsible parties as batteries can bid more competitively and therefore bring down balancing costs. These cost reductions are ultimately passed on to consumers. Lastly, batteries also reduce the need for back-up plants, as there may be a smaller capacity of 'last' plants in the merit order active than in a system without batteries. These savings (fixed costs of these plants) we include as back-up savings.

By summing all costs differences we obtain the net system benefits, which amount to 100 M EUR/year in this case. We can sum these changes as we consider a closed system, as described in more detail in the technical documentation.

Effects for different system actors

In the previous section we looked at the total system benefits, which amounted to 100 M EUR/y. System benefits are actually different for the different actors in the system. We will look here at battery operators, grid operators, electricity consumers and electricity producers.

Battery operators

Battery operators would look at the battery business case. In this scenario, it is negative (-18 M EUR/y), but we have not included all battery revenues and batteries can bid higher prices to generate sufficient revenue in the aFFR markets. The aFFR system benefits are 116 M EUR/y, so batteries have ample opportunity to generate more income for themselves and create a positive business case if markets are not yet fully saturated.

Grid operators

The grid operators benefit from the reduction in aFFR and FCR costs as these are incurred by TenneT. They also profit from the reduction in electricity costs, since they pay for electricity losses (roughly 2% of electricity transported through the high voltage network). Regarding grid fees and expansion effects, we will detail that in the next chapter. Depending on the fee regime, batteries may not result in grid expansions and grid fees collected from batteries would amount to a value transfer to other electricity consumers.

Electricity consumers

The electricity consumers mostly benefit from lower electricity prices as well as lower and fewer peak prices. They also profit by extension from the grid operators' effects, since it is the electricity consumers that mainly pay for the grid.

Electricity producers

For electricity producers we have to distinguish volatile and dispatchable plants. Volatile electricity production such as solar and wind generally experience margin losses due to lower prices, but under some circumstances positive effects due to lower curtailment. Dispatchable plant operators in general experience significant margin losses.

Effects of marginal capacity increases

We can increase the battery capacity in the scenario we saw before to see how the system benefits develop. Below we show what happens when we add another GW of batteries to the scenario with 1 GW of batteries in 2030.

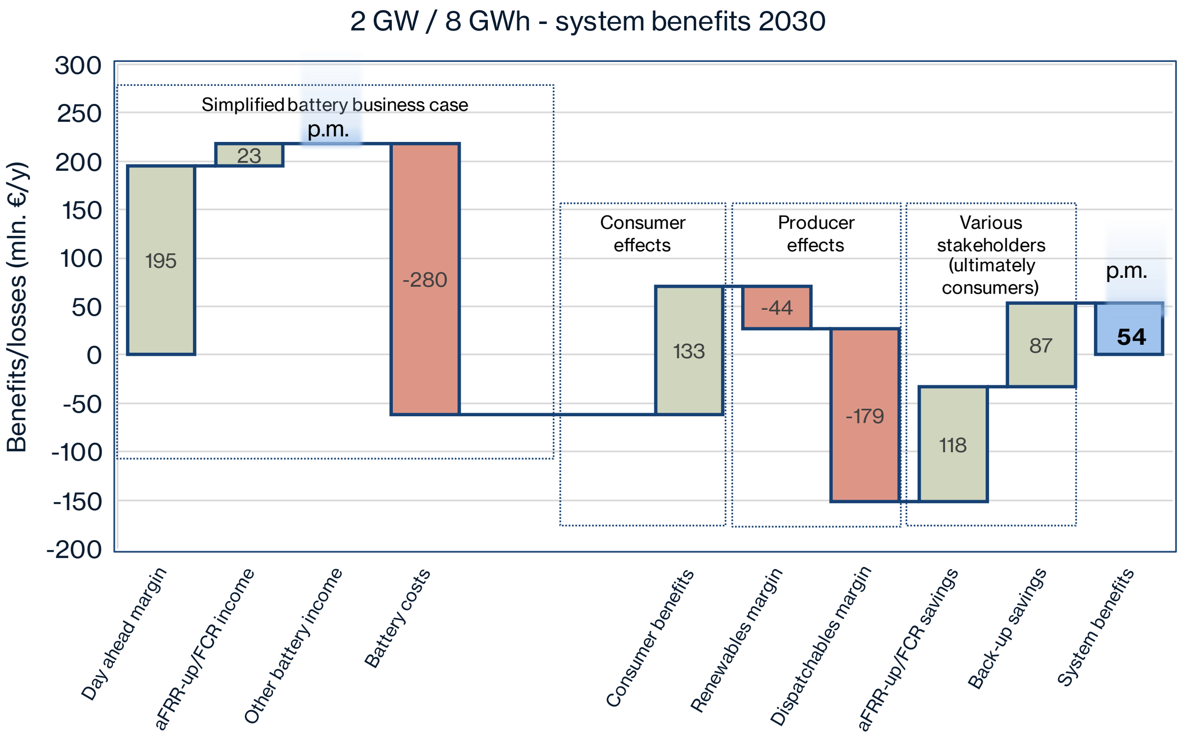


Figure 8. System benefits breakdown for 2 GW of batteries in the reference 2030 scenario.

We see that the system benefits decrease from 100 to 54 M EUR/y as we go from 1 to 2 GW of batteries. The battery costs double (as one would expect) and increase by 140 M EUR/y, while the day ahead margin increases by only 98 M EUR/y. With 2 GW of batteries the total FCR and aFRR benefits (income for battery and savings) are identical to those we saw for 1 GW, 141 M EUR/y, since the FCR and aFRR markets are assumed to be already fully served with 1 GW[8].

We also observe some shifts in the effects on the rest of the system. The consumer benefits increase by over 60%, while we doubled the battery capacity (and the day ahead margin). This suggests that the additional GW does not reduce the electricity price as much as the first one. The renewables margin actually increases. This is likely due to lower curtailment. The dispatchables margin decreases significantly. Lastly, the next GW of batteries also reduces the back-up capacity (but less than the first).

We can repeat this procedure of adding battery capacity in steps of 1 GW. As the system benefits diminish due to competition between batteries and market saturation, we eventually reach a point (capacity) where the system benefits are no longer positive.

[8] . The aFRR battery income is slightly lower and the savings slightly higher for 2 GW compared to 1 GW, the difference being 2 M EUR/y. This is due to an opportunity cost calculation relative to the day-ahead income, which is lower for 2 GW

System benefits evolution in scenarios

We will follow the procedure we explained above to evaluate how the system benefits develop as we increase battery capacity in various scenarios. We first explain which scenarios we take and define, before we present our results. These results will show the system benefits exclusively (the blue bars from the graphs before), not their breakdown as we presented before.

The scenarios we will use are based on the IP2024 and II3050 scenarios. We opt for the 'National' scenarios, i.e. the National Drivers and National Leadership scenarios. In these scenarios the national government mainly is in the driver seat, as arguably it is in current policy and decision-making as well. In general the key assumptions like fuel prices and balancing market sizes and prices are kept unchanged with respect to the reference scenario, but we take the battery cost projections from NREL and the non-flexible electricity demand, solar PV, wind and nuclear power capacity from the IP2024 and II3050 scenarios. Inputs are listed in Table 1.

Table 1. Key parameters of different battery model simulation runs.

	Battery costs ($/kW overnight)	Fuel prices relative to baseline 2030	FCR volume, pricing relative to ref	Non-flexible demand [TWh]*	Solar-PV [GW]	Wind [GW]	Nuclear [GW]
KEV 2030	1204	100%	100%	127	26	23	0.4
IP2024 National Drivers (2030)	1204	100%	100%	172	76	32	0.5
IP2024 National Drivers (2035)	1111	100%	100%	213	98	44	0.5
II3050v2 National Leadership (2040)	1018	100%	100%	231	123	66	1.5
II3050v2 National Leadership (2050)	833	100%	100%	293	173	92	3

In Figure 9 we show the system benefits as a function of battery capacity. We display the results as smoothed, low-dimension polynomials as the battery algorithm sometimes results in step-function like behaviour, until the point the system benefits reach 0.

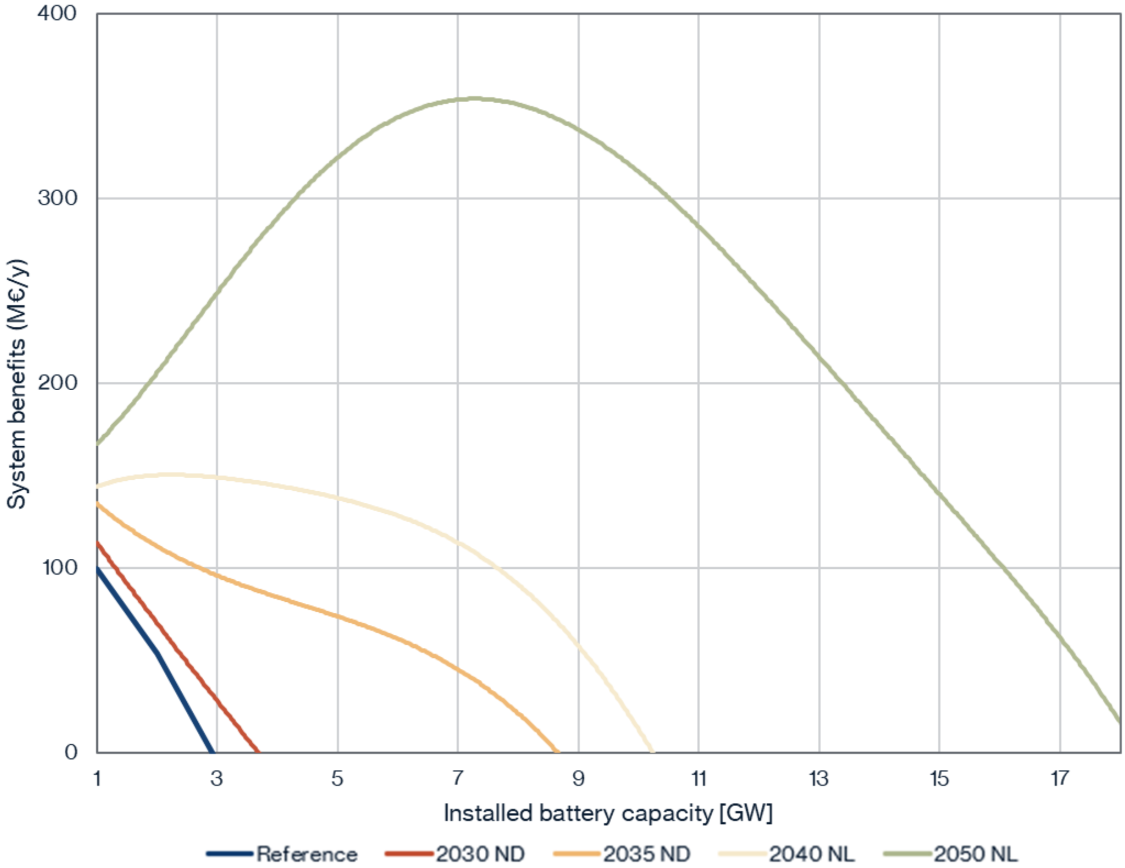


Figure 9. System benefits as a function of battery capacity for the reference 2030 and the ND IP2024 and NL II3050 scenarios for 2030, 2035, 2040 and 2050.

