The supply of flexibility for the power system in the Netherlands, 2015-2050

Report of phase 2 of the FLEXNET project

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Acknowledgement

The overall objective of the FLEXNET project was to analyse demand and supply of flexibility in the power system of the Netherlands up to 2050 at both the national and regional level.[1] The project was commissioned and funded by the Top Sector Energy (TSE) under the tender programme System Integration (NL Ministry of Economic Affairs/RVO.nl; reference number TES0114010).

FLEXNET was carried out by a consortium consisting of the Energy research Centre of the Netherlands (ECN) and several members of Netbeheer Nederland – i.e. the Dutch branch organisation of energy network operators – in particular Alliander, Enexis, Stedin, TenneT and Gasunie Transport Services (GTS). In addition, the consortium included two other partners (GasTerra and Energie-Nederland) who were involved as co-funders of the project.

Over the lifetime of FLEXNET (March 2015 – August 2017), the project was supervised by a Steering Committee consisting of the following members: Eppe Luken (ECN, chair), Frans Nillesen (RVO.nl), Erik van der Hoofd (TenneT/Netbeheer Nederland), Erik ten Elshof (NL Ministry of Economic Affairs), Tjitske Brand (GasTerra) and Walter Ruijgrok (Energie-Nederland).

In addition, FLEXNET benefitted from the support and expertise of a Project Working Group, including the following members: Jos Sijm (ECN, project leader), Bauke Agema (GTS), Piet Nienhuis (GTS), Michiel van Werven (Alliander), Jan Pellis (Stedin), Paul Karremans (ex-Endinet, now Alliander; up to December 2015), Ruud van de Meeberg (Enexis; up to August 2016), Klaas Hommes (TenneT; up to March 2016) and Gerda de Jong (TenneT; starting from April 2016).

A special word of thanks goes to Paul Koutstaal (ECN). During the lifetime of FLEXNET, he provided useful, stimulating feedback to the project leader and participated in the meetings of the Steering Committee. In addition, he acted as the critical coreader of several project deliverables (including the current report).

The FLEXNET project consisted of three phases, each addressing a specific main question:

- *Phase 1 ('The demand for flexibility')*: what are the flexibility needs of a sustainable and reliable power system in the Netherlands up to 2050?
- *Phase 2 ('The supply of flexibility')*: which mix of robust flexibility options can meet the predicted flexibility needs in a socially optimal way?
- *Phase 3 ('Societal framework to trade-off grid reinforcement and deployment of flexibility')*: in which situations is deployment of flexibility a more attractive option than grid reinforcement to overcome predicted overloads of the power network?

[1] FLEXNET is an abbreviation that stands for "**FLEX**ibility of the power system in the **NET**herlands".

The current report presents the methodology and major outcomes of the second phase of the project. It is based on contributions delivered primarily by the following persons (and institutions): Jos Sijm, Marit van Hout, Özge Özdemir, Joost van Stralen, Koen Smekens and Adriaan van der Welle (all ECN), as well as Pieter Gockel, Michiel Musterd and Werner van Westering (all Alliander). ECN was primarily responsible for the analysis at the national level (laid down in Chapters 2-4 of the current report) while Alliander was primarily responsible for the analysis at the regional level (elaborated in Chapter 5).

At ECN, FLEXNET is administered under project number 53626. For further information, you can contact the project leader: Jos Sijm (sijm@ecn.nl; tel.: +31 6 1048 4843).

Abstract

The report presents the methodology and major results of the second phase of the FLEXNET project. This phase is focussed on identifying and analysing the options to meet the flexibility needs of a sustainable and reliable power system in the Netherlands up to 2050. More specifically, following the first phase report of the FLEXNET project (which focussed on identifying and analysing the demand for flexibility of the Dutch power system), the current report identifies and analyses the supply options to meet three different sources ('causes') of flexibility demand, i.e. flexibility needs due to (i) *the variability of the residual load* (defined as total power demand minus VRE generation), (ii) *the uncertainty of the residual load* (notably the lower predictability of VRE power output), and (iii) *the congestion of the grid* (in particular at the Liander distribution network level). A major conclusion of the analysis at the national level is that up to 2050 (hourly changes) in cross-border power trade is the most important option to meet the demand for flexibility due to the variability of the residual load in the Dutch power system (although the size of this option depends on the assumed interconnection capacity across European countries). At the Liander regional network level, a major conclusion is that the potential of flexibility options to avoid network congestion – and, hence, to avoid network expansion – is generally limited (although in specific cases the deployment of flexibility options may be an important tool to reduce the need for network expansion, either temporarily or structurally).

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Summary

Introduction and background
The Netherlands is aiming at a more sustainable, low-carbon energy system. For the power system this implies (i) a larger share of electricity from variable renewable energy (VRE), in particular from sun and wind, (ii) a larger share of electricity in total energy use, i.e. a higher rate of 'electrification' of the energy system, and – as a result of these two trends – (iii) a higher need for flexibility and system integration.

Against this background, the overall objective of the FLEXNET project was to analyse demand and supply of flexibility of the power system in the Netherlands up to 2050 at the national and regional level. More specifically, the FLEXNET project consisted of three phases, each addressing a particular main question:

- *Phase 1 ('The demand for flexibility')*: what are the flexibility needs of a sustainable and reliable power system in the Netherlands up to 2050?
- *Phase 2 ('The supply of flexibility')*: which mix of robust flexibility options can meet the predicted flexibility needs in a socially optimal way?
- *Phase 3 ('Societal framework to trade-off grid reinforcement and deployment of flexibility')*: in which situations is deployment of flexibility a more attractive option than grid reinforcement to overcome predicted overloads of the power network?

The current report outlines the approach and major results of the second phase of the FLEXNET project. This phase has been conducted at two levels: (i) the national level, i.e. for the power sector in the Netherlands as a whole, and (ii) the regional level, i.e. at the regional power distribution grid level of the Liander service area in the Netherlands.

More specifically, the central questions of the second phase of the FLEXNET project regarding these two levels include:

- What are the major options to meet the demand for flexibility due to the variability and uncertainty of the residual load of the power system in the Netherlands over the period 2015-2050)?
- What are the options and (net) economic benefits of deploying flexibility for congestion management rather than the traditional solution of grid reinforcement for mitigating network overloads, in particular at the Liander distribution network level up to 2050?

A summary of the approach and major results at both the national and regional level is provided below.

Approach

Definition and scope of flexibility supply options

In order to meet the demand for flexibility, the following supply options have been considered in the present study:

- *Power generation from (flexible) non-VRE sources*, including conventional sources – in particular (flexible) gas-fired power plants but also, to some extent, other conventional units (coal, nuclear) – as well as 'other RES-E' sources (i.e. besides sun/wind) such as hydro or biomass;
- *VRE curtailment*, i.e. limitation of peak power generation from VRE sources;
- *Demand curtailment*, i.e. limitation of peak power demand;
- *Demand response*, i.e. part of total demand in a certain hour is shifted to another hour of the day, week, month, etc., either forward or backwards.
- *Energy storage*, such as batteries, hydro pumped storage (HPS) or compressed air energy storage (CAES), including energy conversion/storage technologies such as power-to-gas (P2G), power-to-ammonia (P2A), etc.;
- *Power trade*, i.e. hourly variations in (net) imports/exports of electricity.

In principle, all flexibility supply options have been considered throughout the study. Some options, however, turned out to more important (and, hence, have received more attention), while other options appeared to be less or hardly important or even not viable (and, hence, have received less or hardly any attention). Moreover, some options turned out to be more relevant at the national level but less relevant at the regional grid level (or vice versa). In addition, some flexibility options are included and analysed more specifically by some of the models used, while other options are not or hardly analysed by these models (or taken as given; see below).

Three sources ('causes') of the demand for flexibility

In phase 1 of the FLEXNET project, we have distinguished between three main sources ('causes') of the need for flexibility of the power sector (R1, Section 2.1):

1. The demand for flexibility due to the *variability* of the residual power load, in particular due to the variability of power generation from VRE sources;
2. The demand for flexibility due to the *uncertainty* of the residual power load, notably due to the uncertainty (or lower predictability) of electricity output from VRE sources *('forecast error'*);
3. The demand for flexibility due to the *congestion* (overloading) of the power grid, resulting from the increase and changing profiles of electricity demand – due to the increase in electric vehicles, heat pumps, etc. – as well as the increase and changing profiles of power supply from VRE sources (notably decentralised sun PV).

During phase 2, we have considered and analysed the supply options to meet the three different types of flexibility demand. Similar to phase 1, however, phase 2 was also predominantly focussed on modelling and analysing the first and third type of flexibility and hardly on the second type. In particular, the following general approaches and tools have been used to analyse the supply options to meet the three different types of flexibility demand:

1. Options to meet flexibility needs due to the variability of the residual load have been analysed extensively at the national level of the Dutch power system over the period 2015-2050 by means of two models developed by ECN, i.e. COMPETES (an EU28+ electricity market model) and OPERA (an NL energy system model);
2. Options to meet flexibility needs due to the uncertainty of the residual load have been considered briefly by means of a review of available literature;
3. Options to meet flexibility needs due to the congestion of the power grid have been analysed thoroughly at the regional Liander distribution level by means of the Liander network model ANDES.

In order to determine and analyse supply options to meet flexibility needs due to the variability of the residual load at the national level, the two models concerned have been used successively. First of all, the EU28+ electricity market model COMPETES has been used to determine and analyse the supply of some specific flexibility options in particular, notably the cross-border option of power trade and the domestic option of power generation from non-VRE sources (while ignoring the domestic option of demand response). Subsequently, the NL energy system model OPERA has taken the power trade option as given and has focussed more specifically on analysing some domestic flexibility options (in particular demand response and energy storage).

Scenarios: focal years and major characteristics
As part of phase 1 of the FLEXNET project, we have developed the following two scenarios, each with three focal years ('cases'):

- *The Reference scenario*. This scenario is based on the '*accepted policy scenario*' of the '*National Energy Outlook 2015*' (ECN et al., 2015). Its major characteristics are: (i) a strong growth of installed VRE capacity in the power sector up to 2030, and (ii) a weak growth of additional electrification of the energy system as a whole. This scenario includes three focal years, labelled as '*R2015'*, '*R2023'* and '*R2030'* (where the letter R refers to the Reference scenario);
- *The Alternative scenario*. This scenario is similar to the reference scenario with one major exception, i.e. it assumes a strong growth of additional electrification of the Dutch energy system by means of electric vehicles (EVs), heating pumps (HPs), and other means of electrification of the energy system in households, services, transport, industry, etc. This scenario includes also three focal years, labelled as '*A2023'*, '*A2030'* and '*A2050'* (where the letter A refers to the Alternative scenario).

As part of phase 2, we have defined two additional 2050 scenario cases, i.e. besides the A2050 case mentioned above. More specifically, as part of the COMPETES modelling outcomes, the A2050 turned out to be characterised by a large ('optimal') interconnection capacity across all European countries covered by the model (including a large expansion of this capacity since A2030). As this variable appeared to be a key variable for almost all other modelling outcomes (and may be overestimated), we have defined two additional 2050 scenario cases labelled as '*B2050*' and '*C2050*'. Both cases are similar to A2050, but in B2050 we have assumed that the expansion of the interconnection capacity since A2030 is only 50% of the ('optimal') expansion in A2050, whereas in C2050 we have assumed that this expansion is 0%. Hence, in C2050 the interconnection capacity across European countries is assumed to be similar to the capacity in A2030 (for details, see below).

Major results at the national level

1. Options to meet the demand for flexibility due to the variability of the residual power load

1.1 Competes modelling results

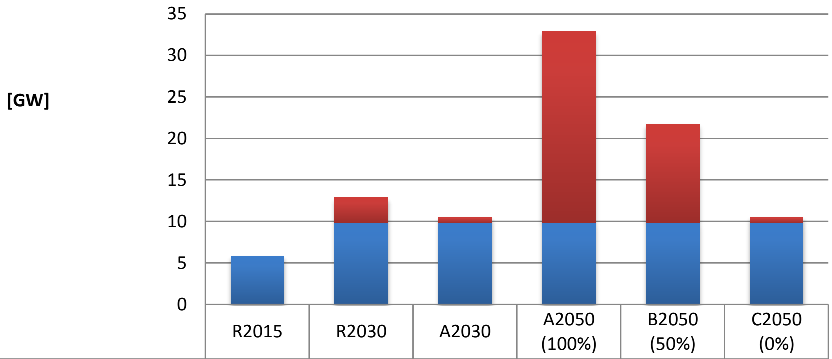
Trends in residual power supply

By means of the COMPETES model, we have first of all analysed the trends in the so-called '*residual power supply*' – and its constituent components – of the Dutch power system in the FLEXNET scenario cases up to 2050 (where residual supply – as opposed to 'residual load' – is defined at total power supply minus VRE power generation). The major findings of this analysis include:

- According to the COMPETES modelling outcomes, the optimal ('least-cost') interconnection capacity across all EU28+ countries increases from 62 GW in R2015 to 121 GW in A2030 and to 241 in A2050. For the Netherlands only, the respective capacity figures amount to 6 GW, 11 GW and 33 GW (see **Figure 1**).

- In B2050 (50% interconnection expansion beyond A2030), the cross-border transmission capacity amounts to 181 GW in the EU28+ as a whole and 22 GW in the Netherlands only. In C2050 (0% interconnection expansion) these figures amount to 121 GW and 11 GW, respectively (i.e. similar to the capacity levels in A2030).

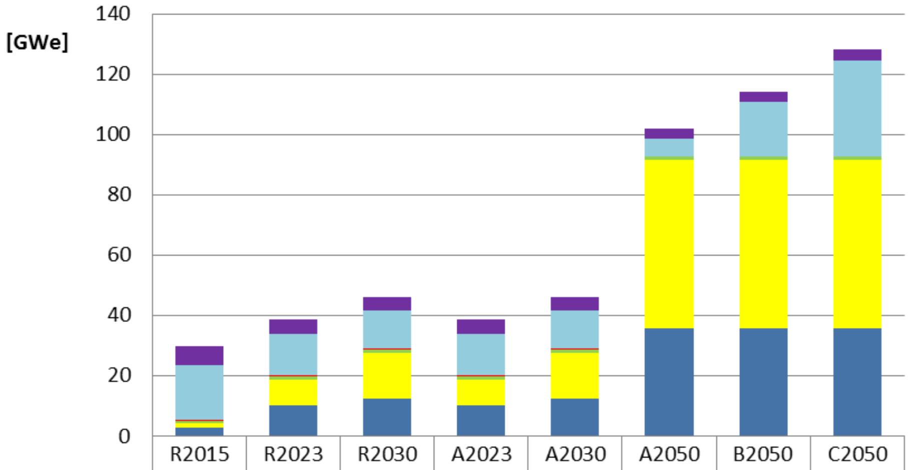
Figure 1: Total interconnection capacity in the Netherlands, 2015-2050



	R2015	R2030	A2030	A2050 (100%)	B2050 (50%)	C2050 (0%)
New transmission capacity	0.0	3.1	0.7	23.1	11.9	0.7
Baseline capacity (TYNDP2016)	5.9	9.8	9.8	9.8	9.8	9.8

- The installed VRE capacity (sun/wind) in the Netherlands increases from almost 5 GW in R2015 to approximately 92 GW in A2050. On the other hand, the conventional capacity (gas/coal/nuclear) declines from 25 GW to 9 GW, respectively (see **Figure 2**). In the 2050 scenario cases, however, gas-fired capacity increases rapidly from 6 GW in A2050 to almost 18 GW in B2050 and even to about 32 GW in C2050 (due to the similar decrease in interconnection capacity over these cases mentioned above). This increase refers particularly to central gas turbines (GTs, +14 GW) and combined cycle gas turbines (CCGTs) with carbon capture and storage (CCS, +12 GW).

Figure 2: Installed power generation capacity in the Netherlands, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Coal	6.6	4.6	4.6	4.6	4.6	3.4	3.4	3.4
Gas	17.8	13.7	12.4	13.7	12.4	5.6	17.9	31.8
Nuclear	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0
Other RES-E	0.6	1.2	1.2	1.2	1.2	1.1	1.1	1.1
Solar	1.5	8.6	15.1	8.6	15.1	56.1	56.1	56.1
Wind	3.0	10.1	12.4	10.1	12.4	35.7	35.7	35.7

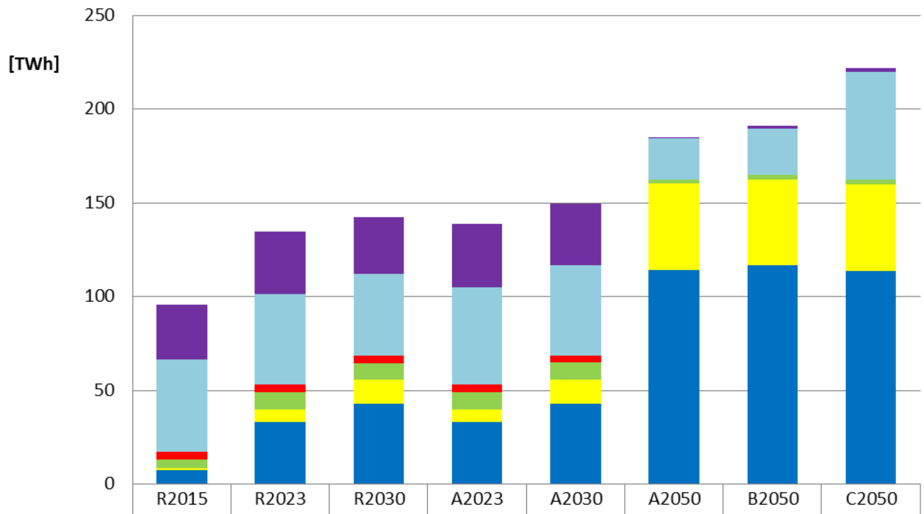
- In the Netherlands, total electricity production doubles in absolute terms from 96 TWh in R2015 to 185 TWh in A2050 (see **Figure 3**). The share of sun and wind in total output increases from 9% to 87%, respectively. On the other hand, for nuclear the share in total power generation declines from 4% in R2015 to zero in A2050, for coal from 31% to 0.2% and for gas from 51% to 12%, respectively.

- In C2050 (0% interconnection expansion), electricity production in the Netherlands is significantly higher (222 TWh) than in A2050 (185 TWh). This increase in total output (+37 TWh) is almost fully met by an increase in gas-fired generation only, which rises steeply from 22 TWh in A2050 to 58 TWh in C2050 (i.e. by 36 TWh; see **Figure 3**). As a result, the share of gas in total electricity production increases from 12% in A2050 to 26% in C2050.

- The increase in total gas-fired power generation by 36 TWh in C2050, compared to A2050, is almost fully met by the newly installed CCGT CCS capacity, i.e. by 32 TWh, and to a lesser extent by the increased GT capacity (by 2 TWh).

- There is a clear trade-off between the availability (and use) of cross-border interconnection capacity and the deployment of (domestic) gas-fired capacity. In A2050, with a relatively large interconnection capacity for the Netherlands (i.e. 33 GW), the need for and deployment of gas-fired generation capacity is relatively low and stable, implying that, on average, a predominant share of this capacity is deployed for a large number of running hours. On the other hand, in C2050 – with a relatively small interconnection capacity (i.e. 11 GW) – the need for, and deployment of peak and upper mid-load gas-fired capacity is relatively high and declines steeply, implying that, on average, a major share of this capacity is deployed for a small number of running hours.

Figure 3: Power generation mix in the Netherlands, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Coal	29	33	30	34	33	0	2	2
Gas	49	48	43	52	48	22	24	58
Nuclear	4	4	4	4	4	0	0	0
Other RES-E	5	9	9	9	9	2	2	3
Sun	1	7	12	7	12	46	46	46
Wind	7	33	43	33	43	114	116	114

- Up to 2030, there is no curtailment of VRE power generation as the share of VRE output in total power demand is still manageable (i.e. less than 50%). In A2050 – with a share of 80% of (uncurtailed) VRE output in total power demand and a large interconnection capacity (33 GW) – the curtailment of power generation from sun PV is still zero, but from wind it amounts to almost 26 TWh, i.e. 22% of realised (curtailed) wind production, 16% of total VRE output and 14% of total electricity generation by the Dutch power system in A2050.

- In C2050 – also with a share of 80% of (uncurtailed) VRE output in total power demand but with a small interconnection capacity (11 GW) – curtailment of sun PV generation amounts to 0.1 TWh and of wind generation to more than 26 TWh, i.e. together almost 17% of total VRE production.

- Curtailment of power demand – as a flexibility option to balance electricity demand and supply – is restricted to the alternative scenario cases of 2030 and 2050 only, while it is limited to a few hours per year (≤ 6 hours) and, in general, to a small amount per hour, varying from 1 GW in A2050 to 10 GW in C2050.

- Energy storage, by means of compressed air energy storage (CAES) or hydro pumped storage (HPS), does not appear as a viable flexibility option for the Netherlands in the FLEXNET-COMPETES modelling scenarios up to 2050 (although indirectly the Netherlands may benefit from HPS as a flexibility option at the EU28+ level through its power trade relations with other, neighbouring EU28+ countries, including Norway, Germany and France).

- At an aggregated (annual) level, power trade by the Netherlands over the period 2015-2030 varies widely from large net imports in R2015 (17 TWh) to large net exports in R2023 (21 TWh) and R2030 (27 TWh). In the alternative scenario cases, however, the Netherlands becomes a major net importer of electricity again, varying from 11 TWh in C2050 (small interconnection capacity) to 48 TWh in A2050 (large interconnection capacity).

- Moreover, within the focal years considered, *hourly* power trade is even more volatile, i.e. varying between the interconnection capacities of the Netherlands in the respective scenario cases. For instance, in A2050 net hourly power trade varies between +33 GW (imports) to -33 GW (exports) whereas in C2050 it varies between +11 GW and -11 GW, respectively.

- Aggregated over all hours of the year, the (domestic, uncurtailed) residual load declines in the reference scenario from 104 TWh in 2015 to 60 TWh in 2030 and in the alternative scenario from 86 TWh in 2023 to 47 TWh in 2050 (see upper part of **Figure 4**). In some cases, this (domestic, uncurtailed) residual load is enhanced by net exports – notably in R2023, R2030 and A2023 – and/or by VRE curtailment, in particular in the alternative 2050 scenario cases (A2050, B2050 and C2050).

- In the reference scenario cases R2015-R2030, the (national, curtailed) residual power demand is met primarily by domestic non-VRE power generation, in particular from fossil fuels (coal, gas) and, to a lesser extent, from nuclear and other RES-E. In addition, in R2015 a minor part of this residual power demand is covered by net imports (**Figure 4**).

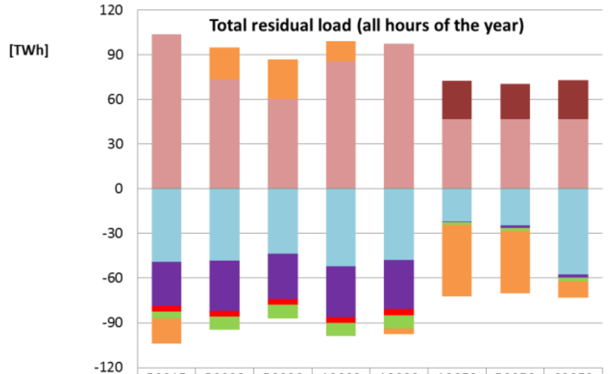
- In the alternative scenario cases A2023 and A2030, the residual supply side shows a similar picture: residual power demand is primarily met by non-VRE power generation, while in A2030 an additional, small part is covered by net imports.

- In the alternative 2050 cases, however, the situation is quite different. Notably in A2050, about two-thirds of the (national, curtailed) residual power demand is covered by net imports while the remaining part is addressed by domestic, non-VRE generation (**Figure 4**).

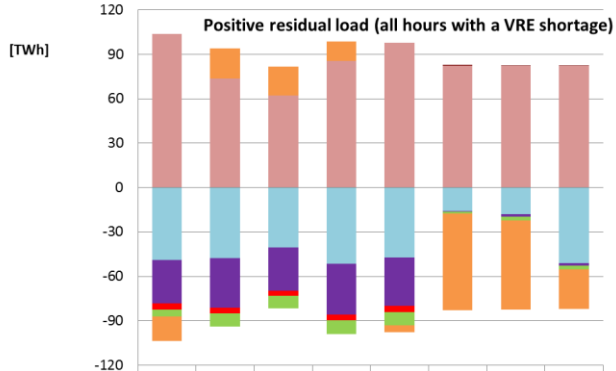
- On the other hand, in C2050 (0% interconnection expansion), the residual supply side is quite different compared to A2050 (100% interconnection expansion). Due to the interconnection restriction, the contribution of net imports to total supply falls from 48 TWh in A2050 to 11 TWh in C2050, whereas the contribution of gas-fired power generation to meet electricity demand increases from 22 TWh to 58 TWh, respectively. As a result, gas becomes by far the most dominant source of total (national) residual power supply in C2050.

- However, in the 2050 scenario cases – with a large VRE surplus over a large number of hours – the residual supply situation is quite different in the hours with a VRE surplus compared to the hours with a VRE shortage (see middle versus lower part of **Figure 4**).).The VRE supply surplus is usually enhanced by non-VRE generation – notably from gas and, to a lesser extent, from other RES-E – because of 'must-run' production considerations and/or ample export opportunities in certain hours. The resulting domestic surplus of power supply is predominantly met by VRE curtailment and, to a lesser extent, by net exports

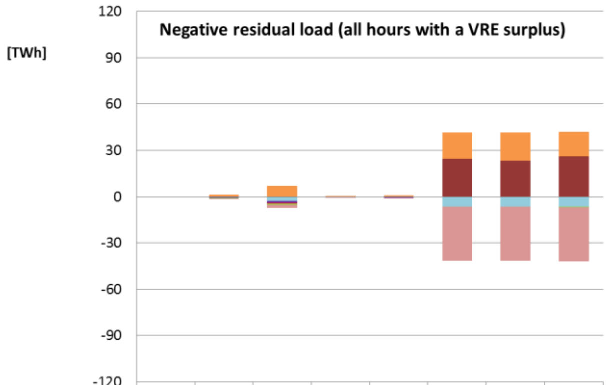
Figure 4: Net residual power balance of the Netherlands, including a distinction between hours with a positive and negative residual load, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Net exports	-16.7	21.3	26.7	13.5	-3.6	-48.2	-41.7	-11.0
VRE curtailment	0.0	0.0	0.0	0.0	0.0	25.5	23.5	26.4
Residual load (uncurtailed)	103.8	73.6	60.2	85.6	97.6	46.8	46.8	46.8
Other RES-E	-4.6	-9.0	-9.0	-9.0	-9.2	-1.7	-2.3	-2.6
Nuclear	-4.1	-4.0	-4.0	-4.0	-4.0	0.0	0.0	0.0
Coal	-29.4	-33.4	-30.4	-34.2	-32.9	-0.4	-1.7	-1.9
Gas	-49.0	-48.4	-43.5	-51.8	-47.8	-22.1	-24.5	-57.7



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Net exports	-16.7	20.2	19.6	13.2	-4.6	-65.0	-60.2	-26.6
VRE curtailment	0.0	0.0	0.0	0.0	0.0	0.9	0.3	0.1
Residual load (uncurtailed)	103.8	73.7	62.0	85.6	97.8	81.9	81.9	81.9
Other RES-E	-4.6	-8.9	-8.3	-9.0	-9.1	-1.6	-2.1	-2.4
Nuclear	-4.1	-4.0	-3.6	-4.0	-4.0	0.0	0.0	0.0
Coal	-29.4	-33.2	-29.2	-34.1	-32.7	-0.4	-1.7	-1.9
Gas	-49.0	-47.8	-40.5	-51.7	-47.4	-15.8	-18.2	-51.0



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Net exports	0.0	1.1	7.1	0.2	1.0	16.8	18.5	15.6
VRE curtailment	0.0	0.0	0.0	0.0	0.0	24.7	23.1	26.2
Residual load (uncurtailed)	0.0	-0.1	-1.8	0.0	-0.2	-35.1	-35.1	-35.1
Other RES-E	0.0	-0.1	-0.7	0.0	-0.1	-0.1	-0.2	-0.2
Nuclear	0.0	-0.1	-0.4	0.0	-0.1	0.0	0.0	0.0
Coal	0.0	-0.3	-1.2	0.0	-0.2	0.0	0.0	0.0
Gas	0.0	-0.5	-3.0	-0.1	-0.4	-6.3	-6.3	-6.6

Trends in hourly variations of residual load and resulting flexibility needs
Following hourly variations in residual load (as defined and analysed in the phase 1 report), we have defined hourly variations ('ramps') in residual supply as the difference between residual supply in hour t and residual supply in hour t-1 (with t = 1,…..n). These variations can be either positive ('ramp-up') or negative ('ramp-down').

In order to analyse the demand for flexibility due to the variability of the residual load during phase 1 of FLEXNET, we have defined and applied the following three specific indicators of flexibility needs resulting from the hourly variations of the residual load:

- *Maximum hourly ramp*, in both directions (upwards and downwards), i.e. the maximum hourly variation in residual load over a year, expressed in capacity terms per hour (GW/h);
- *Maximum cumulative ramp,* in both directions (upwards and downwards), i.e. the maximum variation in residual load – either upwards or downwards – during some consecutive hours in a year, expressed in capacity terms per number of consecutive hours (GW/#h);
- *Total hourly ramps,* in both directions (upwards and downwards), i.e. the total annual amount of hourly ramps – either up or down – aggregated over a year, expressed in energy terms per annum (TWh).

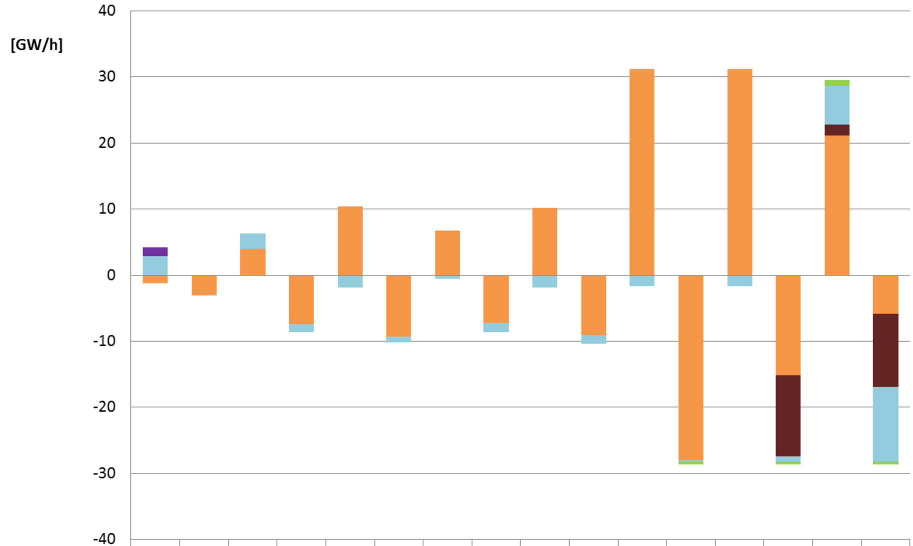
As part of the second phase of FLEXNET, we have estimated and analysed the supply options to meet the demand for flexibility according to the three indicators mentioned above by means of the EU28+ electricity market model COMPETES. The major results of this effort include:

- In R2015, the need for maximum hourly ramp-up (3.0 GW/h) is still solely met by power generation from fossil fuels, in particular from gas (2.9 GW/h) and, to a lesser extent, from coal (1.3 GW/h), whereas the ramp of net imports is still relatively small and even moves in the other direction (-1.2 GW/h).

- In almost all scenario cases the need for both *maximum hourly ramp-up and maximum hourly ramp-down* is predominantly (60-100%) met by hourly changes in net power trade. The only exceptions include the need for upward flexibility in R2015 (as noted above) and the need for downward flexibility in B2050 and C2050. In particular, in C2050 (0% interconnection expansion), only a minor share of the maximum need for hourly ramp-down (-29 GW/h) is met by net imports (-6 GW/h), whereas major shares are addressed by VRE curtailment (-11 GW/h) and gas-fired generation (-11 GW/h) and a small share by other RES-E (<1 GW/h; see **Figure 5**).

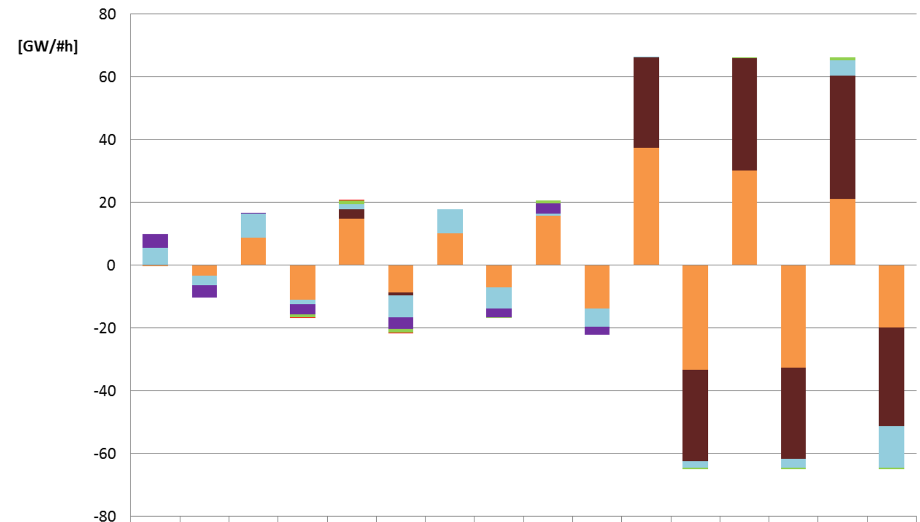
- Hourly variations in power generation from fossil fuels (coal, gas) play a more important role as flexibility options to meet flexibility needs in terms of the *maximum cumulative ramps* up to A2030, notably from coal to meet downward cumulative flexibility needs. In the 2050 scenario cases, the role of (hourly variations in) VRE curtailment in meeting maximum cumulative ramps is more important, whereas the role of (hourly variations in) power trade is less important (compared to meeting maximum hourly ramps, discussed above). More specifically, the share of VRE curtailment in addressing cumulative upward flexibility needs amounts to 44% in A2050 and increases to almost 60% in C2050, whereas the share of power trade is 56% in A2050 and drops to 31% in C2050; see **Figure 6**).

Figure 5: Flexibility options to meet flexibility needs in terms of maximum hourly ramps, 2015-2050



	R2015 Up	R2015 Down	R2023 Up	R2023 Down	R2030 Up	R2030 Down	A2023 Up	A2023 Down	A2030 Up	A2030 Down	A2050 (100%) Up	A2050 (100%) Down	B2050 (50%) Up	B2050 (50%) Down	C2050 (0%) Up	C2050 (0%) Down
Other RES-E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.4	0.0	-0.4	0.9	-0.4
Coal	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	2.9	-0.1	2.2	-1.2	-1.9	-0.8	-0.6	-1.5	-1.9	-1.4	-1.7	-0.3	-1.7	-0.9	5.8	-11.3
VRE curtailment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-12.2	1.7	-11.1
Net imports	-1.2	-3.0	4.0	-7.4	10.4	-9.3	6.7	-7.2	10.1	-9.0	31.2	-28.0	31.2	-15.1	21.1	-5.8

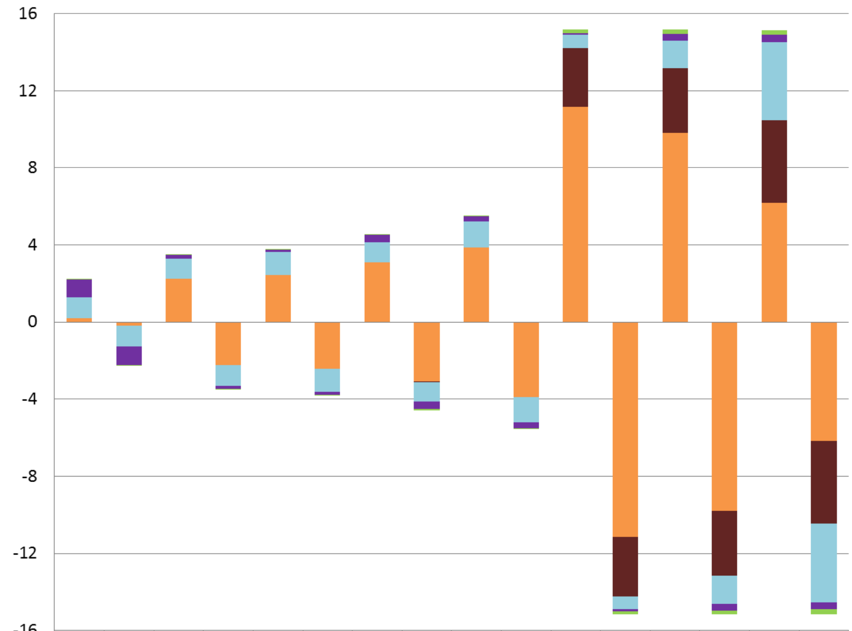
Figure 6: Flexibility options to meet flexibility needs in terms of maximum cumulative ramps, 2015-2050



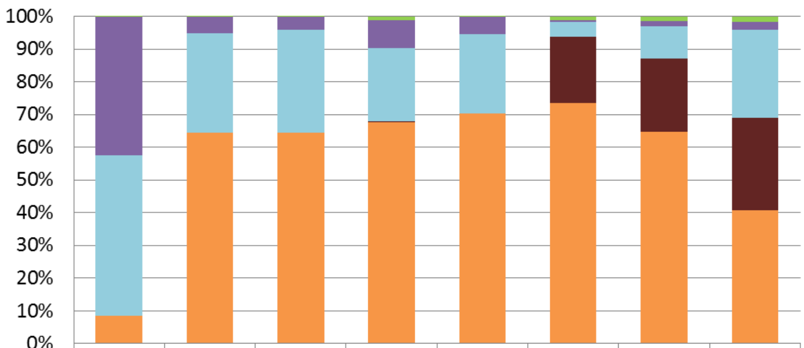
	R2015 Up	R2015 Down	R2023 Up	R2023 Down	R2030 Up	R2030 Down	A2023 Up	A2023 Down	A2030 Up	A2030 Down	A2050 (100%) Up	A2050 (100%) Down	B2050 (50%) Up	B2050 (50%) Down	C2050 (0%) Up	C2050 (0%) Down
Nuclear	0.0	0.0	0.0	-0.1	0.2	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other RES-E	0.0	0.0	0.0	-1.0	1.0	-1.0	0.0	-0.3	1.0	0.0	0.0	-0.4	0.4	-0.4	0.9	-0.4
Coal	4.5	-3.9	0.0	-3.1	0.1	-3.7	0.0	-2.7	3.1	-2.5	0.0	0.0	0.0	0.0	0.0	0.0
Gas	5.4	-3.0	7.6	-1.5	1.5	-7.1	7.7	-6.8	0.8	-5.9	0.0	-2.3	0.0	-2.9	5.0	-13.4
VRE curtailment	0.0	0.0	0.0	0.0	3.1	-0.8	0.0	0.0	0.0	0.0	28.9	-28.9	35.7	-28.9	39.1	-31.4
Net imports	-0.3	-3.4	8.8	-11.1	14.7	-8.8	10.1	-7.0	15.7	-13.8	37.3	-33.4	30.1	-32.8	21.1	-19.8

- Flexibility needs in terms of *total annual for demand for upward/downward flexibility* (due to the hourly variations of the residual load) increase from 2.2 TWh in R2015 to more than 15 TWh in the 2050 scenario cases (see **Figure 7**). In R2015, these needs are predominantly met by (hourly) increases in power generation from gas (49%) and coal (42%), while the remaining part is covered by increases in net imports (9%).