Please note: given the many uncertainties behind important input parameters (such as battery and fuel costs) and the major impact these parameters have on the results and also as a result of methodological simplifications, it cannot be concluded from this graph how much battery power is optimal is in a given scenario.

Batteries provide positive system benefits in all scenarios but with diminishing returns

We see that batteries can give positive system benefits in all scenarios, but that the effects are diminishing. Up to 18 GW (72 GWh) of batteries give positive system benefits in the 2050 scenario. Interestingly, this corresponds in volume to roughly 45 GW of 1.6h hour batteries (the storage volume per battery assumed in the II3050 scenarios). Hence, in storage volume (but not in capacity) this illustrates that batteries under these circumstances would have positive system benefits up to the battery volumes used in the 2050 II3050 scenarios.

The system benefits in 2050 peak at about 350 M EUR/y, at 7 GW battery capacity. This peak might suggest that there is an optimum where a mix of 7 GW of batteries complemented by backup power give the greatest system benefits. We should however emphasise that this study does not attempt to find an optimal flex combination – for that a different setup is necessary. As the sensitivity analysis also will show, the peak, overall shape and point up to which battery capacity give positive system benefits can move significantly subject to one's assumptions.

As batteries become cheaper and renewable electricity production and demand increase towards 2050, more battery capacity can be accommodated, resulting in higher system benefits

What we see in more detail in these reference scenarios is that the first GW of batteries already covers the balancing markets (FCR and aFRR-up, as considered here), yet the system benefits are not the same for these years. On the one hand that is due to a battery cost reduction (some 45 M EUR/y between 2030 and 2050), but the difference is greater than that. The other reason is that there are more opportunities to trade on for a battery in a larger market with more volatile supply. We see that more strongly as we look at the next GWs.

For the 2030 scenarios, system benefits decrease rapidly and almost linearly. For the 2040 and 2050 scenarios, system benefit increase for the first GWs. At 3 GW, there is a 250 M EUR/y difference between the system benefits of the 2030 and 2050 scenario. Just over half of this difference is accounted for by battery costs[9]. The remainder of the difference in system benefits is therefore due to the differences of non-flexible demand and volatile supply between 2030 and 2050 – because the scenarios are equal in all other aspects. This does demonstrate that batteries can contribute more to system benefits as we move to an energy system which is more electrified and has more volatile supply.

In fact what we see is that as battery costs go down and market size and trading opportunities go up, the curve effectively gets tilted upwards more and more – starting from a linear decay for 2030, to a non-linear decay for 2035, via a slight top for 2040 towards a parabola shaped curved for the 2050 scenario (see Figure 9).

System benefits sensitivity analysis

Higher fuel prices give higher system benefits with higher battery capacity (and conversely)

Below we perform a fuel price sensitivity analysis, as shown in Figure 10, on the day-ahead market. We focus on the 2035 ND and 2050 NL scenarios from before. We present a variation of the 2035 scenario with 50% higher fuel prices (e.g. expensive hydrogen in the short term) and a variation of the 2050 scenario with 50% lower fuel prices (e.g. cheaper hydrogen in the long term).

We observe that the system benefits at 1 GW are very similar. This makes sense as the batteries will mostly operate in the balancing markets which are not varied in this part of the sensitivity analysis.

When we look at the next GWs, the picture changes. In the 2035 scenario, additional battery capacity beyond the saturation of the balancing markets leads to positive system benefits when fuel (and CO_2) prices are elevated to 150% of reference prices. This contrasts with the negative marginal system benefits observed in the 2035 reference scenario. This can be explained due to cost reductions resulting from fuel savings from batteries operating in the day-ahead market being larger than annualized battery costs at elevated fuel prices.

[9] 3 GW *45 M EUR/ GW battery cost reduction between 2030 and 2050 = 135 M EUR

For 2050 at reference fuel prices, additional battery capacity beyond the saturation of the balancing markets leads to positive system benefits due to lower battery costs. When fuel prices are reduced by 50%, there is still a slight positive effect of the first GWs of battery capacity active in the day-ahead market. However, the marginal system benefits turn negative at much lower battery capacities (3-4 GW) compared to the 2050 reference scenario (7 GW).

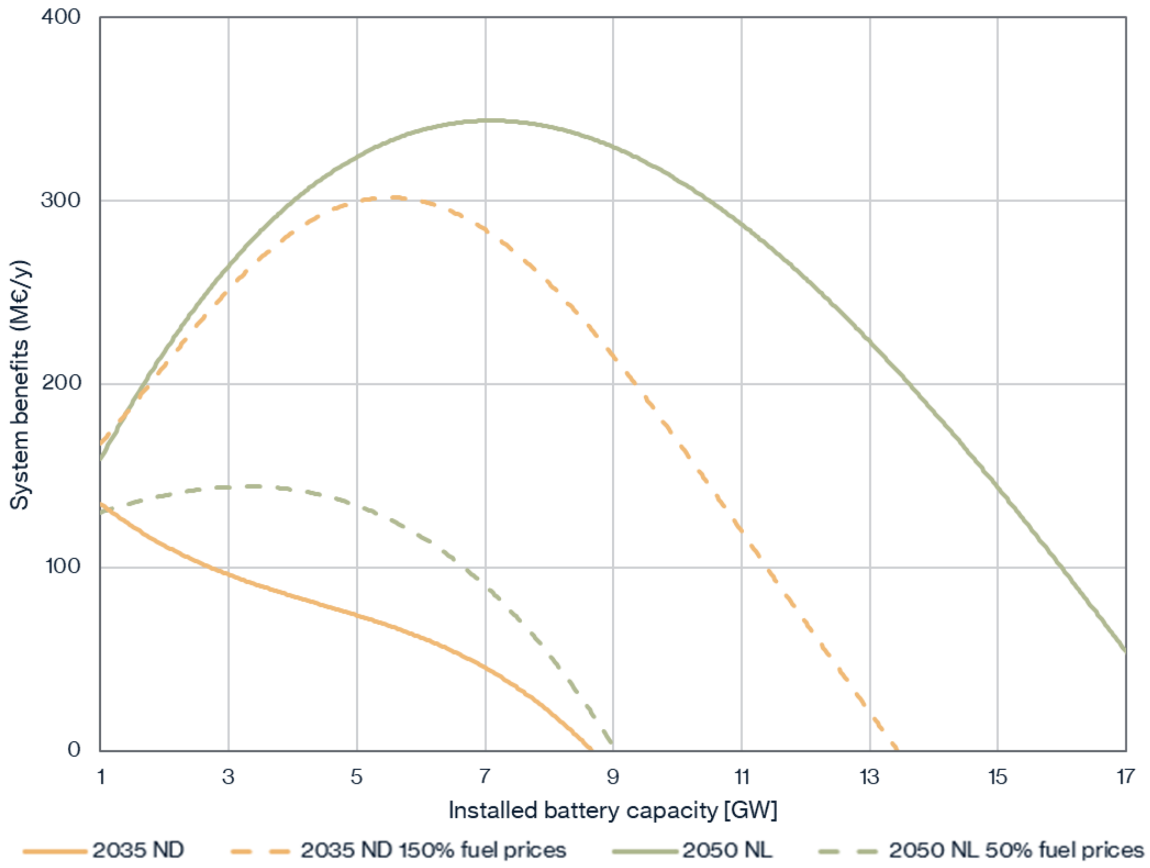


Figure 10. Sensitivity analysis with fuel prices for the 2035 and 2050 II3050 ND and NL scenarios on the day-ahead market exclusively (not on the balancing markets). We show both the results with reference fuel prices and 50% higher prices for 2035 (reflecting for instance more expensive back-up power as hydrogen may be scarcer and more expensive/ gas and CO_2 prices higher) and 50% lower prices for 2050 (reflecting for instance access to cheaper, large-scale produced hydrogen).

We have not run this analysis for a lower price 2035 and a higher price 2050 scenario, but we would expect their outcomes to mirror what we have seen before. That is to say, the 2035 lower price scenario would probably give a faster decay, while the 2050 higher price scenario would give a later and higher peak system benefits and net system benefits up to a higher capacity.

Lower battery investment costs result in higher system benefits up to higher capacities

Next we consider what would happen to the system benefits if battery investment costs would drop. In our reference analysis we use the 'moderate' cost parameters for the NREL[10], whereas

[10] NREL (2023): 2023 Electricity Annual Technology Baseline (ATB) Data. Utility scale battery storage.

here we explore the effects of a 25% reduction. At this reduction cost parameters are slightly higher than the 'optimistic' NREL cost parameters. The results can be found in Figure 11.