Figure 7: Total annual supply of flexibility options to meet total annual demand of flexibility, either upwards or downwards, in all scenario cases, 2015-2050



	R2015 Up	R2015 Down	R2023 Up	R2023 Down	R2030 Up	R2030 Down	A2023 Up	A2023 Down	A2030 Up	A2030 Down	A2050 (100%) Up	A2050 (100%) Down	B2050 (50%) Up	B2050 (50%) Down	C2050 (0%) Up	C2050 (0%) Down
Other RES-E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	-0.2	0.2	-0.2	0.3	-0.3
Coal	0.9	-0.9	0.2	-0.2	0.2	-0.2	0.4	-0.4	0.3	-0.3	0.1	-0.1	0.3	-0.3	0.4	-0.4
Gas	1.1	-1.1	1.1	-1.1	1.2	-1.2	1.0	-1.0	1.3	-1.3	0.7	-0.7	1.4	-1.4	4.1	-4.1
VRE curtailment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	-3.1	3.4	-3.4	4.3	-4.3
Net imports	0.2	-0.2	2.2	-2.2	2.4	-2.4	3.1	-3.1	3.9	-3.9	11.1	-11.1	9.8	-9.8	6.2	-6.2



	R2015	R2023	A2023	R2030	A2030	A2050 (100%)	B2050 (50%)	C2050 (0%)
Other RES-E	0.2%	0.1%	0.0%	1.1%	0.0%	1.1%	1.4%	1.7%
Coal	42.4%	5.0%	4.0%	8.6%	5.4%	0.6%	1.7%	2.4%
Gas	48.9%	30.4%	31.5%	22.2%	24.2%	4.6%	9.8%	26.8%
V-RES curtailment	0.0%	0.0%	0.0%	0.3%	0.0%	20.2%	22.1%	28.2%
Net imports	8.5%	64.5%	64.5%	67.7%	70.4%	73.5%	64.6%	40.8%

- In R2023, the total annual demand for upward flexibility increases to 3.5 TWh. However, already in this scenario case the share of power trade (net imports) increases to 65%, whereas the shares of gas and coal drop to 30% and 5%, respectively (**Figure 7**).

- In the scenario cases A2023 up to A2050, the share of power trade in total flexibility demand (upwards/downwards) is significantly higher, whereas the share of fossil fuels is lower accordingly. In A2050, the share of net power imports in total annual flexibility demand/supply amounts even to almost 74%, whereas the share of gas and coal amounts to only 4.6% and 0.6%, respectively. The remaining part is largely accounted for by (hourly changes in) VRE curtailment (20%) and, to a lesser extent, by generation from other RES-E (1%).

- In the two other 2050 scenario cases – with significantly lower interconnection capacities – the share of power trade in total upward/downward flexibility is significantly lower, while the shares of the other flexibility options are higher accordingly. More specifically, in C2050 (% interconnection expansion), the share of gas-fired generation in total annual flexibility needs increases to 27% (compared to less than 5% in A2050) while the share of VRE curtailment rises from 20% in A2050 to 28% in C2050. In C2050 , however, power trade still accounts for the largest share of all flexibility options (41%), while in B2050 (50% interconnection expansion), the share of net imports in total flexibility needs, however, even amounts to 65% (**Figure 7**).

- To conclude, in R2015 hourly changes in the power generation from non-VRE sources – notably from gas, coal and, to a lesser extent, other RES-E (biomass, hydro) – are the main supply options to meet the demand for upward/downward flexibility due to the (hourly) variability of the residual load, regardless of the indicator used to express and quantify this type of flexibility demand. In all scenario cases over the period 2023-2050, however, hourly changes in power trade become the most important (dominant) supply option to address the demand for flexibility due to the variability of the residual load.

- Our analysis shows, however, that the role of the different supply options to meet the need for flexibility depends highly on the assumptions made with regard to the expansion of the interconnection capacities across the EU28+ countries in general and between the Netherlands and its neighbouring (interconnected) countries in particular. For instance, in A2050, the shares of the three main supply categories in addressing total annual flexibility demand – i.e. power trade, VRE curtailment and power generation from non-VRE resources – amount to 74%, 20% and 6%, respectively.

- On the other hand, in C2050, these shares amount to 41%, 28% and 31%, respectively. In particular, the share of gas-fired power generation increases from 4.6% in A2050 to almost 27% in C2050 (**Figure 7**).

The role of power trade versus other, domestic flexibility options
As observed above, in the coming decades (hourly variations in) power trade plays a major (usually dominant) role in meeting (hourly variations in) residual load (and resulting flexibility needs). Additional analysis of this role has resulted in the following findings:

- Even in hours in which the EU28+ countries as a whole and the Netherlands in particular faces an 'extreme' high level of either a large positive residual load (VRE shortage) or a large negative residual load (VRE surplus), these countries are able to address these situations by a mix of (hourly variations in) non-VRE power generation, VRE curtailment, demand curtailment, energy storage and, in particular, power trade between countries with, on balance, a domestic power surplus (net exports) and countries with a domestic power deficit (net imports).

- Power trade as a flexibility option has a major impact on the business case of other, domestic options to meet the demand for flexibility due to the variability of the residual load in the Dutch power system up to 2050, including the impact of (hourly variations in) power trade volumes and the related hourly fluctuations of domestic electricity prices. Due to these related volume and price effects of power trade, the business case and, hence, the size (share) of other, domestic flexibility options is lower accordingly. This impact, however, depends significantly on the assumptions made with regard to the EU28+ interconnection capacities, in particular between the Netherlands and its neighbouring countries.

Electricity prices and power system costs
In addition, we have analysed hourly electricity prices and (total, annual) power system costs in the FLEXNET scenario cases up to 2050 by means of the COMPETES model. The major findings in this regard include:

- Over the period R2015- A2030, the (weighted average, annual) electricity price increases significantly (mainly due to the higher fuel and CO_2 prices for the marginal units setting the power price over this period). Compared to A2030, however, the electricity price drops substantially in A2050 (due to the large share in total power production by VRE sources with low marginal costs). In C2050, on the other hand, the electricity price is significantly (60%) higher than in A2050 (due to the lower interconnection capacity and the resulting number of hours in which electricity end-users can benefit less from lower-priced electricity imports).

- Over the period 2015-2050, *hourly* electricity prices fluctuate heavily (see **Figure 8** as well as **Figure 9**). Moreover, this price volatility increases over time, mainly due to both the increasing share of VRE sources – with low marginal costs – in total power production, setting the price during a growing number of hours, as well as the decreasing share of gas-fired generation – with high marginal costs, setting the price during a diminishing number of (peak load) hours (i.e. hours with a relatively high VRE shortage). In addition, electricity price volatility increases in B2050 and C2050, compared to A2050, due to the lower interconnection capacities in these scenario cases, (implying that power trade flows play a smaller role in stabilising domestic electricity prices).

Figure 8: Illustration of hourly electricity price levels and fluctuations during the mid of the year (hours 3900-4500) in some selected scenario cases, 2015-2050

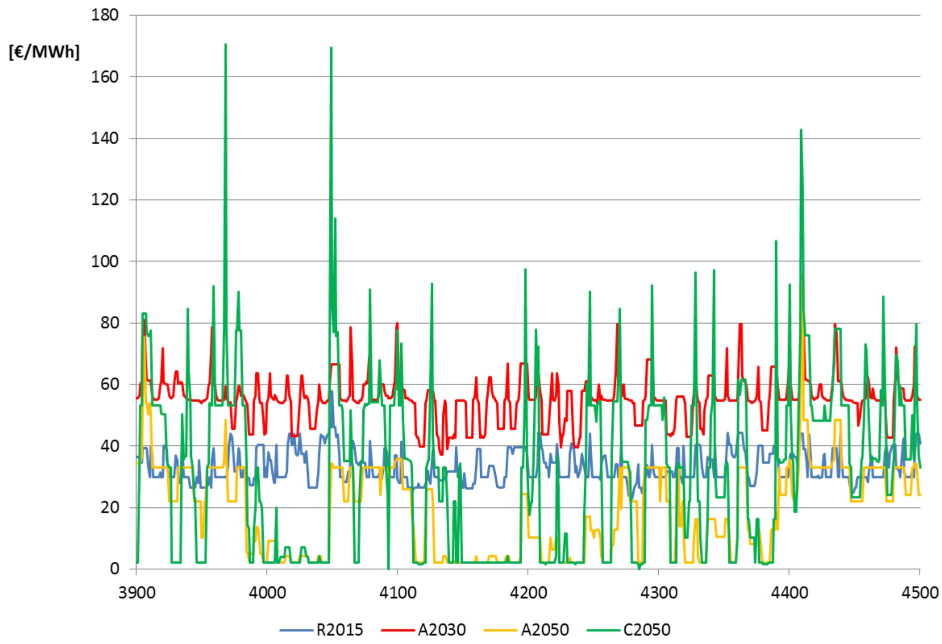
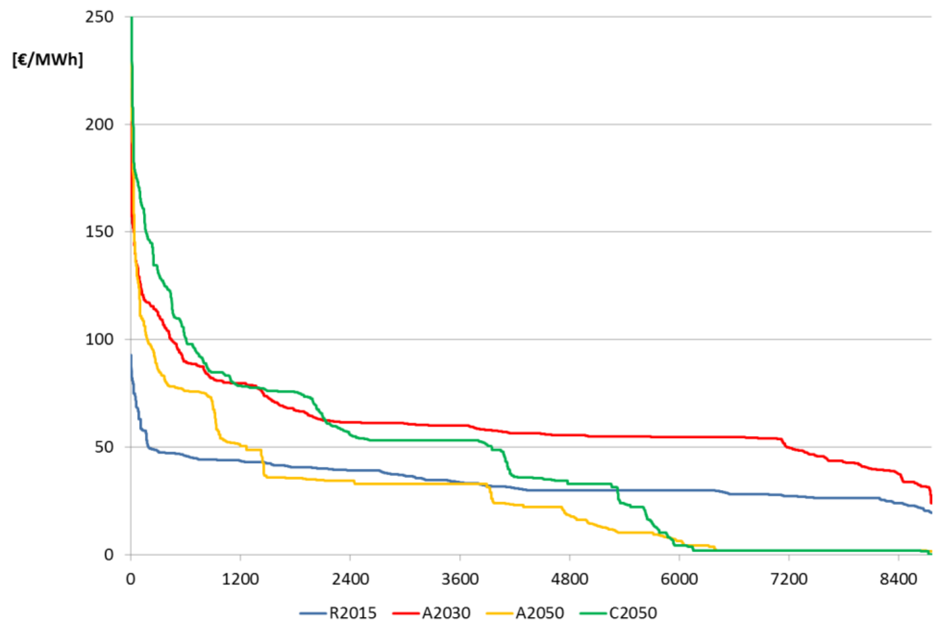


Figure 9: Duration curves of hourly electricity prices in some selected scenario cases, 2015-2050



- Compared to A2050, total power system costs in the EU28+ as a whole are approximately € 2.2 billion (8%) higher in B2050 and about € 10 billion (38%) in C2050. In the Netherlands only, total power system costs are about € 1.9 billion (43%) higher in B2050 and approximately € 2.4 billion (54%) in C2050. These higher costs result, on balance, from lower (annualised) interconnection capacity investments on the one hand and higher costs for (gas-fired) generation capacity investments and (variable) power generation costs on the other hand.

1.2 Opera modelling results

To some extent, the OPERA modelling results are additional, complementary to the COMPETES modelling findings – as discussed above – in the sense that the power trade results of COMPETES are used as given input into OPERA and that, subsequently, OPERA focusses specifically on analysing some domestic flexibility options, in particular on demand response and energy storage (which are not – or to a lesser extent – covered by COMPETES). The major findings of the OPERA modelling analyses – including, where possible and relevant, a comparison with the COMPETES modelling results – are summarised below.

Demand response

As part of the OPERA modelling analyses, we have particularly investigated the potential of demand response by some selected power demand technologies as an option to address flexibility needs of the Dutch power system up to 2050. These technologies include electric vehicles (EVs) as well as three energy conversion technologies, i.e. power-to-gas (P2G), power-to-heat (P2H) and power-to-ammonia (P2A).

At present, the power demand by these technologies is still (negligible) small but it is expected that it will grow rapidly in the coming decades and that it offers, in principle, a large potential for demand response as a flexibility option for the Dutch power system, perhaps already – to some extent – in the period up to 2030 but notably in the years beyond 2030.

The major OPERA modelling findings with regard to the role of demand response by the four selected technologies include:

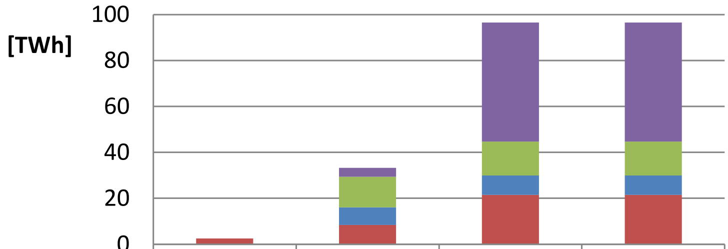
- Total power demand by the four selected technologies increases from almost zero in R2015 to about 33 TWh in A2030 and to 97 TWh in both A2050 and C2050, i.e. more than 40% of total power load in the 2050 scenario cases (**Figure 51**).

- The total annual *upward* demand response of the four technologies considered increases from zero in R2030 to 4.4 TWh in A2030, to 18 TWh in A2050 and even to 25 TWh in C2050 (where the total *downward* demand response shows similar amounts in these scenario cases). As a share of total annual power demand by these four technologies, this corresponds to 13% in A2030, 19% in A2050 and 26% in C2050 (**Figure 55**).

- As expected, the total annual demand response in the 2050 scenario cases is, on balance, significantly negative in all hours with a VRE shortage (i.e. generally a *downward* demand response in hours with a *positive* residual load and, hence, relatively *high* electricity prices) and significantly positive in all hours with a VRE surplus (i.e. generally an *upward* demand response in hours with a *negative* residual load and, therefore, relatively *low* electricity prices).

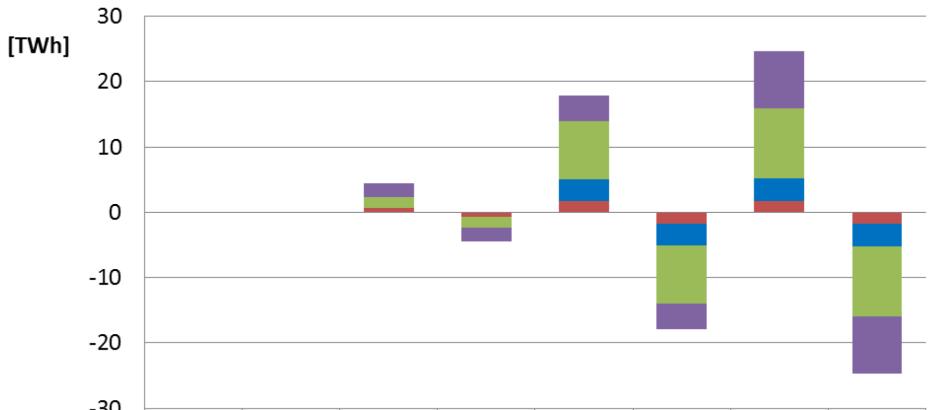
- The total annual flexibility – either upwards or downwards – offered by all demand-response technologies considered amounts to 1.8 TWh in A2050 and to 4.8 TWh in C2050. As a % of total annual flexibility needs due to the hourly variations of the residual load this corresponds to 12% and 32%, respectively (see **Figure 67** below).

Figure 10: Annual power load of selected demand-responsive technologies in selected FLEXNET scenario cases, 2030-2050



	R2030	A2030	A2050	C2050
P2G	0.0	3.9	51.8	51.8
P2H	0.0	13.3	14.7	14.7
P2A	0.0	7.6	8.5	8.5
EV	2.5	8.4	21.5	21.5

Figure 11: Total annual demand response per technology, either upwards or downwards, in selected scenario cases, 2030-2050



	R2030		A2030		A2050		C2050	
	Up	Down	Up	Down	Up	Down	Up	Down
P2G	0.0	0.0	2.0	-2.0	3.9	-3.9	8.7	-8.7
P2H	0.0	0.0	1.7	-1.7	8.9	-8.9	10.6	-10.6
P2A	0.0	0.0	0.0	0.0	3.2	-3.2	3.5	-3.5
EV	0.0	0.0	0.7	-0.7	1.8	-1.8	1.8	-1.8

Overall, there seems to be a large potential to meet future flexibility needs of the Dutch power system by means of demand response. This applies in particular to (industrial) power demand activities that are expected to grow rapidly in the coming decades such as power-to-gas, power-to-heat or power-to-ammonia, but also to power demand by means of more smart (flexible) charging of electric vehicles (as analysed above).

Moreover, there may be a large, additional potential for demand response by other power demand activities in other (household/service) sectors, although – to some extent – this potential may be harder to realise depending on the role of aggregators, price incentives, human behaviour, etc. This potential has not been explored in the current study at the national level, but our analyses at the regional Liander network level show that there is a significant potential of demand response at the local (household) level by means of direct load control (DLC) and various pricing mechanisms (see below).

Energy storage
In addition to the demand response technologies discussed above – of which some can, in principle, also be regarded as energy storage technologies (notably P2G and P2A) – the OPER model includes a wide variety of other, 'pure' electricity storage technologies such as compressed air energy storage (CAES), flywheels, supercapacitors, superconducting magnetic energy storage (SMES) and several types of batteries (conventional, sodium sulphur, lithium ion, flow batteries, etc.). As part of the FLEXNET project, OPERA has analysed the role of these storage technologies as a flexibility option to address the changes and variations of the (hourly) residual load of the Dutch power system in the FLEXNET scenario cases up to 2050.

A major finding of the FLEXNET-OPERA modelling analyses is that the role of 'pure' electricity storage technologies as a flexibility option to address hourly variations of the residual load of the Dutch power sector is low, i.e. nearly zero, up to 2030 and rather limited beyond 2030.More specifically, the major OPERA modelling results on energy storage include:

- The total charging-discharging activities, excluding storage losses, amount to almost 0.25 TWh in A2050 and 0.21 TWh in C2050, whereas the storage losses amount to 0.11 TWh and 0.09 TWh, respectively. All these activities result from one single technology only, i.e. CAES. As a percentage of residual load, these storage activities are generally rather limited, i.e. (far) less than 1%.

- The total annual supply of flexibility offered by energy storage (CAES) in order to meet the flexibility needs of the Dutch power system due to the hourly variation of the residual load in A2050 and C2050 amounts to approximately 0.1 TWh in both scenario cases, corresponding to less than 1% of total annual flexibility needs in these cases (see **Figure 67** below).

As the role of energy storage as a flexibility option turned out to be relatively limited (compared to previous expectations and to what is often suggested by other studies), we have conducted some sensitivity analyses by means of the OPERA model for the scenario case C2050 (which includes the largest part of domestic flexibility options).

In particular, we have reduced the annualised investment costs and the fixed operation and maintenance (O&M) costs of three storage technologies by a factor 10 in C2050, i.e. in the sensitivity runs these costs have been set at 10% of their original, baseline level. These three technologies include (i) compressed air energy storage (CAES), (ii) li-ion batteries, and (iii) superconducting magnetic energy storage (SMES).

The sensitivity analyses show that even in the case of fixed (O&M and investment) costs of the technologies considered have been reduced by 90%, their shares in (residual) power demand and flexibility supply remain relatively limited. For instance, the storage activities by these technologies offer flexibility to the power system by an amount varying between 0.15 TWh and 0.75 TWh per annum, i.e. approximately 1-5% of the annual flexibility needs due to the hourly variation of the residual load.

Explanation of the limited role of energy storage

Why is the role of energy storage in meeting future flexibility needs relatively limited (compared to what is generally expected or usually suggested in the literature), even if it is assumed that the cost of energy storage are reduced substantially (by a factor 10)?

The basic answer is rather simple, i.e. there is a large potential of other, alternative flexibility options that are (much) cheaper to meet these needs, in particular flexibility offered through options such as power trade and demand response, but also – notably in hours with a VRE surplus – by means of VRE curtailment. Besides their volume effect, these options reduce the business case of energy storage technologies through the related price effects in the sense that they reduce the volatility of the electricity price and, hence, reduce the price margin to cover the cost of offering flexibility. This applies particularly for 'pure' electricity storage technologies, such as CAES, SMES or batteries, which have to cover their costs primarily – or even solely – from the price margin earned by this single activity.

Some qualifications, however, may be added to the above observation. Firstly, there are some technologies that – besides their primary function(s) in a more sustainable, low-carbon energy system – can offer flexibility by means of an additional function (energy storage) at relatively low costs to the energy system in general and, to some extent, the power system in particular. This applies notably to energy conversion technologies such as power-to-gas (P2G) and power-to-ammonia (P2A). The power demand by these technologies is expected to grow rapidly in the coming decades as part of the transition to a more sustainable energy system, in particular to meet ambitious carbon reduction targets. As a result, these technologies become more necessary in the future energy system anyhow and, consequently, they can cover the main part of their costs by meeting these primary energy function(s). In addition, they may offer flexibility by means of energy storage functions to the energy system as a whole – and, in specific cases, to the power system as well – at relatively low marginal costs. The current study, however, indicates that the potential of the energy conversion technologies, such as P2G or P2A, to offer flexibility to the power system lies primarily in the option to provide demand response rather than electricity storage (as the costs of supplying electricity by means of these technologies are relatively high).

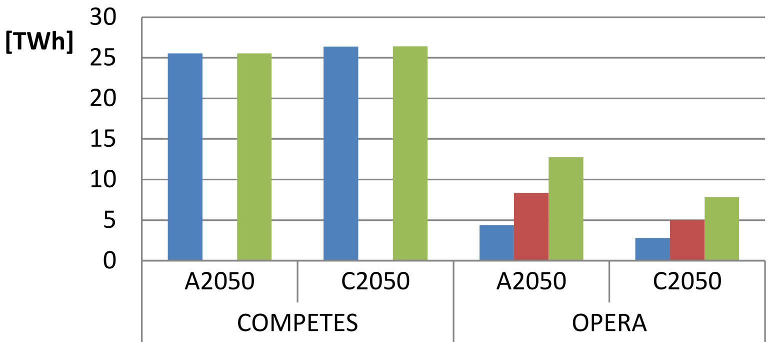
In addition, the above-mentioned qualification applies to some extent also for batteries of electric vehicles (EVs) that may be used to store electricity in order to discharge electricity to the power system again at a later stage. As the costs of this technology are covered predominantly by its primary functions (transport, comfort, etc.), the additional, marginal cost of offering flexibility through electricity storage by this technology are likely low while the benefits may be relatively high. Due to a variety of practical, techno-economic constraints, however, energy storage potential of EVs may be hard to realise while, on the other hand, the potential of this technology to provide flexibility to the power system by means of demand response – through smart charging – seems to be substantial (as analysed in the present study). Therefore, also for this technology the potential to offer flexibility to the power system may be more significant for the option of demand response rather than of energy storage.

A second qualification is that in the OPERA modelling analyses, i.e. in the current chapter, we have focussed our attention on exploring the role of energy storage as an option to meet flexibility needs due to the (hourly) variability of the residual load. Energy storage, however, may be an attractive option to meet other flexibility needs. Although the role and net benefits of energy (battery) storage to address network congestion seems to be limited – and even negative (see below), energy storage may be an attractive, cost-effective option to address short-term power system balancing issues – e.g. due to the uncertainty ('forecast error') of VRE power generation – notably if this function can be combined with other, additional ('ancillary') services such as voltage support, frequency control or resilience/back up power (see below).

Finally, for geographical reasons hydro pumped storage (HPS) is not a cost-effective flexibility option in the Netherlands. In most EU28+ countries, however, HPS is a major, attractive flexibility options. Hence, as noted, indirectly the Netherland may benefit from HPS as a flexibility option at the EU28+ level through its power trade relations with neighbouring countries, including Norway, Germany and France.

Curtailment of VRE power generation
Comparing the role of VRE curtailment as a flexibility option in the OPERA versus COMPETES modelling results lead to the following major findings (**Figure 61**):

Figure 12: Comparison of COMPETES versus OPERA modelling results on VRE curtailment in A2050 and C2050



	A2050	C2050	A2050	C2050
	COMPETES		OPERA	
Wind	25.5	26.4	4.4	2.8
Sun PV	0.0	0.1	8.3	5.0
Total	25.5	26.4	12.7	7.8

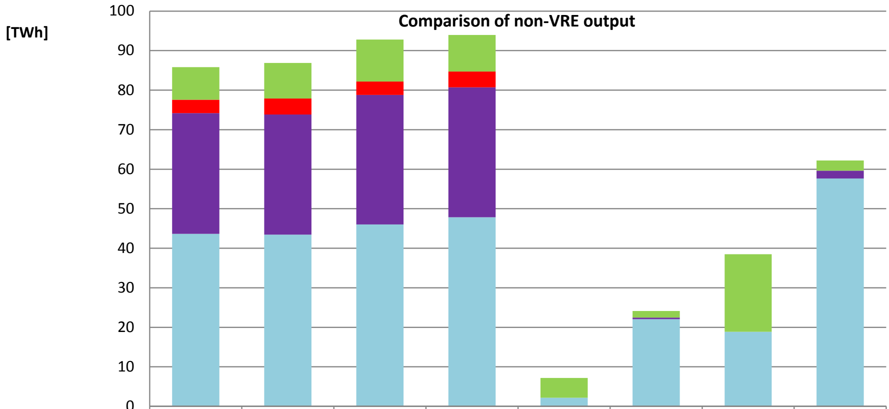
- Total VRE curtailment in OPERA is significantly lower in both A2050 and C2050 than in COMPETES. This is largely due to the fact that OPERA generates a large amount of upward demand response as a flexibility option – which reduces the need for VRE curtailment, notably in VRE surplus hours – whereas COMPETES does not include demand response as a potential flexibility option into the model and, hence, the contribution of (upward) demand response in offering flexibility – and, hence, in reducing the need for VRE curtailment – is consequently zero in COMPETES.

- In COMPETES the curtailment of power generation from sun PV is nearly zero, whereas in OPERA it is quite substantial (and even bigger than VRE curtailment from wind). This is due to different modelling assumptions regarding future network capacities, i.e. no domestic network restrictions – 'copper plate' – in COMPETES versus local (low-voltage) grid restrictions in particular hours (with high PV output) in OPERA.

Non-VRE power generation

Comparing the role of power generation from non-VRE sources (coal, gas, nuclear, biomass, etc.) as a flexibility option in the OPERA versus COMPETES modelling results lead to the following major findings (**Figure 64**):

Figure 13: Comparison of OPERA versus COMPETES modelling results on non-VRE power mix in selected scenario cases, 2030-2050



	OPERA	COMPETES	OPERA	COMPETES	OPERA	COMPETES	OPERA	COMPETES
	R2030		A2030		A2050		C2050	
Other non-VRE supply	8.2	9.0	10.6	9.2	5.0	1.7	19.6	2.6
Nuclear	3.4	4.0	3.4	4.0	0.0	0.0	0.0	0.0
Coal	30.6	30.4	32.8	32.9	0.0	0.4	0.0	1.9
Gas	43.6	43.5	46.0	47.8	2.2	22.1	18.9	57.7

- Compared to OPERA, the non-VRE output level of COMPETES is much higher in both A2050 and C2050. Moreover, the output mix of COMPETES in these scenario cases is quite different in the sense that gas output is much higher whereas the output from other non-VRE sources is much lower than in OPERA, notably in C2050.

- These differences in non-VRE output generation between the two models result in particular from the large amount of demand response in the OPERA modelling outcomes in the 2050 scenario cases, especially in C2050, whereas COMPETES does not include demand response as a flexibility option. As a result, the level of VRE curtailment is much lower in OPERA than in COMPETES, notably due to the upward demand response in hours with a major VRE surplus.

- Hence, in these hours – and over the year as a whole – more VRE output becomes available. In addition, due to the downward demand response – notably in hours with a large VRE shortage – less non-VRE output is needed in these hours and, therefore, over the year as a whole.

- Moreover, due to both the upward and downward demand response, the residual load duration curve becomes much flatter in OPERA than in COMPETES. As a result, there is less need for peak load installations (with relatively high variable costs) –

such as gas-fired plants – and more need for mid or base load units (with relatively high investment costs), such as biomass, waste or geothermal installations.

Net residual power balances

Figure 65 presents the net residual power balances in some selected scenario cases over the years 2030-2050, including a distinction between all hours over the year with a positive residual load (VRE shortage) and all hours with a negative residual load (VRE surplus), according to the OPERA modelling results. This figure resembles a similar set of graphs above, i.e. **Figure 4**, which presents similar net residual power balances for all FLEXNET scenario cases according to the COMPETES modelling results.

Overall, the differences in the net residual power balances of **Figure 4** (COMPETES) and **Figure 65** (OPERA) are generally small for the respective 2030 scenario cases. In the 2050 scenario cases, however, the differences between the two models are quite substantial. As outlined above, these differences are primarily due to the fact that the OPERA modelling results include a large amount of (upward and downward) demand response, whereas this flexibility option is not covered by COMPETES. As a result, VRE curtailment is much lower in OPERA than in COMPETES – notably in hours with a VRE surplus and an upward demand response – while non-VRE output is also much lower in OPERA than in COMPETES, in particular in hours with a VRE shortage and a downward demand response.

Flexibility options to meet hourly variations of the residual load

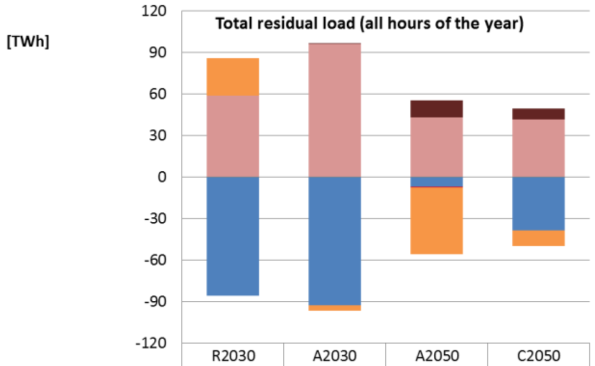
Finally, **Figure 67** presents a comparison between the (corrected) OPERA and COMPETES modelling results with regard to the total annual supply of upward flexibility options due to the hourly variations of the residual load of the Dutch power system in four selected scenario cases over the years 2030-2050.[2] It shows that the differences in modelling outcomes are generally relatively small in the 2030 scenario cases, notably in R2030.

On the other hand, in the 2050 scenario cases – and particularly in C2050 – the differences in domestic flexibility options are quite substantial. For instance, in C2050 the flexibility offered by means of the hourly variations in total demand response amounts to 4.8 TWh in the OPERA modelling results, corresponding to almost 32% of total annual flexibility demand/supply – and being the most dominant 'domestic' flexibility option in C2050 – whereas it amounts to zero in the COMPETES modelling results (as this option is not covered by this model).

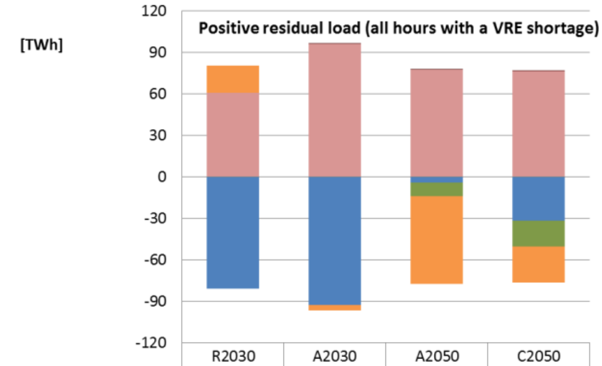
In addition, **Figure 67** shows that in C2050 the flexibility offered by (hourly variations in) VRE curtailment and gas-fired power generation are significantly lower in the OPERA modelling results than in the COMPETES modelling outcomes (due to the difference in modelling results on demand response mentioned above). For instance, in C2050 the share of VRE curtailment in total annual flexibility supply amounts to 10% in the OPERA results and to 28% in the COMPETES outcomes. For gas-fired power generation, these figures amount to 10% and 27%, respectively (see the last two columns in the lower part of **Figure 67**).

[2] The OPERA results have been corrected for the so-called 'time slice effect' as explained in Section 3.7 of the FLEXNET phase 2 report. Note that **Figure 67** shows only a comparison of the *upward* flexibility demand/supply as the downward flexibility demand/supply levels are exactly similar to the upward levels.

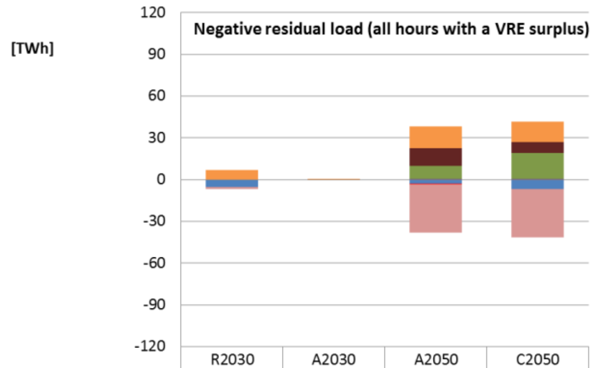
Figure 14: Net residual power balances in some selected scenario cases, 2030-2050, including a distinction between hours with a positive residual load (VRE shortage) and a negative residual load (VRE surplus), according to the OPERA modelling results



	R2030	A2030	A2050	C2050
Net exports	26.7	-3.6	-48.2	-11.0
VRE curtailment	0.1	0.1	12.7	7.8
Residual load (uncurtailed)	59.0	96.4	42.5	41.6
Demand response - total	0.0	0.0	0.0	0.0
Storage - charge (incl. losses)	0.0	0.0	0.4	0.3
Storage - discharge	0.0	0.0	-0.2	-0.2
Non-VRE supply	-85.8	-92.8	-7.2	-38.5

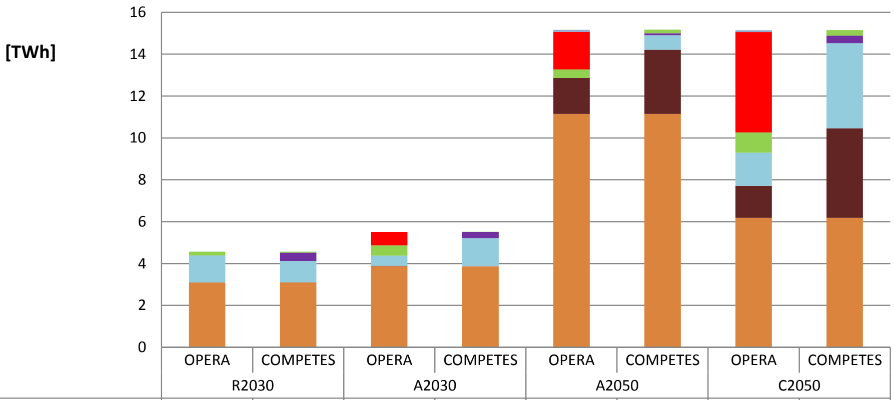


	R2030	A2030	A2050	C2050
Net exports	19.8	-3.8	-63.8	-26.0
VRE curtailment	0.1	0.0	0.0	0.0
Residual load (uncurtailed)	60.7	96.4	77.4	76.4
Demand response - total	0.0	0.0	-9.5	-18.6
Storage - charge (incl. losses)	0.0	0.0	0.1	0.0
Storage - discharge	0.0	0.0	-0.1	-0.1
Non-VRE supply	-80.5	-92.6	-4.1	-31.7

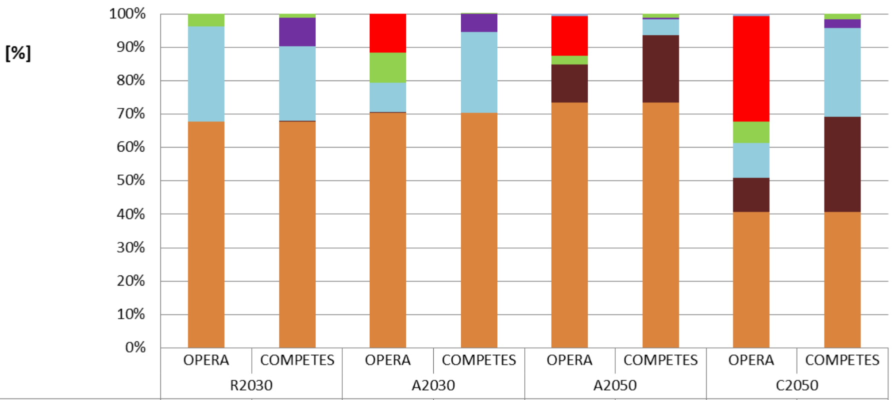


	R2030	A2030	A2050	C2050
Net exports	6.9	0.2	15.7	15.0
VRE curtailment	0.0	0.0	12.7	7.8
Residual load (uncurtailed)	-1.7	0.0	-34.9	-34.8
Demand response - total	0.0	0.0	9.5	18.6
Storage - charge (incl. losses)	0.0	0.0	0.3	0.3
Storage - discharge	0.0	0.0	-0.1	-0.1
Non-VRE supply	-5.3	-0.2	-3.1	-6.7

Figure 15: Comparison of OPERA versus COMPETES modelling results on the total annual supply of upward flexibility options to meet total annual demand of upward flexibility due to the hourly variations ('ramps') of the residual load in selected scenario cases, 2030-2050



	R2030 OPERA	R2030 COMPETES	A2030 OPERA	A2030 COMPETES	A2050 OPERA	A2050 COMPETES	C2050 OPERA	C2050 COMPETES
Storage	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0
Total demand response	0.0	0.0	0.6	0.0	1.8	0.0	4.8	0.0
Other non-VRE supply	0.2	0.0	0.5	0.0	0.4	0.2	1.0	0.3
Coal	0.0	0.4	0.0	0.3	0.0	0.1	0.0	0.4
Gas	1.3	1.0	0.5	1.3	0.0	0.7	1.6	4.1
VRE curtailment	0.0	0.0	0.0	0.0	1.7	3.1	1.5	4.3
Net imports	3.1	3.1	3.9	3.9	11.1	11.1	6.2	6.2



	R2030 OPERA	R2030 COMPETES	A2030 OPERA	A2030 COMPETES	A2050 OPERA	A2050 COMPETES	C2050 OPERA	C2050 COMPETES
Storage	0.0%	0.0%	0.0%	0.0%	0.6%	0.0%	0.6%	0.0%
Total demand response	0.0%	0.0%	11.5%	0.0%	11.8%	0.0%	31.7%	0.0%
Other non-VRE supply	3.8%	1.1%	9.1%	0.0%	2.7%	1.1%	6.4%	1.7%
Coal	0.0%	8.6%	0.0%	5.4%	0.0%	0.6%	0.0%	2.4%
Gas	28.4%	22.3%	8.7%	24.2%	0.0%	4.6%	10.4%	26.8%
VRE curtailment	0.0%	0.3%	0.3%	0.0%	11.3%	20.2%	10.1%	28.3%
Net imports	67.8%	67.8%	70.4%	70.4%	73.6%	73.5%	40.8%	40.8%

2. Options to meet the demand for flexibility due to the uncertainty of the residual power load

In addition to the need for flexibility due to the variability of the residual load (expressed on the day-ahead market), there is also the demand for flexibility resulting from the uncertainty of the residual load, in particular due to the forecast error of VRE power generation (expressed on the intraday/balancing market). Due to modelling, time and budget constraints we have not been able to model and analyse quantitatively the options to meet the demand for flexibility due to the uncertainty of the residual load up to 2050 as part of the present study. Rather we have reviewed a previous ECN study on flexibility on the intraday/-balancing market as well as some other recent, medium-term studies (usually up to 2023) that have considered potential options to meet flexibility needs resulting from the uncertainty of the residual power load in general and the wind forecast error in particular. Some of the major findings of these studies include:

- The total annual demand for upward flexibility on the intraday/balancing market is estimated to increase from 0.6 TWh in 2012 to 3.2 TWh is 2023. Most of (the increase in) this demand by 2023 can be met by incumbent, conventional generators (gas, coal) but there is also some room (0.8 TWh) – and even a business case – for new entrants such as conventional generators (notably CCGTs) or storage, in particular compressed air energy storage (CAES; see Koutstaal et al., 2014 as well as Özdemir et al., 2015).

- Under the condition that the comfort of living should remain equal, only a limited number of devices in households are suitable for balancing purposes, including in particular freezers, refrigerators, electric water heaters, heat pumps and air conditioners. The potential of these devices for both up and down balancing, however, was found to be relatively large, i.e. there is 100 MW of down regulation and 200 MW up regulation available in the Netherlands while the current (2013) absolute imbalance is around 110 MW (Bal, 2013).

- Realising the household balancing potential by means of demand response would result in a decrease in imbalance costs of approximately € 30 million annually. This is, on average, € 40 per household annually, which provides a relatively low incentive for the implementation of smart household appliances for balancing purposes. Moreover, the balancing market – which was expected to increase due to increased imbalance resulting from growing VRE generation shares – will likely decrease in the next years because a large part of total imbalance will be settled within the International Grid Control Cooperation (IGCC) between Germany, the Netherlands and some other north-western European countries (or by other arrangements to enhance international TSO cooperation and integration of balancing markets over a larger control area). This provides a lower incentive to realise the household balancing potential by means of demand response. Finally, this potential may also be harder to realise due to the competition by other, alternative balancing options such as providing balancing services through energy storage or by VRE generators themselves, which increasingly are technically well suited for being ramped down quickly – when generating electricity – or even to ramp up, when producing below potential output such that some VRE generation is constantly curtailed. (Bal, 2013; Hirth and Ziegenhagen, 2015).

- The development of the balancing market up to 2030 is highly uncertain. Compared to the day-ahead/intraday markets, imbalance prices show wider fluctuations – with peak prices running up to 600 €/MWh – although they occur less often. Moreover, the volume of the balancing market is limited, implying that energy storage will meet swiftly competition from other flexibility/balancing options (Berenschot, et al., 2015).

- Due to the higher price differences and the number of peak prices per day, the perspectives for some storage technologies are better on the Dutch balancing market than on the Dutch spot market (where variations in electricity prices are not sufficient in 2030 to make longer-term storage attractive). Current regulation, however, may be a potential barrier for storage activities on the balancing market (Berenschot, et al., 2015).

- With regard to the market for regulation and reserve power, it is noticed in (international) practice that – besides conventional generators – also energy storage is deployed for offering services on this market, notably by technologies such as flywheels and li-ion batteries that meet the required specifications for these services. Economic analysis shows that with the current price levels and costs for some technologies (flywheels), there is a positive business case for offering primary reserve services. In addition, market consultations show that commercial parties are interested to become active with li-ion batteries in this field (Berenschot, et al., 2015).

- In general, the available capacity for upward and downward balancing seems to be sufficient to meet balancing needs up to 2023. It should be realised, however, that the balancing needs to correct VRE forecast errors are usually highest during situations of high VRE output levels. During these situations, the availability of conventional options to meet these needs – i.e. gas-fired spinning reserves – will become under increasing pressure. This likely creates the need for the availability of other options such as storage or demand response (CE Delft, 2016).

- The business case of a windmill and energy storage for balancing purposes can be positive if some conditions are met, notably if a certain size of the storage is met – for instance, a cooperative storage system that connects several smaller windmills – and if it is used for several purposes, including (i) avoiding imbalance and, hence, avoiding the imbalance costs that windmill owners have to pay, (ii) trading on the balancing market by providing secondary reserve power, and (iii) using part of the electricity from storage for own consumption and, hence, reducing grid connection costs (DNV GL, 2017).

Overall, it can be concluded that in the coming years the increasing demand for flexibility on the intraday/balancing market due to the increasing share of VRE power generation – and, hence, the increasing uncertainty (forecast error) of the residual load – can be met by incumbent, conventional generators (notably gas) as well as by new entrants, including flexible conventional gas units (particularly CCGTs) but also new, additional flexibility options such as storage, demand response or providing balancing services by VRE generators themselves.

The perspectives of the balancing market in the Netherlands, however, are rather uncertain. In particular, the market for activated control power may grow slowly – or even decline – because a major part of total imbalance may be settled by means of the International Grid Control Cooperation (IGCC) or by other arrangements to enhance international TSO cooperation and integration of balancing markets over a larger control area.

Moreover, it should be realised that most of the studies reviewed cover only a short to medium term period (e.g., up to 2023) and consider usually a single option to address the demand for flexibility on the intraday/balancing market resulting from the forecast error of VRE power production rather than to determine the optimal mix of a set of supply options in the long run. Therefore, it is hard to say which mix and size of supply options will meet the demand for flexibility on the intraday/balancing market due to the uncertainty of the residual load in either the medium or long run.

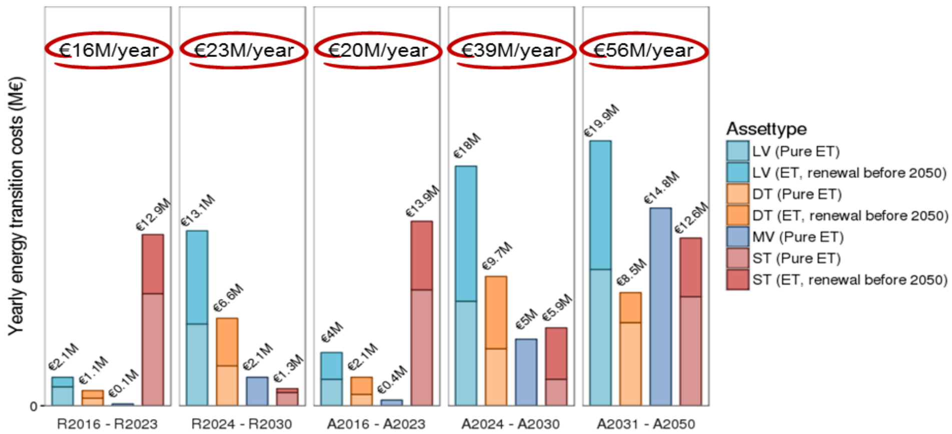
Major results at the regional Liander network distribution level

3. Options to meet the demand for flexibility due to the congestion of the power grid

The Liander regional grid analysis has assessed the potential benefits of addressing predicted grid congestion by deploying flexibility options rather than by network expansions. The major findings of this assessment are summarised below.

Benefits of deployment of flexibility as alternative for grid reinforcements
Based on the results of the ANDES model and the FLEXNET scenario cases, it is estimated that additional investments in grid reinforcements of 2 to 5% per year up to 2030 and about 7% per year in the period from 2030 to 2050 are required to prevent overloads in the Liander grid due to the increased deployment of sun PV, electric passenger vehicles (EVs) and household heat pumps (HPs). Given current annual grid investments in the Liander service area of, on average, € 750 million in 2012-2016, this corresponds to a cumulative grid reinforcement investment of € 1.0-1.5 billion up to 2050 (alternative scenario; see **Figure 16**).

Figure 16: Increase of average network investments due to the energy transition (phase 1 results)



In order to limit the required additional grid investments, a number of promising, flexibility-based overload mitigation measures is selected and assessed. In particular, five different types of *demand response* measures to mitigate grid overloads (congestion) have been analysed:

1. *Direct Load control (DLC)* i.e. energy management of EV and HP (e.g. smart charging) through a third party (e.g. the network operator or aggregator).
2. *Critical Peak Pricing (CPP)*. During high wholesale market prices or power system emergency conditions, the price for electricity is substantially raised for a specified time period.

3. *Time of Use Pricing (TOU)*. Typically this measure applies to usage over broad blocks of hours where the price for each period is predetermined and constant.
4. *Real Time Pricing (RTP)*. Pricing rates generally apply to usage on an hourly basis.
5. *Critical Peak Rebate (CPR)*. Similar to CPP, the price for electricity during these time periods remains the same but the customer is refunded at a predetermined value for any reduction in consumption.

In addition to demand response, other flexibility options analysed as the regional level to mitigate grid overloads include VRE curtailment – notably decentralised PV curtailment – and energy storage, in particular by means of (lithium ion) batteries at the household level or the distribution transformer (DT) level.

Grid overloads can be addresses by either flexibility-based mitigation measures or grid reinforcements (or a mix of both options). Overload mitigation measures can substantially reduce the capital expenditures (CAPEX) i.e. investments in grid reinforcements. In terms of CAPEX reduction, it is estimated that PV curtailment (assuming a 30% peak reduction in PV production) or time-of-use (TOU) pricing (assuming a 16% peak demand reduction) alone can save up to about € 250 million (cumulative) in energy transition related grid investments up to 2050 (in the alternative scenario). A combination of curtailment and TOU pricing can save up to € 700 million of these types of grid investments up to 2050 (see **Figure 17**). This € 700 million is an indication of the value of flexibility for network investment planning by Liander.

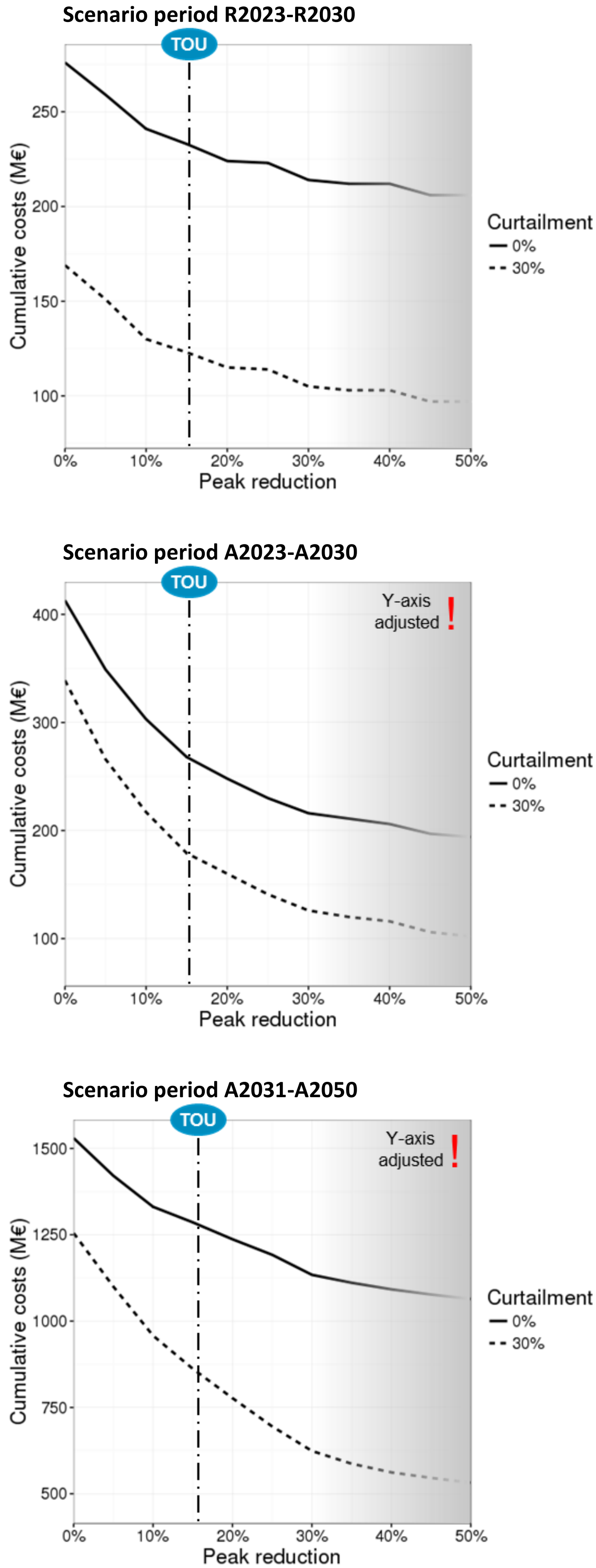
The effectiveness of PV curtailment versus demand response depends on the adoption levels of sun PV versus EVs and HPs. In the reference scenario (up to 2030), PV curtailment is more effective in reducing reinforcement costs than demand response, due to the fact that in this specific scenario, PV production creates more congestion problems than the adoption of EV and HP. The alternative scenario shows that the higher adoption of EV and HP increases the effectiveness of demand response significantly.

Net benefits of deployment of flexibility as alternative for grid reinforcements
The numbers provided above do not yet include additional costs required to implement and operate each of the selected mitigation measures. The net benefits of deployment of flexibility as an alternative for grid reinforcements are therefore significantly lower. Given estimates for additional costs, net benefits for PV curtailment, direct load control, and pricing mechanisms have been determined, as discussed below.

PV curtailment
The benefits of PV curtailment consist of an estimated 20% avoided ET grid reinforcement investments for the A2050 case i.e. € 300 million, but when taking into account the cost of 30% PV curtailment in terms of lost revenue, the net benefit is about half of this amount i.e. € 150 million.

The lost revenue on the wholesale market is calculated by estimating the lost energy in the A2050 scenario and multiplying this amount by the corresponding hourly APX price. Subsequently, the total lost revenue up to 2050 is obtained by linear interpolation between scenario cases. Similar to other overload mitigation measures, these amounts do not take into account additional grid losses as a result of deferred or avoided investments (which are estimated at € 55 million in A2050).

Figure 17: Reduction of cumulative grid investment costs during different scenario periods



Direct load control
Direct load control (DLC) can potentially avoid 13-30% of grid reinforcement investments in the alternative scenario i.e. € 200 million alone and € 450 million when combined with PV curtailment respectively. Assuming a linear development in cost (rough estimation), the total costs of implementation and operation will be about € 70 million without PV curtailment and about € 150 million with PV curtailment for the A2050 scenario. The net result of DLC would be about € 130 million without curtailment and about € 300 million with curtailment (including lost PV revenue) up to 2050 for the Liander service area at most. This is, on average, around 1% per year of the total grid investments in the Liander service area up to 2050.

These costs figures do not include a possible penalty for DSOs for not meeting contractual capacity (kW) agreements as well as costs of additional grid losses. Furthermore, the assumption is made that no additional investments are required in grid digitization/measurements besides the smart meter. On the other hand, since restoring power after an outage in a region with a high adoption of HPs and/or EVs can lead to high currents and overloads, investments in DLC might already be made for power restoration reasons, decreasing required DLC investments for congestion management purposes.

Pricing mechanisms
Pricing mechanisms (CPP, TOU, RTP, CPR) alone can potentially avoid up to 18% of grid reinforcement investments in the alternative scenario, while the combination with PV curtailment may result in savings of 48% of grid reinforcement investments. In absolute terms this amounts to € 275 million and € 725 million, respectively. For several reasons, however, the net savings of pricing mechanisms are likely to be smaller.

First of all, research shows that the percentage of peak reductions used in this analysis can only be achieved if local devices such as, for instance, washing machines can be automatically controlled. This requires investments from either consumers in home automation or from market participants in an IT platform, which controls devices in a certain area. Although part of the cost may be attributed to deployment of flexibility for portfolio optimization and balancing purposes, assuming pricing mechanisms do not levy any costs on deployment of flexibility for congestion management is a strong assumption.

Furthermore, the grid operator should have sufficient insight in the (near) real-time load in the controlled area to effectively use pricing mechanisms for congestion management. Smart metering may fulfil this requirement, although additional investments in grid digitization or measurements might be required.

In addition, grid losses which are expected to be higher for pricing mechanisms compared to grid reinforcement, have not been taken into account. According to Liander estimates, these grid losses may result in additional operational costs of € 55 million per year in the A2050 scenario.

Besides, the unpredictable behaviour of customers makes it unlikely that the indicated net benefits can be achieved in practice as grid operators will need some security margin in their grid design. Especially at the lower grid levels, the number of controlled devices will be limited and the risk of relying on pricing mechanisms to prevent overloads for DSOs is higher.

Considering the above, the net result of pricing mechanisms is estimated to be less than 1% per year of the total grid investments in the Liander service area.

Energy storage (batteries)
For energy storage, the benefits of the use of a battery system for mitigating overloads do not outweigh the costs. Relatively large battery capacities are required to mitigate overloads of distribution transformers (DTs). Given (i) the accompanying cost of a battery system, (ii) the required operational expenditures (OPEX), (iii) the additional energy losses, and (iv) the added complexity and, therefore, the higher operational risks, it is safe to assume that the use of a battery system at the distribution transformer (DT) level in comparison to DT reinforcement purely for the purpose of mitigating an overload is only economically feasible for a very limited number of cases at most. The use of a battery system might be more profitable in case the same system could provide other services such as for instance voltage support, energy trading, frequency support, or resilience/back up power.

Overall conclusions
In contrast with some earlier studies and expectations beforehand, based upon a comprehensive quantitative analysis the current study shows limited net benefits of deployment of flexibility solutions by DSO Liander in order to prevent traditional grid reinforcements. However, a rough comparison of the ANDES modelling results of Liander with modelling outcomes of DSO Stedin indicates more overloads in 2050 in the Stedin service area and, therefore, a higher demand for flexibility in this area. This difference in regional outcomes is partially due to differences in regional network topology, differences in input assumptions, notably on the allocation of technology adoption rates to grid levels, as well as to differences in regional/local load profiles.

Given the Liander analysis, some policy recommendations can be inferred. DSOs should be cautious in claiming flexibility for congestion management purposes as, *in general*, the scope and benefits of deploying flexibility for congestion management seems to be limited. Moreover, flexibility could have a higher value for purposes such as portfolio optimization or system balancing. Flexibility providers should be aware that generally flexibility has relatively a limited scope and limited net benefits for DSOs, implying no large payments for flexibility can be expected from network operators.

At the same time it should be noted that in *specific* (local) situations deploying flexibility for congestion management may offer a significant potential and relatively high net benefits for DSOs, resulting in a concomitant high value of flexibility and associated benefits for flexibility providers. In which type of situations and how frequently these situations could occur is a subject for further research.[3]

[3] See also the report of phase 3 of the FLEXNET project, focusing on the development of a societal framework for the trade-off between grid reinforcement versus deployment of flexibility for congestion management.

Key messages

National level

Cross-border trade becomes dominant flexibility option in future years but its size depends on available interconnection capacity as well as on the available potential and costs of alternative, domestic flexibility options.

In order to meet the rapidly growing demand for flexibility due to the variability of the residual load of the power system in the Netherlands up to 2050, cross-border power trade becomes the most important flexibility option in the coming years (decades), with shares ranging for this option from 65% to 74% of total annual flexibility needs in the period 2023-2050. As a result, power trade has a major impact on the business case of other, domestic options to meet the demand for flexibility by the Dutch power system, including the impact of (hourly variations in) power trade volumes and the related hourly fluctuations of domestic electricity prices. Due to these related volume and price effects of power trade, the business case and, hence, the size (share) of other, domestic flexibility options is lower accordingly (depending on the available potential and costs of these options). This impact, however, depends in particular on the assumptions made with regard to the optimal interconnection capacities across European countries, notably between the Netherlands and its neighbouring countries. However, even under more (very) restrictive interconnection assumptions, however, the share of power trade in total annual flexibility demand still amounts to approximately 40-65% in 2050.

Non-VRE power generation becomes less important to meet future flexibility needs but gas-fired units may remain import as back-up capacity

In the current situation (scenario R2015), power generation from conventional, non-VRE sources is the most dominant flexibility option to meet total annual flexibility needs due to the variability of the residual load of the Dutch power system (estimated at 2.2 TWh, aggregated per annum), in particular by (hourly changes in) power generation from gas (49%) and coal (42%), while the remaining share of these needs is addressed by (hourly variations) in power trade (9%). In the coming years (decades), however, the shares of these conventional power generation sources in the (rapidly growing) demand for flexibility declines steeply. Already in 2023, the share of gas falls to about 30% and of coal even to 5% (while the share of power trade increases to 65%). Under 'optimal' (i.e. 'least-cost') interconnection conditions, the share of gas in total annual flexibility needs in 2050 (estimated at about 15 TWh, aggregated per annum) declines further to less than 5% and of coal to less than 1% (while the share of power trade rises to 74%). Under very restrictive interconnection conditions, however, the share of gas becomes about 27% in 2050 and of coal some 2.4% (while the share of power trade becomes approximately 41%).

Curtailment of VRE power generation becomes a major flexibility option only far beyond 2030 depending to the availability of alternative options (in particular power trade and demand response)

Up to 2030, there is hardly or no curtailment of power generation from VRE sources (sun/wind) needed to balance (hourly) power demand and supply as the share of VRE output in total power demand is still manageable in almost all hours of the year. In 2050, however, - with a large share of potential VRE output in total power demand (80%) and a large number of hours (>3200) with a (large) VRE surplus – VRE curtailment becomes a major flexibility option. In that year, total VRE curtailment is estimated at about 26 TWh per annum, i.e. approximately 16-17% of total realised VRE power production. Under optimal (least-cost) interconnection conditions, the share of (hourly variations in) VRE curtailment in total annual flexibility needs due to the variability of the residual load amounts to some 20%, while under very restrictive interconnection conditions this share increases to approximately 28%.

Demand response has a large potential to meet future flexibility needs, but the role of demand curtailment is negligible

In general, there seems to a large potential to meet future flexibility needs of the Dutch power system by means of demand response, i.e. *shifting* part of (peak) power demand in a certain hour to another hour of the day, week, month, etc., either forwards or backwards. This applies in particular to (industrial) power demand functions that are expected to grow rapidly in the coming decades, such as power-to-gas (P2G), power-to-heat (P2H) or power-to-ammonia (P2A) but also to power demand by means of more smart (flexible) charging of electric vehicles (as all explored in the current study). In addition, there may be a substantial potential for demand response by other power demand functions in other sectors such as services or households (as explored at the regional network level; see below). This potential, however, may be harder to realise depending on the role of aggregators, price incentives, human behaviour, etc. On the other hand, the role of *demand curtailment* – i.e. *limiting* (peak) power demand in a certain hour (and, hence, demand is lost) – as a flexibility option is negligible, at least in the present study in which the value of lost load (VOLL) is set at a relatively high level of 3000 €/MWh.

Energy storage plays generally a limited role in meeting future flexibility needs of the power system (due to its relatively high costs) but in specific cases it may be more significant

The role of energy storage is generally limited to meet future flexibility needs (or at least generally less than what is sometimes expected or suggested in the literature). This applies in particular to longer-term, single ('pure') storage functions to address flexibility needs due to the variability of the residual load on the day-ahead market or, at the regional grid level, to using battery systems purely for congestion management reasons (see also below). The main reason is that the costs of these storage functions are generally high compared to alternative, amply available options such as power trade, demand response, VRE curtailment or – at the regional network level – grid reinforcement.

In specific cases, however, the role of energy storage to meet flexibility needs may be more significant. This applies, for instance, notably for providing short-cycle storage functions to meet flexibility/balancing needs due to the uncertainty ('forecast error') of the residual load on the intraday and balancing markets, in particular to provide primary/secondary power reserves (although on these markets storage also has to compete with alternative options while power reserve markets are usually relatively small, illiquid and/or uncertain).

In addition, energy storage becomes more attractive (profitable) if it is not the only – or primary – function of a technology and could be combined with providing other (more important) functions so that its costs can be shared or even covered primarily by these other functions and its benefits and revenues are broader and higher. Examples may include storage options such as power-to-gas (aimed primarily at reducing CO_2

emissions) or using EV batteries for storage functions (although the potential of these options to provide flexibility to the power system is likely higher through demand response than by energy storage).

Regional grid level

The net benefits of deploying large-scale flexibility options purely for congestion management in the Liander area are, *in general*, limited
In order to prevent overloads (congestion) in the Liander grid due to the increased deployment of sun PV, electric passenger vehicles (EVs) and household heat pumps (HPs) – as laid down in the FLEXNET scenario cases – *additional* investments in grid reinforcements are required of 2 to 5% per year up to 2030 and about 7% per year in the period from 2030 to 2050. Given current annual grid investments in the Liander service area of, on average, € 750 million in 2012-2016, this corresponds to a cumulative grid reinforcement investment of € 1.0-1.5 billion up to 2050 scenario.

In terms of capital investment savings (CAPEX), it is estimated that a mix of flexibility-based measures to mitigate grid overloads – notably deploying PV curtailment and demand response pricing mechanisms – can save up to about € 700 million (cumulative) in energy transition related grid investments up to 2050. This amount of € 700 million is an indication of the value of flexibility for network investment planning by Liander.

The amount of € 700 million mentioned above, however, does not yet include additional costs required to implement and operate the flexibility-based measures to mitigate grid overloads, such as lost PV revenues, additional grid losses, additional smart metering costs, higher risks, etc. Hence, the net benefits of deploying flexibility as an alternative for grid reinforcements are significantly lower. Moreover, flexibility could have a higher value for purposes such as portfolio and investment planning optimization or system balancing. Flexibility providers should be aware that generally flexibility has relatively a limited scope and limited net benefits for DSOs, implying no large payments for flexibility can be expected from network operators. Therefore, distribution systems operators (DSOs) should be cautious in claiming flexibility for congestion management purposes as, *in general*, the scope and benefits of deploying flexibility for congestion management seems to be limited.

It should be noted that the results have been calculated based on the current perspective on the future. Because of the many variables and assumptions, the rapid changing context and ever increasing complexity, modelling should become an integrated part of strategic decision making of the distribution system operators. This will enable a DSO to rapidly adjust their strategy based on the latest insights. In *specific* situations, however, deploying flexibility may offer a significant potential with a relatively high value and is therefore an important capability for any DSO

In specific situation (e.g., locally and/or temporarily), the deployment of flexibility measures to prevent or mitigate grid overloads – and, hence, to avoid or reduce investment costs in grid reinforcements – may offer a significant potential and relatively high value for DSOs, resulting in a concomitant high value of flexibility and associated benefits for flexibility providers. Other applications and opportunities besides congestion management which could be a reason for a DSO to deploy flexibility options include among others: local voltage support, system balancing, synergies groundwork with other infrastructural companies, black-out recovery. Moreover, a rough comparison of the Liander modelling results with modelling outcomes of DSO Stedin indicates more overloads in the Stedin service area and, therefore, a higher demand for flexibility in this area and, perhaps, a higher value (net benefits) of deploying flexibility as an alternative for grid reinforcements.

Energy storage: benefits of using battery system purely for congestion management do not outweigh costs

For energy storage at the regional grid level, the benefits of the use of a battery system for mitigating overloads do not outweigh the costs. Relatively large battery capacities are required to mitigate overloads of distribution transformers (DTs). Given (i) the accompanying cost of a battery system, (ii) the required operational expenditures (OPEX), (iii) the additional energy losses, and (iv) the added complexity and, therefore, the higher operational risks, it is safe to assume that the use of a battery system at the distribution transformer (DT) level in comparison to DT reinforcement purely for the purpose of mitigating an overload is only economically feasible for a very limited number of cases at most. The use of a battery system might be more profitable in case the same system could provide other services such as for instance voltage support, energy trading, frequency support, or resilience/back up power.

1

Introduction

The Netherlands is aiming at a more sustainable, low-carbon energy system. For the power system this implies (i) a larger share of electricity from variable renewable energy (VRE), in particular from sun and wind, (ii) a larger share of electricity in total energy use, i.e. a higher rate of 'electrification' of the energy system, and – as a result of these two trends – (iii) a higher need for flexibility and system integration.

Against this background, the overall objective of the FLEXNET project was to analyse demand and supply of flexibility of the power system in the Netherlands up to 2050 at the national and regional level. More specifically, the FLEXNET project consisted of three phases, each addressing a particular main question:

- *Phase 1 ('The demand for flexibility')*: what are the flexibility needs of a sustainable and reliable power system in the Netherlands up to 2050?
- *Phase 2 ('The supply of flexibility')*: which mix of robust flexibility options can meet the predicted flexibility needs in a socially optimal way?
- *Phase 3 ('Societal framework to trade-off grid reinforcement and deployment of flexibility')*: in which situations is deployment of flexibility a more attractive option than grid reinforcement to overcome predicted overloads of the power network?

The current report outlines the approach and major results of the second phase of the FLEXNET project. This phase has been conducted at two levels: (i) the national level, i.e. for the power sector in the Netherlands as a whole, and (ii) the regional level, i.e. at the regional power distribution network level of the Liander service area in the Netherlands.[4]

More specifically, the central questions of the second phase of the FLEXNET project regarding these two levels include:

- What are the major options to meet the demand for flexibility due to the variability and uncertainty of the residual load of the power system in the Netherlands over the period 2015-2050 (where residual load is defined as total power demand minus power generation from variable renewable energy, notably sun and wind)?

[4] The analysis at the national level was conducted by ECN (see particularly Chapters 2-4 of the current report), while the analysis at the regional level was carried out primarily by Alliander (see Chapter 5)

- What are the options and (net) economic benefits of deploying flexibility for congestion management rather than the traditional solution of grid reinforcement for mitigating network overloads, in particular at the Liander distribution network level up to 2050?

Definition and scope of flexibility supply options

In order to meet the demand for flexibility, the following supply options have been considered in the present study:

- *Power generation from (flexible) non-VRE sources*, including conventional sources – in particular (flexible) gas-fired power plants but also, to some extent, other conventional units (coal, nuclear) – as well as 'other RES-E' sources (i.e. besides sun/wind) such as hydro or biomass;
- *VRE curtailment*, i.e. limitation of peak power generation from VRE sources;
- *Demand curtailment*, i.e. limitation of peak power demand;
- *Demand response*, i.e. part of total demand in a certain hour is shifted to another hour of the day, week, month, etc., either forward or backwards.
- *Energy storage*, such as batteries, hydro pumped storage (HPS) or compressed air energy storage (CAES), including energy conversion/storage technologies such as power-to-gas (P2G), power-to-ammonia (P2A), etc.;
- *Power trade*, i.e. hourly variations in (net) imports/exports of electricity.

In principle, all flexibility supply options have been considered throughout the study. Some options, however, turned out to more important (and, hence, have received more attention), while other options appeared to be less or hardly important or even not viable (and, hence, have received less or hardly any attention). Moreover, some options turned out to be more relevant at the national level but less relevant at the regional grid level (or vice versa). In addition, some flexibility options are included and analysed more specifically by some of the models used, while other options are not or hardly analysed by these models (or taken as given; see below).

General approach of phase 2

In phase 1 of the FLEXNET project, we have distinguished between three main sources ('causes') of the need for flexibility of the power sector (R1, Section 2.1):

1. The demand for flexibility due to the *variability* of the residual power load, in particular due to the variability of power generation from VRE sources;
2. The demand for flexibility due to the *uncertainty* of the residual power load, notably due to the uncertainty (or lower predictability) of electricity output from VRE sources *('forecast error'*);
3. The demand for flexibility due to the *congestion* (overloading) of the power grid, resulting from the increase and changing profiles of electricity demand – due to the increase in electric vehicles, heat pumps, etc. – as well as the increase and changing profiles of power supply from VRE sources.

During phase 1, FLEXNET has considered all three types of flexibility demand mentioned above, although it was predominantly focussed on modelling and analysing the first and third type of flexibility and hardly on the second type, i.e. the demand for flexibility due to the uncertainty of the residual load.

During phase 2, we have considered and analysed the supply options to meet the three different types of flexibility demand. Similar to phase 1, however, phase 2 was also predominantly focussed on modelling and analysing the first and third type of flexibility and hardly on the second type. In particular, the following general approaches and tools have been used to analyse the supply options to meet the three different types of flexibility demand:

1. Options to meet flexibility needs due to the variability of the residual load have been analysed extensively at the national level of the Dutch power system over the period 2015-2050 by means of two models developed by ECN, i.e. COMPETES (an EU28+ electricity market model) and OPERA (an NL energy system model);
2. Options to meet flexibility needs due to the uncertainty of the residual load have been considered by means of a review of recent studies;
3. Options to meet flexibility needs due to the congestion of the power grid have been analysed thoroughly at the regional Liander distribution level by means of the Liander network model ANDES.

Report structure

Details of the abovementioned approaches and the major results achieved are discussed in the chapters below. More specifically, Chapters 2 and 3 discuss the methodology and major results of the national analysis of supply options to meet flexibility needs due to the variability of the residual load by means of the models COMPETES and OPERA, respectively. Chapter 4 outlines briefly the major findings of the literature review on the options to address the demand for flexibility due to the uncertainty of the residual load. Finally, Chapter 5 presents and discusses the approach and main outcomes of the regional analysis of the options to meet flexibility needs due to predicted, future congestion of the Liander power distribution network.

2

Options to meet flexibility needs due to the variability of the residual load (i): COMPETES modelling results

This chapter presents and discusses the methodology and major results of the national analysis of supply options to meet the demand for flexibility due to the variability of the residual load in the Dutch power system up to 2050 by means of the COMPETES model. More specifically, first Section 2.1 outlines briefly the COMPETES modelling approach (while more details are provided in Appendix A and Appendix B of the current report). Subsequently, following the discussion of the results of phase 1 of FLEXNET (see R1, Chapter 3), Section 2.2 presents the COMPETES modelling results related to the trends in the so-called '*residual supply*' (opposed to 'residual load' or 'residual demand') defined as total power supply minus power generation from VRE sources (sun/wind). Section 2.3 discusses the modelling results related to the trends in the hourly variations ('ramps') of the residual supply, i.e. the supply of flexibility for the Dutch power system over the years 2015-2050. In addition, Section 2.4 presents some other relevant modelling results, in particular referring to hourly electricity prices and total annual costs of the Dutch power system up to 2050. Finally, in Section 2.5 we conclude this chapter with a summary of the main findings of the COMPETES modelling outcomes.

2.1 COMPETES modelling approach

In order to determine and analyse supply options to meet flexibility needs due to the variability of the residual load in the Dutch power system up to 2050, the following two models have been used successively:

1. *COMPETES*, i.e. the EU28+ electricity market model developed by ECN.[5] Major advantages of this model are that it includes (i) detailed information on (flexible) generation technologies in the Netherlands, and (ii) interconnection capacities and power trade relationships across all EU28+ countries, thereby enabling to include and analyse electricity trading among these countries as a major flexibility option for the Dutch power system. A drawback of COMPETES is that it includes little or no inputs on other, domestic flexible options such as demand response and energy storage by means of power-to-gas (P2G), power-to-heat (P2H), power-to-ammonia (P2A), etc.
2. *OPERA,* i.e. the NL energy system model developed also by ECN. A major advantage of this model is that it includes detailed technological and socioeconomic information of all sectors and (flexible) technology options of the Dutch energy system as a whole, including P2G, P2H, P2A, etc. As a result, OPERA enables to make a more detailed, integrated optimisation analysis of the energy system in the Netherlands. A drawback of the model is, however, that it is restricted to the Dutch energy system and has no (trading) links with foreign countries.

Due to the characteristics of the models mentioned above, we have first used the COMPETES model to determine and analyse (hourly) power trade between the Netherlands and neighbouring EU countries as well as other, domestic flexibility options such as the deployment of flexible generation units or the curtailment of VRE power generation. Subsequently, we have used the COMPETES modelling output on hourly power trade volumes as fixed input profiles into the OPERA model in order to further analyse the potential role of other, domestic flexibility options, in particular energy storage and demand response by means of energy conversion technologies such as P2G, P2H, P2A, etc.

Whereas the current chapter further discusses the approach and results of the COMPETES modelling analysis on flexibility options, the next chapter considers the follow-up assessment of these options by means of the OPERA model.

Brief COMPETES model description

COMPETES is a power optimization and economic dispatch model that seeks to minimize the total power system costs of the European power market whilst accounting for the technical constraints of the generation units, the transmission constraints between European countries as well as the transmission capacity expansion and the generation capacity expansion for conventional technologies. The model consist of two major modules that can be used to perform hourly simulations for two types of purposes:

- A transmission and generation capacity expansion module in order to determine and analyse least-cost capacity expansion with perfect competition, subject to a set of power system constraints;
- A unit commitment and economic dispatch module to determine and analyse least-cost unit commitment (UC) and economic dispatch with perfect competition, subject to an even wider set of power system constraints (for further details, see Appendix A).

5 The expression 'EU28+' refers to the fact that the COMPETES model covers all present 28 EU Member States as well as some non-EU countries, i.e. Norway, Switzerland and the Balkan countries.

The COMPETES model covers all present 28 EU Member States and some non-EU countries (i.e., Norway, Switzerland, and the Balkan countries) including a representation of the cross-border transmission capacities interconnecting these European countries. The model has time steps of one hour. In this study, the target (focal) years of the FLEXNET scenario cases are optimised over all 8760 hours per annum.

For a more detailed description of the general characteristics of the COMPETES model, see Appendix A of the current report, while a more specific explanation of the major assumptions and inputs used by COMPETES to determine the outcomes of the FLEXNET scenario cases is provided in Appendix B

Modelling steps
The COMPETES modelling approach consists of the following steps (for details, see both Appendix A and Appendix B):

1. Insert output of phase 1 of the FLEXNET project, i.e. the power demand and VRE supply profiles, as input of the COMPETES model during phase 2 of the project;
2. Expand FLEXNET scenarios from the Dutch level to the EU28+ level;
3. Determine the baseline scenario – including hourly demand profiles, hourly VRE supply profiles, installed generation and transmission capacities, fuel and CO_2 prices, etc. – as a starting point for running the capacity investment module of COMPETES;
4. Run the capacity investment module in order to calculate the balance of installed generation capacity (new capacity versus decommissioning of existing capacity) and of installed cross-border transmission (interconnection) capacity for the respective FLEXNET scenario cases;
5. Run the unit commitment (UC) dispatch module – including the capacity results of the investment module – in order to determine the modelling output in terms of power generation, trade, electricity prices, system costs, supply of flexibility options, etc.

Table 1: Overview of COMPETES modelling runs for the benefit of the FLEXNET scenario cases

	Reference scenario			Alternative scenario		
Focal years	Generation investments	Transmission investments	Unit commitment	Generation investments	Transmission investments	Unit commitment
2015[a]			✓			
2023[b]	✓		✓	✓		✓
2030	✓		✓	✓	✓	✓
2050[c]				✓	✓	✓

✓ = Module run performed.

a) The alternative scenario does not include the focal year 2015.
b) Only decommissioning of generation units.
c) The reference scenario does not include the focal year 2050.

Table 1 presents an overview of the COMPETES modelling runs in order to determine the outcomes of the FLEXNET scenario cases. It shows, for instance, that in the reference scenario for 2015 (R2015) only the unit commitment (UC) model was run (as both the installed generation and interconnection capacities are assumed to be fixed in R2015). On the other hand, in the alternative scenario cases for 2030 and 2050 (A2030 and A2050) both the capacity investment module and the unit commitment module of COMPETES were run successively.

Modelling outputs

The COMPETES model calculates the following main outputs for the EU28+ as a whole as well as for the individual EU28+ countries and regions:

- Investments in cross-border transmission (interconnection) capacities (capacity expansion module output).
- Investments in conventional generation capacities (capacity expansion module output);
- The allocation of power generation and cross-border transmission capacity;
- Hourly and annual power generation mix – and related emissions – in each EU28+ country and region;
- The supply of flexibility options, including power generation, power trade, energy storage and VRE curtailments
- Hourly competitive electricity prices per country/region;
- Power system costs per country/region.

The specific outcomes of the COMPETES modelling runs of the FLEXNET scenario cases are presented and discussed in the sections below.