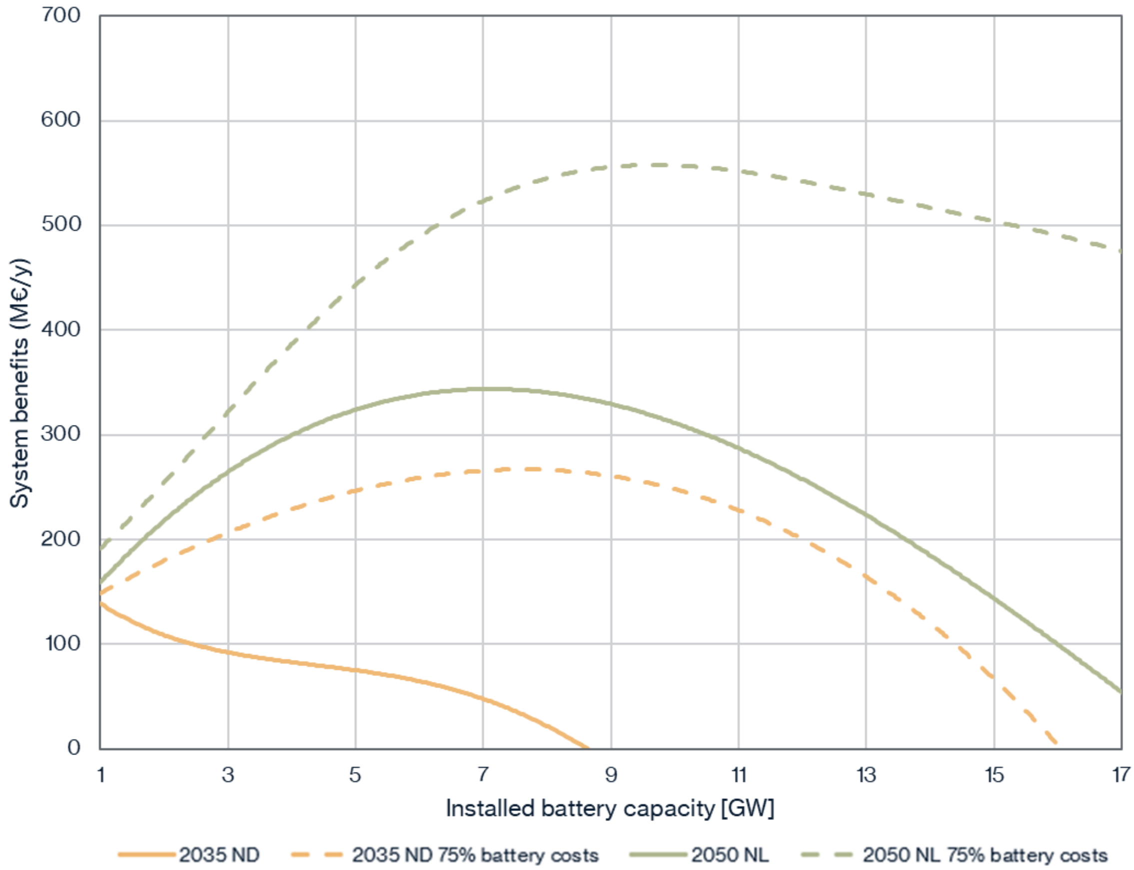


Figure 11. Sensitivity analysis with 25% reduction in battery investment costs for the 2035 and 2050 II3050 ND and NL scenarios. We show both the results with reference cost figures and 25% lower investment costs for 2035 and 2050. This cost reduction puts the assumed investment costs slightly higher than the 'optimistic' cost figures from NREL.

Both for the 2035 and 2050 scenarios a 25% reduction in battery investment costs has a very large impact on system benefits. This effect becomes more pronounced at higher battery capacities as the cost reduction is cumulative for each GW of battery capacity. Such a battery cost reduction can be the difference between positive and negative marginal system benefits for additional GWs of battery capacity, as is illustrated by the 2035 ND scenario variants.

For 2050, a battery cost reduction results in much higher maximum system benefits at a higher battery capacity of 10 GW instead of 7 GW in the reference variant. The graph shows results up to 17 GW but the system benefits for 2050 at lowered battery costs remain positive up to roughly 30 GW. Lowering battery investment costs by 25% has a stronger effect on system benefits compared to changing fuel prices by 50% higher. This suggests that the battery's own costs plays a more important role than the external factor of fuel prices.

While we cannot know with certainty what battery costs will amount to for these years, this analysis does show that batteries do deliver more sustained and significant system benefits if cost curves decline sharper than the NREL moderate projections.

Higher balancing prices mostly affect the first GW(s)

Another element of uncertainty is that of the balancing prices, as we do not know what other actors in these markets can and will bid if batteries would not be active in these balancing markets. In 2022, due to high fuel prices, the balancing compensation was significantly higher than the long-term average. While we before looked at the effects of higher fuel prices, we only evaluated the effects on the day-ahead market.

To simulate however the effect of higher balancing prices, we run our analysis with the 2022 balancing prices as well as the 2021 reference prices. The results can be found in Figure 12.

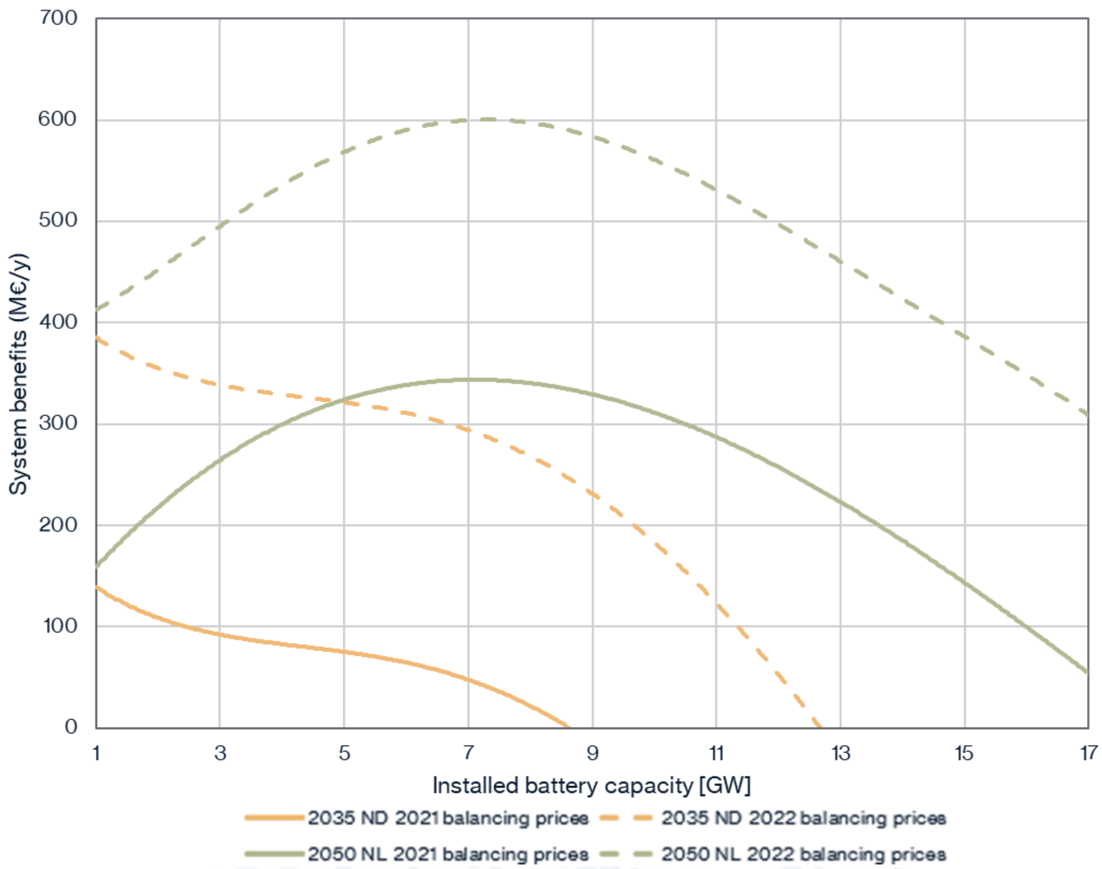


Figure 12. Sensitivity analysis with 2022 rather than 2021 reference balancing prices for the aFRR market for 2035 and 2050. 2022 aFRR market prices were significantly higher than the long-term average and reflect higher fuel prices and more volatility.

With the 2022 balancing prices the system benefits are some 250 M EUR/year higher for the first GW[11]. We also see here that the overall curve is pretty much identical in shape between the 2022 and 2021 balancing prices. This is because the markets are effectively already saturated with the first GWs, resulting in a curve is shifted upwards. As a consequence, we also find higher peaks and a later point where system benefits turn negative.

[11] There are many ways in which they can be distributed. If we recall the cost breakdown from earlier, it is possible the battery bids very aggressively and the consumer reaps most of the benefits, or conversely the battery places very strategically high bids and claims most of the benefits for itself. This is a zero-sum game, the overall results for system benefits are the same.

Other benefits

Some of the battery benefits are not directly financial or, conversely, monetized but extending greater value. While our aim here is not give an overview of all such benefits, there are three we wish to highlight which also follow directly from our analysis: the reductions of CO_2 emissions, electricity prices and curtailment. The financial effects of these benefits are already included in the calculations we showed before (via ETS pricing).

The first 3 GW of batteries in 2030 reduce emissions by 0.5 Mton CO_2

In the reference 2030 scenario, the first 3 GW of batteries result in an emission reduction of about 0.5 Mton CO_2. The CO_2 emissions of electricity generation drop from 9.8 tot 9.3 Mton. This is because fossil back-up plants are less active. The costs (ETS) of this CO_2 is already priced in the marginal costs of the plants. Hence these do not constitute additional savings. For the CO_2 reduction we only look at the CO_2 that is not emitted for electricity generation; after all a heat demand would have to be fulfilled with another technology should a CHP run less. Given the scenario, we assume a gas burner with 90% efficiency as an alternative to meet this heat demand not covered in hours when a CHP reduces its activity due to batteries.

The first 3 GW of batteries in 2030 reduce consumer electricity expenses by 3.8%

The electricity price also goes down due to battery activity. Consumer expenses for electricity decrease by about 3.8% for the first 3 GW of batteries in the 2030 scenario. Formulated more technically: the hourly electricity price times hourly demand gives total expenses that are 3.8% lower in the scenario with batteries than the scenario without. The average electricity price decreases by a comparable 3.6%. Volatility of electricity prices also decreases, resulting in lower risk levels for all electricity consumers.

The first 3 GW of batteries in 2030 reduce curtailment by 2.5 TWh

Curtailment also goes down in our scenarios: volatile electricity producers have to shut down less. The first 3 GW of batteries in the 2030 scenario reduce curtailment from 32 to 29.5 TWh, hence putting 2.5 TWh of electricity to use. This also helps avoid emissions since this electricity can be used to displace fossil power generation at a later moment on the day-ahead market. This effect is already taken into account in the total emission reduction reported before. The curtailment reduction of 2.5 TWh amounts to roughly 830 full load hours of charging for 3 GW of batteries. This does not constitute all charging activity for batteries: they also charge at moments when there is no excess electricity. Since the total full load hours of batteries (single direction) are roughly 1800 hours in this scenario, batteries charge roughly 45% of the time when electricity prices are zero or negative.

IV. Batteries and grid tariffs

In theory, the ATR85 grid fees should ensure batteries do not result in grid expansion

The system cost analysis and cost benefit breakdown shown in the previous chapter does not include grid tariffs and possible grid operator costs. Currently, battery operators are required to pay grid tariffs for transport of electricity. These grid tariffs are lower than the maximum grid tariffs that other grid users have to pay in the new ATR85 ruling. ATR85 ruling states that if a grid user agrees to have guaranteed transport capacity for at least 85% of the time and restricted capacity for at most 15% of the time, they would receive a grid tariff discount. ATR85 transport contracts are only available at locations within the grid with sufficient unused grid capacity.