2.2 Trends in residual power supply, 2015-2050

This section presents and discusses the COMPETES modelling results referring to the trends in the so-called '*residual supply'* of the Dutch power system over the period 2015-2050 (where 'residual supply' – as opposed to 'residual load' or 'residual demand' – is defined as total power supply minus VRE power generation). In particular, it analyses the constituent components of this residual supply and the related supply options to meet the demand for flexibility due to the variability of the residual load (as analysed during the first phase of FLEXNET).

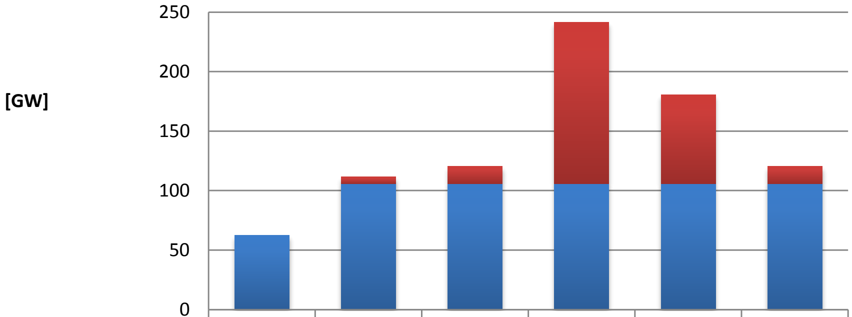
More specifically, this section presents and discusses the COMPETES modelling results with regard to trends up to 2050 in the following issues:

- *Interconnection capacity* (in the EU28+ as a whole and in the Netherlands in particular; Section 2.2.1);
- *Generation capacity* (in the EU28+ as a whole and in the Netherlands in particular; Section 2.2.2);
- *Generation output mix* (in the EU28+ as a whole and in the Netherlands in particular; Section 2.2.3).
- *Curtailment of VRE power generation* (in the Netherlands only; Section 2.2.4);
- *Curtailment of power demand* (in the Netherlands only; Section 2.2.5);
- *Energy storage* (in the EU28+ countries, including the Netherlands; Section 2.2.6);
- *Power trade* (by the Netherlands; Section 2.2.7);
- *Electricity balances* (including net residual power balances, for the Netherlands only; Section 2.2.8);
- *Residual supply* (including a distinction between hours with a VRE shortage and hours with a VRE surplus, for the Netherlands only; Section 2.2.9).

2.2.1 Interconnection capacity

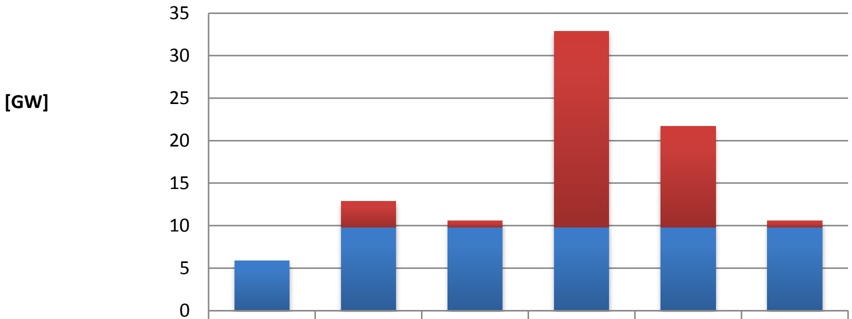
Figure 18 presents the trend in total interconnection capacity in the EU28+ as a whole over the period 2015-2050, while **Figure 19** shows a similar trend for the Netherlands only. These figures make a distinction between baseline capacity and new transmission capacity. The baseline interconnection capacity is similar to the current capacity (in 2015) and the projected increase in this capacity up to 2030 as laid down in the most recent Ten Year Network Development Plan (TYNDP) of ENTSO-E (2016). The new transmission capacity is the additional interconnection capacity calculated by the COMPETES model in order to meet the optimal interconnection capacity in the respective FLEXNET scenario cases (i.e. the interconnection capacity resulting in the lowest total system costs across the EU28+).[6]

Figure 18: Total interconnection capacity in the EU28+, 2015-2050



	R2015	R2030	A2030	A2050 (100%)	B2050 (50%)	C2050 (0%)
New transmission capacity	0	6	15	135	75	15
Baseline capacity (TYNDP2016)	62	106	106	106	106	106

Figure 19: Total interconnection capacity in the Netherlands, 2015-2050



	R2015	R2030	A2030	A2050 (100%)	B2050 (50%)	C2050 (0%)
New transmission capacity	0.0	3.1	0.7	23.1	11.9	0.7
Baseline capacity (TYNDP2016)	5.9	9.8	9.8	9.8	9.8	9.8

[6] The methodology to estimate additional cross-border transmission (interconnection) investments – and the related investment costs – is explained in Appendix A, notably Section A.3. The installed interconnection capacity of the Netherlands in the baseline scenario, 2015-2030, is clarified in Appendix B, in particular in Section B.2. Finally, Appendix C presents and discusses in some more details the expansion of the interconnection capacities across individual EU28+ countries in the scenario cases A2030, A2050 and C2050.

Figure 18 shows that the baseline interconnection capacity in the EU28+ increases from 62 GW in 2015 to 106 GW in 2030. For A2030, the new (additional) transmission capacity is estimated at 15 GW, while for A2050 this figure amounts to 135 GW. For the Netherlands, the baseline interconnection capacity increases from 5.9 GW in 2015 to 9.8 GW in 2030, whereas the additional transmission capacity is estimated at 0.7 GW in A2030 and 23.1 GW in A2050 (see **Figure 19**).

So, for both the EU28+ as a whole and for the Netherlands in particular the COMPETES model calculates a large increase in the optimal interconnection capacity up to 2050. For two reasons, however, this capacity increase may be overestimated. Firstly, COMPETES includes the investment costs of the additional interconnection capacity, in particular the costs of the cables – depending on the average distance between the nodal point of the countries concerned – as well as the costs of the converter stations at each end of the cable (for details, see Appendix A). COMPETES, however, does not include possible additional costs of expanding the domestic transmission and distribution system that may be required to meet the increase in the interconnection capacity. Secondly, in practice, some expansions of interconnection capacity are hard to realise due to lengthy administrative procedures, conflicting interests between and within countries concerned, social acceptance issues, etc.

Hence, in addition to the 'least-cost optimum' interconnection capacity in A2050, we have defined two alternative scenario cases for 2050 in which the respective expansion of interconnection capacity is assumed to be much lower. More specifically, in scenario case B2050 we have assumed that the increase in interconnection capacity is only 50% of the increase in interconnection capacity between A2030 and A2050, whereas in C2050 this increase is assumed to be 0% (i.e. the interconnection capacity in C2050 is assumed to be similar to the capacity in A2030 (see **Figure 18** and **Figure 19**).[7]

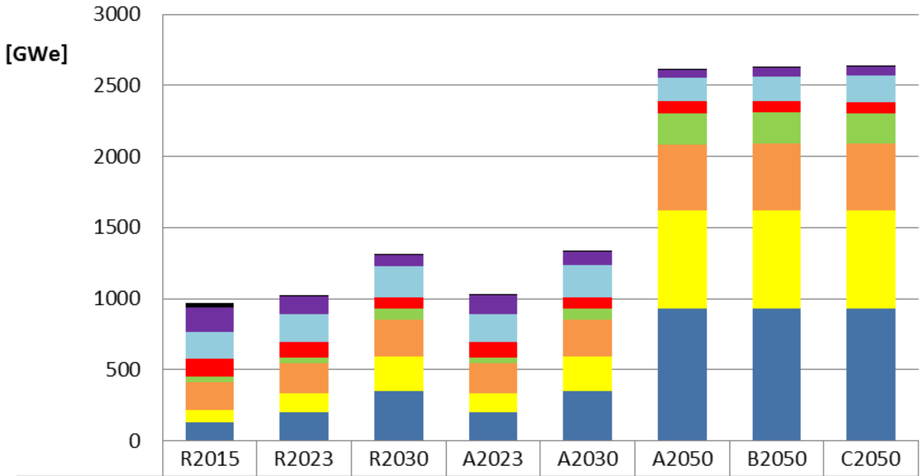
A major advantage of having three 2050 scenario cases with three different levels of interconnection capacity is that it enables to show the impact and sensitivity of this variable for the outcomes of the other variables discussed below, in particular for the supply of flexibility options for the Dutch power system up to 2050.

2.2.2 Generation capacity

Figure 20 presents the installed power generation capacity mix in the EU28+ over the years 2015-2050, while **Figure 21** provides a similar picture of the generation capacity mix in the Netherlands. For the EU28+, **Figure 20** shows that the installed capacity of electricity from all renewable energy sources (RES-E) increases rapidly from almost 450 GW in R2015 to more than 2300 GW in A2050. This increase in RES-E capacity applies in particular to electricity from *variable* renewable energy (VRE, i.e. sun/wind) but also to hydro and other RES-E (including biomass, geo-energy, etc.). Conventional capacity, however, declines significantly over the period 2015-2050, notably of oil, coal and nuclear. Gas-fired capacity in the EU28+ initially increases from 191 GW in R2015 to 227 GW in A2030 but declines to 166 GW in A2050.

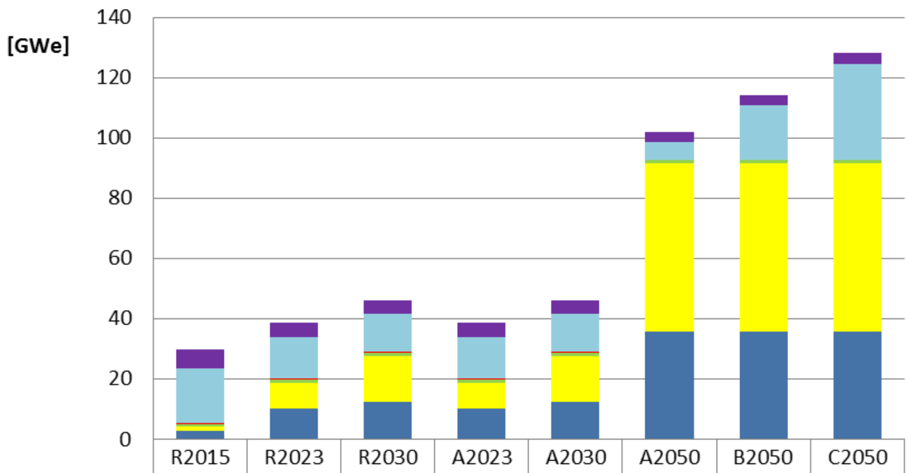
7 **Figure 18** shows that the new transmission capacity increases from 15 GW in A2030 to 135 GW in A2050, i.e. an increase by 120 GW. In B2050, we assume that the new (additional) interconnection capacity increases by only 50% of this amount (60 GW), i.e. from 15 GW in A2030 to 75 GW in B2050.

Figure 20: Installed power generation capacity in the EU28+, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Oil	30	1	2	8	6	2	2	2
Coal	173	128	76	128	93	59	62	60
Gas	191	198	221	203	227	166	175	187
Nuclear	125	106	80	106	80	80	80	80
Other RES-E	34	38	75	38	75	221	220	217
Hydro	201	217	266	217	266	463	464	464
Solar	87	128	243	128	243	690	690	690
Wind	127	204	347	204	347	933	933	933

Figure 21: Installed power generation capacity in the Netherlands, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Coal	6.6	4.6	4.6	4.6	4.6	3.4	3.4	3.4
Gas	17.8	13.7	12.4	13.7	12.4	5.6	17.9	31.8
Nuclear	0.5	0.5	0.5	0.5	0.5	0.0	0.0	0.0
Other RES-E	0.6	1.2	1.2	1.2	1.2	1.1	1.1	1.1
Solar	1.5	8.6	15.1	8.6	15.1	56.1	56.1	56.1
Wind	3.0	10.1	12.4	10.1	12.4	35.7	35.7	35.7

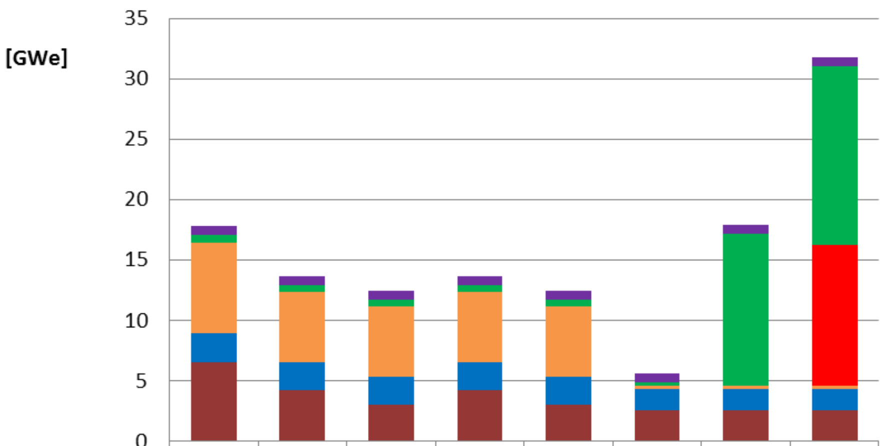
For the Netherlands, **Figure 21** shows that the installed RES-E capacity increases even faster than for the EU28+ as a whole, i.e. from about 5 GW in 2015 to approximately 93 GW in 2050. This increase applies notably to sun and wind and, to a lesser extent, to other RES-E. On the other hand, similar to the EU28+, conventional capacity declines significantly from 25 GW in R2015 to 9 GW in A2050. This decline applies not only to coal and nuclear but also to gas, including both centralised gas capacity and decentralised gas capacity (CHP).

A striking feature of **Figure 21**, however, is that the total gas-fired capacity in the Netherlands increases rapidly from nearly 6 GW in scenario case A2050 to almost 18 GW in B2050 and even to approximately 32 GW in C2050. This increase results from the decrease in interconnection capacity from 33 GW in A2050 to 22 GW in B2050 and to about 11 GW in C2050 (**Figure 19**). This implies that in the Netherlands the decrease in cross-border transmission capacity is more than compensated by an increase in the domestic, gas-fired generation capacity.[8]

Gas-fired generation capacity mix

Figure 22 provides a slightly more detailed picture of the gas-fired generation capacity mix in the Netherlands over the various scenario cases. It shows that the decentralised CHP capacity declines significantly from 6.6 GW in 2015 to 3.1 GW in 2030 and to 2.6 GW in 2050. Centralised CHP capacity, however, remains rather stable over the years 2015-2030 at a level of approximately 2.3 GW, but declines slightly to 1.8 GW in 2050.

Figure 22: Installed gas-fired power generation capacity in the Netherlands, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Other gas	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Gas GT	0.7	0.5	0.5	0.5	0.5	0.3	12.6	14.8
Gas CCGT + CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.6
GAS CCGT	7.5	5.8	5.8	5.8	5.8	0.2	0.2	0.2
Gas CHP cental	2.4	2.3	2.3	2.3	2.3	1.8	1.8	1.8
Gas CHP decentral	6.6	4.3	3.1	4.3	3.1	2.6	2.6	2.6

[8] Note that, on balance, the relationship between interconnection capacity and generation capacity is far less outspoken in the EU28+ as a whole. More specifically, whereas the interconnection capacity for the EU28+ decreases from more than 240 GW in A2050 to about 120 GW in C2050 (**Figure 18**), the conventional generation capacity increases only from approximately 307 GW to 329 GW, respectively (**Figure 20**).

The installed capacity of gas turbines (GTs) is rather small and declines from 0.7 GW in R2015 to 0.3 GW in A2050. In B2050, on the contrary, GT capacity jumps to almost 13 GW and to 15 GW in C2050 due to the restriction of the increase in the interconnection capacity of the Netherlands over the years 2030-2050 by 12 GW in B2050 and 1 GW in C2050, compared to 23 GW in A2050 (see **Figure 19**).

The installed capacity of Combined Cycle Gas Turbines (CCGTs) is quite substantial in R2015 (7.5 GW) but declines slightly to a stable level of 5.8 GW over the years 2023-2030. In all three 2050 scenario cases, however, it drops to 0.2 GW. On the other hand, CCGT combined with carbon capture and storage (CCS) becomes highly significant in C2050 (almost 12 GW) due to a mix of a relatively high CO_2 price – i.e. more than 90 €/tCO_2 (see Appendix B, **Figure 96**) – and a relatively low (restricted) interconnection capacity, resulting in relatively high, but rather volatile electricity prices (see Section 2.4.1 below).[9]

2.2.3 Generation output mix

Figure 23 presents the power generation output mix in the EU28+ as a whole over the years 2015-2050 (both in TWh and as a percentage of total output), whereas **Figure 24** shows a similar picture for the Netherlands only. In the EU28+, the share of all renewable energy sources (RES-E) in total electricity production increases from 33% in R2015 to approximately 90% in A2050. For *variable* renewable sources only (wind/sun), this share increases from about 10% to 68%, respectively. The shares of conventional generation in the EU28+, on the contrary, decline accordingly. Coal-fired generation decreases from almost 30% in R2015 to less than 1% in A2050, nuclear from 27% to 8% and gas-fired electricity production from 11% to 1%, respectively (although in C2050 the share of gas in the power mix is somewhat higher – i.e. almost 4% - than in A2050; see **Figure 23**).

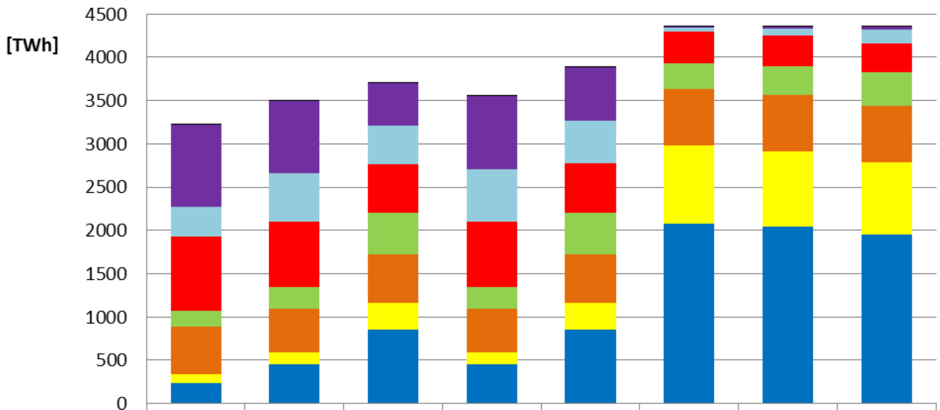
For the Netherlands, the trends in the power generation show a similar pattern (**Figure 24**). Whereas total electricity production doubles in absolute terms from 96 TWh in R2015 to 185 TWh in A2050, the share of sun and wind in total output increases from 9% to 87%, respectively. On the other hand, for nuclear the share in total power generation declines from 4% in R2015 to zero in A2050, for coal from 31% to 0.2% and for gas from 51% to 12%, respectively.

In C2050 – i.e. a scenario case with substantial less interconnection capacity and, hence, less power trade (see below) – electricity production in the Netherlands is significantly higher (222 TWh) than in A2050 (185 TWh). This increase in total output (+37 TWh) is almost fully met by an increase in gas-fired generation only, which rises steeply from 22 TWh in A2050 to 58 TWh in C2050 (i.e. by 36 TWh). As a result, the share of gas in total electricity production increases from 12% in A2050 to 26% in C2050. On the other hand, whereas the total output of electricity from sun and wind in A2050 and C2050 remains the same in absolute terms (160 TWh), the share of VRE generation in total power production declines from 87% to 72%, respectively (**Figure 24**).

[9] **Figure 22** mentions also the category 'Other gas'. This includes coke oven gas (internal combustion) as well as derived gas (both CHP and internal combustion). The total installed capacity of other gas is relatively small but quite stable at 0.7 GW over the years 2015-2050.

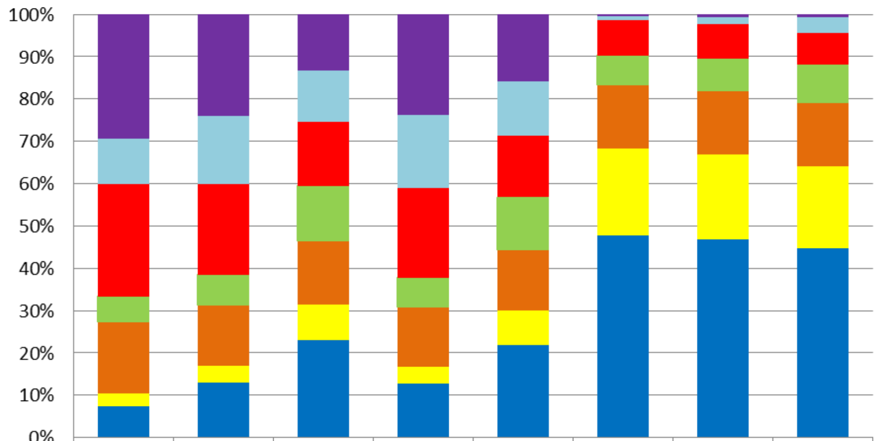
Figure 23: Power generation mix in the EU28+, 2015-2050

[in TWh]



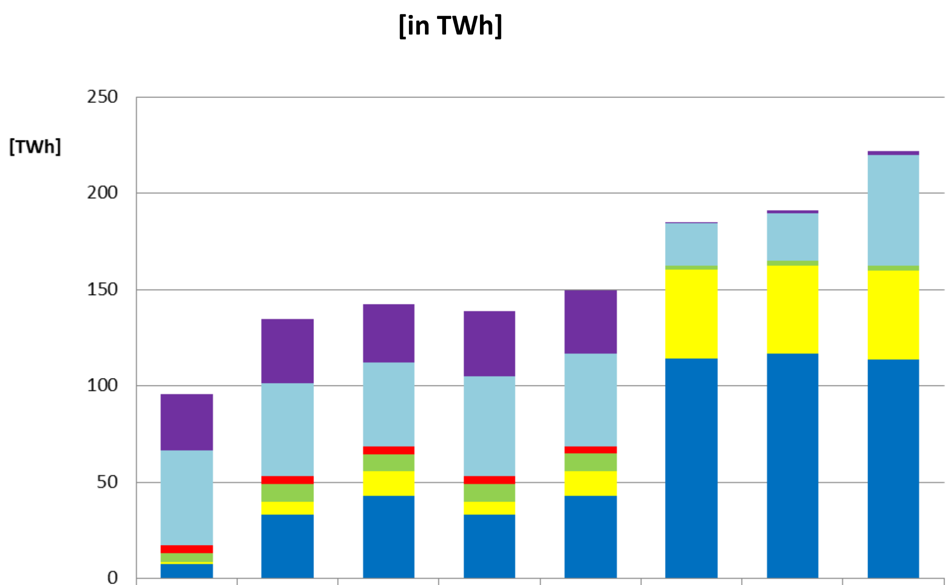
	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Oil	0.0	0.0	0.1	0.2	0.1	0.0	0.0	0.0
Coal	951	836	494	846	613	16	27	34
Gas	344	562	442	613	496	46	71	161
Nuclear	855	751	564	751	565	359	355	323
Other RES-E	192	249	477	249	481	303	337	388
Hydro	550	501	556	501	557	654	653	653
Sun	96	141	318	141	318	896	870	843
Wind	237	454	849	454	849	2081	2038	1948

[in %]

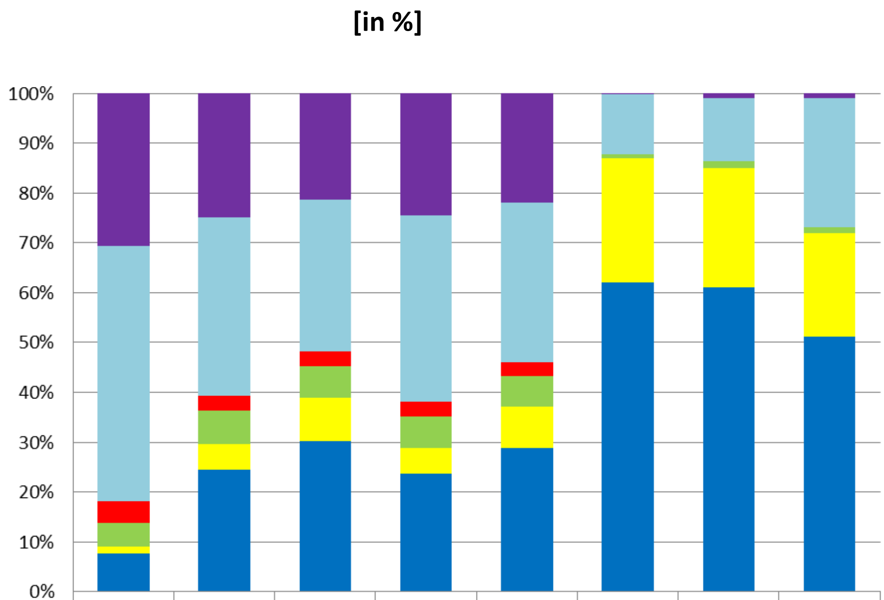


	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Coal	29.5%	23.9%	13.3%	23.8%	15.8%	0.4%	0.6%	0.8%
Gas	10.7%	16.1%	12.0%	17.3%	12.8%	1.1%	1.6%	3.7%
Nuclear	26.5%	21.5%	15.3%	21.1%	14.6%	8.2%	8.2%	7.4%
Other RES-E	6.0%	7.1%	12.9%	7.0%	12.4%	7.0%	7.7%	8.9%
Hydro	17.1%	14.3%	15.0%	14.1%	14.4%	15.0%	15.0%	15.0%
Sun	3.0%	4.0%	8.6%	4.0%	8.2%	20.6%	20.0%	19.4%
Wind	7.3%	13.0%	22.9%	12.8%	21.9%	47.8%	46.8%	44.8%

Figure 24: Power generation mix in the Netherlands, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Coal	29	33	30	34	33	0	2	2
Gas	49	48	43	52	48	22	24	58
Nuclear	4	4	4	4	4	0	0	0
Other RES-E	5	9	9	9	9	2	2	3
Sun	1	7	12	7	12	46	46	46
Wind	7	33	43	33	43	114	116	114

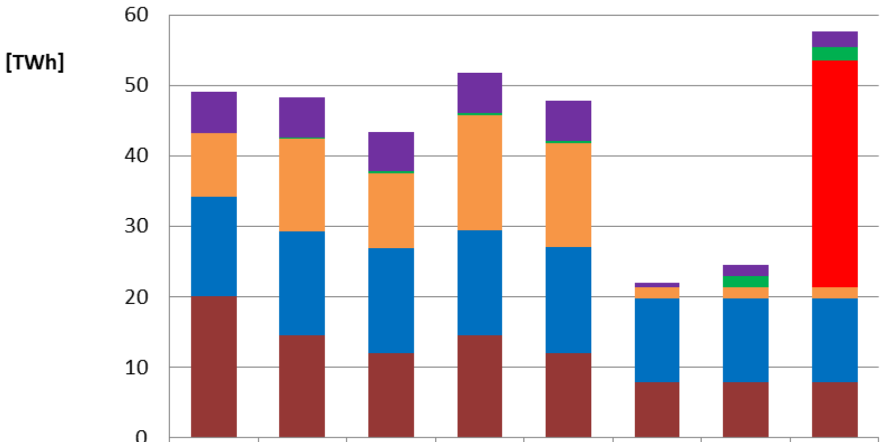


	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Coal	30.7%	24.8%	21.4%	24.6%	22.0%	0.2%	0.9%	0.9%
Gas	51.2%	35.9%	30.5%	37.3%	32.0%	12.0%	12.8%	26.0%
Nuclear	4.3%	3.0%	2.8%	2.9%	2.7%	0.0%	0.0%	0.0%
Other RES-E	4.8%	6.7%	6.3%	6.5%	6.2%	0.9%	1.2%	1.2%
Sun	1.3%	5.3%	8.7%	5.1%	8.3%	24.9%	24.1%	20.7%
Wind	7.7%	24.4%	30.2%	23.7%	28.8%	62.0%	61.0%	51.2%

Gas-fired power generation in the Netherlands

Figure 25 presents a more detailed picture of the gas-fired power generation mix in the Netherlands across the various FLEXNET scenario cases up to 2050. Electricity output from decentral CHP declines steadily from 20 TWh in R2015 to 8 TWh in the 2050 scenario cases, whereas generation output from central CHP initially increases slightly from 14 TWh in R2015 to 15 TWh in the 2030 scenario cases but declines to 12 TWh in the 2050 scenario cases. Similarly, power production from CCGTs initially increases significantly from 9 TWh in R2015 to 16 TWh in A2023, subsequently declines slightly to 15 TWh in A2030 and, finally, drops steeply to 2 TWh in both A2050 and C2050. Production from other gas-fired installation remains stable at 6 TWh over the period R2015-A2030 but drops to 1 TWh in A2050 (although the level of installed 'other gas' capacity remains the same – at 0.7 GW – over the period R2015-A2050 as a whole (compare **Figure 22** and **Figure 25**).

Figure 25: Gas-fired power generation mix in the Netherlands, 2015-2050



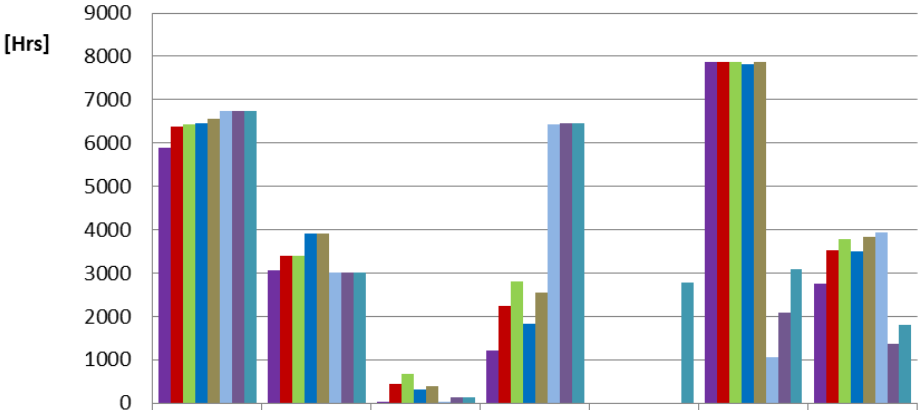
	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Other gas	5.7	5.7	5.7	5.7	5.7	0.8	1.5	2.2
Gas GT	0.0	0.2	0.2	0.4	0.2	0.0	1.6	1.9
Gas CCGT + CCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	32.2
Gas CCGT	9.1	13.1	10.7	16.3	14.8	1.5	1.5	1.5
Gas CHP cental	14.0	14.7	14.9	14.9	15.1	12.0	12.0	12.0
Gas CHP decentral	20.1	14.6	12.0	14.6	12.0	7.8	7.8	7.8

The increase in total gas-fired power generation by 36 TWh in C2050, compared to A2050, is almost fully met by the newly installed CCS CCGT plant, i.e. by 32 TWh, and to a lesser extent by the increased GT capacity (by 2 TWh). Note that the capacity of the newly installed CCS CCGT plant amounts to 12 GW in C2050, whereas the capacity of GT generation increases from 0.3 GW in A2050 to almost 15 GW in C2050 (**Figure 22**). Although the installed capacity of GT in C2050 is, hence, somewhat higher than the capacity of CCS CCGT, the output by GT is C2050 is substantially lower than the production from CCS CCGT, i.e. 1.9 TWh and 32 TWh, respectively. This implies that the number of full load hours (FLHs) of the installed GT capacity is substantially lower than of the installed CCS CCGT capacity (as further discussed below).

Full load hours of gas-fired power generation

Figure 26 presents the resulting full load hours (FLHs) of gas-fired power generation in the Netherlands over the years 2015-2050.[10] The FLHs of central CHP – including industrial ‘must-run’ installations – are relatively high and even increase steadily from almost 5900 in R2015 to more than 6700 in the 2050 scenario cases. On the other hand, the FLHs of decentral CHP are, on average, significantly lower (3000-4000 hours). More specifically, the FLHs of decentral CHP initially increase from almost 3100 in R2015 to more than 3900 in the 2030 scenario cases but drop to approximately 3000 in the 2050 scenario cases.

Figure 26: Full load hours of gas-fired power generation in the Netherlands, 2015-2050



	Gas CHP cental	Gas CHP decentral	Gas GT	Gas CCGT	Gas CCGT + CCS	Other gas	Total (average)
R2015	5889	3065	7	1219		7884	2750
R2023	6380	3410	438	2249		7882	3541
A2023	6435	3410	684	2799		7884	3794
R2030	6466	3917	314	1841		7821	3495
A2030	6551	3917	402	2544		7884	3847
A2050	6733	3021	21	6437		1065	3935
B2050	6742	3021	130	6450		2093	1365
C2050	6749	3021	127	6463	2770	3089	1813

The FLHs of gas turbines (GTs) are relatively low and instable, i.e. they increase from only 7 FLHs in R2015 to about 680 in A2023 but fall to 21 in A2050 (and to 127 in C2050). The FLHs of Combined Cycle Gas Turbines (GCCGTs), excluding CCS, increases substantially over the period considered, i.e. from about 1200 in R2015 to 2200 in R2023, 2500 in A2030 and even to more than 6400 in A2050 (as well as in B2050 and C2050).

For the newly installed CCCGT capacity in C2050, including CCS, the number of FLHs amount to almost 2800. FLHS of the other (industrial) gas-fired installations are relatively high and stable over the years R2015-A2030 – at, on average, 7900 hours per annum – but decline steeply to approximately 1100 hours in A2050 (and recover to 3100 hours in C2050).

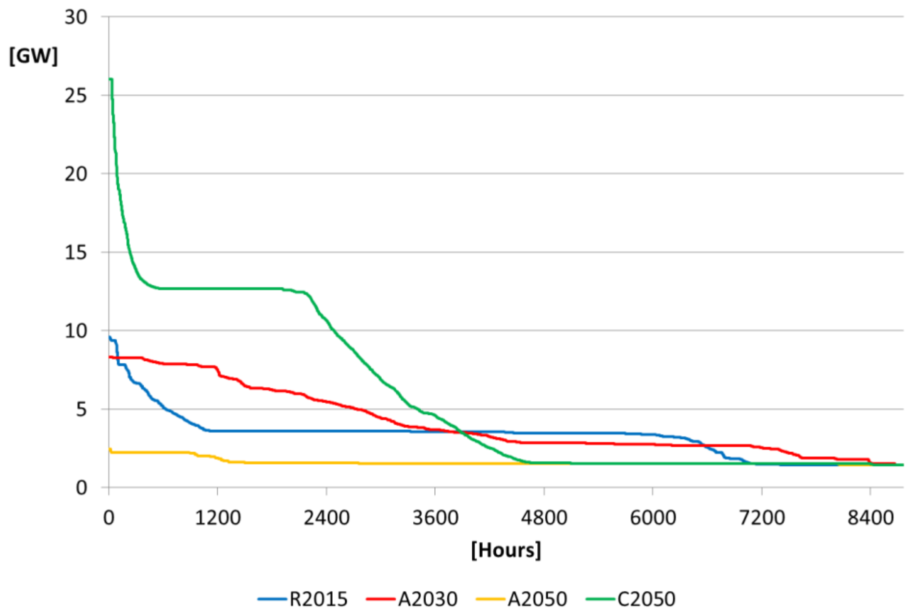
[10] Full load hours are simply defined – and calculated – as the total output of a technology (in TWh; see, for instance, **Figure 25**) divided by its installed capacity (in GW; see **Figure 22**).

Overall, the average number of FLHs of the total gas-fired generation capacity in the Netherlands increases steadily from almost 2800 in R2015 to more than 3900 in A2050, but declines steeply to 1800 in C2050 and even to 1400 in B2050. The increase in average FLHs over the years R2015-A2050 is largely due to the increase in the role of gas CHP in the generation mix (with a relatively high number of FLHs), whereas the decrease in average FLHs in B2050 (and C2050) is mainly due to the relatively high increase in the installed capacity of GTs (with a relatively low number of FLHs).

Duration curves of gas-fired power generation

Figure 27 presents the duration curves of gas-fired power generation in some selected scenario cases over the period 2015-2050. It shows that, in each case, there is a minimum base load ('must- run') output – notably of CHP installations – of approximately 1.4 GW throughout the year. The peak and mid load output of gas-fired power generation, however, varies widely both within and between the selected scenario cases. For instance, in R2015, the maximum (peak) gas-fired output amounts to 9.6 GW but falls significantly to a rather stable mid-load level of 3.5 GW and, subsequently, to a base load ('must-run') level of 1.4 GW. In A2050, however, the maximum (peak) gas-fired production amounts to only 2.5 GW and declines smoothly to a stable mid/base load level of approximately 1.4-1.5 GW.

Figure 27: Duration curves of gas-fired electricity output in the Netherlands in selected scenario cases, 2015-2050

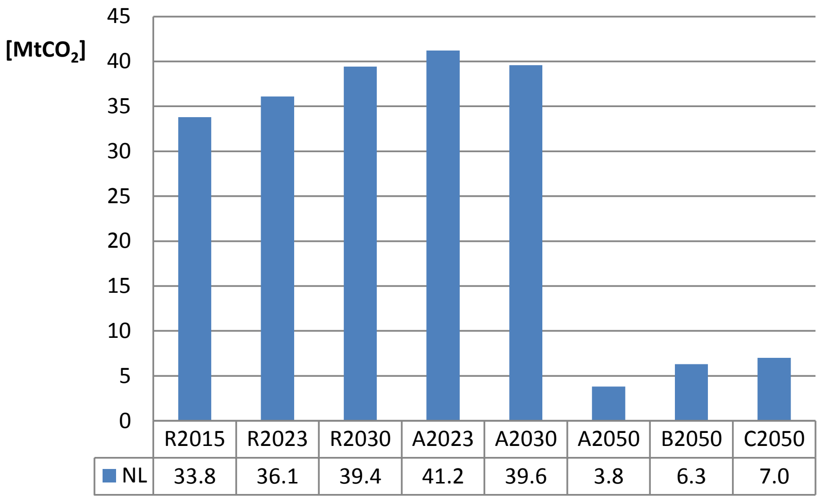


Finally, in C2050, on the contrary, the duration curve of the gas-fired output once again shows a quite different pattern, compared to A2050, at least up to the first 4500 hours of the duration curve (see **Figure 27**). More specifically, in C2050, the maximum (peak) gas-fired output amounts to 26 GW ('hour 1'), falls steeply to a stable mid load level of almost 13 GW (hours 600-2000) and, subsequently, declines smoothly to a mid/base load level of approximately 1.5 GW (hours 4500-8760).

The findings above indicate that there is a clear trade-off between the availability (and use) of cross-border interconnection capacity and the deployment of (domestic) gas-fired capacity. In A2050, with a relatively large interconnection capacity for the Netherlands (i.e. 33 GW; see **Figure 19**), the need for and deployment of gas-fired generation capacity is relatively low and stable, implying that a predominant share of this capacity is deployed for a large number of running hours. On the other hand, in C2050 – with a relatively small interconnection capacity (i.e. 11 GW) – the need for, and deployment of peak and upper mid-load gas-fired capacity is relatively high and declines steeply, implying that a major share of this capacity is deployed for a small number of running hours.

CO_2 emissions of power generation
Figure 28 presents the total CO_2 emissions of power generation in the Netherlands over the years 2015-2050. A striking feature is that these emissions increase up to A2030, compared to 2015, despite a significant increase of power production from sun and wind over the period 2015-2030. The main reason for this increase is that total power production increases significantly over this period, including a small increase in fossil-fuelled power generation, notably from coal (see **Figure 24**).

Figure 28: CO_2 emissions of power generation in the Netherlands, 2015-2050



In A2050, however, power sector CO_2 emissions decline substantially to 3.8 $MtCO_2$, i.e. a CO_2 reduction by 89% over the years 2015-2050. In C2050, on the contrary, CO_2 emissions of the Dutch power system amount to 7 $MtCO_2$ (due to the higher coal- and, notably, gas-fired electricity output). Compared to R2015, this corresponds to a CO_2 reduction of 79% in C2050.[11]

2.2.4 Curtailment of VRE power generation

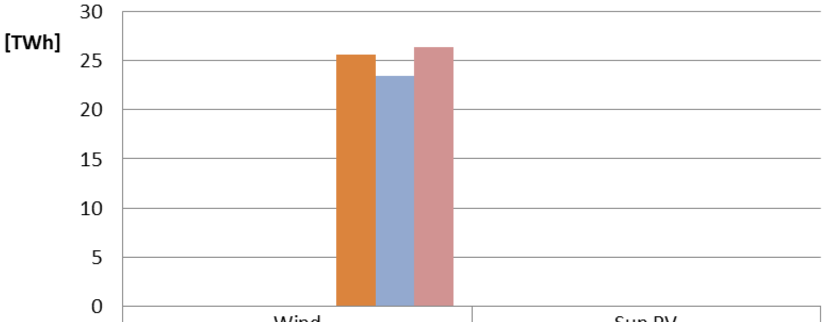
The generation data discussed above – notably the data presented in **Figure 23** and **Figure 24** – do not consider explicitly the possible curtailment of power generation from

[11] For the EU28+ as a whole, the CO_2 reduction amounts to 98% in A2050 – compared to R2015 – and to 95% in C2050.

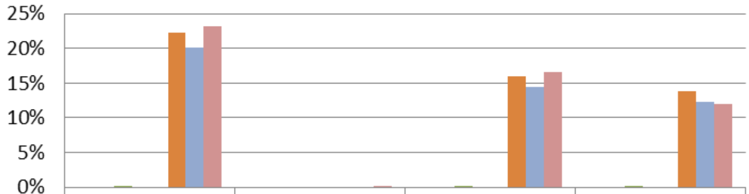
VRE sources such as sun or wind. Curtailment of VRE generation, however, is a major flexibility option to balance (the hourly variation of) electricity demand and supply, notably in those hours with a large share of VRE output in total demand/supply - or, more relevant, with a (large) negative residual load (i.e. a VRE surplus; see also Section 2.2.9 below).

Figure 29 presents the curtailment of VRE power generation in the Netherlands in both absolute and relative terms across all FLEXNET scenarios over the period 2015-2050. It shows that up to 2030 there is no VRE curtailment. In A2050, the curtailment of power generation from sun PV is still zero, but from wind it amounts to almost 26 TWh, i.e. 22% of realised (curtailed) wind production, 16% of total VRE output and 14% of total electricity generation by the Dutch power system in A2050.

Figure 29: Curtailment of VRE generation in the Netherlands in absolute and relative terms, 2015-2050



	Wind	Sun PV
R2015	0.0	0.0
R2023	0.0	0.0
R2030	0.0	0.0
A2023	0.0	0.0
A2030	0.0	0.0
A2050	25.5	0.0
B2050	23.5	0.0
C2050	26.4	0.1



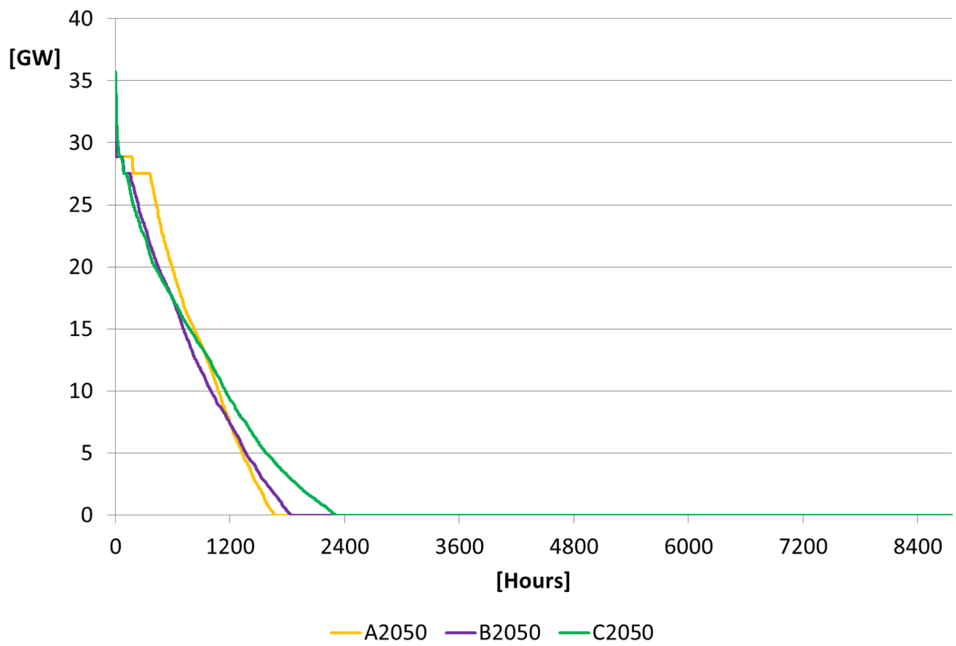
	Wind curtailment as % of wind production	Sun PV curtailment as % of sun PV production	VRE curtailment as % of VRE production	VRE curtailment as % of total production
R2015	0.0%	0.0%	0.0%	0.0%
R2023	0.0%	0.0%	0.0%	0.0%
R2030	0.1%	0.0%	0.1%	0.0%
A2023	0.0%	0.0%	0.0%	0.0%
A2030	0.0%	0.0%	0.0%	0.0%
A2050	22.3%	0.0%	15.9%	13.8%
B2050	20.1%	0.0%	14.4%	12.3%
C2050	23.2%	0.1%	16.6%	11.9%

The major reasons why curtailment of power generation from wind is particularly high in A2050 (rather than from sun PV) are (i) that usually it is easier – and cheaper – to curtail power generation from (centralised) wind than from (decentralised) sun PV and, notably in the Netherlands, (ii) generation output from wind is generally significantly higher than from sun PV, in particular in hours with a high share of VRE output – or, more relevant, with a relatively high VRE surplus.

In C2050 (with 0% interconnection capacity expansion, compared to A2030), VRE curtailment in the Netherlands is slightly higher, compared to A2050 (100% interconnection capacity expansion). More specifically, curtailment of sun PV generation in C2050 amounts to 0.1 TWh and of wind generation to more than 26 TWh , i.e. 0.1% of realised sun PV production and 23% of realised wind production, and – for total VRE curtailment – almost 17% of total VRE production (**Figure 29**).

In contrast to the Netherlands, sun PV curtailment in the EU28+ as a whole is far more substantial (up to 2050), whereas total VRE curtailment increases more significantly in C2050 (compared to A2050). More specifically, PV curtailment in the EU28+ amounts to almost 110 TWh in A2050 (i.e. 12% of realised PV production) and increases to more than 160 TWh in C2050 (19% of realised PV production). Total VRE curtailment amount to about 430 TWh in A2050 (15% of total realised VRE output) and rises to almost 620 TWh in C2050 (i.e. 22% of total realised VRE output and 14% of total power generation in the EU 28+).

Figure 30: Duration curves of VRE curtailment in the Netherlands in the 2050 scenario cases



Duration curves of VRE power generation

Figure 30 presents the duration curves of VRE curtailment in the Netherlands for the three 2050 scenario cases. The surface below these curves corresponds to the amounts of total VRE curtailment in the respective scenario cases (in TWh, as indicated in **Figure 29**). **Figure 30** shows that in some hours the amount of VRE curtailment can be quite substantial. For instance, in A2050 the maximum hourly VRE curtailment amounts to 30 GW and in both B2050 and C2050 even to 36 GW. In addition, **Figure 30** indicates that the number of hours in which VRE generation is curtailed is limited (even in the 2050 scenario cases with a large number of hours with a VRE surplus; see Section 2.2.9 below). For instance, in A2050 this number amounts to less than 1700, in B2050 to about 1850 and in C2050 to approximately 2300 (whereas the amount of hours with a VRE surplus amounts to more than 3200 in all three 2050 scenario cases; see Section 2.2.9 below, notably **Table 4**).

Due to the curtailment of VRE generation, curtailed – i.e. realised – VRE output may be substantially lower than uncurtailed (potential) VRE output. **Table 2** shows that, for instance, in A2050 (and C2050) the potential (uncurtailed) VRE output amounts to 186 TWh, whereas the realised VRE output – including VRE curtailment – is substantially lower (160 TWH). As a percentage of total power demand, uncurtailed VRE output amounts to 80% in A2050 (and C2050), whereas curtailed VRE output is significantly lower (i.e. 69% of total power demand).

Table 2: Curtailed versus uncurtailed VRE output related to total electricity demand in the Netherlands, 2015-2050

		Reference scenario			Alternative scenario				
	Unit	**R2015**	**R2023**	**R2030**	**A2023**	**A2030**	**A2050**	**B2050**	**C2050**
Uncurtailed (potential) VRE output	TWh	8.6	40.0	55.5	40.0	55.5	186.0	186.0	186.0
VRE curtailment	TWh	0.0	0.0	0.0	0.0	0.0	25.5	23.5	26.4
Curtailed (realised) VRE output	TWh	8.6	40.0	55.4	40.0	55.5	160.4	162.5	159.5
Total electricity demand	TWh	112.5	113.5	115.6	125.5	153.1	232.8	232.8	232.8
VRE output as % of total power demand:									
Uncurtailed VRE output	%	8%	35%	48%	32%	36%	80%	80%	80%
VRE curtailment	%	0%	0%	0%	0%	0%	11%	10%	11%
Curtailed VRE output	%	8%	35%	48%	32%	36%	69%	70%	69%

2.2.5 Curtailment of power demand

In addition to curtailment of VRE power generation, curtailment of power demand can also be a socially optimal flexibility option to balance electricity demand and supply, notably in those hours where the residual load is exceptionally high and non-VRE supply capacity – including import capacity – is insufficient to meet this residual demand. **Table 3** presents a summary overview of some data on demand curtailment in all scenario cases up to 2050. It shows that in the reference scenario there is no demand curtailment at all, while in the alternative scenario it is restricted to the 2030 and 2050 cases.

Table 3: Demand curtailment in all scenario cases, 2015-2050

		Reference scenario			Alternative scenario				
	Unit	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Number of hours with demand curtailment	[#hrs]	0	0	0	0	4	2	6	6
Maximum hourly demand curtailment	[GW]	0	0	0	0	1.5	1.0	2.1	9.8
Total demand curtailment (p.a.)	[GWh]	0	0	0	0	2.5	1.3	4.7	17.1
Value of lost load (VOLL)	[€/MWh]	3000	3000	3000	3000	3000	3000	3000	3000
Total value of lost load	[M€]	0	0	0	0	7.6	3.8	14.1	51.4

More specifically, in the alternative scenario the number of hours with demand curtailment is limited, varying from two hours in A2050 to six hours in B2050 and C2050, whereas the maximum demand curtailment per hour ranges from 1.0 GW in A2050 to 9.8 GW in C2050. Overall, total annual demand curtailment is relatively low (compared to total annual demand), varying from 1.3 GWh in A2050 to 17 GWh in C2030 (i.e. <0.01% of total demand).

In the COMPETES model, the value of lost load (VOLL) – i.e. the value of curtailed power demand – is set at 3000 €/MWh. As a result the total values of lost load (demand curtailment) varies from € 3.8 million in A2050 to € 51 million in C2050 (see bottom line of **Table 3**).

To conclude, in specific hours demand curtailment can be a socially optimal flexibility option to balance electricity demand and supply. In the FLEXNET scenario cases, however, the role of demand curtailment is very limited. Therefore, we will not further consider and include demand curtailment as a flexibility option in the rest of the current report.

Demand response
In addition to demand *curtailment* (in which power demand is *reduced* and, hence, *lost* in a certain hour by a certain amount), a related flexibility option is demand *response* (in which part of total demand in a certain hour is *shifted* to another hour of the day, week, month, etc., either forwards or backwards). Demand response has not been modelled and analysed by means of COMPETES, but has been included as part of the OPERA modelling analysis (see Chapter 3 below).

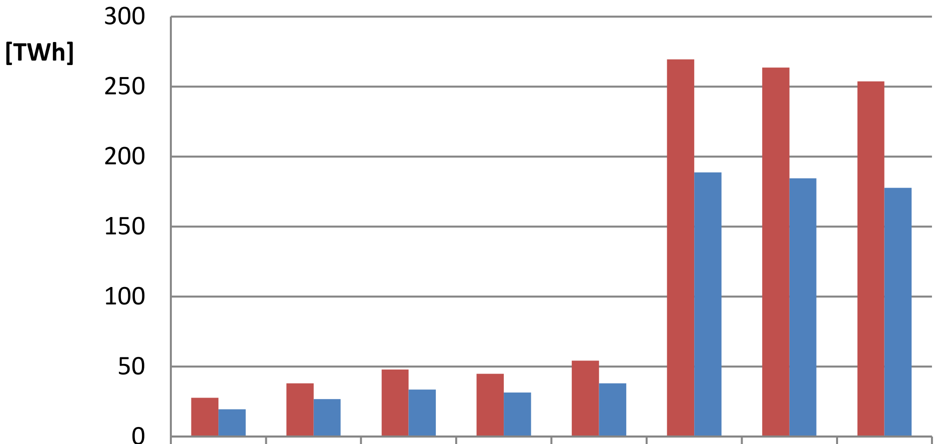
2.2.6 Energy storage

As outlined in Appendix A, for the purpose of providing flexibility on timescales of an hour and more in sufficient volumes, the COMPETES model focuses mainly on the bulk electricity storage technologies such as hydro pumped storage (HPS) and compressed air energy storage (CAES). These electricity storage technologies are modelled to operate such that they maximize their revenues by charging and discharging electrical energy within a day. By doing so, they are able to increase or decrease system demand for electricity and contribute to the flexibility for generation-demand balancing. The amount of the power demanded and supplied in the charge and discharge processes and the duration of these processes depend on the characteristics of the storage technology such as efficiency losses and power/energy ratings which are input to the model.

In the baseline scenario of the COMPETES model, storage capacity refers to hydro pumped storage (PS) only. Investments in new storage capacity – including both hydro PS and CAES – are, in theory, possible but, in practice, generates too low revenues (see Appendix B, notably **Figure 92** and Section B.7). Hence, in the COMPETES FLEXNET scenario cases, electricity storage is restricted to hydro power storage on a daily cycle only.

Figure 31 presents a summary overview of the hydro power storage activities in the EU28+ as a whole over the years 2015-2050. It shows that charging hydro power increases almost tenfold from 28 TWh in R2015 to 270 TWh in A2050, whereas discharging hydro power rises from 19 TWh to 190 TWh, respectively.[12]

Figure 31: Hydro power storage in the EU28+, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Charge	28	38	48	45	54	269	264	254
Discharge	19	27	33	31	38	189	184	178

In A2050, hydro power charging corresponds to about 40% of total hydro power generation output and to approximately 6% of total power production in the EU28+. In A2050, however, almost 80% of hydro PS activities is restricted to six EU28+ countries/regions, i.e. Spain, France, Norway, Germany, Austria and the Balkan region. On the other hand, there are five EU28+ countries – including the Netherlands – which do not deploy any hydro PS activities themselves over the years 2015-2050. Therefore, (hydro) power storage in the Netherlands is not included as a flexibility option in the further COMPETES-FLEXNET analyses below (although indirectly the Netherlands may benefit from hydro PS as a flexibility option at the EU28+ level through its power trade

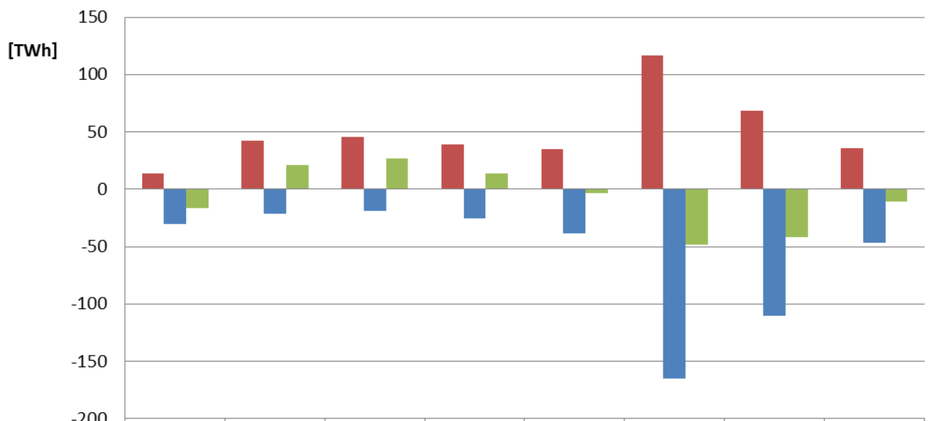
12 The difference between charging and discharging refers to physical energy storage losses.

relations with other, neighbouring EU28+ countries, including Norway, Germany and France; see Section 2.3.4 below).[13]

2.2.7 Power trade

Figure 32 presents an overview of the aggregated power trade flows of the Netherlands in the scenario cases over the years 2015-2050. In most hours of the year the Netherlands is both exporting electricity to (some) neighbouring countries and importing electricity from (other) neighbouring countries. Net power trade – either net imports or net exports – may vary, however, significantly from hour to hour but also, aggregated over the year as a whole, between the scenario cases considered. **Figure 32** shows, for instance, that in R2015 total power imports amount to approximately 31 TWh and total power exports to 14 TWh, resulting in net imports of 17 TWh. In A2050, however, total electricity imports increase to 165 TWh, whereas exports rise to 117 TWh, leading to a net import position of 48 TWh.

Figure 32: Power trade by the Netherlands, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Exports	13.8	42.5	45.9	38.9	35.1	116.8	68.6	35.6
Imports	-30.5	-21.2	-19.2	-25.5	-38.8	-165.0	-110.4	-46.6
Net exports	-16.7	21.3	26.7	13.5	-3.6	-48.2	-41.7	-11.0

Note: A negative sign for net exports actually implies net imports.

The increase in trade volumes in A2050, compared to R2015, results from several factors, including in particular (i) the increase in total power demand in the Netherlands (and the EU28+ as a whole; see **Table 2** and Appendix B, **Figure 95**), (ii) the increase in total installed VRE capacity and the resulting increase in (the highly variable) VRE output, both in the Netherlands and across the EU28+ as a whole (see **Figure 20**, **Figure 21**, **Figure 23**, and **Figure 24**, as well as the FLEXNET phase 1 report, Chapter 3), and (iii) the increase in the (assumed, optimal) interconnection capacity between the

[13] For a recent, more detailed analysis by means of the COMPETES model of large-scale balancing with Norwegian hydro power in the future European electricity market, see Van Hout et al. (2017). Note that energy storage as a flexibility option will be considered further in the present report when discussing the OPERA modelling results (Chapter 3) as well as the ANDES modelling results (Chapter 5).

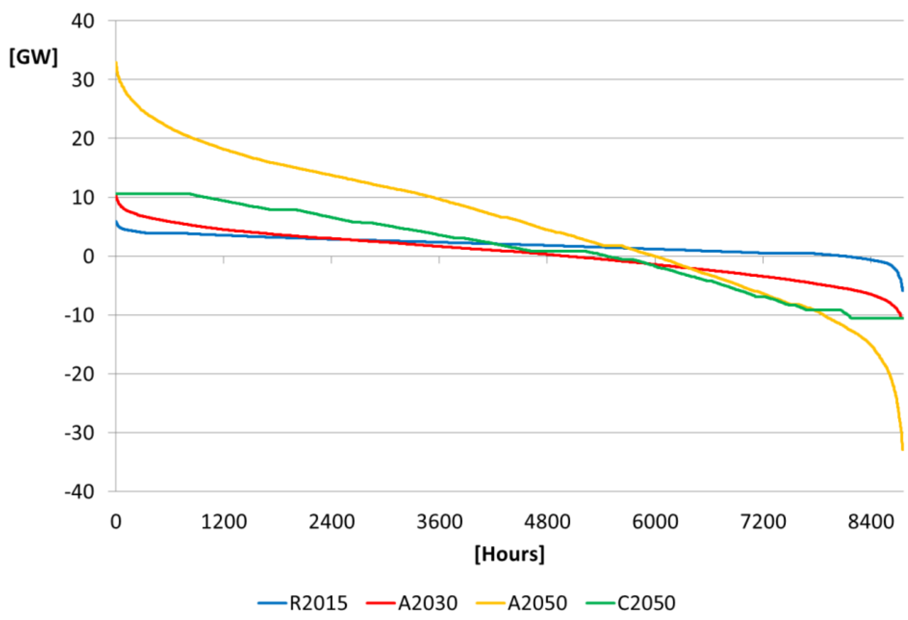
Netherlands and its neighbouring countries (and across the EU28+ as a whole; see **Figure 18** and **Figure 19**).[14]

In case the assumed interconnection is much lower than in A2050, the resulting power trade flows are lower accordingly. For instance, in C2050 the interconnection capacity of the Netherlands amounts to 11 GW, compared to 33 GW in A2050 (**Figure 19**). As a result, (gross) electricity imports of the Netherlands in C2050 amount to 47 TWh and (gross) exports to 36 TWh, implying a net import position of 11 TWh (compared to – as noted above – 165 TWh, 117 TWh and 48 TWh, respectively, in A2050; see **Figure 32**).

Power trade duration curves

Figure 33 presents the duration curves of the net hourly power trade of the Netherlands in some selected scenario cases, 2015-2050. It shows that the trade volumes – either net imports or net exports – varies between the interconnection capacity of the Netherlands in the respective scenario cases. For instance, in A2050 net hourly power trade varies between +33 GW (imports) to -33 GW (exports) whereas in C2050 it varies between +11 GW and -11 GW, respectively (similar to the interconnection capacities in these scenario cases; see **Figure 19**).

Figure 33: Duration curves of net hourly power trade by the Netherlands, 2015-2050



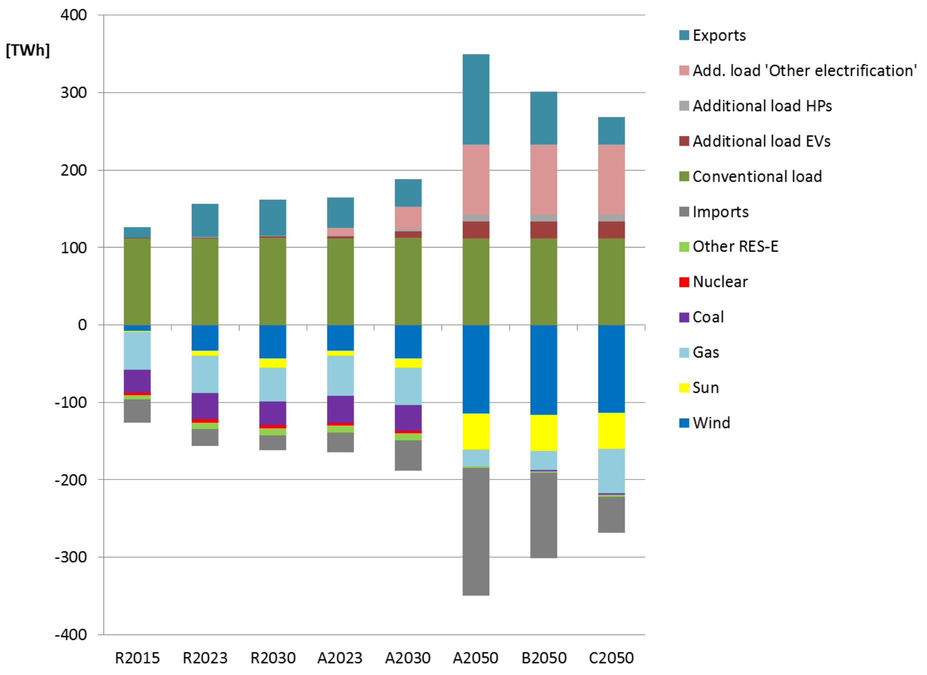
The maximum interconnection capacities, however, apply generally to a few hours of the year only, whereas in most hours trade volumes are significantly lower than these maximum capacities. This applies particularly for A2050 (and A2030). Note, however, that in C2050 – where interconnection capacity is restricted to the A2030 level – power trade is limited to the maximum interconnection capacity over a substantial number of hours (see both ends of the C2050 duration curve in **Figure 33**).

[14] Note, however, that the (hourly) volatility of VRE output is often not (fully) simultaneously across the EU28+ countries, implying that in many hours VRE output is relatively high in some countries but relatively low in other countries, resulting in large trade flows across these two types of countries, notably in cases with a high VRE penetration and a high interconnection capacity across EU28+ countries, such as in A2050 (see also Section 2.3.4 below).

2.2.8 Electricity balances

Figure 34 presents the total electricity balance of the Netherlands in all FLEXNET scenario cases up to 2050. Above the X-axis, **Figure 34** shows the demand side of the electricity balance, including its constituent components, i.e. cross-border exports of electricity and the four elements of domestic power demand analysed and discussed in the report of the first phase of the FLEXNET project: (i) conventional load, (ii) additional load by electric passenger vehicles (EVs), (iii) additional load by household heat pumps (HPs), and (iv) additional load by other means of electrification, such as power-to-gas (P2G), power-to-heat (P2H), power-to-ammonia (P2A), etc. (see R1, Chapters 2 and 3).

Figure 34: Electricity balance of the Netherlands, 2015-2050

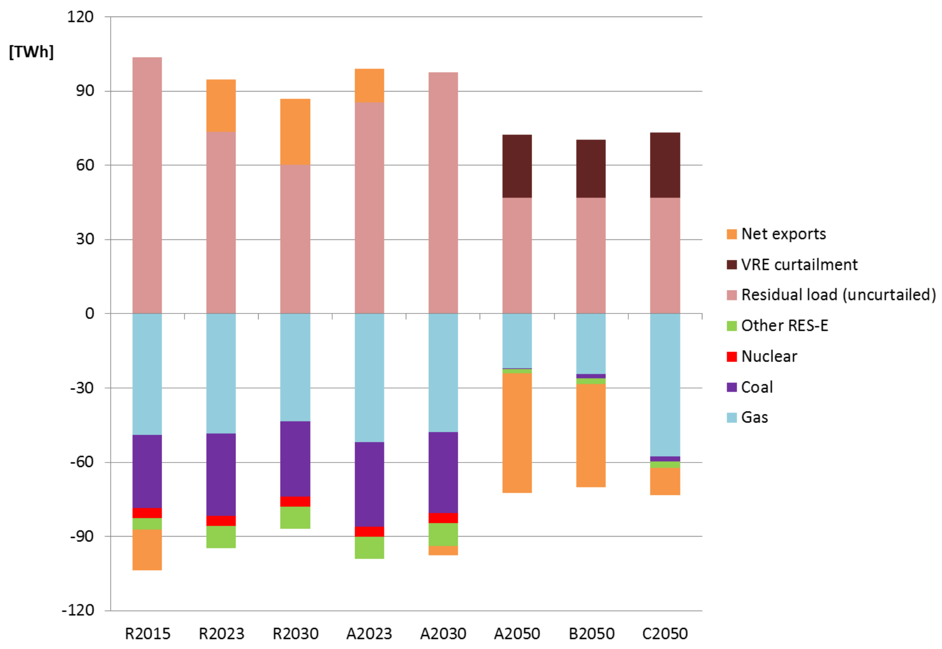


Below the X-axis, **Figure 34** presents the supply side of the electricity balance in the Netherlands, including its constituent components, i.e. cross-border imports of electricity and the six sources of domestic power generation discussed in Section 2.2.3 above: (i) wind, (ii) sun, (iii) other RES-E, (iv) gas, (v) coal, and (vi) nuclear.

Net residual power balance

Figure 35 presents the so-called '*net residual power balance*' of the Netherlands in all scenario cases up to 2050. Compared to the electricity balance presented in **Figure 34** – as discussed above – the net residual power balance differs in two respects. Firstly, it does not show total (gross) exports and total (gross) imports of electricity over a year but only the net annual trade position (i.e. either net exports or net imports). Secondly, it does not show VRE generation output and (the constituent components of) total power load but only domestic residual load and the four sources of domestic residual supply, i.e. non-VRE power generation from (i) coal, (ii) gas, (iii) nuclear, and (iv) non-variable renewable energy sources such as biomass and geothermic energy (labelled as 'other RES-E').

Figure 35: Net residual power balance of the Netherlands, 2015-2050



In the phase 1 report of FLEXNET, we have defined residual load as total power demand minus generation output from VRE sources, notably from sun and wind (see R1, Chapters 2 and 3). In this report (R1), however, we did not consider the (flexibility) option of VRE curtailment (as discussed in Section 2.2.4 above). Hence, the definition of residual load in the phase 1 report (R1) did not include possible VRE curtailment and actually referred to *uncurtailed* (potential) VRE output and, hence, to *uncurtailed* residual load (i.e. residual load, excluding VRE curtailment).

In case there is no VRE curtailment – as in scenario cases R2015 up to A2030 (**Figure 29**) – uncurtailed residual load is equal to curtailed residual load and can be simply called 'residual load' (as defined above). In case, however, there is VRE curtailment – as in the 2050 scenario cases – uncurtailed residual load is not equal to curtailed residual load and, hence, *curtailed* residual load should be redefined as '*uncurtailed residual load plus VRE curtailment*' or, put differently, *uncurtailed* residual load as '*curtailed residual load minus VRE curtailment'*.

Moreover, in case of net power trade, a distinction can (should) be made between *domestic* residual load (i.e. excluding net power trade) versus *national* residual load (including net power trade).

Hence, in **Figure 35** the *domestic curtailed residual load* is presented above the X-axis by (the sum of) the green bars (uncurtailed residual load) and, if applicable, by the brown bars (VRE curtailment). The *domestic curtailed residual supply*, on the contrary, is presented below the X-axis of **Figure 35** by means of the four non-VRE sources of domestic power generation (gas, coal, nuclear and other, non-variable RES-E).

On the other hand, the *national curtailed residual load* includes net power exports (in case there are any net exports) while the *national curtailed residual supply* includes net power imports (if there are any net imports).

Figure 35 can be expressed by some simple equations. For instance, starting at the most aggregated level, it can be expressed by the following equation:

(1) National curtailed residual load = national curtailed residual supply

Or, slightly less aggregated:

(2) Exports + domestic curtailed residual load = Imports + domestic curtailed residual load

Or, as domestic curtailed residual load = domestic uncurtailed residual load + VRE curtailment, by:

(3) Exports + domestic uncurtailed residual load + VRE curtailment = Imports + domestic curtailed residual load

And, finally, by reshuffling exports and VRE curtailment to the right side of the equation:

(4) Domestic uncurtailed residual load = Domestic curtailed residual supply – VRE curtailment – net exports[15]

Actually, the left side of equation (4) refers to the term (domestic curtailed) residual load as analysed and discussed implicitly in the phase 1 report of FLEXNET (notably in R1, Section 3.1) whereas the right side refers to the three main sources of residual supply to meet this residual load as analysed and discussed in the current chapter of the phase 2 report, i.e. (i) domestic power generation from non-VRE sources, i.e. from conventional units (gas, coal, nuclear) as well as from other, non-variable renewable energy sources (RES-E), (ii) VRE curtailment, and (iii) power trade (i.e. net exports).

Equations 1-4 can be used for any time, not only per year but also per month, week, day, hour, etc. Moreover, besides in absolute terms, equations 1-4 can also be expressed in relative terms for any time frame, i.e. as the change (Δ) between two (consecutive) time periods, for instance as the change between two (consecutive) years, months, years, hours, etc. More specifically in relative terms equation 4 runs as follows:

(5) ΔDomestic uncurtailed residual load = ΔDomestic curtailed residual supply – ΔVRE curtailment – Δnet exports

Actually, in hourly terms, the left side of equation 5 refers to the hourly variations in the residual load – and the resulting flexibility needs – as discussed in the phase 1 report of FLEXNET (R1, Section 3.2), whereas the right part refers to the three main flexibility options – i.e. variations in (i) domestic non-VRE power generation, (ii) VRE curtailment and (iii) net power trade – as analysed and discussed in the current phase 2 report.

[15] Net exports = gross exports – gross imports. In case imports > exports, the sign of the term 'net exports' becomes negative and actually implies net imports.

More specifically, in the last part of the current section (i.e. in Section 2.2.9 below) we first have a closer look at the three main sources of 'residual supply' to meet the residual power load – i.e. domestic residual power generation, VRE curtailment and net power trade – in particular by making a distinction between hours with a positive residual load ('VRE shortage') and hours with a negative residual load ('VRE surplus').

Subsequently, in Section 2.3 we focus on analysing the three main options to meet the hourly variations in residual load – and the resulting flexibility needs – i.e. the hourly variations in (i) domestic residual power generation, (ii) VRE curtailment, and (iii) net power trade.

2.2.9 Residual supply: VRE shortages versus surpluses

In the phase 1 report of FLEXNET (R1, Section 3.1.3), we made a distinction between hours with a 'positive residual load' ('VRE shortage') and hours with a 'negative residual load'('VRE surplus'), i.e. hours in which the output of power generation from VRE sources (sun/wind) is larger than the total power load during these hours. **Table 4** provides a brief summary of the main data on VRE shortages and surpluses discussed in the phase 1 report.[16]

Table 4: Summary data on residual load, VRE shortages and VRE surpluses in all scenario cases, 2015-2050

		Reference scenario			Alternative scenario		
	Unit	2015	2023	2030	2023	2030	2050
Total residual load	TWh	103.8	73.6	60.2	85.6	97.6	46.8
Hours with a positive residual load ('VRE shortage')							
Total number of VRE shortage hours (p.a.)	Hrs	8760	8615	7887	8731	8640	5543
Total hourly VRE shortage (p.a.)	TWh	103.8	73.7	62.0	85.6	97.8	81.9
Hours with a negative residual load ('VRE surplus')							
Total number of VRE surplus hours (p.a.)	Hrs	0	145	873	29	120	3217
Total hourly VRE surplus (p.a.)	TWh	0	0.1	1.8	0.0	0.2	35.1

Source: FLEXNET report phase 1 (R1, Section 3.1.2).

Figure 36 presents annual net residual power balances of the Netherlands, including a distinction of these balances during hours with a negative residual load and hours with a positive residual load (uncurtailed), for all scenario cases up to 2050. The upper part of **Figure 36** illustrates the net residual power balance for all hours in the year, i.e. for the total annual residual load (uncurtailed).[17] It shows that on the demand side of this balance, i.e. above the X-axis, the (domestic, uncurtailed) residual load declines in the reference scenario from 104 TWh in 2015 to 60 TWh in 2030 and in the alternative

[16] For a more extensive summary, see R1, Section 3.1.3, Table 8.

[17] Note that the upper part of **Figure 36** is similar to **Figure 35** presented above.

scenario from 86 TWh in 2023 to 47 TWh in 2050 (as explained in R1, Chapter 3). In some cases, this (domestic, uncurtailed) residual load is enhanced by net exports – notably in R2023, R2030 and A2023 – and/or by VRE curtailment, in particular in the alternative 2050 scenario cases (A2050, B2050 and C2050).

On the supply side of the net residual power balance, i.e. below the X-axis of **Figure 36**, the picture shows how the abovementioned (national, curtailed) residual power demand is met. In the reference scenario cases, R2015-R2030, this demand is primarily addressed by domestic non-VRE power generation, in particular from fossil fuels (coal, gas) and, to a lesser extent, from nuclear and other (non-variable) RES-E. In addition, in R2015 a minor part of the residual power demand is covered by net imports.

In the alternative scenario cases A2023 and A2030, the supply side shows a similar picture: residual power demand is primarily met by domestic power generation, while in A2030 an additional, small part is covered by net imports. In the alternative 2050 cases, however, the situation is quite different. Notably in A2050, about two-thirds of the (national, curtailed) residual power demand is covered by net imports while the remaining part is addressed by domestic, non-VRE generation.

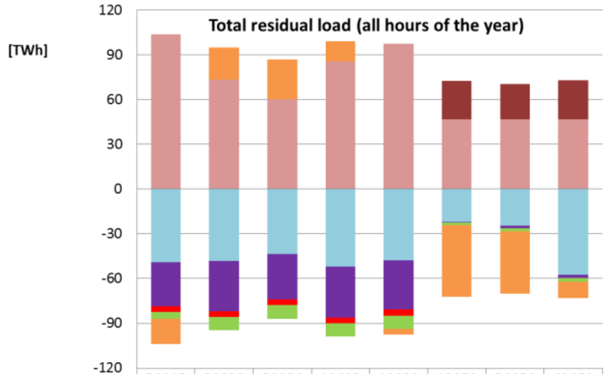
More specifically, **Figure 36** shows that in A2050 non-VRE power generation declines significantly compared to A2030. This applies particularly to coal (from 33 TWh in A2030 to 0.4 TWh in A2050) and to nuclear (from 4 TWh to 0 TWh) but also to other RES-E (from 9 TWh to 2 TWh) and to gas (from 48 TWh to 22 TWh). In relative terms, however, the share of gas in total non-VRE power generation rises from about 50% in A2030 to more than 90% in A2050.

In B2050 (with only 50% of the interconnection capacity expansion between 2030 and 2050, compared to 100% in A2050), the picture is largely similar to A2050, although the contribution of net imports in total supply is slightly lower and the contribution of domestic power generation is slightly higher, notably from fossil fuels (coal, gas).

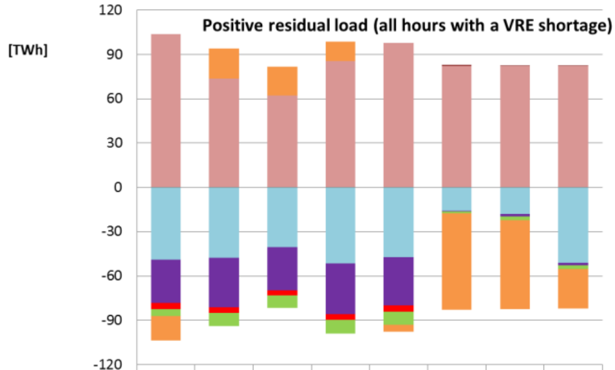
On the other hand, in C2050 (with 0% of the interconnection capacity expansion between 2030 and 2050), the residual supply side is quite different compared to A2050 (and B2050). Due to the interconnection restriction, the contribution of net imports to total supply falls from 48 TWh in A2050 to 11 TWh in C2050, whereas the contribution of gas-fired power generation to meet electricity demand increases from 22 TWh to 58 TWh, respectively (even far beyond gas-fired output levels in R2015-A2030). As a result, gas becomes by far the most dominant source of total (national) power supply in C2050.

The middle part of **Figure 36** presents the annual net residual power balance for those hours of the year in which there is a positive residual load (‘VRE shortage’), while the lower part provides this balance for those hours in which there is a negative residual load (‘VRE surplus’). Since the number of hours with a VRE surplus and the total annual amount of hourly VRE surpluses is limited in R2015 and A2030 (see **Table 4** as well the lower part of **Figure 36**), the net residual power balance for hours with a positive residual demand is largely similar to the balance for total residual demand in these scenario cases (compare the middle part with the upper part of **Figure 36**).