Based on our discussions with grid operators, we can state that the effects of batteries on the grid are determined by two main elements: behaviour and location.

- Behaviour wise batteries should move 'against' the predominant direction, i.e. charge at high production and discharge at high demand. However, during times of low grid loads there is room for batteries to move 'with' the predominant direction.
- Location wise, batteries should therefore be located in areas where grid loads are predominantly inverted to battery behaviour. For example, batteries located near solar-PV installations will likely charge during moments of high solar-PV production and discharge during moments of low solar-PV production. Another preferred location for batteries would be areas in which there is sufficient 'unused' grid capacity outside peak hours.

The ATR85 proposal is conceived with this idea in mind as it can limit battery charging or discharging 15% of the time. In theory, batteries should therefore not lead to additional network congestion and therefore should not require additional grid investments[12]. However, grid operators did note that the effect of battery location and behaviour on grid loads is a complex subject, and that one must be reserved in drawing hard conclusions regarding grid impacts.

Given new/proposed grid tariff regulation (ATR85[12] and code change for time-dependent transmission tariffs[13]), battery operators have to pay grid tariffs based on their maximum monthly charging rate (in kilowatts). Based on the height of grid tariffs in 2023 and 2024, the maximum grid tariffs for large scale batteries would be 44 or 80 €/kW/year respectively[14]. See the technical documentation for further substantiation of these figures.

The grid fees can result in a negative business case, while system benefits are positive

Figure 13 shows what happens when we apply grid tariffs using 2024 price levels including ATR85 discounts to the 2035 ND scenario with 50% higher fuel prices. We look at the point

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[12] ACM (2024). Ontwerpbesluit Alternatieve transportrechten

[13] Netbeheer Nederland (2023). Codewijzigingsvoorstel tijdsafhankelijke transporttarieven [extra-]hoogspanningsnet

[14] The steep increase in grid tariffs in 2024 is the result the energy crises in 2022 which resulted in very high costs for grid losses, balancing and congestion management, and a two year time lag between grid operator expenses and grid tariff calculation.

where 6 GW / 24 GWh of battery capacity is installed, which is the battery capacity at which system benefits are at the highest level for this scenario (see Figure 10). This variant is selected as it represents a situation in which batteries trading on the day-ahead market lead to system benefits. Any other scenario in which this would be the case (e.g. the 2050 NL reference scenario) would lead to similar conclusions.

While grid costs might not be significantly affected by batteries connected using the ATR85 transport rights (except for possible additional costs for grid losses, grid balancing, maintenance and other operational expenses to the extent that batteries actually lead to a marginal increase of these costs), the net earnings of battery storage deteriorate significantly. So much so that, based on Figure 13, it seems unlikely that 6 GW / 24 GWh of battery storage will be invested in. It is important to note that the actual business case of battery storage is much more complex and comprises many more markets (aFRR-down, mFRR, passive imbalance, intraday and ancillary services). However, we expect that the significant impact of grid tariffs as shown in Figure 13 will still hold true to a large extent in actual business cases. Even if future grid tariffs would be lowered with respect to 2024, impact on the business case of batteries remains significant. For example, 2023 grid tariffs (264 mln €/year, almost 50% lower than in 2024) would still result in net negative battery earnings.

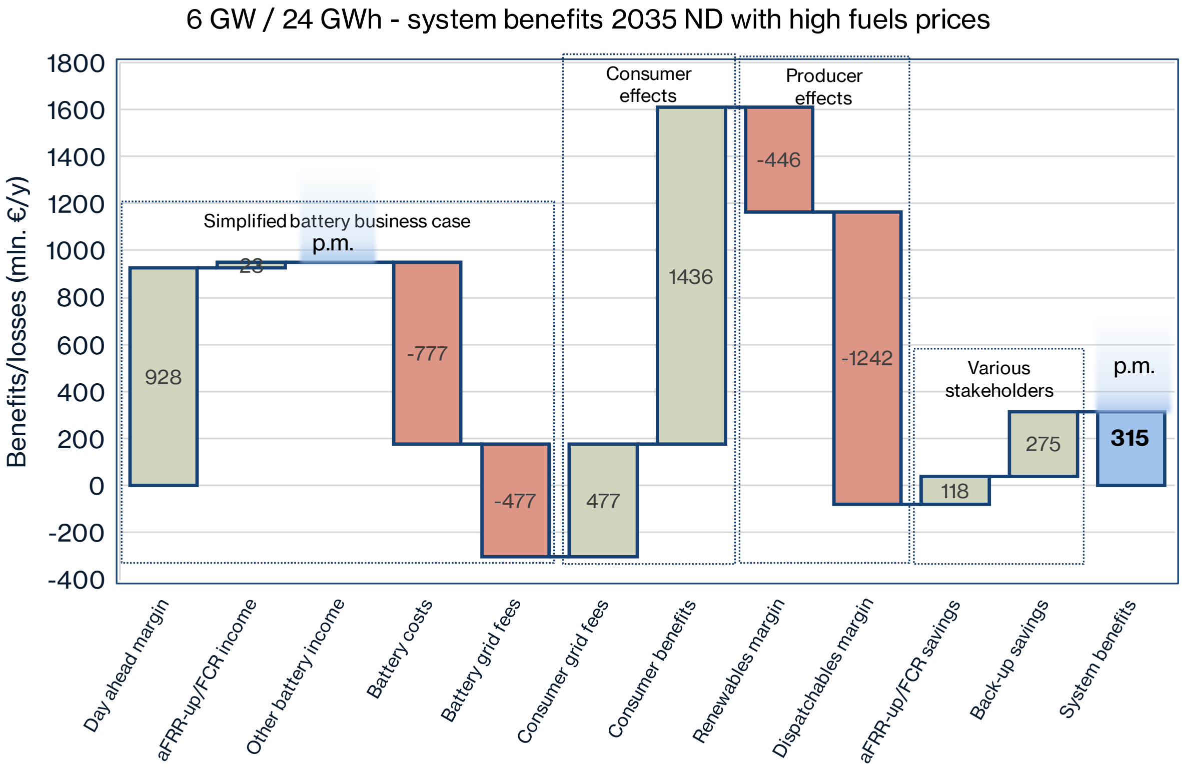

Figure 13. Annual system benefits breakdown for the 2035 ND II3050 scenario with 6 GW / 24 GWh installed battery capacity, including grid tariffs under the assumption that batteries using ATR85 transport rights do not lead to significant additional grid costs which therefore results in a value transfer towards other consumer grid fees.

Grid fees are a cost distribution problem, which should weigh in positive system effects

Given the positive system benefits of batteries in the example above, the detrimental effects of grid tariffs on battery net earnings and the limited grid impact, the question is to what extent batteries should pay grid tariffs. On the one hand we observe positive system effects, but on the other batteries do use the electricity grid and besides grid expansion and congestion management costs (which batteries using ATR85 contracts should in theory not be responsible for), costs are made for grid losses, grid balancing, maintenance and other operational expenses.

The extent to which batteries should contribute to cover these costs is therefore purely a cost distribution issue. On the one hand it can be argued that as a net consumer of electricity, batteries should pay grid tariffs just like all other consumers. On the other hand batteries also take the role of back-up power generators and actually reduce the need for dispatchable powerplants who in turn do not pay grid tariffs, while it is unclear whether an energy system with backup power plants or one with batteries has lower grid costs.

V. Conclusions

We have found in this study that large scale batteries can result in positive system benefits, while marginal capacity additions ultimately result in diminishing system benefits. The extent of these benefits depends both on intrinsic as well as extrinsic factors such as battery investment costs, fuel prices, system electricity demand and volatile supply and balancing market characteristics. Due to the significant impact of these parameters, the coherence and emergent picture of the results is more important than the individual quantitative scenario outcomes.

On the shorter term, around 2030, we find that in our reference scenario (based on reference climate policy/KEV2022) the first gigawatts (GWs) of batteries lead to a sizeable system cost reduction. Upon saturation of the balancing markets, system benefits quickly decline. When additional battery capacity is added that is mainly dependent on the day-ahead market, the system benefits drop to zero at 3 to 4 GW.

When we look further towards years based on the IP2024 and II3050 scenarios, we see that picture changes. For the 2050 scenario under reference conditions, the system benefits actually increase when adding battery capacity beyond saturation of the balancing market. This is due to the lower battery costs assumed for 2050. Increasing system benefits continue up to 7-8 GW of installed battery capacity. After that, the marginal benefits decrease for additional batteries, eventually dropping to zero at 18 GW.

This outcome however is rather sensitive to external conditions. Higher fuel prices, lower battery costs, higher electricity demand and more volatile supply can greatly impact system benefits from batteries. A 25% battery investment cost reduction would result in an increase in maximum system benefits by more than 50%. Furthermore, higher imbalance fees result in significantly higher system benefits for the first GW of batteries, as the balancing markets quickly become saturated.

One element that however directly affects the battery net earnings are the grid fees. While our study does not consider all battery revenue streams (but it includes the most important ones), it is rather clear that grid fees can pose a serious barrier to further battery expansion. At the peak benefits for a 2035 scenario with high fuel prices, we find that 6 GW of batteries would owe grid fees that are higher than the system benefits or the battery net earnings. The grid fee structure and fees therefore merit further reflection and consideration as it seems to jeopardise battery development, which here would give system benefits and not result in additional grid expansion.

Lastly, it ought to be pointed out that system benefits here refer to a general, net and financial effect. In more detail, we find that most actors in the energy system would profit. Electricity consumers pay lower electricity prices, grid operators have cheaper balancing options, except for electricity producers who experience a margin loss. More electricity is put to use (less curtailment), there is more resilience against price shocks and emissions, especially on the short term, would decrease.

Appendix: Technical documentation

This study introduces a battery model that leverages hourly demand and supply profiles from the Energy Transition Model (ETM) to assess system costs with and without extra battery storage. The model fills a gap in the existing battery module in the ETM, which lacks an algorithm for optimizing battery margins[15] and excludes balancing markets.

Electricity demand and supply profiles

The battery model processes electricity supply and demand data from the ETM, using the Climate and Energy Outlook 2022 scenario for 2030 (hereinafter referred to as KEV 2030)[16]. It aggregates hourly electricity demand across all demand sectors – industry, construction, transport, and agriculture – throughout the year. On the supply side, it sums the electricity generated by solar-PV, wind (offshore and onshore) and must-run power plants. Dispatch of flexible power plants and imports is calculated separately within the battery model, further explanation is provided later in this chapter. The supply of renewable and must-run electricity and the aggregated demand curve is displayed in Figure 14. Solar-PV generation from the KEV 2030 has been adjuster from 26 to 34 GW (based on IP2024 Climate Ambtion), as it is already clear today that the development of solar PV is going significantly faster than assumed in the KEV.