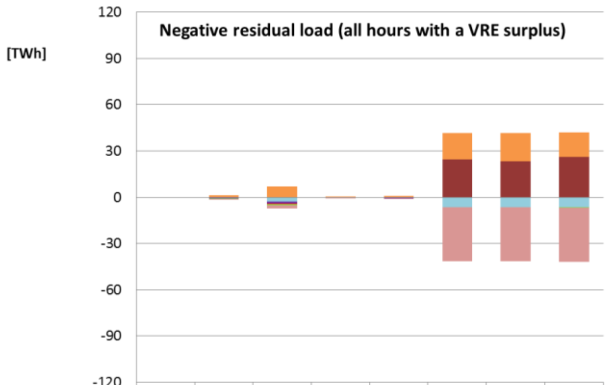
Figure 36: Net residual power balance of the Netherlands, including a distinction between hours with a positive and negative residual load, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Net exports	-16.7	21.3	26.7	13.5	-3.6	-48.2	-41.7	-11.0
VRE curtailment	0.0	0.0	0.0	0.0	0.0	25.5	23.5	26.4
Residual load (uncurtailed)	103.8	73.6	60.2	85.6	97.6	46.8	46.8	46.8
Other RES-E	-4.6	-9.0	-9.0	-9.0	-9.2	-1.7	-2.3	-2.6
Nuclear	-4.1	-4.0	-4.0	-4.0	-4.0	0.0	0.0	0.0
Coal	-29.4	-33.4	-30.4	-34.2	-32.9	-0.4	-1.7	-1.9
Gas	-49.0	-48.4	-43.5	-51.8	-47.8	-22.1	-24.5	-57.7



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Net exports	-16.7	20.2	19.6	13.2	-4.6	-65.0	-60.2	-26.6
VRE curtailment	0.0	0.0	0.0	0.0	0.0	0.9	0.3	0.1
Residual load (uncurtailed)	103.8	73.7	62.0	85.6	97.8	81.9	81.9	81.9
Other RES-E	-4.6	-8.9	-8.3	-9.0	-9.1	-1.6	-2.1	-2.4
Nuclear	-4.1	-4.0	-3.6	-4.0	-4.0	0.0	0.0	0.0
Coal	-29.4	-33.2	-29.2	-34.1	-32.7	-0.4	-1.7	-1.9
Gas	-49.0	-47.8	-40.5	-51.7	-47.4	-15.8	-18.2	-51.0



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Net exports	0.0	1.1	7.1	0.2	1.0	16.8	18.5	15.6
VRE curtailment	0.0	0.0	0.0	0.0	0.0	24.7	23.1	26.2
Residual load (uncurtailed)	0.0	-0.1	-1.8	0.0	-0.2	-35.1	-35.1	-35.1
Other RES-E	0.0	-0.1	-0.7	0.0	-0.1	-0.1	-0.2	-0.2
Nuclear	0.0	-0.1	-0.4	0.0	-0.1	0.0	0.0	0.0
Coal	0.0	-0.3	-1.2	0.0	-0.2	0.0	0.0	0.0
Gas	0.0	-0.5	-3.0	-0.1	-0.4	-6.3	-6.3	-6.6

On the other hand, in the 2050 scenario cases – with a large VRE surplus over a large number of hours – the residual supply situation is quite different, notably in the hours with a VRE surplus compared to the hours with a VRE shortage (although the situation is quite similar in the hours with a VRE surplus for the three individual 2050 scenario cases, i.e. A2050, B2050 and C2050).

In case of a VRE surplus, the (uncurtailed) residual load is negative and, actually, appears on the supply side – rather than on the demand side – of the net residual power balance (see the pink bars in **Figure 36**, notably in the lower part). Although there is already a surplus of VRE generation (compared to domestic demand), power supply is further enhanced by non-VRE generation – notably from gas and, to a lesser extent, from other RES-E – because of 'must-run' production considerations and/or ample export opportunities in certain hours. The lower part of **Figure 36** shows that the domestic surplus of power supply is predominantly met by VRE curtailment and, to a lesser extent, by net exports (see red and orange bars in **Figure 36**).

Finally, note in addition that, as expected, total VRE curtailment in the 2050 scenario cases is almost completely due in the hours with a VRE surplus (and hardly in VRE shortage hours), while – on balance – net exports occur predominantly in hours with a VRE surplus and net imports in hours with a VRE shortage.

Duration curves of residual demand and supply

Figure 37 presents the duration curves of the (uncurtailed) residual power load – as analysed and discussed in the phase 1 report – as well as the duration curves of the three main sources of residual supply analysed and discussed in the current report chapter, i.e. (i) non-VRE supply (notably from gas, see Section 2.2.3), (ii) VRE curtailment (Section 2.2.4), and (iii) net power trade (Section 2.2.7), for both A2050 and C2050.

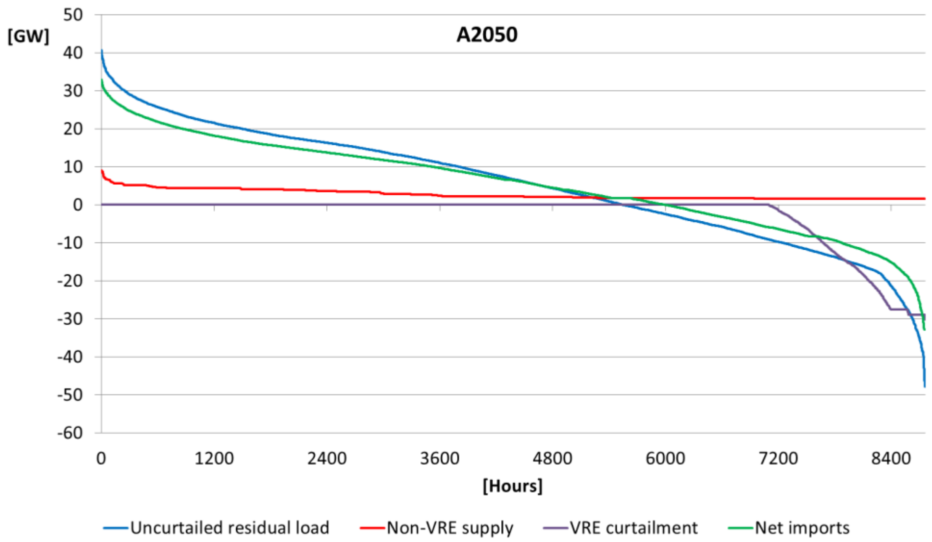
The duration curve of the uncurtailed residual demand is exactly similar in A2050 and C2050, while the duration curve of VRE curtailment is largely similar in A2050 and C2050 (although the number of hours with VRE curtailment and the total annual amount of VRE curtailment are slightly higher in C2050 than in A2050, as discussed in Section 2.2.4).[18] **Figure 37** indicates (and confirms) that VRE curtailment is mainly used in hours with a negative residual load (VRE surplus), as outlined above.[19]

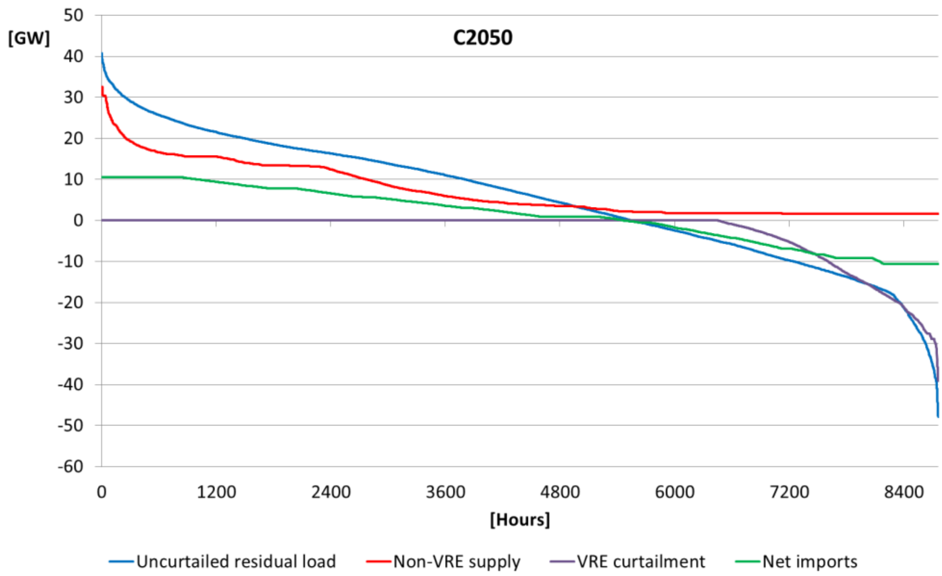
The duration curves of non-VRE supply and net imports, however, are quite different in A2050 versus C2050. In A2050, the non-VRE supply duration curve is rather flat, also at the left side of the curve, with a maximum non-VRE output level of almost 9 GW. In C2050, however, this curve is more steep, notably at the left side of the curve, with a maximum non-VRE output level of almost 33 GW. This indicates that during peak load hours, non-VRE generation is more variable (flexible) in C2050 than in A2050 and that the number of running hours of a large part of the (peak) non-VRE capacity in C2050 is rather limited.

[18] Note that for consistency reasons – i.e. related to the duration curve of the residual load – the duration curve of VRE curtailment presented in **Figure 37** is the mirror picture of the duration curve of VRE curtailment shown in **Figure 30** (Section 2.2.4) as the VRE curtailment data now have negative signs.

[19] Note, however, that the ranking of specific, individual hours may be (slightly) different between the duration curves of the residual load and VRE curtailment, but – to a large extent – they generally show a similar ranking, notably in case of a VRE surplus.

Figure 37: Duration curves of residual load (uncurtailed) and residual supply, i.e. non-VRE power generation, VRE curtailment and net imports in A2050 and C2050





As observed in the sections above, non-VRE output in 2050 – notably in C2050 – consists predominantly of gas-fired power generation and, hence, the variability (flexibility) of the non-VRE output and the low number of running hours of peak-load, non-VRE capacity refers predominantly to gas, in particular to the flexible ('no-must-run') part of the gas-fired power generation (see Section 2.2.3).

On the other hand, the duration curve of net imports in A2050 (with a relatively high interconnection capacity) is relatively steep (at both ends of the curve), whereas in C2050 (with a relatively low, restricted interconnection capacity) this curve is relatively flat (also at both ends).

To conclude, **Figure 37** indicates that in A2050 (with a relatively large interconnection capacity) hours with a VRE shortage are largely met by net imports (and, to a lesser extent, by domestic power generation), whereas hours with a VRE surplus are addressed by means of VRE curtailment and/or net exports. On the other hand, in C2050 (with a relatively low interconnection capacity) hours with a VRE shortage are mainly covered by domestic power generation (and, to a lesser extent, by net imports), whereas hours with a VRE surplus are addressed by means of (more) VRE curtailment and/or – although to a lesser extent – by net exports.

2.3 Trends in hourly variations of residual supply and resulting flexibility options

This section focusses more specifically on the trends in the *hourly variations* of the residual supply in the Dutch power system up to 2050 and the supply of flexibility options resulting from these variations. In brief, Section 2.3.1 defines and illustrates the concept of '*hourly variations of residual supply*', Section 2.3.2 shows some duration curves of hourly variations of residual supply, Section 2.3.3 presents and discusses the supply of flexibility options to meet the hourly variations of residual load (according to three indicators of the resulting demand for flexibility) and, finally, Section 2.3.4 discusses more specifically the role of power trade and other, alternative options to meet flexibility needs, notably in two 'extreme' residual load hours in the Netherlands in scenario case A2050.

2.3.1 Hourly variations of residual supply

In the phase 1 report of FLEXNET (R1, Section 3.2.1), we have defined *hourly variations ('ramps') of residual load* as the difference between residual load in hour *t* and residual load in hour *t-1* (with *t* = 1,……n), where residual load is defined as total power demand minus power generation from VRE sources. Similarly, we can define *hourly variations ('ramps') of residual supply* as the difference between residual supply in hour *t* and residual supply in hour *t-1* (with *t* = 1,……n), where residual supply is defined as total power supply minus power generation from VRE sources (as mentioned in Section 2.2 above).

In Section 2.2.7 of the current phase 2 report, however, we have explained that the concept 'residual load/supply' should be distinguished between *uncurtailed* versus *curtailed* residual load/supply (to account for any curtailment of VRE generation) as well as between *domestic* versus *national* residual load/supply (to account for any net trade of electricity). As a result, the term 'domestic uncurtailed residual load' was defined, according to equation 4, as follows:

(4) Domestic uncurtailed residual load = Domestic curtailed residual supply – VRE curtailment – net exports

As noted, the left side of equation (4) refers to the term (domestic curtailed) residual load whereas the right side refers to the three main sources of residual supply to meet this residual load, i.e. (i) domestic power generation from gas, coal, nuclear and other, non-variable RES-E, (ii) VRE curtailment, and (iii) power trade (i.e. net exports).

As an illustration of the concept ‘hourly variations of residual load’, **Figure 38** presents once again a net residual power balance but this time on an hourly basis for the first day of week 4 in scenario case A2030, while the related hourly variations (‘ramps’) of both the residual load and the residual supply are shown in **Figure 39**.[20]

More specifically, **Figure 38** shows that the residual load fluctuates significantly from hour to hour during the first day of week 4 in A2030. The supply of power generated from other RES-E and nuclear, however, is quite stable – even flat – while from coal it is flexible in a few hours but rather stable (flat) during most hours of the day. Power generation from gas, on the other hand, is quite flexible over most hours of the day. This applies also to (power demand from) net exports – which actually even turn to net imports (power supply) during hour 19 of the day (see **Figure 38**).

As said, **Figure 39** present the related hourly variations (‘ramps’) of residual load and supply. Following Section 3.2 of the phase 1 report of FLEXNET, the hourly variations in residual load are labelled as ‘flexibility demand’ and expressed as pink diamonds in **Figure 39**, either as upward flexibility needs (above the X-axis) or as downward flexibility needs (below the X-axis). As power generation from other RES-E and nuclear is completely flat during the first day of week 4 in A2030, **Figure 39** does not show any hourly changes for these two types of (residual) power supply. For coal, however, **Figure 39** presents ramps in a few hours, whereas for gas and net exports hourly changes are shown in most hours of the day.

Note that in most hours of the day presented in **Figure 39**, the hourly changes of the constituent components of the residual supply (‘flexibility options’) move in the same direction as the hourly changes of the residual load (‘flexibility needs’), i.e. either upwards or downwards. In that case the size of the hourly flexibility need (i.e. the height of the pink diamond) is just equal to the *sum* of the ramps of the residual supply components.

In some cases, however, the flexibility options may move in different directions. For instance, in hour 14 the ramp of gas-fired power generation is positive (‘upward flexibility’) whereas the hourly variation of net exports is negative (‘downward flexibility’). In that case the size of the hourly flexibility demand is equal to the *balance* of the power supply ramps.

[20] Note that the case presented in **Figure 38** and **Figure 39** (i.e. A2030, week 4, day 1) does not include any curtailment of VRE generation and, hence, uncurtailed residual load is similar to curtailed residual load and, therefore, can be simply denoted as residual load. In case of VRE curtailment, however, a distinction should be made between uncurtailed and curtailed VRE residual load. In that case, the amount of hourly VRE curtailment can be illustrated by distinguishing between uncurtailed residual load and VRE curtailment (as in **Figure 36**) whereas the hourly variations in VRE curtailment – either upwards or downwards – can be added to a related figure on hourly variations in residual demand and supply (similar to **Figure 39**). See, as an example of a picture including VRE curtailment, **Figure 44** in Section 2.3.3 below.

Figure 38: Net residual power balance in A2030, week 4, day 1

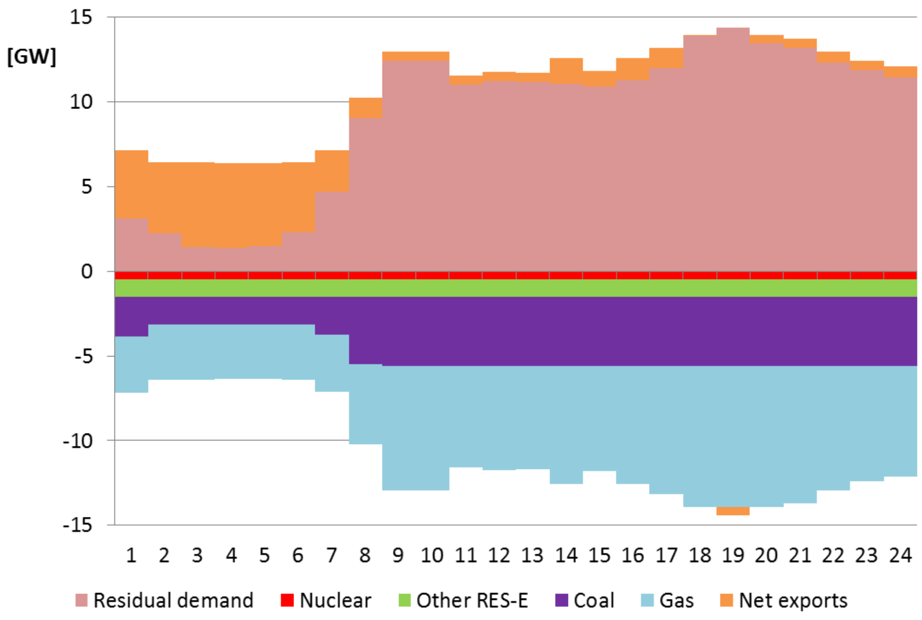
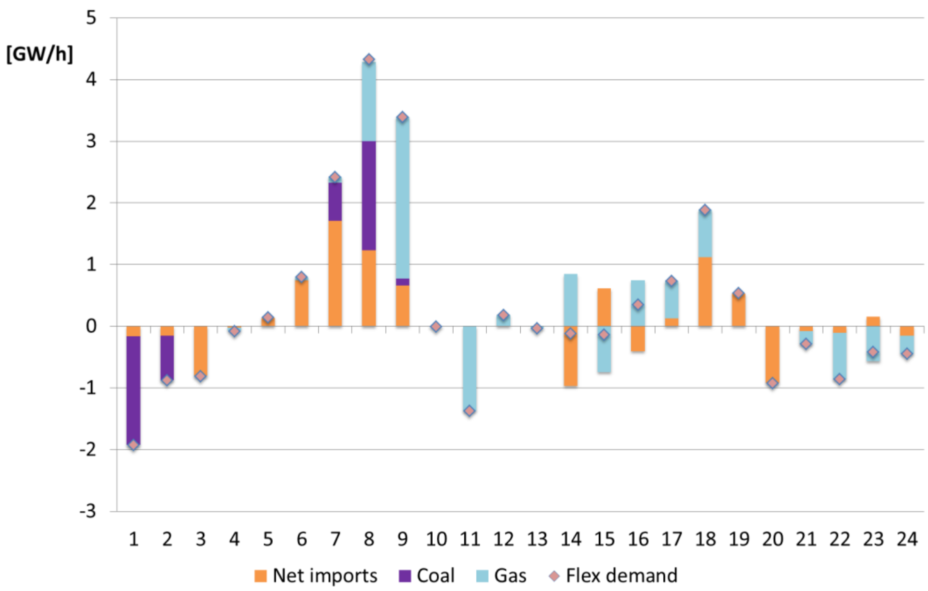


Figure 39: Hourly changes ('ramps') of residual demand and supply (i.e. demand and supply of flexibility), A2030, week 4, day 1



Note that in **Figure 39** (and in similar figures below), the flexibility options refer to hourly changes in residual supply – i.e. the supply of flexibility options – in order to meet hourly changes in (domestic, uncurtailed) residual load, i.e. the demand for flexibility. For power generation from domestic, non-VRE resources (gas, coal, nuclear, other RES-E) – which is indeed a major element of power supply (presented below the X-axis in **Figure 38**) – this means that a *positive* sign in **Figure 39** refers to an *increase* in power generation (*upward* flexibility) and a *negative* sign to a *decrease* in power generation (*downward* flexibility).

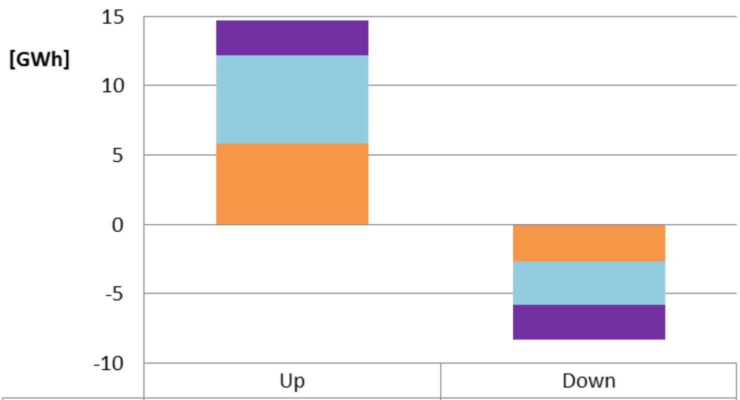
For net exports, however, – which is actually an element of power *demand* (presented *above* the X-axis in **Figure 38**) – this means that a positive sign in **Figure 39** refers to a *decrease in net exports* or, put differently, an *increase in net imports* (through either less gross exports or more gross imports; as presented as an upward flexibility options in **Figure 39**). On the other hand, a negative sign for net exports (in **Figure 38**) refers to an increase in net exports or, put differently, a decrease in net imports through either more gross exports or less gross imports (as presented as a downward flexibility option in **Figure 39**).

Similarly, in case of VRE curtailment – which is actually also an element of power demand (presented above the X-axis in **Figure 38**) – this means that a *positive* sign in **Figure 39** refers to *less* VRE curtailment (upward flexibility) and a *negative* sign to *more* VRE curtailment (downward flexibility).[21] Therefore, **Figure 39** indicates that, for instance, in hour 8 the demand for upward flexibility (+4.3 GW/h, i.e. an increase in the residual load by 4.3 GW/h) is met by more power generation from coal (1.8 GW/h) and gas (1.3 GW/h) and by less net exports – i.e. more net imports (1.2 GW/h).

On the other hand, in hour 2 the demand for downward flexibility (-0.9 GW/h, i.e. a decrease in the residual load by 1.9 GW in hour 2 compared to hour 1) is addressed by a decrease in power generation from coal (-0.7 GW/h) and an increase in net exports – i.e. a decrease in net imports (-0.2 GW/h).

Total hourly demand and supply of flexibility

Figure 40: Total supply of flexibility, either upwards or downwards, in A2030, week 4, day 1



	Up	Down
Coal	2.5	-2.5
Gas	6.3	-3.2
Net imports	5.8	-2.6

Figure 40 presents the total hourly demand and supply of flexibility of the Dutch power system over the first day of week 4 in A2030, either upwards or downwards (expressed in aggregated energy terms, i.e. in GWh). Similar to the analysis conducted during the first phase of FLEXNET, the total hourly demand for upward flexibility is just the aggregated sum of all hourly ramp-ups of the residual load over the period considered

[21] See also equation 4 in Section 2.2.8 above, which shows that if VRE curtailment and net exports have a negative sign if included on the supply side of the equation (and, hence, a positive sign in case the supply side is expressed in terms of net imports).

(in this case one day). For the first day of week 4 in A2030, this total demand for upward flexibility is just equal to the sum of all pink diamonds above the X-axis of **Figure 40**. On the other hand, the total hourly demand for downward flexibility is the aggregated sum of all hourly ramp-downs of the residual load (i.e. the sum of all pink diamonds below the X-axis of **Figure 40**).

The total hourly supply of flexibility, either upwards or downwards, usually consists of different components ('flexibility options'). As said, for each component, the total hourly supply of upward flexibility is equal to the sum of the contributions made to meet the hourly upward flexibility needs over the period considered, whereas the total hourly supply of downward flexibility is equal to the sum of the contributions made to meet the hourly downward flexibility needs.

Note that, as mentioned above, in case the hourly supply of flexibility moves in another direction than the hourly demand for flexibility (as, for instance, is the case for gas in hour 14 presented in **Figure 39**), the total hourly supply of upward (downward) flexibility is equal to the *balance* of the contributions made to meet the hourly upward (downward) flexibility needs over the period considered. However, as the hourly supply of flexibility options usually moves in the same direction as the hourly demand for flexibility, the balance of the total hourly supply of each flexibility option usually moves in the same direction as the total hourly demand for flexibility over the period considered.

Figure 40 shows that over the first day of week 4 in A2030 the total hourly demand for upward flexibility (14.6 GWh) is met by, on balance, upwards movements of coal-fired power generation (2.5 GWh), gas-fired output (6.3 GWh) and net imports of electricity (5.8 GWh). On the other hand, the total hourly demand for downward flexibility over this day (-8.3 GWh) is addressed by, on balance, downward movements of coal (-2.5 GWh), gas (-3.2 GWh) and net imports (-2.6 GWh).

2.3.2 Ramp duration curves of residual supply

Figure 41 presents the duration curves of the hourly variations ('ramps') for three residual supply components ('flexibility options') in some selected scenario cases over the period 2015-2050, i.e. for (i) gas-fired power generation (as the main flexible domestic generation option), (ii) VRE curtailment, and (iii) net power trade.[22] It shows, for instance, that both VRE curtailment and gas-fired power generation offer flexibility during only a limited number of hours of the year – i.e. less than 1200 hours for either upwards or downwards flexibility – whereas net imports offers flexibility during most hours of the year.

Moreover, besides the number of hours concerned, the size of the flexibility offered by these options also varies significantly, both within and across the scenario cases concerned. For instance, in A2050 (with a relatively high interconnection capacity and a relatively low domestic gas-fired generation capacity), gas-fired power generation offers flexibility only during a very restricted number of hours, varying hardly between 0

[22] For VRE curtailment, **Figure 41** presents only duration curves for the scenario cases A2050 and C2050 as there is hardly or no VRE curtailments in R2015 and A2030.

Figure 41: Ramp duration curve of gas-fired power generation, VRE curtailment and net trade in selected scenario cases, 2015-2050

and less than 1 GW/h (either upwards or downwards). However, in C2050 (with a relatively low interconnection capacity and a relatively high domestic gas-fired generation capacity), gas offers flexibility during a larger number of hours and, more strikingly, varying significantly between 0 and more than 12 GW/h.

On the other hand, in A2050 net imports offer flexibility during a relatively large number of hours, varying substantially between 0 and 34 GW/h in case of upwards flexibility and between 0 and 29 GW/h in case of downwards flexibility. In C2050, however, the flexibility offered through changes in hourly power trade is less outspoken, i.e. between 0 and 21 GW/h (for either upwards or downwards flexibility; see **Figure 41**, as well as **Table 5** for more details on maximum hourly ramping by different flexibility options in all scenario cases).

Table 5: Maximum hourly ramping by different components of residual supply ('flexibility options') in all scenario cases, 2015-2050 (in GW/h)

	Reference scenario			Alternative scenario				
	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Gas fired generation:								
• Upward	3.7	4.7	4.7	4.7	4.6	0.7	10.3	12.1
• Downward	-3.7	-4.5	-4.5	-4.5	-4.5	-0.7	-10.3	-12.1
VRE curtailment:								
• Upward	0.0	0.0	0.0	0.0	0.0	28.9	28.9	20.8
• Downward	0.0	0.0	0.0	0.0	0.0	-28.9	-27.6	-23.2
Net power trade:								
• Upward	3.9	7.8	7.4	10.4	10.1	34.0	31.2	21.1
• Downward	-4.3	-7.4	-8.0	-9.3	-9.0	-29.2	-28.0	-21.1

For VRE curtailment, the differences in terms of number of hours and the size of the flexibility offered are less significant between A2050 and C2050. The main difference is that the maximum hourly ramping of VRE curtailment, either upwards or downwards, is significantly higher in A2050 than in C2050 (see **Figure 41** and **Table 5**).

2.3.3 Flexibility options to meet hourly variations of residual load

In order to analyse the demand for flexibility due to the variability of the residual load during phase 1 of FLEXNET, we have defined and applied the following three specific indicators of flexibility needs resulting from the hourly variations of the residual load (see R1, Section 3.2.4):

- *Maximum hourly ramp*, in both directions (upwards and downwards), i.e. the maximum hourly variation in residual load over a year, expressed in capacity terms per hour (GW/h);
- *Maximum cumulative ramp,* in both directions (upwards and downwards), i.e. the maximum variation in residual load – either upwards or downwards – during some

consecutive hours in a year, expressed in capacity terms per number of consecutive hours (GW/#h);

- *Total hourly ramps,* in both directions (upwards and downwards), i.e. the total annual amount of hourly ramps – either up or down – aggregated over a year, expressed in energy terms per annum (TWh).

As part of the first phase of FLEXNET, we have estimated and analysed the demand for flexibility according to these three indicators for all scenario cases by means of a simple, static simulation spreadsheet model. The main results of this exercise are summarised in **Table 6**.

Table 6: Summary overview of the demand for flexibility due to hourly variations in residual load ('ramps') in all scenario cases, 2015-2050

	Reference scenario			Alternative scenario		
	2015	**2023**	**2030**	**2023**	**2030**	**2050**
Demand for flexibility						
Maximum hourly ramp-up (in GW/h)	3.0	6.3	8.5	6.2	8.2	29.6
Maximum hourly ramp-down (in GW/h)	3.1	8.6	10.2	8.7	10.4	28.6
Maximum cumulative ramp-up (in GW/#h)	9.7	16.4	20.7	17.7	20.6	66.2
• *Number of consecutive ramp-up hours*	14	14	9	14	9	10
Maximum cumulative ramp-down (in GW/#h)	10.3	16.8	21.7	16.8	22.2	65.0
• *Number of consecutive ramp-down hours*	10	17	17	19	17	17
Total hourly ramp-up (p.a.; in TWh)	2.2	3.5	4.6	3.8	5.5	15.2
Total hourly ramp-down (p.a.; in TWh)	2.2	3.5	4.6	3.8	5.5	15.2

Source: FLEXNET report phase 1 (R1, Section 3.2.4).

As part of the second phase of FLEXNET, we have estimated and analysed the supply options to meet the demand for flexibility according to the three indicators mentioned above by means of the EU28+ electricity market model COMPETES. The major results of this effort are presented and discussed below.[23]

Maximum hourly ramps

Figure 42 presents the flexibility options to meet the maximum hourly ramps of the residual load, either upwards or downwards, in all scenario cases up to 2050. It shows that in R2015, the need for maximum hourly ramp-up (3.0 GW/h) is still solely met by power generation from fossil fuels, in particular from gas (2.9 GW/h) and, to a lesser extent, from coal (1.3 GW/h), whereas the ramp of net imports is still relatively small and even moves in the other direction (-1.2 GW/h).

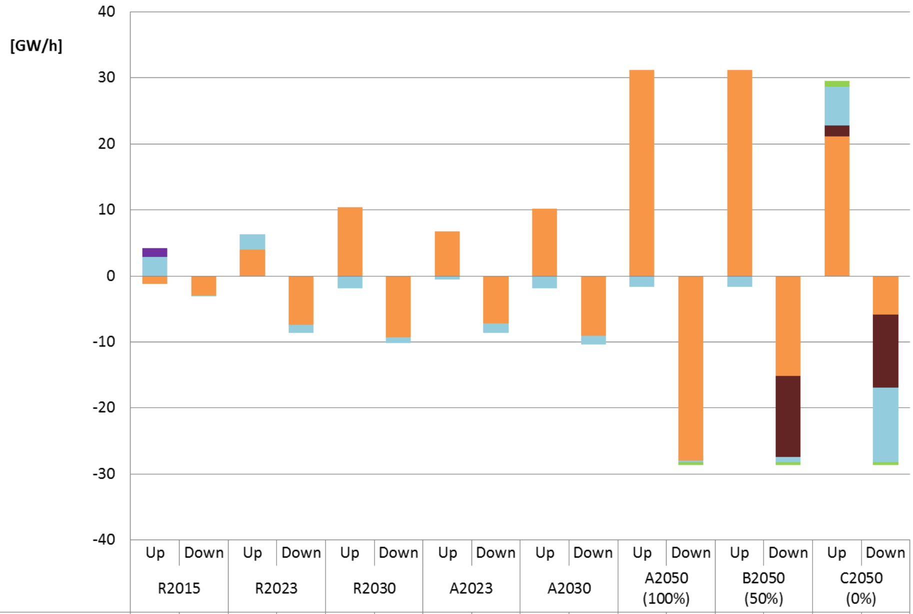
In all other scenario cases up to C2050, however, coal-fired power generation does not play any role in addressing the need for maximum hourly ramp-up. The role of gas in providing upward flexibility declines slightly in absolute terms in R2023 and even

[23] Note that in the discussion below the demand for flexibility in B2050 and C2050 is similar to the flexibility demand in A2050 (as determined in phase 1 of the project) whereas the supply options to meet this demand differs across the 2050 scenario cases (as outlined in the sections below).

becomes negative (downward ramping) in the scenario cases R2030 up to B2050, but its role falls substantially in relative terms over the years 2015-2050 (i.e. compared to the large increase in the need for maximum hourly ramp-up over this period). Only in C2050 (% interconnection expansion), gas once again offers a significant, positive contribution to address the maximum need for hourly ramp-up (although a minor role in relative terms).

Figure 42 shows that in almost all scenario cases the need for both maximum hourly ramp-up and maximum hourly ramp-down is predominantly (60-100%) met by hourly changes in net power trade. The only exceptions include the need for upward flexibility in R2015 (as discussed above) and the need for downward flexibility in B2050 and C2050 (where the expansion of the interconnection capacity is restricted to 50% and 0%, respectively, of the capacity expansion over the years A2030-A2050).

Figure 42: Flexibility options to meet flexibility needs in terms of maximum hourly ramps, 2015-2050



	R2015 Up	R2015 Down	R2023 Up	R2023 Down	R2030 Up	R2030 Down	A2023 Up	A2023 Down	A2030 Up	A2030 Down	A2050 (100%) Up	A2050 (100%) Down	B2050 (50%) Up	B2050 (50%) Down	C2050 (0%) Up	C2050 (0%) Down
Other RES-E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.4	0.0	-0.4	0.9	-0.4
Coal	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	2.9	-0.1	2.2	-1.2	-1.9	-0.8	-0.6	-1.5	-1.9	-1.4	-1.7	-0.3	-1.7	-0.9	5.8	-11.3
VRE curtailment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-12.2	1.7	-11.1
Net imports	-1.2	-3.0	4.0	-7.4	10.4	-9.3	6.7	-7.2	10.1	-9.0	31.2	-28.0	31.2	-15.1	21.1	-5.8

In B2050 (50% interconnection expansion), a major share of the need for maximum hourly ramp-down (-28.6 GW/h) is met by VRE curtailment (-12.2 GW/h) and net imports (-15.1 GW/h), while the remaining part is addressed by other RES-E (-0.4 GW/h) and gas (-0.9 GW/h). In C2050 (0% interconnection expansion), only a minor share of the maximum need for hourly ramp-down (-28.6 GW/h) is met by net imports (-5.8 GW/h), whereas major shares are addressed by VRE curtailment (-11.1 GW/h) and gas-fired generation (-11.3 GW/h) and a small share by other RES-E (-0.4 GW/h).

Note that in **Figure 42** – and in the current Section 2.3 as a whole – VRE curtailment refers to hourly changes ('ramps') in VRE curtailment as a flexibility options. In case of VRE curtailment, as explained in Section 2.3.1 above, a *positive* sign means that the level of VRE curtailment has been *reduced* in the respective hour by the amount indicated (compared to the previous hour), whereas a *negative* sign implies that the level of VRE curtailment has been *increased* in the respective hour by the amount indicated (compared to the previous hour). Hence, **Figure 42** indicates that, for instance, in C2050 the need for *downward* flexibility has been met predominantly by a mix of three flexibility supply options, i.e. (i) *less* power generation from gas, (ii) *less* net imports (or *more* net exports), and (iii) *more* VRE curtailment.

Maximum cumulative ramp

Figure 43 presents the flexibility options to meet flexibility needs in terms of the maximum cumulative ramps of the residual load, either upward or downwards, in all scenario cases up to 2050 (in both absolute terms, i.e. in GW/#h, and in relative terms, i.e. as a % of the maximum cumulative ramp). Compared to the maximum hourly ramps discussed above, hourly variations in power generation from fossil fuels plays a more important role to meet flexibility needs in terms of the maximum cumulative ramps up to A2030, notably from coal to meet the downward cumulative flexibility needs.

In the 2050 scenario cases, the role of (hourly variations in) VRE curtailment in meeting maximum cumulative ramps is more important, whereas the role of (hourly variations in) power trade is less important (compared to meeting maximum hourly ramps). More specifically, the share of VRE curtailment in addressing cumulative upward flexibility needs amounts to 44% in A2050 and increases to almost 60% in C2050, whereas the share of power trade is 56% in A2050 and drops to 31% in C2050.

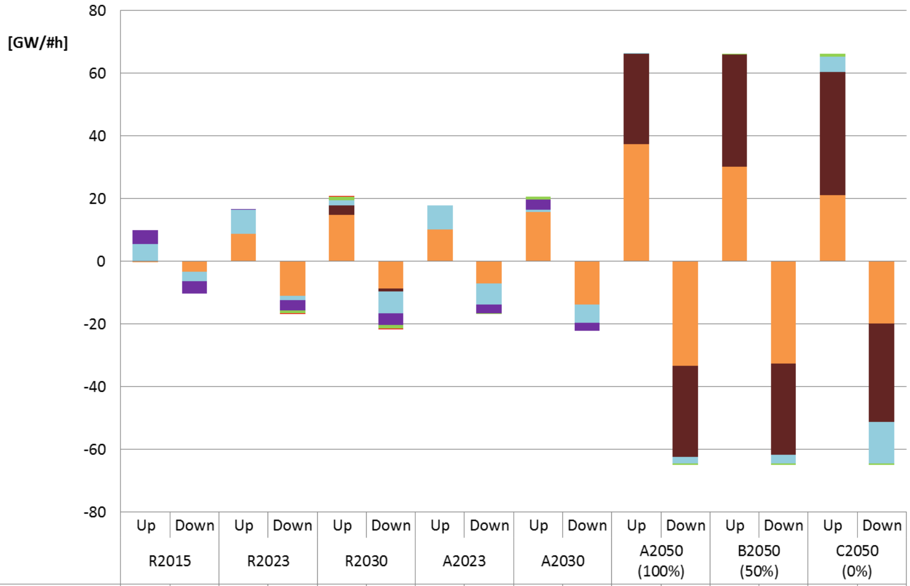
Figure 44 illustrates the case of the maximum cumulative ramp-up of 66 GW in A2050, which takes place over the hours 3279-3288, i.e. somewhere in mid-May of A2050.[24] More specifically, **Figure 44** presents the residual power balance over this time interval (upper part of the picture) as well as the related hourly changes of residual demand and supply – and the resulting flexibility options to meet this cumulative ramp-up (lower part of the picture). The upper part shows that the residual load increases steadily from -48 GW in hour 3278 to +18 GW in hour 3288, i.e. equal to a cumulative ramp-up of 66 GW over these hours (and equal to the sum of the pink diamonds presented in the lower part of the figure).

In addition, **Figure 44** shows that during the first few hours of the time interval considered (hours 3279-3282) – in which there is a large negative residual load (i.e. a major VRE surplus) – the upward flexibility need is met solely by a decrease of net exports (or an increase by net imports, as indicated in the lower part of the picture). Subsequently, during hours 3283-3285, the demand for upward flexibility is met by reducing the level of VRE curtailment. Finally, in hours 3286-3288 – in which there is a relatively large positive residual load (i.e. a major VRE shortage) – the upward flexibility need is met largely by an increase in net imports and, notably in hour 3286, an increase in power generation from other RES-E and gas.

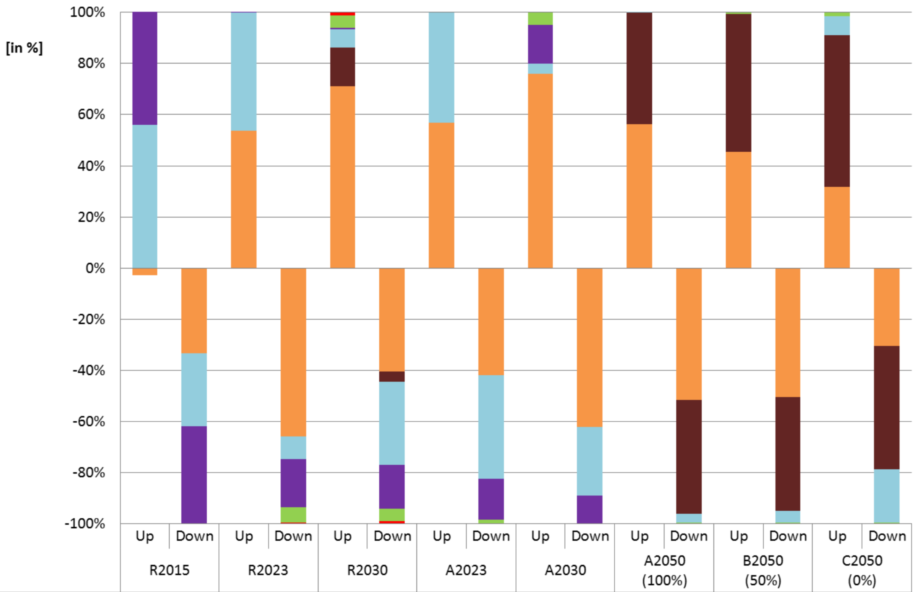
Note that in hour 3288 the increase in net imports is even much bigger than the demand for upward flexibility, most likely because imports of electricity are cheaper than domestic power generation. As a result, the generation from particularly gas and, to a lesser extent, from other RES-E declines even though residual load is positive and increases in this hour.

[24] See also Figure 27 as presented and discussed in Section 3.2.4 of the FLEXNET phase 1 report.

Figure 43: Flexibility options to meet flexibility needs in terms of maximum cumulative ramps, 2015-2050

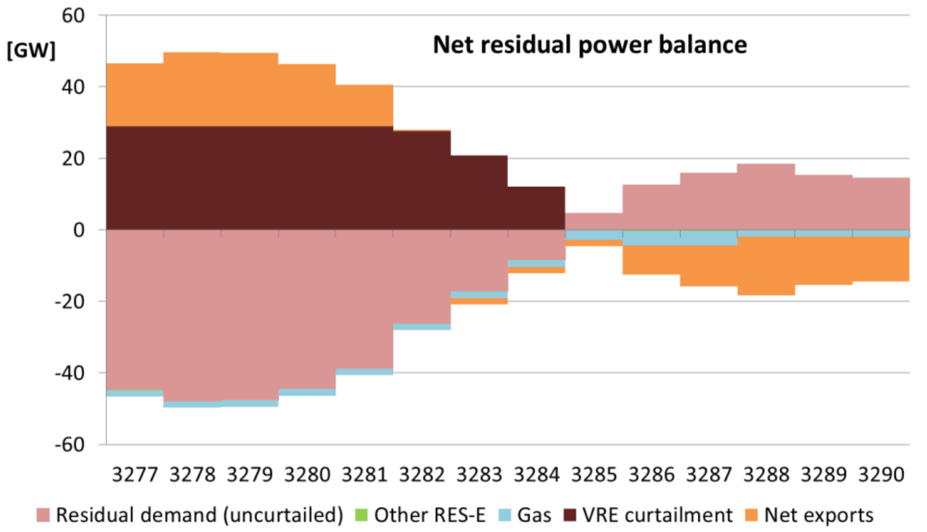


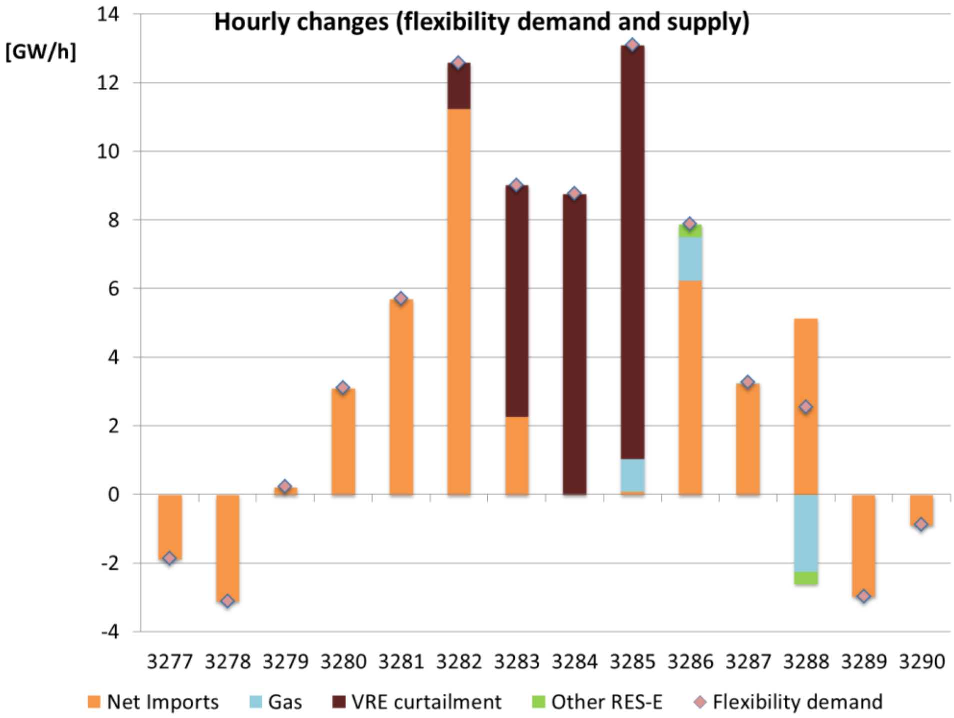
	R2015 Up	R2015 Down	R2023 Up	R2023 Down	R2030 Up	R2030 Down	A2023 Up	A2023 Down	A2030 Up	A2030 Down	A2050 (100%) Up	A2050 (100%) Down	B2050 (50%) Up	B2050 (50%) Down	C2050 (0%) Up	C2050 (0%) Down
Nuclear	0.0	0.0	0.0	-0.1	0.2	-0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Other RES-E	0.0	0.0	0.0	-1.0	1.0	-1.0	0.0	-0.3	1.0	0.0	0.0	-0.4	0.4	-0.4	0.9	-0.4
Coal	4.5	-3.9	0.0	-3.1	0.1	-3.7	0.0	-2.7	3.1	-2.5	0.0	0.0	0.0	0.0	0.0	0.0
Gas	5.4	-3.0	7.6	-1.5	1.5	-7.1	7.7	-6.8	0.8	-5.9	0.0	-2.3	0.0	-2.9	5.0	-13.4
VRE curtailment	0.0	0.0	0.0	0.0	3.1	-0.8	0.0	0.0	0.0	0.0	28.9	-28.9	35.7	-28.9	39.1	-31.4
Net imports	-0.3	-3.4	8.8	-11.1	14.7	-8.8	10.1	-7.0	15.7	-13.8	37.3	-33.4	30.1	-32.8	21.1	-19.8



	R2015 Up	R2015 Down	R2023 Up	R2023 Down	R2030 Up	R2030 Down	A2023 Up	A2023 Down	A2030 Up	A2030 Down	A2050 (100%) Up	A2050 (100%) Down	B2050 (50%) Up	B2050 (50%) Down	C2050 (0%) Up	C2050 (0%) Down
Nuclear	0.0%	0.0%	0.0%	-0.5%	1.1%	-1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Other RES-E	0.0%	0.0%	0.0%	-6.1%	5.0%	-4.8%	0.0%	-1.5%	4.8%	0.0%	0.0%	-0.6%	0.6%	-0.6%	1.4%	-0.6%
Coal	46.7%	-38.0%	0.1%	-18.8%	0.4%	-17.1%	0.0%	-16.2%	15.2%	-11.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Gas	56.0%	-28.8%	46.2%	-8.8%	7.3%	-32.6%	43.2%	-40.5%	3.9%	-26.6%	0.0%	-3.5%	0.0%	-4.5%	7.6%	-20.6%
VRE curtailment	0.0%	0.0%	0.0%	0.0%	15.1%	-3.8%	0.0%	0.0%	0.0%	0.0%	43.6%	-44.5%	53.9%	-44.5%	59.1%	-48.3%
Net imports	-2.7%	-33.2%	53.7%	-65.9%	71.0%	-40.5%	56.8%	-41.8%	76.1%	-62.2%	56.3%	-51.5%	45.5%	-50.4%	31.8%	-30.5%

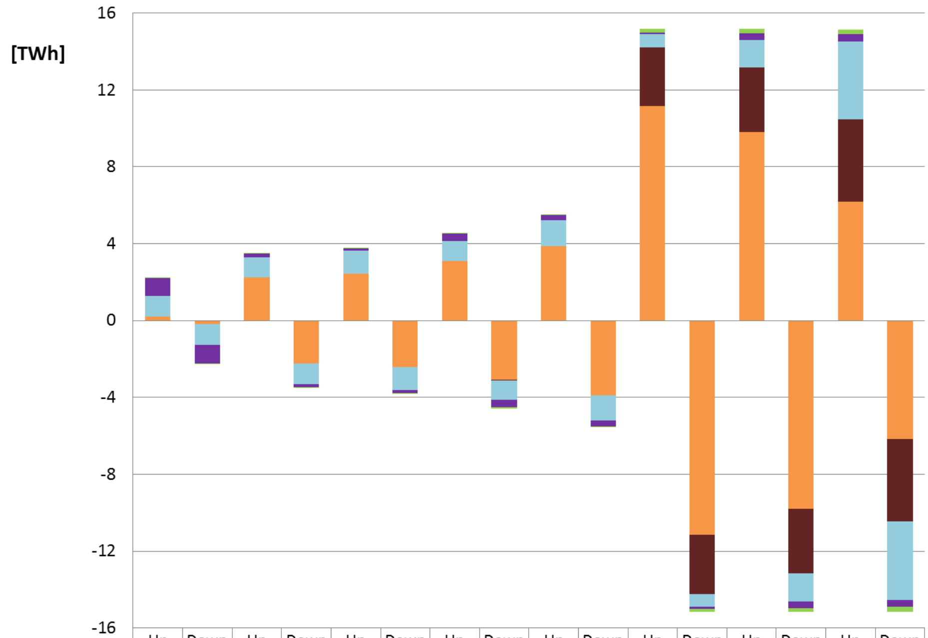
Figure 44: Illustration of net residual power balance, related hourly changes ('ramps') of residual demand and supply, and resulting flexibility options to meet maximum cumulative ramp-up in mid-May A2050 (hours 3277-3290)



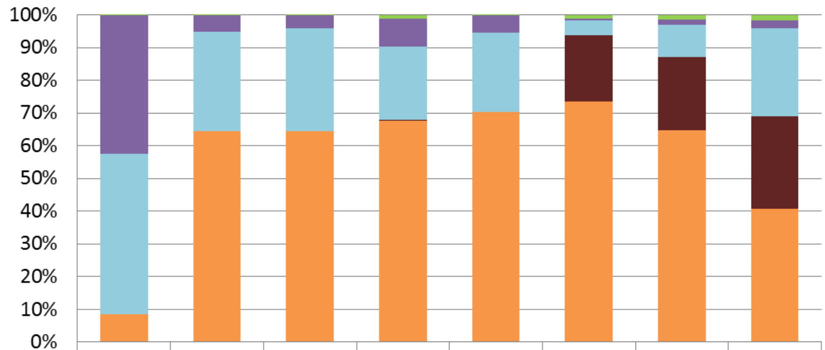


Overall, the maximum cumulative ramp-up of 66 GW in A2050 is met by, on balance, an increase in net imports (+37 GW) and a decrease in VRE curtailment (+29 GW; see **Figure 43**). In C2050, on the contrary, a similar cumulative demand for upward flexibility is met by a decrease of VRE curtailment (+39 GW), an increase in net imports (+21 GW) and an increase in domestic power generation from gas (+5 GW) and other RES-E (1 GW).

Figure 45: Total annual supply of flexibility options to meet total annual demand of flexibility, either upwards or downwards, in all scenario cases, 2015-2050



	R2015 Up	R2015 Down	R2023 Up	R2023 Down	A2023 Up	A2023 Down	R2030 Up	R2030 Down	A2030 Up	A2030 Down	A2050 (100%) Up	A2050 (100%) Down	B2050 (50%) Up	B2050 (50%) Down	C2050 (0%) Up	C2050 (0%) Down
Other RES-E	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	-0.2	0.2	-0.2	0.3	-0.3
Coal	0.9	-0.9	0.2	-0.2	0.2	-0.2	0.4	-0.4	0.3	-0.3	0.1	-0.1	0.3	-0.3	0.4	-0.4
Gas	1.1	-1.1	1.1	-1.1	1.2	-1.2	1.0	-1.0	1.3	-1.3	0.7	-0.7	1.4	-1.4	4.1	-4.1
VRE curtailment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.1	-3.1	3.4	-3.4	4.3	-4.3
Net imports	0.2	-0.2	2.2	-2.2	2.4	-2.4	3.1	-3.1	3.9	-3.9	11.1	-11.1	9.8	-9.8	6.2	-6.2



	R2015	R2023	A2023	R2030	A2030	A2050 (100%)	B2050 (50%)	C2050 (0%)
Other RES-E	0.2%	0.1%	0.0%	1.1%	0.0%	1.1%	1.4%	1.7%
Coal	42.4%	5.0%	4.0%	8.6%	5.4%	0.6%	1.7%	2.4%
Gas	48.9%	30.4%	31.5%	22.2%	24.2%	4.6%	9.8%	26.8%
VRE curtailment	0.0%	0.0%	0.0%	0.3%	0.0%	20.2%	22.1%	28.2%
Net imports	8.5%	64.5%	64.5%	67.7%	70.4%	73.5%	64.6%	40.8%

Total hourly ramps

Figure 45 presents the total annual supply of flexibility options to meet the total annual demand for flexibility (i.e. the total hourly ramps of the residual load, either upwards or downwards), in all scenario cases up to 2050 in both absolute energy terms (TWh) and as a % of total annual demand/supply of flexibility.

A striking feature of **Figure 45** is that the mix of the total annual supply of downward flexibility options is exactly similar ('mirror image') to the mix of the total annual supply of upward flexibility options (only the sign of the volume – i.e. the direction – of the flexibility options is opposite). This results from the fact that in our modelling scenarios the last hour of the focal year considered is exactly similar to the last hour of the previous year. Therefore, over the year as a whole, the upward changes of the different components of (residual) power demand and supply are – in total – exactly similar to the downward changes of these components (and, hence, the net balance of these total annual upward and downward changes is zero).[25]

As said, only the sign of the volume of the upwards versus downward flexibility options presented in **Figure 45** is different. This implies that the mix of supply options to meet the total annual demand for upward flexibility is similar to the options to meet the total annual demand for downward flexibility. In particular, this means that the total annual demand for *upward* flexibility as presented in **Figure 45** is met by the following three categories of flexibility supply options, i.e. (i) an *increase* in power generation (from gas, coal and/or other RES-E), (ii) an *increase in net imports* (or a *decrease in net exports*), and (iii) a *decrease* in VRE curtailment. On the other hand, the total annual demand for downward flexibility as presented in **Figure 45** is met by (i) a *decrease* in power generation (from gas, coal and/or other RES-E), (ii) a *decrease in net imports* (or an *increase in net exports*), and (iii) an *increase* in VRE curtailment.

More specifically, **Figure 45** shows that the total annual demand for upward/downward flexibility increases from 2.2 TWh in R2015 to more than 15 TWh in the 2050 scenario cases (see also **Table 6**, as analysed in the phase 1 report of FLEXNET). In R2015, this need is predominantly met by (hourly) increases in power generation from gas (49%) and coal (42%), while the remaining part is covered by increases in net imports (9%).

In R2023, the total annual demand for upward flexibility increases to 3.5 TWh. However, already in this scenario case the share of power trade (net imports) increases to 65%, whereas the shares of gas and coal drop to 32% and 4%, respectively.

Figure 45 shows that in the scenario cases A2023 up to A2050, the share of power trade in total flexibility demand (upwards/downwards) is even significantly higher, whereas the share of fossil fuels is lower accordingly. In A2050 (with a socioeconomic optimal expansion of interconnection capacity), the share of net power imports in total annual flexibility demand/supply amounts even to almost 74%, whereas the share of gas and coal amounts to only 4.6% and 0.6%, respectively. The remaining part is largely accounted for by (hourly changes in) VRE curtailment (20%) and, to a lesser extent, by generation from other RES-E (1%).

In the two other 2050 scenario cases – with significantly lower interconnection capacities – the share of power trade in total upward/downward flexibility is significantly lower, while the shares of the other flexibility options are higher

[25] In practice, of course, there will be some (small) differences in the levels and components of (residual) power demand and supply between the last hour of the current (focal) year and the last hour of the previous year. These (small) differences between two hours, however, will be negligible compared to the volumes of the total annual supply of upward/downward flexibility options aggregated over the 8760 hours of the year. Therefore, also in practice, the mix of the total annual supply of downward flexibility options will be (almost exactly) similar to the mix of the total annual supply of upward flexibility options.

accordingly. More specifically, in C2050 (% interconnection expansion), the share of gas-fired generation in total annual flexibility needs increases to 27% (compared to less than 5% in A2050) while the share of VRE curtailment rises from 20% in A2050 to 28% in C2050. In B2050 (50% interconnection expansion), the share of net imports in total flexibility needs, however, still amounts to 65% while in C2050 power trade still accounts for the largest share of all flexibility options (41%).

To conclude, in 2015 hourly changes in the power generation from non-VRE sources – notably from gas, coal and, to a lesser extent, other RES-E (biomass, hydro) – are the main supply options to meet the demand for upward/downward flexibility due to the (hourly) variability of the residual load, regardless of the indicator used to express and quantify this type of flexibility demand. In all scenario cases over the period 2023-2050, however, hourly changes in power trade become the most important (dominant) supply option to address the demand for flexibility due to the variability of the residual load. For instance, in the scenario cases R2023 up to A2050, the share of power trade in total annual flexibility demand/supply varies from 65% to 74%, respectively.

In addition, in the 2050 scenario cases – which are characterised by a large number of hours with a substantial negative residual load (VRE surplus) – hourly changes in VRE curtailment also becomes a major supply option to address the demand for flexibility due to the variability of the residual load. For instance, the share of VRE curtailment in total annual flexibility demand amounts to 20% in A2050 and even to 28% in C2050.

As a result, although the demand for flexibility increases substantially over the period 2015-2050, the role of (hourly changes in) domestic power generation from non-VRE sources (gas, coal, nuclear, other RES-E) decreases significantly over this period, notably in relative terms between R2015 and A2050 (but even in absolute terms). For instance, the share (amount) of gas-fired power generation in total annual flexibility demand/supply decreases from almost 49% (1.1 TWh) in R2015 to less than 5% (0.7 TWh) in A2050, while the share (amount) of coal-fired power generation declines from more than 42% (0.9 TWh) to less than 1% (0.1 TWh), respectively.

Our analysis shows, however, that the role of the different supply options to meet the need for flexibility depends highly on the assumptions made with regard to the expansion of the interconnection capacities across the EU28+ countries in general and between the Netherlands and its neighbouring (interconnected) countries in particular. For instance, in A2050 – which assumes a 100% expansion of the socioeconomic optimal interconnection capacity of all EU28+ countries between A2030 and A2050 – the shares of the three main supply categories in addressing total annual flexibility demand – i.e. power trade, VRE curtailment and power generation from non-VRE resources – amount to 74%, 20% and 6%, respectively.

In C2050, however, - which assumes a 0% expansion of the EU28+ optimal interconnection capacity between A2030 and A2050 – these shares amount to 41%, 28% and 31%, respectively. In particular, the share of gas-fired power generation increases from 4.6% in A2050 to almost 27% in C2050. Nevertheless, even in C2050, hourly changes in net power trade remain the most dominant supply option to meet total annual upward/downward flexibility needs due to the variability of the residual load with, as noted, a share of 41%.

2.3.4 The role of power trade and other flexibility options in extreme load hours

The section above concludes that (hourly changes in) power is the main supply option to meet total annual demand for upward/downward flexibility due to the variability of the residual load, notably in A2050 (with a share of 74% in total flexibility demand/supply). As noted before, residual load is defined as total power load minus power generation from VRE sources, in particular from sun and wind. The generation output from either wind or sun, however, is usually correlated between neighbouring countries.

As outlined in Appendix B, in order to account for the correlations between countries concerning either wind patterns or sun patterns, the same climate year – as assumed for the Netherlands during phase 1 of the project – has been taken in the COMPETES modelling analyses to represent either hourly wind profiles or hourly sun profiles for the other EU28+ countries, i.e. 2012 for wind and 2015 for sun PV. Since there is a seasonal correlation between wind and solar – e.g. summer is relatively more sunny and less windy - but not necessarily an hourly correlation, it is acceptable to use wind and solar profiles of two different years to represent a future year.[26]

The correlation of either wind patterns or sun patterns across EU28+ countries raises questions on the role of power trade as a flexibility option, in particular during extreme hours, i.e. hours with either a high positive residual load (VRE shortage) or a high negative residual load (VRE surplus), notably in the Netherlands but also in other (neighbouring) EU28+ countries. In order to address these questions, we have analysed two extreme hours of scenario case A2050, i.e. hour 354 – in which the Netherlands has its most extreme VRE shortage – and hour 3278, in which the Netherlands has its most extreme VRE surplus.

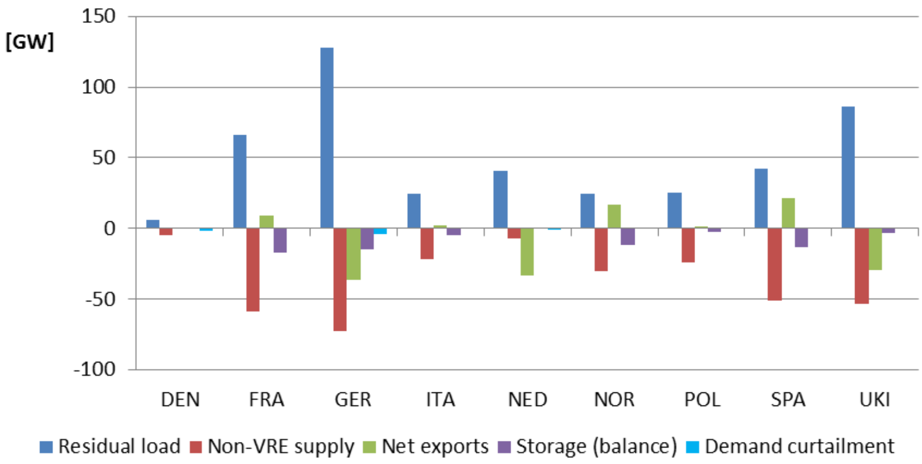
The main results of the analyses of these two extreme hours are presented and discussed below.

Hour 354: extreme VRE shortage
In hour 354 of A2050, i.e. a peak load hour by mid-January, total power demand in the Netherlands amounts to almost 41.4 GW, whereas power generation from VRE resources amounts to 0.7 GW, resulting in a net residual load of 40.7 GW. This is the most extreme (highest) level of hourly VRE shortages in A2050 and corresponds to the highest point of the duration curve of the residual load presented at the extreme left side ('hour 1') of the upper part of **Figure 37** (see Section 2.2.9 above).

In the EU28+ as a whole, total power demand in hour 354 amounts to almost 797 GW, whereas (uncurtailed) VRE generation amounts to 297 GW, i.e. an (uncurtailed) residual load of approximately 500 GW. For the EU28+, this implies a rather extreme situation in terms of hourly VRE shortages (although not the most extreme situation) as it results in a rather extreme position on the upper-left part of the duration curve of the residual load in the EU28+ (i.e. on 'hour 11' of this curve).

26 For more details on the COMPETES modelling assumptions and inputs with regard to VRE generation and hourly profiles for power supply from wind and sun across the EU28+ countries, see Appendix A and Appendix B.

Figure 46: The role of power trade and other flexibility options across EU28+ countries in hour 354 of A2050 (i.e. hour with a maximum VRE shortage in the Netherlands)



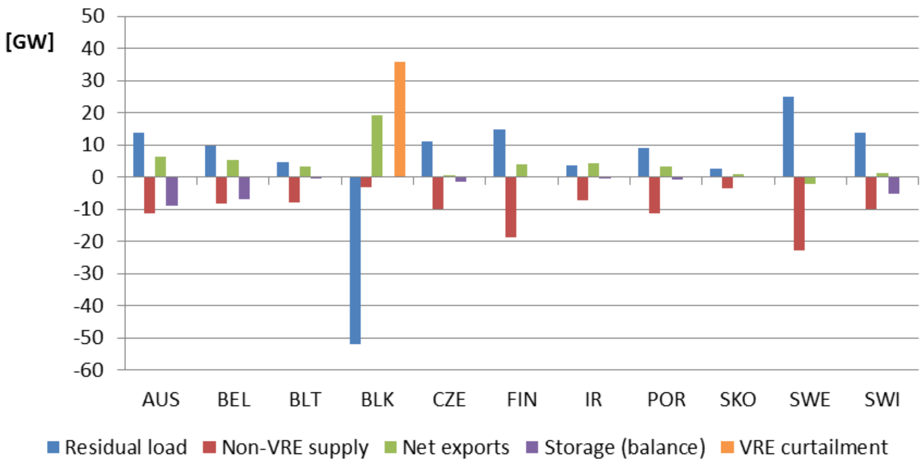


Figure 46 indicates how in hour 353 the residual load is met in the Netherlands and the other countries/regions of the EU28+, including the role of power trade (net exports) and other flexibility options across these countries/regions (where the upper part of the figure includes the Netherlands and some main EU28+ countries and the lower part the other, smaller EU28+ countries and regions).

Figure 46 shows, among others, that in hour 354 the Netherlands faces, as noted, a large ('extreme') positive residual load of almost 41 GW. A small amount of this demand (about 1 GW) cannot be met by any source of supply and is, hence, curtailed (hardly visible in **Figure 46** as 'demand curtailment'). Subsequently, a small part of the remaining (curtailed) residual demand (40 GW) is met by domestic non-VRE generation (7 GW) while the major part is addressed by net imports (33 GW).

In hour 354, there are several other EU28+ countries facing a major positive residual load, which is not fully covered by domestic non-VRE power supply (including storage discharges) and, hence, rely on net imports of electricity to balance power demand. For instance, Germany has a residual load of about 127 GW, which is covered partly by domestic non-VRE generation (73 GW), partly by storage discharges (14 GW), partly by net imports (36 GW) and, for the remaining part, by demand curtailment (4 GW; see upper part of **Figure 46**).

Other EU28+ countries or regions, however, are able to realise large net exports of electricity in hour 354. For instance, Spain faces a residual load of almost 43 GW but generates non-VRE electricity output of 51 GW. In addition, it discharges its electricity storage by 13 GW. As a result, Spain is able to realise net electricity exports of more than 21 GW.

The countries in the Balkan region even face a major negative residual load (VRE surplus) of approximately 52 GW in hour 354. In addition, these countries produce non-VRE electricity of more than 3 GW. About 70% of VRE generation (i.e. 36 GW), however, is curtailed as the Balkan countries are not able to use/store it domestically or export it outside the Balkan region. Nevertheless, on balance, they are able to realise net electricity exports of more than 19 GW in hour 254 (see lower part of **Figure 46**).

Hence, even in an hour in which the EU28+ as a whole and the Netherlands in particular face an 'extreme' high level of positive residual load (VRE shortage), these countries are able to deal with this situation by means of a mix of non-VRE power generation, storage discharges, demand curtailment and power trade between countries with, on balance, a domestic power surplus (net exports) and countries with a domestic power deficit (net imports). The Balkan region even has to curtail a large part of its VRE surplus in hour 354, most likely due to a lack of interconnection capacity, even though the rest of the EU28+ faces a large residual demand in this hour.

Hour 3278: extreme VRE surplus

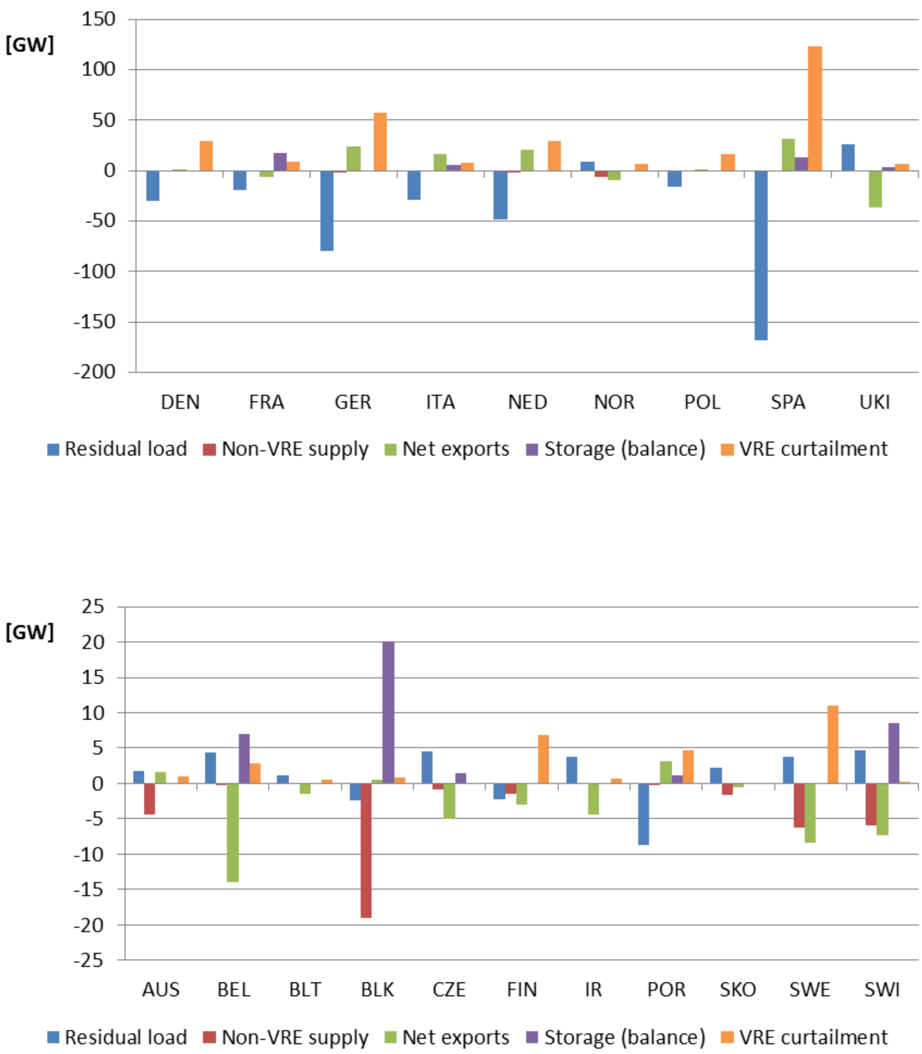
In hour 3278 of A2050, i.e. a base load hour by mid-May, total power demand in the Netherlands amounts to almost 22 GW, whereas (uncurtailed) VRE power generation amounts to almost 70 GW, resulting in a large negative residual load of approximately 48 GW. This is the most extreme (highest) level of hourly VRE surpluses in A2050 and corresponds to the lowest point of the duration curve of the residual load presented at the extreme right side ('hour 8760') of the upper part of **Figure 37** (see Section 2.2.9 above).

In the EU28+ as a whole, total power demand in hour 3278 amounts to almost 440 GW, whereas (uncurtailed) VRE generation amount to almost 780 GW, i.e. a large (uncurtailed) negative residual load of approximately 340 GW. For the EU28+, this implies a rather extreme situation in terms of hourly VRE surpluses (although not the most extreme situation) as it results in a rather extreme position on the bottom-right part of the duration curve of the residual load in the EU28+ (i.e. on 'hour 8740' of this curve).

Figure 47 indicates how in hour 3278 the residual load is met in the Netherlands and the other countries/regions of the EU28+, including the role of power trade (net exports) and other flexibility options across these countries/regions. It shows, among others, that in hour 3278 the Netherlands faces, as noted, a large ('extreme') negative residual load of about 48 GW. This VRE surplus is enhanced by non-VRE production ('must-run') of almost 2 GW. A main part of the potential VRE power generation, however, is curtailed (almost 29 GW, i.e. about 42% of the uncurtailed, potential VRE generation).[27] As a result, there is a net supply surplus of 21 GW, which is exported to the other EU28+ countries (see upper part of **Figure 47**).

In hour 3278 there are several other EU28+ countries that face a major negative residual load (VRE surplus), which is addressed by VRE curtailment and net exports, as well as by electricity storage. For instance, in hour 3278 of A2050 Spain faces a huge negative residual load of almost 168 GW. This VRE surplus is addressed mainly by VRE curtailment (123 GW) and, to a lesser extent, by net exports (32 GW) and electricity storage (13 GW).

Figure 47: The role of power trade and other flexibility options across EU28+ countries in hour 3278 of A2050 (i.e. hour with a maximum VRE surplus in the Netherlands)



27 For the EU28+ as a whole, total VRE curtailment in hour 3278 amounts to 315 GW, i.e. almost 41% of the uncurtailed, potential VRE generation (780 GW).

Other EU28+ countries or regions, however, rely on net imports of electricity in hour 3278 in order to cover (part of) their domestic power needs. For instance, Belgium faces a positive residual load of 4.3 GW. A small part of this demand is met by domestic non-VRE generation (0.2 GW). On the other hand, total annual domestic power demand is enhanced by the fact that part of VRE generation is curtailed (2.9 GW) or stored (7.0 GW), mainly because there are (more) attractive options due to the opportunity to import large (cheap) amounts of VRE surpluses from other EU28+ countries. Similar power demand and supply patterns in hour 3278 are observed in other EU28+ countries such as Sweden, Switzerland or the UK (see **Figure 47**).

Note also the specific position of the countries of the Balkan region (BLK) in hour 3278, presented in the lower part of **Figure 47**. In this hour, the Balkan region faces a negative residual load of 2.4 GW. This VRE surplus is enhanced by a large amount of domestic non-VRE power generation ((19 GW). Only a small part of the domestic supply surplus (21.4 GW), however, is exported (0.5 GW) while the main part is stored (20 GW), which can be used or exported during other hours of the year.

To conclude, even in an hour in which the EU28+ countries as a whole and the Netherlands in particular faces an 'extreme' high level of negative residual load (VRE surplus) – which is enhanced by a significant amount of ('must-run') non-VRE power generation – these countries are able to address this surplus situation by a mix of VRE curtailment, electricity storage and power trade between countries with, on balance, a domestic power surplus (net exports) and countries with a domestic power deficit (net imports). In such an hour, some countries even import more (cheap) electricity than to cover their VRE shortage – or export less (low-priced) electricity than to address their domestic supply surplus – in order to store the surplus of electricity to be used or exported during other (higher-priced) hours of the year.

2.4 Other relevant COMPETES modelling results

In this section, we present and discuss some other relevant, interesting findings related to the scenario cases and results of the COMPETES modelling analyses elaborated above. In particular, these findings refer to the trends and changes in electricity prices as well as in power system costs presented and discussed below in Section 2.4.1 and 2.4.2, respectively.

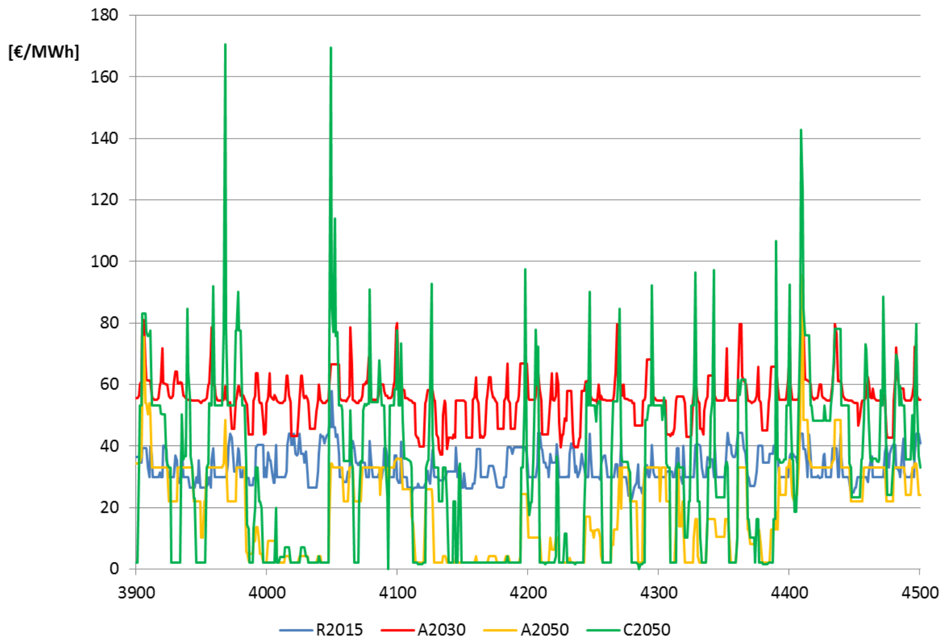
2.4.1 Electricity prices

Price levels and fluctuations

As an illustration, **Figure 48** presents fluctuations of hourly electricity price levels in the Netherlands during the mid of the year (hours 3900-4500) in selected scenario cases up to 2050. It shows that hourly electricity prices fluctuate heavily over the time frame considered, notably in the 2050 scenario cases. In particular, in C2050 – with a limited interconnection capacity – electricity prices fluctuate between 2 €/MWh (during hours with a relatively high VRE power supply) and 170 €/MWh (during hours with a relatively low VRE generation output, i.e. with a relatively high residual load). These price fluctuations are an indication for the potential business case of domestic flexibility options such as energy storage and demand response (which are considered further in Chapter 3 below).

In addition, **Figure 48** indicates that in some scenario cases the average electricity price level is higher than in other cases. For instance, over the time frame considered in **Figure 48**, electricity prices in A2030 are usually significantly higher than in R2015

Figure 48: Illustration of hourly electricity price levels and fluctuations during the mid of the year (hours 3900-4500) in some selected scenario cases, 2015-2050



Price duration curves

Figure 49 presents the duration curves of hourly electricity prices over the year as a whole for some selected scenario cases up to 2050. It shows that in R2015, this curve is still relatively flat, ranging from about 20 €/MWh in the bottom-right to some 90 €/MWh in the upper-left. In addition, it confirms that the (average) price level in R2015 is generally substantially lower than in A2030.

In A2030, the price variation is already significantly wider, ranging from about 25 €/MWh in the bottom right to more than 250 €/MWh in the upper-left of the price duration curve presented in **Figure 49**.[28] Moreover, electricity prices in A2030 are generally substantially higher in A2030 than in all other scenario cases presented in **Figure 49**.

[28] For visibility reasons, the electricity price at the Y-axis is capped at a level of 250 €/MWh. In a few hours in A2030, A2050 and C2050, however, electricity prices are much higher than 250 €/MWh (running up to 460 €/MWh). Moreover, in a few hours of these scenario cases, power demand is curtailed and priced at the value of lost load (VOLL), i.e. 3000 €/MWh, as discussed in Section 2.2.5. These higher prices (>250 €/MWh) are not recorded in **Figure 49**.