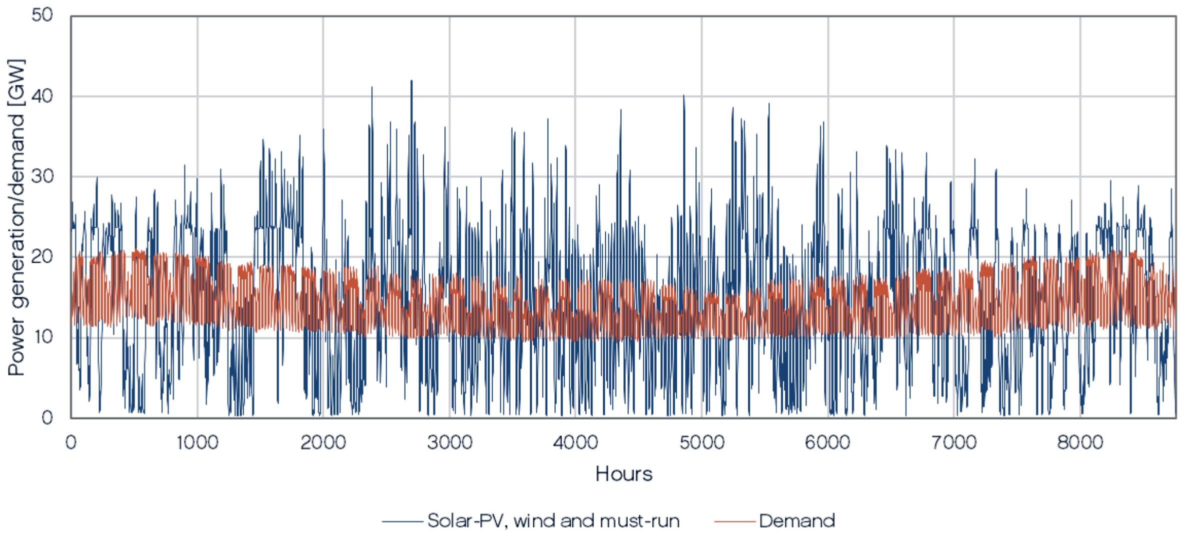

Figure 14. Hourly production of non-dispatchable power production (solar-PV, wind and must-run) and aggregated electricity demand based on the KEV 2030 scenario

Both the supply of renewable electricity and the aggregated demand are used as variables in the sensitivity analysis, resulting in different supply and demand curves. An overview of the different supply and demand volumes used in the sensitivity analysis is shown in Table 2. These figures are

[15] The battery algorithm of the ETM uses residual load as an input for battery charging and discharging decisions. This does not maximize battery margin.

[16] https://energytransitionmodel.com/saved_scenarios/15969

based on the demand and supply volumes of IP2024 and II3050 scenario's created by the Dutch grid operators.

The KEV 2030 demand profile only contains inflexible demand as there are virtually no technologies such as power-to-heat or power-to-hydrogen present in the scenario. Consequently, changing the supply and demand volumes in order to match supply and demand volumes of other scenarios does not reproduce the flexible demand technologies present in these scenarios. The effect of adding battery capacity to scenarios without other demand flexibility is more favourable than if there was flexible demand. After all, flexible technologies cannibalise their own profitability by competing amongst each other as more flexibility is added to a power system.

In other words, changes to supply and demand volumes in order to explore IP2024 and II3050 scenario's result in optimistic system cost effects, as if batteries do not compete with other flexible demand technologies.

Table 2. Electricity demand and renewable generation of the KEV 2030, IP2024 and II3050 scenarios

	Non-flexible demand [TWh]*	Solar-PV [GW]	Wind [GW]	Nuclear [GW]
KEV 2030	127	26	23	0.4
IP2024 Climate ambition (2030)	151	59	31	0.5
IP2024 International Ambition (2030)	137	42	31	0.5
IP2024 National Drivers (2030)	172	76	32	0.5
IP2024 Climate ambition (2035)	186	76	41	0.5
IP2024 International Ambition (2035)	161	53	40	0.5
IP2024 National Drivers (2035)	213	98	44	0.5
II3050v2 Decentral Initiatives (2040)	202	126	48	0
II3050v2 European Integration (2040)	211	93	40	4
II3050v2 International Trade (2040)	190	68	47	0
II3050v2 National Leadership (2040)	231	123	66	1.5
II3050v2 Decentral Initiatives (2050)	246	183	60	0
II3050v2 European Integration (2050)	255	126	48	8
II3050v2 International Trade (2050)	218	100	56	0
II3050v2 National Leadership (2050)	293	173	92	3

*Non-flexible demand excludes demand of from power-to-heat, power-to-hydrogen and storage

Power plant dispatch

The residual demand that remains after aggregated demand and renewable + must-run supply have been settled must are then met by dispatchable power plants and imports (see next section for imports). Dispatch of power plants follows the merit-order principle. Power plants with the lowest marginal costs are activated first before plants with higher marginal costs are activated, until demand is met. The electricity price is equal to the marginal costs of the last power plant that is activated. The marginal costs and capacities of different dispatchable power plants from the KEV 2030 are listed in Table 3. The natural gas price in the KEV 2030 ETM scenario is 42 €/MWh and the CO_2 price is 110 €/ton. The marginal costs of dispatchable power plants are used as variables in the sensitivity analysis.

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Table 3. Marginal costs and capacities of dispatchable power plants based on the KEV 2030 in the ETM

	Marginal costs [€/MWh]	Capacity [MW]
Nuclear 2nd Gen	5	431
Waste CHP	29	734
Biomass CHP	46	616
Gas CCGT CHP	78	617
Industry gas CCGT CHP	93	837
Gas CCGT	94	8616
Agriculture gas motor CHP	109	2626
Gas motor CHP	116	61
Industry gas motor CHP	127	83
Gas conventional	141	1062
Gas turbine	166	balancing*

*The gas turbine is used for guaranteeing sufficient supply at each hour of the year. The capacity is therefore a result of the maximum residual demand but is affected by batteries.

Imports and (no) exports

Besides dispatchable power plants, imports can also be used for meeting residual demand. The KEV 2030 scenario contains 9800 MW of interconnection capacity. Import capacity participates in the merit order in a similar manner as dispatchable power plants. However, the import prices and the import availability differ on an hourly basis.

The KEV 2030 scenario contains price curves for five different interconnection nodes. Import availability curves are then synthesized based on these price curves. This is a modification to the original KEV 2030 scenario. At higher prices, import availability goes down as higher prices in neighbouring countries often correspond with impending scarcity of production capacity. Price curves and availability curves for imports are shown in Figure 15.

Exports are excluded from the battery analysis as it makes a clear system costs analysis much more challenging. Exports effectively leads to foreign electricity consumers being added to the system, resulting in unclear system delineation.

Excluding exports from the model leads to lower electricity prices since there is less demand relative to cheap renewable power generation. Without export there are more hours with electricity prices equal or lower than zero. There are also less hours with (extremely) high electricity prices. However, the volatility of the electricity price (measured using standard deviation) does not change significantly when excluding exports. Since battery operators are mainly concerned with price volatility, the effects of excluding exports on battery revenue is limited. For the 2030 reference scenario battery revenue excluding exports was less than 10% lower than battery revenue including exports. The number of full load hours did not change significantly.

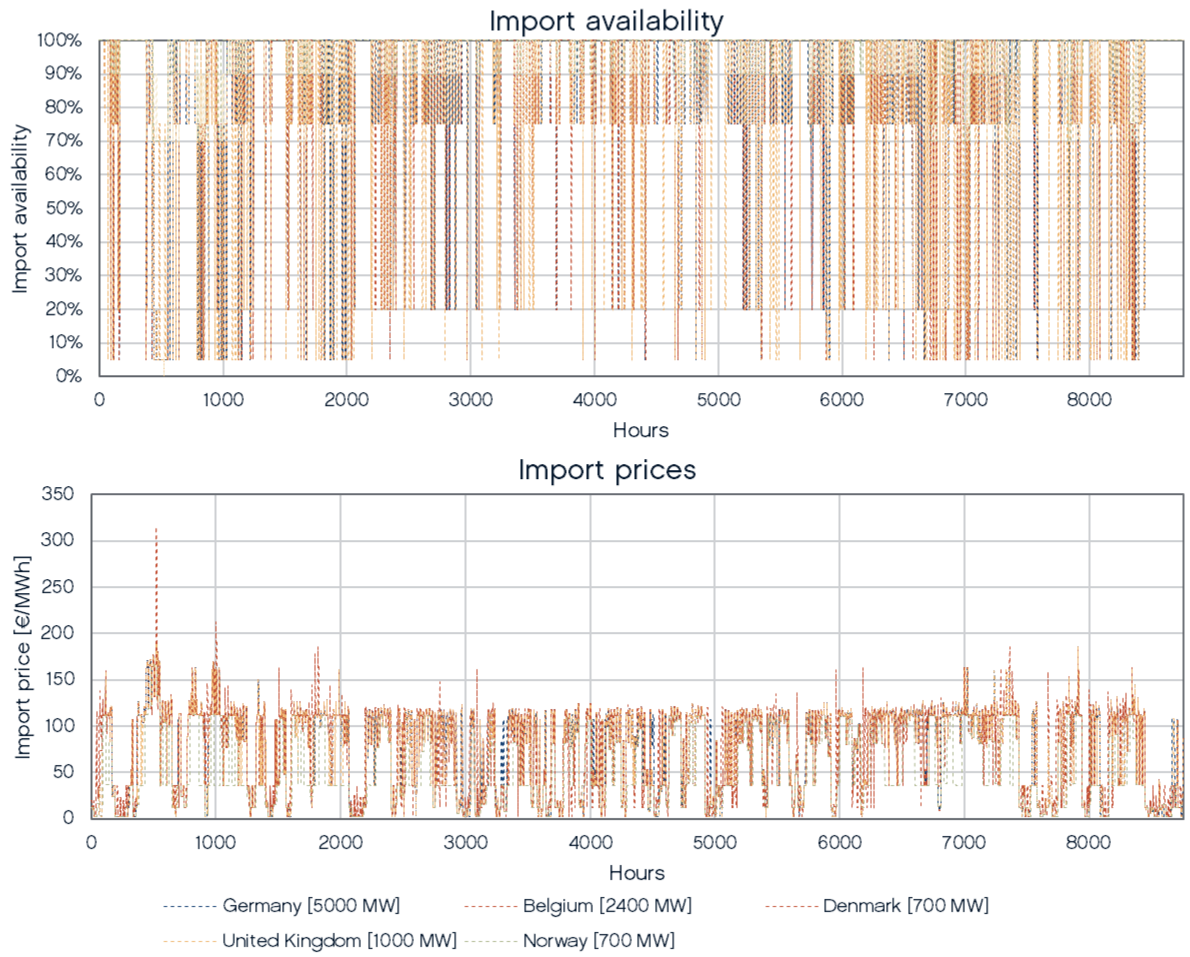

Figure 15. Import availability curve and import price curve per interconnector, based the KEV 2030 scenario in the ETM

Negative pricing and scarcity pricing

The electricity prices in the ETM are solely based on marginal costs of dispatchable power plants and import prices. When excluding exports, this results in the price curve shown in Figure 16. This price curve seems unrealistic as prices oscillate, for the most part, between 0 and 100 €/MWh without much of the variability seen in actual electricity price data. This disparity can be largely attributed to two factors; negative pricing and scarcity pricing.

In the ETM, electricity prices are 0 €/MWh when there is a surplus of renewables, which is then curtailed. In practice however, subsidies, Guarantee of Origin certificates, conventional power plants not ramping down and technical limitations of solar-PV installations can result in renewable generation being curtailed only at negative prices. In the battery model, negative prices are added to the price curve and are set to be relative to the solar-PV generation (between 0 and 100%) during hours of excess renewable generation. The minimum price is set to -65 €/MWh, reflecting the estimated income from subsidies and Guarantees of Origin.

Negative pricing due to subsidies will likely decrease over time due to changes in the structure of subsidies and/or phasing out of renewable generation subsidies altogether. Negative pricing does influence the distribution of system benefits among actors (battery operators, consumers & producers), but does not influence battery system benefits itself.

The highest electricity prices in the KEV 2030 ETM scenario result from marginal costs of the last power plant that is required to meet demand. In practice however, electricity prices can rise significantly higher when peaker power plants are required to meet demand. Operators of these power plants regularly bid tactically in the market, asking higher prices than their marginal costs. These inframarginal rents are used to recoup the investment costs of these power plants. In the battery model, scarcity prices are incorporated in the price curve by multiplying the electricity prices with a factor between 100% and 200%, depending on the percentage of flexible gas-fired power plants that are dispatched. The multiplication factor is arbitrary and can be varied. A factor of 100-200% is chosen as it resulted in a more recognizable price curve.

Changes to the electricity prices do not significantly affect system costs changes resulting from adding battery capacity to the power system. However, changes in battery income, dispatchable power plant income, renewable generation income and consumer spending are impacted greatly by negative pricing and scarcity pricing.

The new electricity price curve with negative pricing and scarcity pricing is shown in Figure 17.

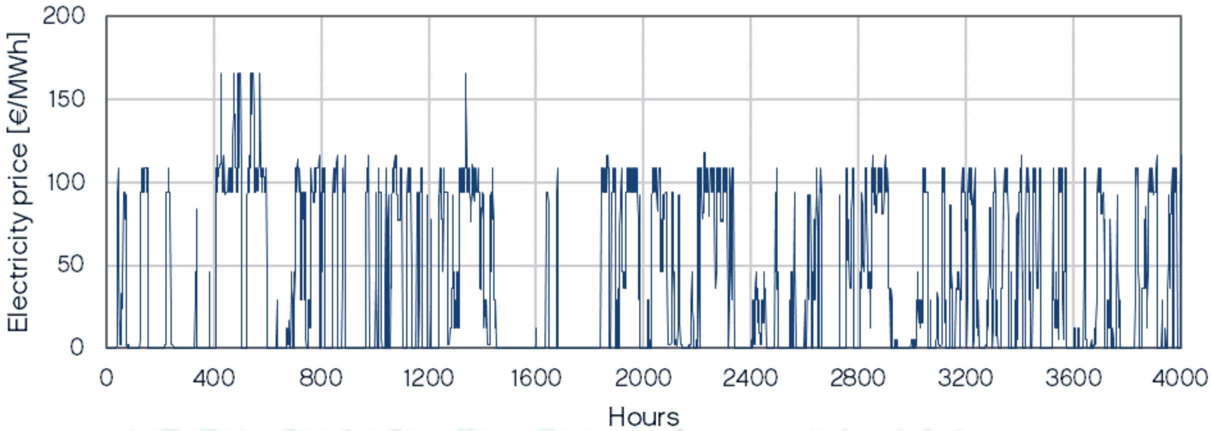

Figure 16. Electricity price curve from the KEV 2030 ETM scenario without exports. Only the first 4000 hours are shown to improve readability

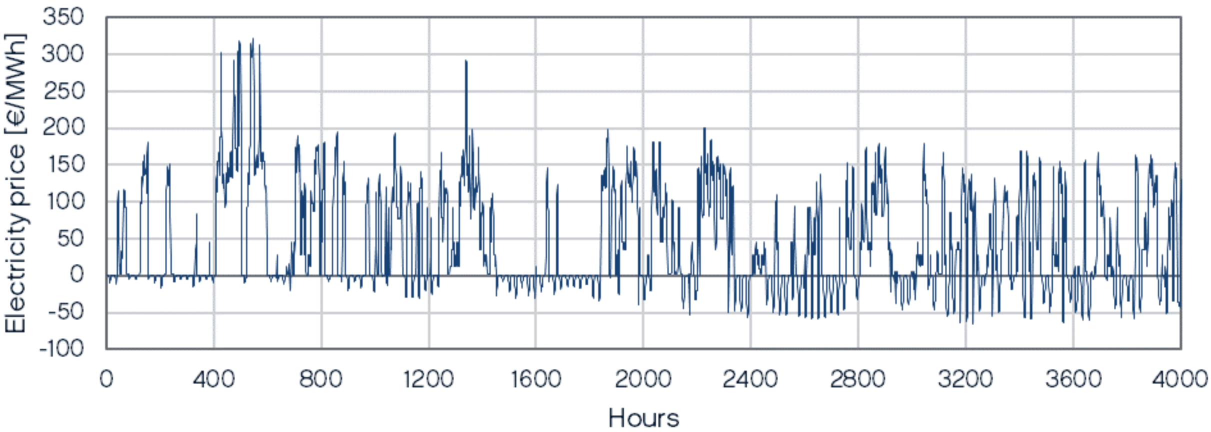

Figure 17. Electricity price curve from the KEV 2030 ETM scenario without exports, but with negative pricing and scarcity pricing. Only the first 4000 hours are shown to improve readability

Day-ahead battery algorithm

The battery algorithm in the ETM operates based on residual load and not based on electricity prices. As a result, the battery charging and discharging behaviour does not maximize battery margin (electricity revenue minus electricity costs). A new battery algorithm has therefore been developed for the battery model, in which charging and discharging behaviour is based on day-ahead electricity prices, resulting in significantly more operating hours and higher margins.

The new battery algorithm uses foresight up to 12 hours ahead to select hours with low electricity prices for charging and high electricity prices for discharging. An example of the battery behaviour during 20 days (July the 27th up to August the 16th in the 2030 scenario) is shown in Figure 18.

This algorithm does not take into account potential charging or discharging restrictions from grid operators due to ATR85 transport rights. It is very difficult to foresee how these restrictions will manifest in practice and how battery charging and discharging behaviour will adapt in order to accommodate these restrictions in the most cost effective way.

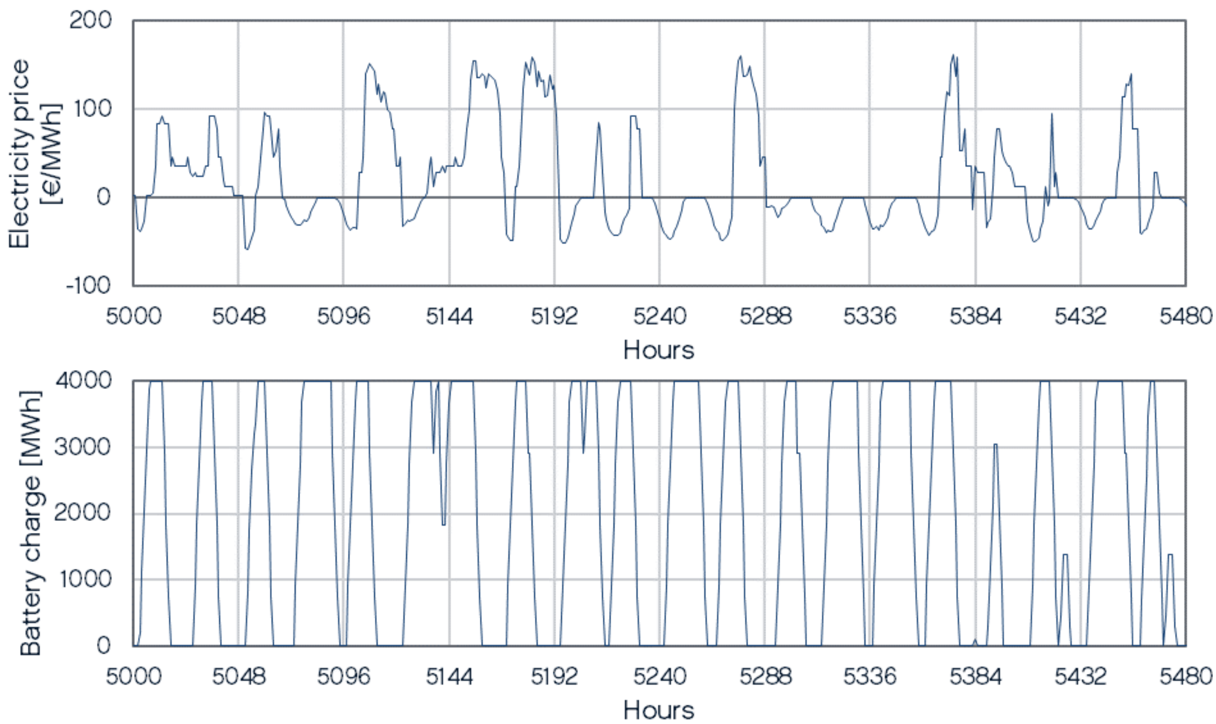

Figure 18. Example of the charging and discharging behaviour of a 1 GW / 4 GWh battery in the context of the electricity price curve

Balancing markets

In addition to trading on the day-ahead market, batteries can also be (and are primarily) used in the balancing markets. This study includes the Frequency Containment Reserve (FCR) and automatic Frequency Restoration Reserve (aFRR) markets but excludes the mFRR, passive imbalance and intraday markets.

FCR

FCR is used by TenneT to balance grid frequency within the second to minute timeframe. FCR capacity is activated automatically based on grid frequency. FCR suppliers are reimbursed on a capacity basis. Historical FCR revenue on a capacity basis is shown in Table 4. This capacity must be symmetrical, meaning that power can both be supplied and absorbed from the grid in order to maintain the desired frequency level of 50 Hz. The auction period for capacity bids is 4 hours. Suppliers of FCR must be able to maintain either an upward or downward power shift for at least 15 minutes.

In the battery model, battery power (MW) and storage capacity (MWh) used for FCR cannot be used for other applications. Per 1 MW of FCR capacity, 0.5 MWh of storage capacity is be reserved for FCR (roughly 0.23 MWh up and 0.27 MWh down depending on battery efficiency). Physical power flows to and from the battery as a result of FCR are not modelled.

Table 4. Average compensation on the Dutch FCR market an hourly basis, based on the TenneT Annual Market Updates 2021 and 2022

Year	Average FCR compensation (€/MW/h)
2019	15
2020	20
2021	24

aFRR

aFRR is used to maintain power balance in real time and capacity can be activated automatically by TenneT. There are two ways in which market participants can bid into the aFRR market; volume bids and capacity bids.

The auction period for volume bids is 15 minutes. Capacity bids must be asymmetrical, meaning that power can either supplied or absorbed from the grid but not both. When a volume bid is accepted, the bidder must be ready to provide the required power delta within minutes. A bidder is only reimbursed for the volume of electricity that is actually activated. For example, if a 10 MW upwards power bid is accepted for 4 consecutive time periods of 15 minutes, but only activated for a total of 15 minutes, the bidder is reimbursed for 2.5 MWh following a pay-as-clear auction.

The auction period for capacity bids is 24 hours, but will be lowered to a shorter time window of 4 hours. Similar to volume bids, capacity bids are also asymmetrical. When a capacity bid is accepted, the bidder is reimbursed following a pay-as-bid auction and has the obligation to provide volume bids for the full duration of the capacity bid. For example, when a capacity bid of 10 MW upwards (extra supply or decreased demand) is accepted, the bidder is obliged to provide volume bids for at least 10 MW upwards for the entire duration of the auction period which is currently 24 hours.

In the battery model, only aFRR-up (providing power with the battery) has been included and aFRR-down has not. When choosing to provide aFRR services with the battery, the day-ahead algorithm is changed such that there is always enough power (MW) and storage volume (MWh) to provide the required aFRR services. Historical aFRR-up bid activation data has been used for the years 2021-2023 (see Figure 19). Historical aFRR-up price data is shown in Table 5.

This new combined day-ahead and aFRR algorithm uses foresight to plan day-ahead activity such that aFRR-up activities lead to the lowest possible margin reduction in the day-ahead market. This is a very optimistic approach as in practice power and storage volume will often be reserved for aFRR without being actually used. However, battery operators will likely attempt to combine several markets in the most optimal way using sophisticated algorithms. It is possible that battery operators may approach results that can be achieved with perfect foresight.

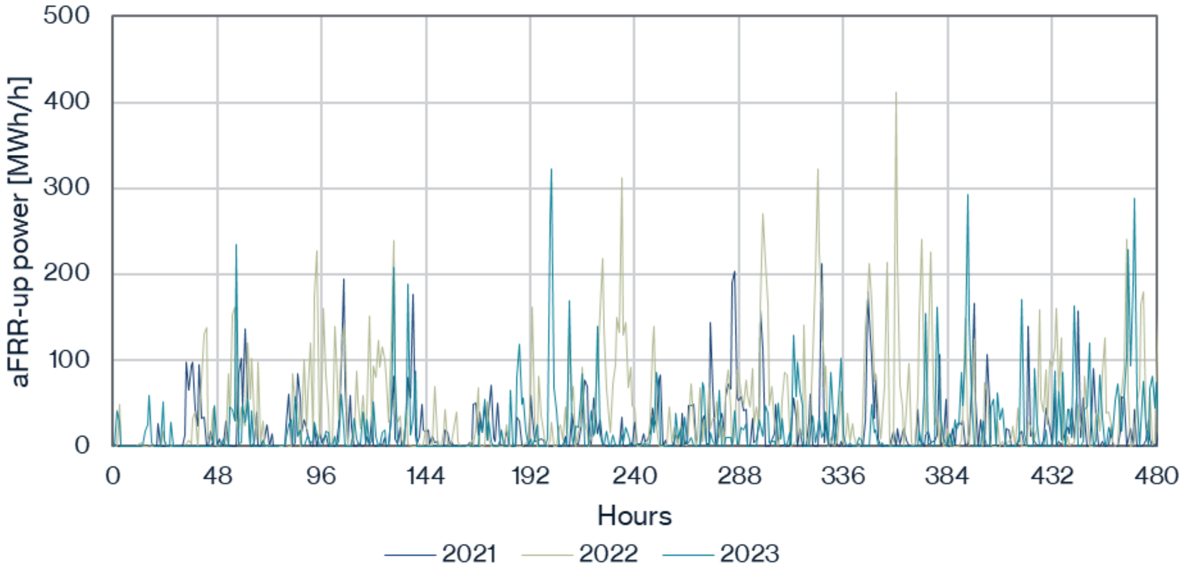

Figure 19. Historical data for activation of aFRR-up volume

Table 5. Historical aFRR-up market data

Year	Revenue from volume bids [mln. €/year]	Revenue from capacity bids [mln. €/year]
2021	72.26	88.9
2022	206.3	325.3
2023	93.38	135.9

System costs and benefits

In the battery model, system costs are defined as the sum of:

1. marginal costs of dispatched power plants, consisting fuel CO_2 and variable O&M costs,
2. electricity imports,
3. battery CAPEX and fixed OPEX,
4. delta of required backup capacity CAPEX and fixed OPEX,
5. balancing costs (FCR and aFRR-up are considered in this study).

These costs are calculated twice, once with and once without added battery capacity in the system. The delta between these costs are the additional system costs or system benefits resulting from battery activity.

Fuel and CO_2 costs and imports

Fuel and CO_2 costs for electricity generation are included in the marginal costs of the different power plants listed in Table 3 (page 33). The total fuel and CO_2 costs plus the costs of imports is calculated by multiplying the volume of electricity production/imports with the respective marginal costs.

By adding batteries, surplus renewable energy generation that would otherwise be curtailed can be used at a later time, thereby reducing fuel consumption, CO_2 emissions and/or imports. Batteries can also charge during moments when low marginal cost power plants (e.g. nuclear) take the final place in the merit order, to discharge at a later moment to displace higher marginal cost power generation (e.g. gas turbines).

These system cost savings are divided among battery operators, consumers and producers. Figure 20 shows that the reduction in marginal/system costs can mathematically be constructed using the delta in consumer spending, the delta in producer margin and the battery margin.

- Consumer spending is the total money spent by consumers to buy electricity.
- Producer margin is the margin that producers receive based on the pay-as-close merit order.
- Battery margin is the difference between the revenue by discharging electricity for the day-ahead market and the costs of charging the battery.

The example below does not include scarcity pricing, however the mathematical relations deduced from this figure do not change when scarcity pricing is introduced.

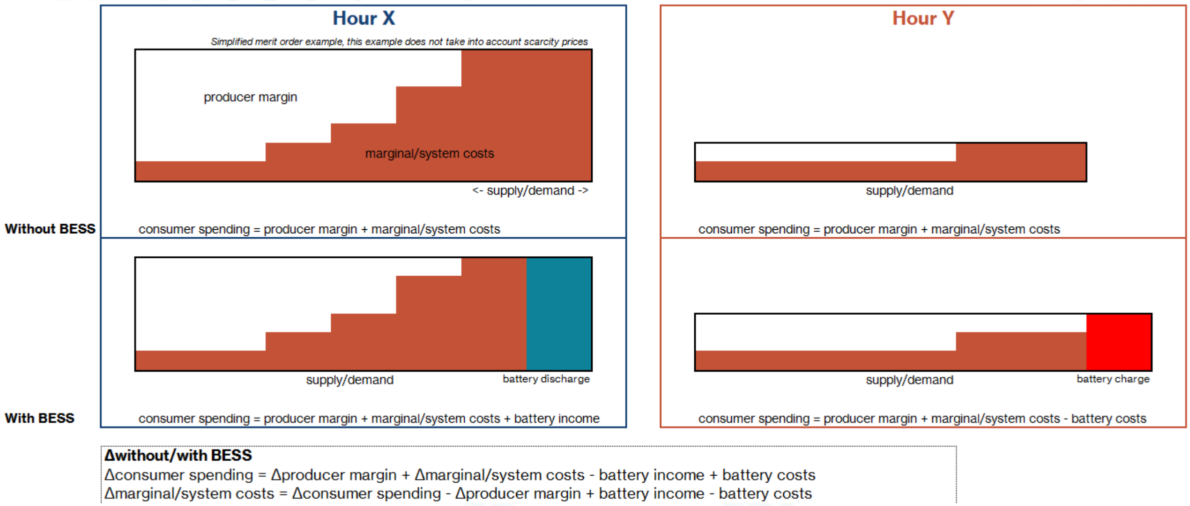

Figure 20. The mathematical relation between marginal/system costs, consumer spending, producer margin and battery margin

Battery costs

Battery costs consist of CAPEX and fixed OPEX (excluding charging costs which are included in battery margin). Cost estimates for 2030 up to 2050 are based on data from NREL, see Figure 21. A lifetime of 15 years is assumed, a WACC of 6% and an exchange rate of 1.1 $/€. The annual costs are calculated using the formula below:

$$Annualized\ battery\ costs = \left(\frac{wacc \cdot (1 + wacc)^{lifetime}}{(1 + wacc)^{lifetime} - 1} \cdot CAPEX + OPEX_{fixed}\right) \cdot battery\ power$$

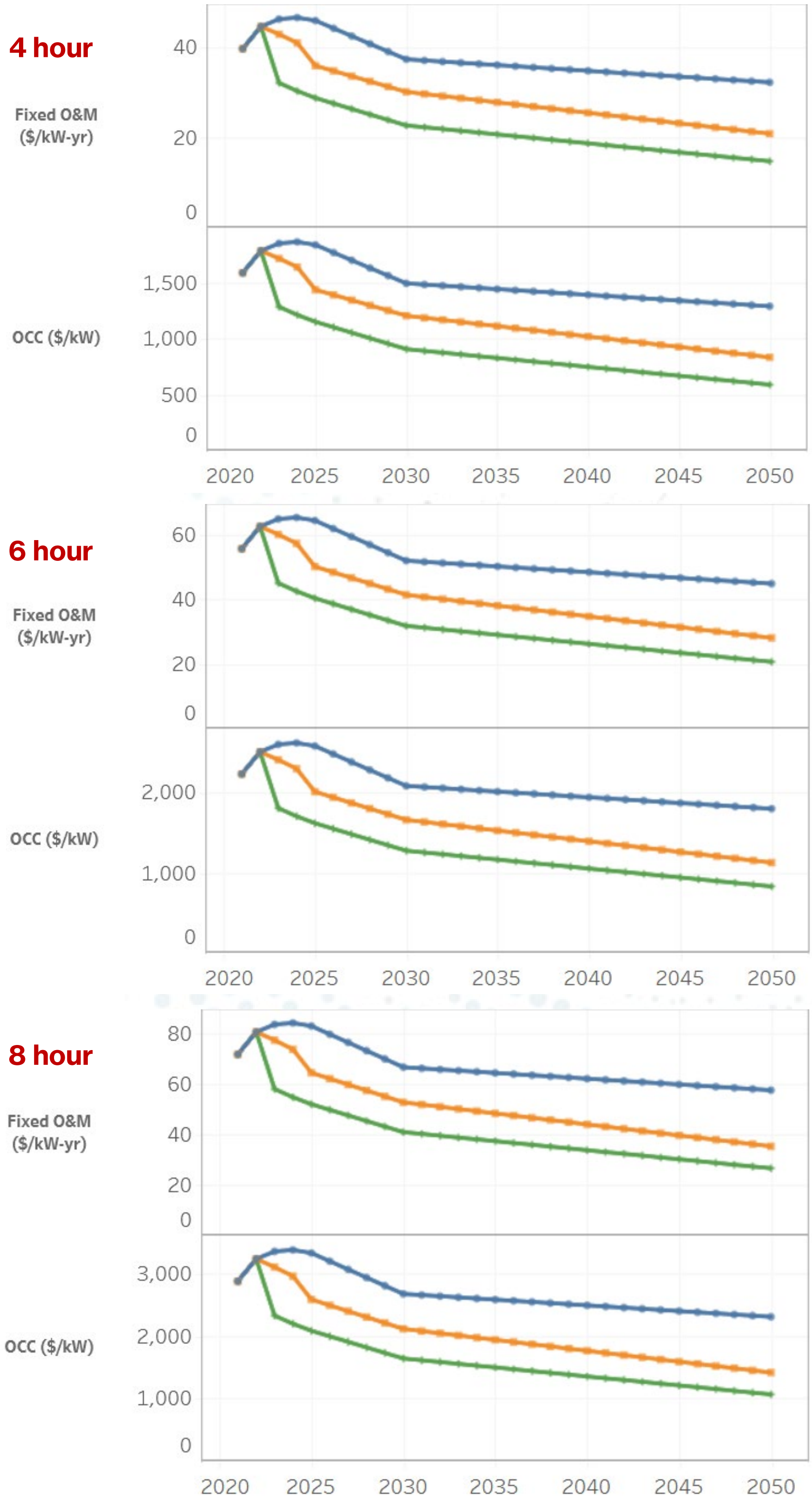

Figure 21. Cost projections for 4, 6 and 8 hour batteries from NREL (2023): Utility Scale Battery Storage

Backup capacity costs

Batteries can reduce the need for backup capacity (e.g. gas turbines) to some extent by delivering power during moments of peak demand and low renewable generation. The degree to which batteries can reduce backup capacity depends on the renewable generation profiles, consumption profile, other flexible capacity already present in the system as well as other factors.

The principle we use to determine how much backup capacity is rendered unnecessary by batteries is maintaining a certain level of supply reliability. For example, if 10 GW of backup capacity is required to ensure no more than four hours per year of power shortages, but 8 GW backup capacity plus 3 GW battery capacity would also lead to the same level of supply reliability, 3 GW of battery capacity 'replaces' 2 GW of backup capacity.

From a system costs perspective, the reduction in backup capacity can be considered a cost benefit. This cost benefit is calculated based on typical CAPEX and fixed OPEX figures for backup capacity. In the battery model, a CAPEX of 535 k€/MW is used[17] and fixed annual OPEX is assumed to be 3% of the CAPEX. A lifetime of 40 years is assumed and a WACC of 6%. The annual costs are calculated using the formula below:

$$Annualized\ backup\ savings = \left(\frac{wacc \cdot (1 + wacc)^{lifetime}}{(1 + wacc)^{lifetime} - 1} \cdot CAPEX + OPEX_{fixed}\right) \cdot backup\ capacity\ reduction$$

The exact backup capacity savings per unit of battery capacity is calculated in the battery model by comparing the maximum power level of gas turbine dispatch in a year with and without batteries. In the example above, backup savings would be calculated using a backup capacity delta of 2 GW.

Balancing costs

Historical FCR and aFRR-up market prices (see Table 4 and Table 5) are used for estimating future balancing costs. For FCR capacity and aFRR-up volume markets, these prices represent the weighted average market closing prices and not the marginal balancing costs. Using market prices as proxy for balancing costs leads to an overestimation, but clear data on marginal balancing costs is not available. However, historical balancing costs are likely an underestimation for future balancing costs, as increasing volatile electricity production and less hours in which flexible power generation capacity is active in the market increases balancing costs. Historical balancing costs are therefore multiplied with estimates of the future increase of balancing markets. These cost estimates indicate what FCR and aFRR-up would cost given the historical balancing prices, without market changes due to batteries. When batteries are to provide these balancing services, the reference/historical FCR and aFRR-up costs are no longer incurred and are seen as system cost benefits.

In the analysis, 2021 balancing cost data is used by default. Balancing cost data from 2022 and 2023 are used in the sensitivity analysis. The FCR market size (currently 110 MW for the Dutch-only market) is assumed to remain a similar size in the future. The FRR market is assumed to increase towards 2000 MW as the largest power plant in the Netherlands will be half of the Ijmuiden Ver offshore wind farm (4 GW). 900 MW of the FRR capacity market is assumed to be

[17] Based on cost figures for gas turbines used in the Energy Transition Model

aFRR in 2030 (450 MW aFRR-up, 450 MW aFRR-down), increasing to 1100 MW from 2035. The aFRR volume is assumed to increase with a similar amount as the aFRR capacity (+29%). Default assumptions regarding balancing capacities, volumes and reference price levels are listed in Table 6.

It is difficult to say how the FCR and aFRR markets will develop towards 2050. Therefore, different balancing capacity and volume levels will be explored in the sensitivity analysis. Besides these uncertainties, reference market prices are also uncertain. These are the FCR and aFRR market prices in the future if there would be no battery capacity at all. These prices are relevant for this analysis as it serves as a reference system cost level used for calculating system benefits due to battery capacity. Reference market price are likely to increase since there are less hours in which flexible generation is active due to increasing renewable generation.

Table 6. Default FCR and aFRR-up assumptions used in the analysis, these values are subsequently varied in the sensitivity analysis

	FCR	aFRR-up
Historical capacity [MW]	110	350
Historical volume [GWh]	-	272
Historical capacity price 2021 [€/MW/h]	24	29
Historical volume price 2021 [€/MWh]	-	266
Capacity 2030 [MW]	110 (100%)	450 (129%)
Capacity from 2035 [MW]	110 (100%)	550 (157%)
Volume 2030 [GWh]	-	350 (129%)
Volume from 2035 [GWh]	-	427 (157%)
Default reference capacity price from 2030 [€/MW/h]	24 (100%)	29 (100%)
Default reference volume price from 2030 [€/MWh]	-	266 (100%)

Batteries can, given enough available capacity, saturate the entire FCR (capacity) and aFRR-up volume markets. However, it is uncertain whether batteries will also be able to saturate the aFRR-up capacity market. Even if auction periods are reduced from 24 to 4 hours, batteries may not be able to effectively absorb periods of prolonged one-way and high imbalance. In practice, a portfolio of various assets, including batteries, are more likely to perform these aFRR capacity bids. It is therefore not fair to allocate the entire aFRR-up capacity market towards batteries. Instead, we have chosen to allocate 50% of the aFRR-up capacity market towards system benefits resulting from battery capacity.

Grid tariffs

Currently, battery operators have to pay grid tariffs to grid operators for the transport of electricity. These tariffs have increased significantly in the past few years. The grid tariffs for 2023 and 2024 are listed in Table 7.

Table 7. Transport grid tariffs from TenneT in 2023 and 2024 for Dutch grid connections at the HV and EHV grid (TenneT, 2023, Tarievenbesluit TenneT 2024)

	kW contract 2023 (€/kW/year)	kW max 2023 (€/kW/month)	kW contract 2024 (€/kW/year)	kW max 2024 (€/kW/month)
Extra High Voltage*	27.90	3.03	60.65	5.91
High Voltage*	41.04	4.21	73.52	7.62

*High Voltage grid connections: >100 MW, Extra High Voltage connections: >300 MW

Recently the Dutch Authority for Consumers & Markets (ACM) decided that if battery operators adapt the charging and discharging behaviour of batteries at the request of grid operators up to a maximum of 15% of the time, they would be exempt from paying kW contract tariffs (ACM, 2024, Ontwerpbesluit Alternatieve transportrechten). This new type of transport right is also called ATR85.

Furthermore, the ACM recently made the decision to change the kW_{max} tariff based on the hour of the day, the day of the week and the month of the year (ACM, 2024, Ontwerpbesluit Tijdgebonden transporttarieven hoogspanningsnet). The new so called $kW_{maxgewogen}$ can reach a maximum of 87% of the kW_{max} tariff if a battery operator would use full charging capacity during peak hours of each month.

For batteries that are connected to the High Voltage grid, using the maximum charging capacity during each month of the year, grid tariffs based on 2023 and 2024 prices would be 44 and 80 €/kW/year respectively. This figure will be used in the analysis.

ATR85 transport rights are designed in such a way that, in theory, batteries should not lead to additional network congestion and therefore should not require additional grid investments (ACM, 2024, Ontwerpbesluit Alternatieve transportrechten). In that case, grid tariffs do not represent additional system costs (with the exception of higher grid losses depending on battery placement and operation) but rather a value transfer between battery operators and other grid users.