Figure 49: Duration curves of hourly electricity prices in some selected scenario cases, 2015-2050

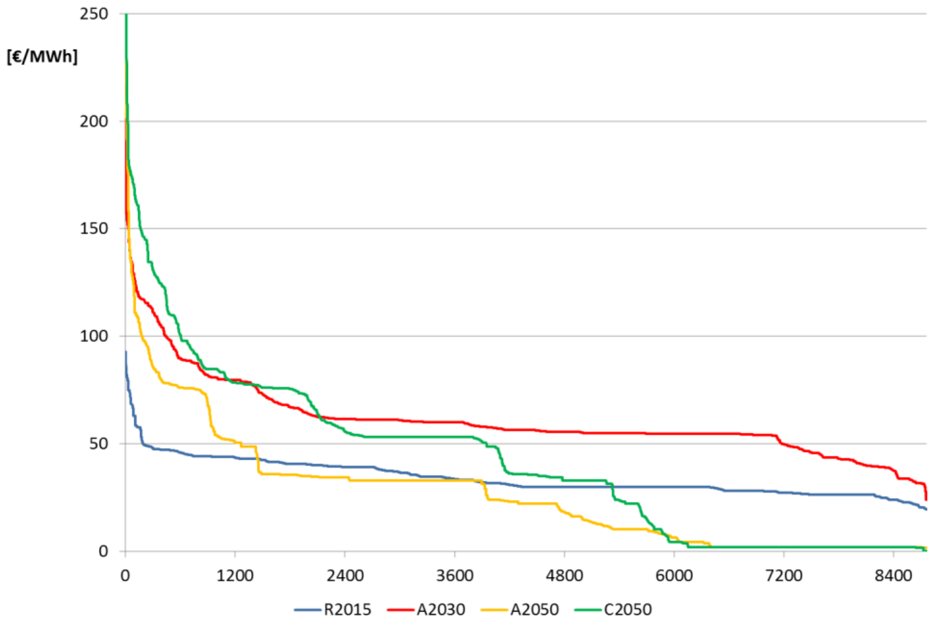


Figure 49 also shows the price duration curve for the two extreme 2050 scenario cases, i.e. A2050 – with an optimal (100%) expansion of the EU28+ interconnection capacity since A2030 – and C2050, with 0% interconnection expansion beyond A2030. In both cases, electricity prices vary widely, ranging from 2 €/MWh (during some 2000 hours of the year) to more than 250 €/MWh.[29] The low (minimum) price level of 2 €/MWh is set by the marginal costs of power generation from VRE sources (sun/wind) and refers particularly to hours in which there is a large VRE surplus (including power trade).

Figure 49 indicates that – apart from the hours in which electricity prices are set at the minimum marginal cost level of 2 €/MWh – power prices are usually substantially higher in C2030 than in A2050. This is due to the lower interconnection capacity in C2050. As a result, during a range of hours electricity end-users can benefit less from lower-priced electricity imports and have to pay prices set by domestic generation units, notably gas-fired plants, with often higher marginal costs.

Indicators of price volatility

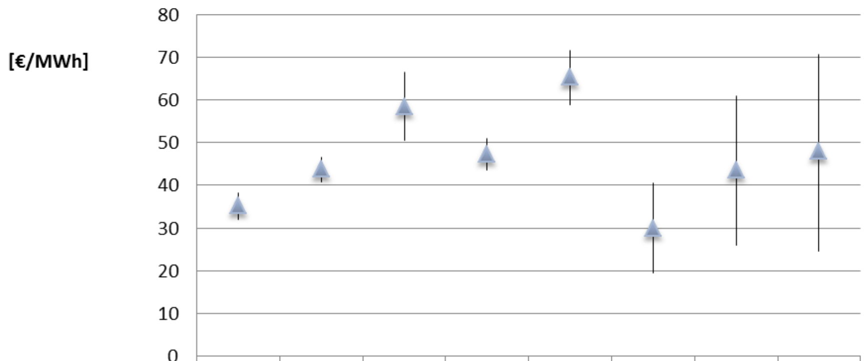
Finally, **Figure 50** presents some indicators of the level and volatility of the hourly electricity prices in all scenario case up to 2050. In the upper part of the figure, it shows that the weighted average electricity price increases from 35 €/MWh in R2015 to 65 €/MWh in A2030. This price increase results from the (assumed) increase of the fuel and CO_2 prices for the marginal coal- or gas-fired plants setting the power price.[30]

In A2050, however, the weighted average electricity price drops to 30 €/MWh. As indicated above, this price drop is particularly due to the fact that during a large number of hours of this scenario case the electricity price is set by the low marginal costs of domestic VRE generation or by the relatively cheap (VRE) power imports from abroad.

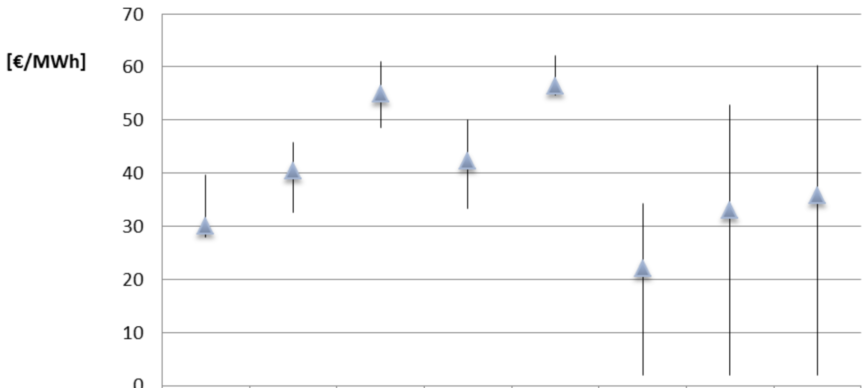
[29] See previous footnote.

[30] See Appendix B, Section B.5, for the assumed trends in fuel and CO_2 prices up to 2050.

Figure 50: Indicators of the level and volatility of the hourly electricity prices in all scenario cases, 2015-2050



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
Price volatility up	38	47	66	51	72	41	61	71
Price volatility down	32	41	50	44	59	19	26	25
▲ weighted average	35	44	58	47	65	30	44	48



	R2015	R2023	R2030	A2023	A2030	A2050	B2050	C2050
3rd quartile	40	46	61	50	62	34	53	60
1st quartile	28	33	49	33	55	2	2	2
▲ Median	30	40	55	42	56	22	33	36

Compared to A2050, the weighted average electricity price increases to 44 €/MWh in B2050 and to 48 €/MWh in C2050. As explained above, this is due to the lower (sub-optimal) interconnection capacities in B2050 (50%) and C2050 (0%), compared to A2050 (100%).

The upper part of **Figure 50** indicates also that the volatility of the hourly electricity prices increases substantially over the period 2015-2050. For instance, in R2015 the standard deviation – either upwards or downwards – amounts to 3 €/MWh, while in A2050 this deviation is 11 €/MWh. This increase in price volatility is mainly due to the large increase of the share of VRE sources in A2050, resulting in high hourly fluctuations of VRE output in total power supply.

In B2050 and C2050, the average standard deviation of electricity prices becomes even higher, i.e. approximately 17-18 €/MWh and 23 €/MWh, respectively. This increase in price volatility, compared to A2050, is due to the lower interconnection capacities in these scenario cases (implying that power trade flows play a smaller role in stabilising domestic electricity prices).

Finally, the lower part of **Figure 50** provides some alternative indicators of the (average) level and volatility of the hourly electricity prices in the FLEXNET scenario cases up to 2050. It shows, for instance, that the *median* electricity price moves in the same direction as the weighted average price, but it is generally lower than the weighted average price. Moreover, this price difference becomes larger over time (notably in B2050 and C2050). This implies that the weighted average electricity price is skewed by some (extremely) large values – which even becomes stronger over time – and, hence, the mean electricity price may provide a better idea of the 'typical' value of the electricity price.[31]

In addition, the lower part of **Figure 50** shows that the difference between the so-called '*first quartile'* and the '*third quartile'* increases substantially over the period 2015-2050. This is another, alternative indicator for the volatility of the electricity prices, confirming that the price fluctuations become larger over the period considered and that they are much stronger in C2050 than in A2050.[32]

Implications of power trade and related electricity price fluctuations for domestic flexibility options

Power trade in general – including the underlying assumptions on cross-border interconnection capacities and the resulting domestic electricity price fluctuations in particular – has a major impact on the business case of domestic flexibility options . This impact runs through two related lines. Firstly, the size (share) of the total flexibility needs met by cross-border power trade reduces the size (share) of the other, domestic flexibility options accordingly.

Secondly, power trade stabilises domestic electricity prices, i.e. it reduces the volatility (fluctuations) of these prices, thereby reducing the price incentives for other, domestic flexibility options. This applies in particular to those options that rely primarily on intertemporal price differences – notably short-run price fluctuations – to cover their business case, such as (domestic) energy storage and demand response (see also Chapter 3 below).

As noted, however, the impact of power trade on the business case of other, domestic flexibility options depends on the assumptions made with regard to the expansion of the interconnection capacities across the EU28+ as a whole and between the Netherlands and its neighbouring countries in particular. As illustrated in Section 2.3.3 above, in A2050 – with an 100% ('optimal') capacity expansion since A2030 – power trade accounts for almost three-fourths (74%) of total annual upward/downward flexibility needs, while the remaining part is addressed by VRE curtailment (20%) and non-VRE power generation (6%), notably from gas (5%) and, to a lesser extent, from other RES-E and coal (see **Figure 45** above).

31 The median is the value separating the higher half of a data sample from the lower half. For a ranked data set, it may be regarded as the 'middle' value. The basic advantage of the median in describing data compared to the mean – often simply described at the (weighted) 'average' – is that it is not skewed so much by extremely large or small values, and so it may give a better idea of a 'typical' value (source: Wikipedia).

32 In descriptive statistics, the quartiles of a ranked set of data values are the three points that divide the data set into for equal groups, each group comprising a quarter of the data. The first quartile (Q1) is defined as the middle number between the smallest number and the median of the data set. The second quartile (Q2) is the median of the data set. The third quartile (Q3) is the middle value between the median and the highest value of the data set (source: Wikipedia).

In B2050 – with 50% interconnection capacity expansion, compared to A2050 – the share of power trade declines significantly but still accounts for about two-thirds (65%) of the total annual upward/downward flexibility needs in this scenario case. The shares of the other (domestic) flexibility options increase accordingly, i.e. for VRE curtailment to 22% and for non-VRE power generation to 13%, in particular from gas (10%).

Finally, in C2050 – with 0% interconnection capacity expansion since A2030 – the share of power trade drops substantially – compared to both A2050 and B2050 – but still accounts for more than 40% of the total annual upward/downward flexibility needs in this scenario case. Similar to B2050, the shares of the other (domestic) flexibility options increase accordingly, i.e. for VRE curtailment to 28% and for non-VRE power generation even to 31%, in particular from gas (27%).

Note that in the COMPETES modelling analyses only domestic flexibility options such as VRE curtailment and non-VRE power generation benefit from lower interconnection capacities (and resulting lower trade volumes as well as related higher domestic price levels/fluctuations), whereas other options – such as energy storage or demand response – do not benefit at all (and do not even materialise in B2050 and C2050). For demand response this is simply due to the fact that it is not included in the FLEXNET-COMPETES modelling analysis, while energy storage options included in COMPETES (CAES, hydro pumped storage) appeared not to be viable, even not in B2050 and C2050 (see Section 2.2.6 and Appendix B). As remarked above, energy storage and demand response are consider further as part of the OPERA modelling analysis (discussed below in Chapter 3).

To conclude, power trade as a flexibility option has a major impact on the business case of other, domestic options to meet the demand for flexibility due to the variability of the residual load in the Dutch power system up to 2050, including the impact of power trade volumes and the related fluctuations of domestic electricity prices. Due to these related volume and price effects of power trade, the business case and, hence, the size (share) of other, domestic flexibility options is lower accordingly This impact, however, depends significantly on the assumptions made with regard to the EU28+ interconnection capacities, in particular between the Netherlands and its neighbouring countries.

2.4.2 Power system costs

Table 7 provides a summary overview of the power system costs in the EU28+ as a whole for all scenario cases up to 2050. For the (annualised) investment costs and the fixed operation and maintenance (O&M) costs, the figures presented in **Table 7** are additional to the costs of the baseline scenario (as these baseline costs are regarded as ‘fixed’ or ‘sunk’ costs, regardless of the FLEXNET scenario cases). **Table 7** shows that the total (additional) power system costs in the EU28+ *decrease* from € 48 billion in R2015 to € 27 billion in A2050. This decrease, however, results mainly from the large increase of power generation from VRE sources, which have generally high investment costs (included in the baseline, although not in **Table 7**) but low marginal generation costs (included in the table).

Table 7: Power system costs in the EU28+ as a whole in all scenario cases, 2015-2050 (in million €)

	Generation costs	Fixed O&M costs	Transmission investment costs	Generation capacity investment costs	Demand curtailment costs	Total costs
R2015	48099	28	-	-	-	48127
R2023	58926	32	-	-	146	59104
R2030	65900	44	-	1410	35	67389
A2023	61893	32	-	-	307	62232
A2030	73782	45	733	4325	65	78949
A2050	21832	104	5024	0	22	26981
B2050	25965	104	2512	522	57	29161
C2050	32985	104	0	3941	71	37101
Difference (in million €)						
B2050-A2050	4133	0	-2512	522	36	2180
C2050-B2050	7020	0	-2512	3419	14	7940
C2050-A2050	11153	0	-5024	3941	49	10120
Difference (in %)						
B2050-A2050	19%	0%	-50%	-	165%	8%
C2050-B2050	27%	0%	-100%	654%	24%	27%
C2050-A2050	51%	0%	-100%	-	229%	38%

Definitions:

- *Generation costs*: Includes variable O&M costs, fuel costs, CO_2 costs, start-up costs and the no-load costs.
- *Fixed O&M costs*: Fixed operation and maintenance costs of units (Installed capacity (MW) * Fixed O&M (euro/MW/year)). Renewables are included as well.
- *Transmission investment costs*: Investments costs for cross-border transmission (i.e. interconnection costs, representing line costs + additional equipment) are assumed to be paid per country on a 50-50% basis.
- *Generation capacity investment costs*: Investments in new generation capacity.
- *Demand curtailment costs*: Value of Lost Load (VOLL, i.e. 3000 euro/MWh) * volume of demand curtailment (MWh).

Note: investment costs and fixed O&M costs are additional to the costs included in the baseline scenario.

Hence, it is more relevant and interesting to look at the *differences* in power system costs included in **Table 7** *between* the 2050 scenario cases (as the baseline fixed O&M and investment costs are similar in these scenario cases). **Table 7** shows that, compared to A2050, power system costs in the EU28+ as a whole are approximately € 2.2 billion (8%) higher in B2050 and about € 10 billion (38%) in C2050.

The higher total costs in B2050 and C2050 result, on balance, from lower (annualised) transmission investment costs on the one hand and higher costs for both generation capacity investments and (variable) power generation operations on the other hand (including higher costs due to higher levels of VRE curtailment in these scenario cases).

In particular, the lower costs for interconnection capacity investments are more than compensated by the higher costs for additional domestic investment needs in non-VRE generation capacities, operating at higher marginal production costs (for details, see **Table 7**).

Table 8 provides the power system costs in all scenario cases up to 2050 for the Netherlands only. Compared to **Table 7**, this table includes an additional column to account for the net power trade costs (besides the domestic power generation costs).[33] It shows that, compared to A2050, total power system costs in the Netherlands are about € 1.9 billion (43%) higher in B2050 and approximately € 2.4 billion (54%) in C2050.

Table 8: Power system costs in the Netherlands in all scenario cases, 2015-2050 (in million €)

	Generation costs	Net trade costs	Fixed O&M costs	Transmission investment costs	Generation capacity investment costs	Demand curtailment costs	Total costs
R2015	1424.0	550.9	0.4	-	-	-	1975.3
R2023	2066.0	-882.2	1.1	-	-	-	1184.8
R2030	2736.2	-1365.6	1.5	-	0.0	-	1372.0
A2023	2246.8	-564.1	1.1	-	-		1683.8
A2030	3116.6	607.5	1.5	18.6	0.0	7.6	3751.8
A2050	986.2	3117.4	4.5	338.4	0.0	3.8	4450.4
B2050	1450.2	4187.2	4.5	169.2	522.4	14.1	6347.7
C2050	3330.5	1907.7	4.7	0.0	1573.9	51.4	6868.2
Difference (in million €)							
B2050-A2050	464.0	1069.8	0.0	-169.2	522.4	10.3	1897.3
C2050-B2050	1880.3	-2279.5	0.1	-169.2	1051.5	37.3	520.5
C2050-A2050	2344.3	-1209.7	0.2	-338.4	1573.9	47.5	2417.8
Difference (in %)							
B2050-A2050	47%	34%	1%	-50%	-	267%	43%
C2050-B2050	130%	-54%	3%	-100%	201%	264%	8%
C2050-A2050	238%	-39%	4%	-100%	-	1236%	54%

Note: See definitions and note under **Table 7**. In addition, net trade costs are defined as the sum of the hourly net trade volumes (MWh) * the hourly electricity price in the Netherlands (€/MWh).

The higher total system costs in B2050 and C2050 result mainly from (i) higher (annualised) generation capacity investment costs (notably in additional gas-fired units) and (ii) higher generation costs (due to higher domestic generation volumes times higher marginal generation costs of gas-fired units), which is only partially compensated by (iii) lower (annualised) transmission capacity investment costs, and (iv) lower net trade costs (due to lower net trade volumes multiplied by the respective hourly

[33] Net power trade costs are defined as the sum of the hourly net trade volumes times the hourly electricity price in the Netherlands. These costs are not included in **Table 7** as for the EU28+ as a whole there is no net (external) power trade and, hence, the generation costs of total ('domestic') power demand are similar to the generation costs of total ('domestic') power supply.

electricity prices). Hence, the lower interconnection capacities in B2050 and C2050 result in lower transmission investments and lower net trade (import) volumes, but also in higher domestic generation capacity investments and higher, non-VRE electricity production (including more VRE curtailment in C2050) and therefore, on balance, in higher total power system costs in B2050 and C2050.

2.5 Summary and conclusions

This chapter has analysed the options to meet the demand for flexibility due to the variability of the residual load in the Dutch power system up to 2050 by means of the EU28+ electricity market model COMPETES. The major findings of this analysis include:

- According to the COMPETES modelling outcomes, the optimal ('least-cost') interconnection capacity across all EU28+ countries increases from 62 GW in R2015 to 121 GW in A2030 and to 241 in A2050. For the Netherlands only, the respective capacity figures amount to 6 GW, 11 GW and 33 GW.

- In B2050 (50% interconnection expansion beyond A2030), the cross-border transmission capacity amounts to 181 GW in the EU28+ as a whole and 22 GW in the Netherlands only. In C2050 (0% interconnection expansion) these figures amount to 121 GW and 11 GW, respectively (i.e. similar to the capacity levels in A2030).

- The installed VRE capacity (sun/wind) in the Netherlands increases from almost 5 GW in R2015 to approximately 92 GW in A2050. On the other hand, the conventional capacity (gas/coal/nuclear) declines from 25 GW to 9 GW, respectively. In the 2050 scenario cases, however, gas-fired capacity increases rapidly from 6 GW in A2050 to almost 18 GW in B2050 and even to about 32 GW in C2050 (due to the similar decrease in interconnection capacity over these cases mentioned above). This increase refers particularly to central gas turbines (GTs, +14 GW) and combined cycle gas turbines (CCGTs) with carbon capture and storage (CCS, +12 GW).

- In the Netherlands, total electricity production doubles in absolute terms from 96 TWh in R2015 to 185 TWh in A2050. The share of sun and wind in total output increases from 9% to 87%, respectively. On the other hand, for nuclear the share in total power generation declines from 4% in R2015 to zero in A2050, for coal from 31% to 0.2% and for gas from 51% to 12%, respectively.

- In C2050 (0% interconnection expansion), electricity production in the Netherlands is significantly higher (222 TWh) than in A2050 (185 TWh). This increase in total output (+37 TWh) is almost fully met by an increase in gas-fired generation only, which rises steeply from 22 TWh in A2050 to 58 TWh in C2050 (i.e. by 36 TWh). As a result, the share of gas in total electricity production increases from 12% in A2050 to 26% in C2050.

- The increase in total gas-fired power generation by 36 TWh in C2050, compared to A2050, is almost fully met by the newly installed CCGT CCS capacity, i.e. by 32 TWh, and to a lesser extent by the increased GT capacity (by 2 TWh).

- There is a clear trade-off between the availability (and use) of cross-border interconnection capacity and the deployment of (domestic) gas-fired capacity. In A2050, with a relatively large interconnection capacity for the Netherlands (i.e. 33 GW), the need for and deployment of gas-fired generation capacity is relatively low and stable, implying that, on average, a predominant share of this capacity is deployed for a large number of running hours. On the other hand, in C2050 – with a relatively small interconnection capacity (i.e. 11 GW) – the need for, and deployment of peak and upper mid-load gas-fired capacity is relatively high and declines steeply, implying that, on average, a major share of this capacity is deployed for a small number of running hours.

- Up to 2030, there is no curtailment of VRE power generation as the share of VRE output in total power demand is still manageable (i.e. less than 50%). In A2050 – with a share of 80% of (uncurtailed) VRE output in total power demand and a large interconnection capacity (33 GW) – the curtailment of power generation from sun PV is still zero, but from wind it amounts to almost 26 TWh, i.e. 22% of realised (curtailed) wind production, 16% of total VRE output and 14% of total electricity generation by the Dutch power system in A2050.

- In C2050 – also with a share of 80% of (uncurtailed) VRE output in total power demand but with a small interconnection capacity (11 GW) – curtailment of sun PV generation amounts to 0.1 TWh and of wind generation to more than 26 TWh , i.e. together almost 17% of total VRE production.

- Curtailment of power demand – as a flexibility option to balance electricity demand and supply – is restricted to the alternative scenario cases of 2030 and 2050 only, while it is limited to a few hours per year (≤ 6 hours) and, in general, to a small amount per hour, varying from 1 GW in A2050 to 10 GW in C2050.

- Energy storage, by means of compressed air energy storage (CAES) or hydro pumped storage (HPS), does not appear as a viable flexibility option for the Netherlands in the FLEXNET-COMPETES modelling scenarios up to 2050 (although indirectly the Netherlands may benefit from HPS as a flexibility option at the EU28+ level through its power trade relations with other, neighbouring EU28+ countries, including Norway, Germany and France).

- At an aggregated (annual) level, power trade by the Netherlands over the period 2015-2030 varies widely from large net imports in R2015 (17 TWh) to large net exports in R2023 (21 TWh) and R2030 (27 TWh). In the alternative scenario cases, however, the Netherlands becomes a major net importer of electricity again, varying from 11 TWh in C2050 (small interconnection capacity) to 48 TWh in A2050 (large interconnection capacity).

- Moreover, within the focal years considered, *hourly* power trade is even more volatile, i.e. varying between the interconnection capacity of the Netherlands in the respective scenario cases. For instance, in A2050 net hourly power trade varies between +33 GW (imports) to -33 GW (exports) whereas in C2050 it varies between +11 GW and -11 GW, respectively.

- Aggregated over all hours of the year, the (domestic, uncurtailed) residual load declines in the reference scenario from 104 TWh in 2015 to 60 TWh in 2030 and in the alternative scenario from 86 TWh in 2023 to 47 TWh in 2050. In some cases, this (domestic, uncurtailed) residual load is enhanced by net exports – notably in R2023, R2030 and A2023 – and/or by VRE curtailment, in particular in the alternative 2050 scenario cases (A2050, B2050 and C2050).

- In the reference scenario cases R2015-R2030, the (national, curtailed) residual power demand is met primarily by domestic non-VRE power generation, in particular from fossil fuels (coal, gas) and, to a lesser extent, from nuclear and other RES-E. In addition, in R2015 a minor part of this residual power demand is covered by net imports.

- In the alternative scenario cases A2023 and A2030, the residual supply side shows a similar picture: residual power demand is primarily met by non-VRE power generation, while in A2030 an additional, small part is covered by net imports.

- In the alternative 2050 cases, however, the situation is quite different. Notably in A2050, about two-thirds of the (national, curtailed) residual power demand is covered by net imports while the remaining part is addressed by domestic, non-VRE generation.

- On the other hand, in C2050 (0% interconnection expansion), the residual supply side is quite different compared to A2050 (100% interconnection expansion). Due to the interconnection restriction, the contribution of net imports to total supply falls from 48 TWh in A2050 to 11 TWh in C2050, whereas the contribution of gas-fired power generation to meet electricity demand increases from 22 TWh to 58 TWh, respectively. As a result, gas becomes by far the most dominant source of total (national) residual power supply in C2050.

- However, in the 2050 scenario cases – with a large VRE surplus over a large number of hours – the residual supply situation is quite different in the hours with a VRE surplus compared to the hours with a VRE shortage. The VRE supply surplus is usually enhanced by non-VRE generation – notably from gas and, to a lesser extent, from other RES-E – because of 'must-run' production considerations and/or ample export opportunities in certain hours. The resulting domestic surplus of power supply is predominantly met by VRE curtailment and, to a lesser extent, by net exports.

- In R2015, the need for maximum hourly ramp-up (3.0 GW/h) is still solely met by power generation from fossil fuels, in particular from gas (2.9 GW/h) and, to a lesser extent, from coal (1.3 GW/h), whereas the ramp of net imports is still relatively small and even moves in the other direction (-1.2 GW/h).

- In almost all scenario cases the need for both *maximum hourly ramp-up and maximum hourly ramp-down* is predominantly (60-100%) met by hourly changes in net power trade. The only exceptions include the need for upward flexibility in R2015 (as mentioned above) and the need for downward flexibility in B2050 and C2050. In particular, in C2050 (0% interconnection expansion), only a minor share of the maximum need for hourly ramp-down (-29 GW/h) is met by net imports (-6 GW/h), whereas major shares are addressed by VRE curtailment (-11 GW/h) and gas-fired generation (-11 GW/h) and a small share by other RES-E (<1 GW/h).

- Hourly variations in power generation from fossil fuels (coal, gas) play a more important role as flexibility options to meet flexibility needs in terms of the *maximum cumulative ramps* up to A2030, notably from coal to meet downward cumulative flexibility needs.

- In the 2050 scenario cases, the role of (hourly variations in) VRE curtailment in meeting maximum cumulative ramps is more important, whereas the role of (hourly variations in) power trade is less important (compared to meeting maximum hourly ramps, discussed above). More specifically, the share of VRE curtailment in addressing cumulative upward flexibility needs amounts to 44% in A2050 and increases to almost 60% in C2050, whereas the share of power trade is 56% in A2050 and drops to 31% in C2050.

- Flexibility needs in terms of *total annual for demand for upward/downward flexibility* (due to the hourly variations of the residual load) increase from 2.2 TWh in R2015 to more than 15 TWh in the 2050 scenario cases. In R2015, these needs are predominantly met by (hourly) increases in power generation from gas (49%) and coal (42%), while the remaining part is covered by increases in net imports (9%).

- In R2023, the total annual demand for upward flexibility increases to 3.5 TWh. However, already in this scenario case the share of power trade (net imports) increases to 65%, whereas the shares of gas and coal drop to 30% and 5%, respectively.

- In the scenario cases A2023 up to A2050, the share of power trade in total flexibility demand (upwards/downwards) is significantly higher, whereas the share of fossil fuels is lower accordingly. In A2050, the share of net power imports in total annual flexibility demand/supply amounts even to almost 74%, whereas the share of gas and coal amounts to only 4.6% and 0.6%, respectively. The remaining part is largely accounted for by (hourly changes in) VRE curtailment (20%) and, to a lesser extent, by generation from other RES-E (1%).

- In the two other 2050 scenario cases – with significantly lower interconnection capacities – the share of power trade in total upward/downward flexibility is significantly lower, while the shares of the other flexibility options are higher accordingly. More specifically, in C2050 (% interconnection expansion), the share of gas-fired generation in total annual flexibility needs increases to 27% (compared to less than 5% in A2050) while the share of VRE curtailment rises from 20% in A2050 to 28% in C2050. In C2050 , however, power trade still accounts for the largest share of all flexibility options (41%), while in B2050 (50% interconnection expansion), the share of net imports in total flexibility needs, however, even amounts to 65%.

- To conclude, in R2015 hourly changes in the power generation from non-VRE sources – notably from gas, coal and, to a lesser extent, other RES-E (biomass, hydro) – are the main supply options to meet the demand for upward/downward flexibility due to the (hourly) variability of the residual load, regardless of the indicator used to express and quantify this type of flexibility demand. In all scenario cases over the period 2023-2050, however, hourly changes in power trade become the most important (dominant) supply option to address the demand for flexibility due to the variability of the residual load.

- Our analysis shows, however, that the role of the different supply options to meet the need for flexibility depends highly on the assumptions made with regard to the expansion of the interconnection capacities across the EU28+ countries in general and between the Netherlands and its neighbouring (interconnected) countries in particular. For instance, in A2050, the shares of the three main supply categories in addressing total annual flexibility demand – i.e. power trade, VRE curtailment and power generation from non-VRE resources – amount to 74%, 20% and 6%, respectively.

- On the other hand, in C2050, these shares amount to 41%, 28% and 31%, respectively. In particular, the share of gas-fired power generation increases from 4.6% in A2050 to almost 27% in C2050.

- Even in hours in which the EU28+ countries as a whole and the Netherlands in particular faces an ‘extreme’ high level of either a large positive residual load (VRE shortage) or a large negative residual load (VRE surplus), these countries are able to address these situations by a mix of (hourly variations in) non-VRE power generation, VRE curtailment, demand curtailment, energy storage and, in particular, power trade between countries with, on balance, a domestic power surplus (net exports) and countries with a domestic power deficit (net imports).

- Over the period R2015- A2030, the (weighted average, annual) electricity price increases significantly (mainly due to the higher fuel and CO_2 prices for the marginal units setting the power price over this period). Compared to A2030, however, the electricity price drops substantially in A2050 (due to the large share in total power production by VRE sources with low marginal costs). In C2050, on the other hand, the electricity price is significantly (60%) higher than in A2050 (due to the lower interconnection capacity and the resulting number of hours in which electricity end-users can benefit less from lower-priced electricity imports).

- Over the period 2015-2050, *hourly* electricity prices fluctuate heavily. Moreover, this price volatility increases over time, mainly due to both the increasing share of VRE sources – with low marginal costs – in total power production, setting the price during a growing number of hours, as well as the decreasing share of gas-fired generation – with high marginal costs, setting the price during a diminishing number of (peak load) hours (i.e. hours with a relatively high VRE shortage). In addition, electricity price volatility increases in B2050 and C2050, compared to A2050, due to the lower interconnection capacities in these scenario cases, (implying that power trade flows play a smaller role in stabilising domestic electricity prices).

- Power trade as a flexibility option has a major impact on the business case of other, domestic options to meet the demand for flexibility due to the variability of the residual load in the Dutch power system up to 2050, including the impact of (hourly variations in) power trade volumes and the related fluctuations of domestic electricity prices. Due to these related volume and price effects of power trade, the business case and, hence, the size (share) of other, domestic flexibility options is lower accordingly. This impact, however, depends significantly on the assumptions made with regard to the EU28+ interconnection capacities, in particular between the Netherlands and its neighbouring countries.

- Compared to A2050, total power system costs in the EU28+ as a whole are approximately € 2.2 billion (8%) higher in B2050 and about € 10 billion (38%) in C2050. In the Netherlands only, total power system costs are about € 1.9 billion (43%) higher in B2050 and approximately € 2.4 billion (54%) in C2050. These higher costs result, on balance, from lower (annualised) interconnection capacity investments on the one hand and higher costs for (gas-fired) generation capacity investments and (variable) power generation costs on the other hand.

3

Options to meet flexibility needs due to the variability of the residual load (ii): OPERA modelling results

This chapter presents and discusses the methodology and major results of the national analysis of supply options to meet the demand for flexibility due to the variability of the residual load in the Dutch power system up to 2050 by means of the OPERA model. As explained in Section 2.1, the OPERA modelling results are additional, complementary to the COMPETES modelling findings as outlined in Chapter 2 in the sense that the power trade results of COMPETES are used as given input into OPERA and that, subsequently, OPERA focusses specifically on analysing some domestic flexibility options, in particular on demand response and energy storage (which are not – or to a lesser extent – covered by COMPETES). Hence, this chapter provides an addition to – but also a comparison of the OPERA modelling results with the COMPETES modelling results discussed in the previous chapter.

More specifically, the structure of the current chapter is, to some extent, similar but additional to the previous chapter and runs as follows. First, Section 3.1 outlines briefly the OPERA modelling approach (while more details are provided in Appendix D of the current report). Subsequently, the OPERA modelling results are presented and discussed with regard to four flexibility options individually, i.e. (i) demand response (Section 3.2), (ii) energy storage (Section 3.3), (iii) curtailment of VRE power generation (Section 3.4), and (iv) non-VRE power generation (Section 3.5). Next, Section 3.6 presents a summary overview of the net residual power balances of the scenario cases analysed by OPERA, whereas Section 3.7 presents a summary overview of the total annual supply of flexibility options to meet the demand for flexibility due to the variability of the residual load. Finally, Section 3.8 summarizes the major findings and conclusions of the current chapter.

3.1 OPERA modelling approach

OPERA (*Option Portfolio for Emissions Reduction Assessment*) is an integrated optimisation model of the energy system in the Netherlands developed by ECN. It is a bottom-up technology model that determines which configuration and operation of the energy system – combined with other sources of emissions – meet all energy needs and other, environmental requirements of the Dutch society, whether market-driven or policy imposed, at minimal energy system costs. These requirements generally include one or multiple emission caps. In addition to energy related technologies and emissions, the model is capable to include technologies and emissions that are not energy-related as well.

For the choice of technologies (technology options), OPERA draws upon an elaborate database containing technology factsheets, as well as upon data on energy and resource prices, demand for energy services, emission factors of energy carriers, emission constraints and resource availability. In addition, for the baseline scenario, OPERA derives various baseline data from the Dutch Reference Outlooks and, more recently, from the National Energy Outlooks (see, for instance, ECN et al., 2016). These data provide a baseline scenario based on extrapolation of existing and proposed policies.

The baseline includes, among others, the demand for energy services that must be met (e.g. the demand for space heating, lightning, transport, products, etc.). OPERA uses the baseline to compare its results with the outcomes of alternative (policy) scenarios in terms of additional emission reductions, changes in energy demand and supply, changes in energy system costs, etc.

The baseline scenario is represented by a technology portfolio based on the complete energy balances of the Netherlands as reported in MONIT (www.monitweb.nl). These energy balances distinguish between energetic energy use, non-energetic use (feedstock in e.g. the petro-chemical industry) and other energy conversions (e.g. cokes ovens or refineries).

The OPERA model covers both the demand and supply side of the Dutch energy system, as well as the energy networks connecting the various parts of this system, including electricity, gas, heat, hydrogen and energy conversion sectors such as oil refineries or liquid biofuel installations

For further details of the OPERA model, see Appendix D.

Time slice approach
Demand and (variable) supply profiles are input into the OPERA model with hourly resolution. This means that there are 8760 values per profile input into the model. Such a high temporal resolution with a large number of technologies and other input variables would lead to excessive runtime and memory use of the computer model. It was therefore decided to decrease the number of time periods used in the optimization loop by grouping the hours of the year into sets, called *time slices*.

Hence, in order to achieve a match between hourly energy demand and supply within computability limitations, the OPERA model applies a so-called ‘time slice approach’ in which the 8760 hours of the year are attributed to a limited set of separate time slices. Consequently, OPERA adopts an innovative approach in utilizing most relevant patterns in energy demand and supply covering the 8760 hours of the year, while not explicitly modelling each of these hours separately.

The basic time slice approach is to smartly group together those hours of the year that have very similar characteristics with respect to the (time sequence of) energy demand and supply. Energy supply and demand exhibits particular patterns over the hours of the day, over the week, across seasons, etc. Based on historical hourly data on all relevant supply and demand patterns (i.e. wind and solar profiles, heat and electricity demand profiles), time slice algorithms smartly combine those hours of the year that are (most) similar, and take account of the sequence of a particular hour relative to the daily peak in demand. In this way, model simulations can capture the different energy system balances throughout the year, while not putting to heavy requirements upon computing power capacity. The approach is flexible as the desired amount of time slices (and associated computing time per scenario run) can be varied in the OPERA interface. For the analysis of the FLEXNET scenario cases, OPERA has used the relatively high number of 61 time slices.

A consequence (disadvantage) of the time slice approach, however, is that it generally tends to reduce the hourly variations of energy demand and supply as the outcomes are based on ‘average’ values of the respective time slices. Hence, the OPERA modelling outcomes on the hourly variations of the residual power demand and supply – and the resulting flexibility demand and supply – are not always fully similar, i.e. usually lower, than the comparable COMPETES modelling results.

Moreover, due to the OPERA modelling characteristics (of an integrated energy system) it was not always possible to model the electricity demand profiles of the FLEXNET project – as developed during the first phase of the project – in exactly the same way as conducted by the COMPETES model. As a result, there are sometimes (small) differences between the OPERA versus COMPETES modelling results in terms of total electricity demand, flexibility needs, etc.

Finally, in order to save in modelling efforts, time, etc., the OPERA modelling analysis has not been conducted for all (eight) FLEXNET scenarios but for the (four) most relevant, interesting cases, i.e. R2030, A2030, A2050 and C2050 (including some additional sensitivity scenario analyses). In addition, as said, the OPERA modelling efforts have been focussed on analysing some specific domestic flexibility options, in particular demand response and energy storage. The results of these analyses are presented and discussed in the sections below.

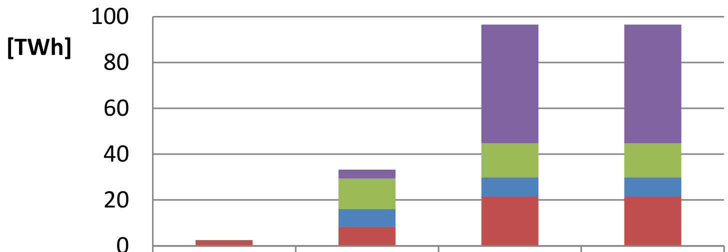
3.2 Demand response

As part of the OPERA modelling analyses, we have particularly investigated the potential of demand response by some selected power demand technologies as an option to address flexibility needs of the Dutch power system up to 2050 (where demand response is defined as shifting part of power demand in a certain hour to another hour of the day, week, month, etc., either forwards or backwards). These technologies include electric passenger vehicles (EVs) as well as three energy conversion technologies, i.e. power-to-gas (P2G), power-to-heat (P2H) and power-to-ammonia (P2A).

At present, the power demand by these technologies is still (negligible) small but it is expected that it will grow rapidly in the coming decades and that it offers, in principle, a large potential for demand response as a flexibility option for the Dutch power system, perhaps already – to some extent – in the period up to 2030 but notably in the years beyond 2030.

Figure 51 presents the projected annual power demand of the four selected technologies in four selected FLEXNET scenario cases over the years 2030-2050. These demand projections are partly based on the underlying assumptions of these scenario cases, in particular for the projected power demand by electric vehicles (as discussed in the report on the first phase of FLEXNET), and partly on the outcomes of the OPERA modelling analyses – notably for the projected demand by the three energy conversion technologies (P2G, P2H and P2A) – in order to meet the required long-term policy target of transforming the energy system towards a greenhouse gas reduction of at least 85% by 2050, compared to 1990.

Figure 51: Annual power load of selected demand-responsive technologies in selected FLEXNET scenario cases, 2030-2050



	R2030	A2030	A2050	C2050
P2G	0.0	3.9	51.8	51.8
P2H	0.0	13.3	14.7	14.7
P2A	0.0	7.6	8.5	8.5
EV	2.5	8.4	21.5	21.5

Figure 51 shows that in the reference scenario case of 2030 (R2030), power demand by the three selected energy conversion technologies is still zero while the annual power load by EVs is relatively low (i.e. 2.5 TWh). In the alternative scenario case of 2030 (A2030), however, power demand by EVs increases to 8.4 TWh while it amounts to

almost 25 TWh for the three technologies P2G, P2H and P2A as a whole. In the two 2050 scenario cases (A2050 and C2050), these figures increase rapidly and amount to almost 22 TWh and 75 TWh, respectively. Together these four technologies demand almost 97 TWh by 2050, i.e. more than 40% of total power load in that year (about 230 TWh).

Demand response by the energy conversion technologies

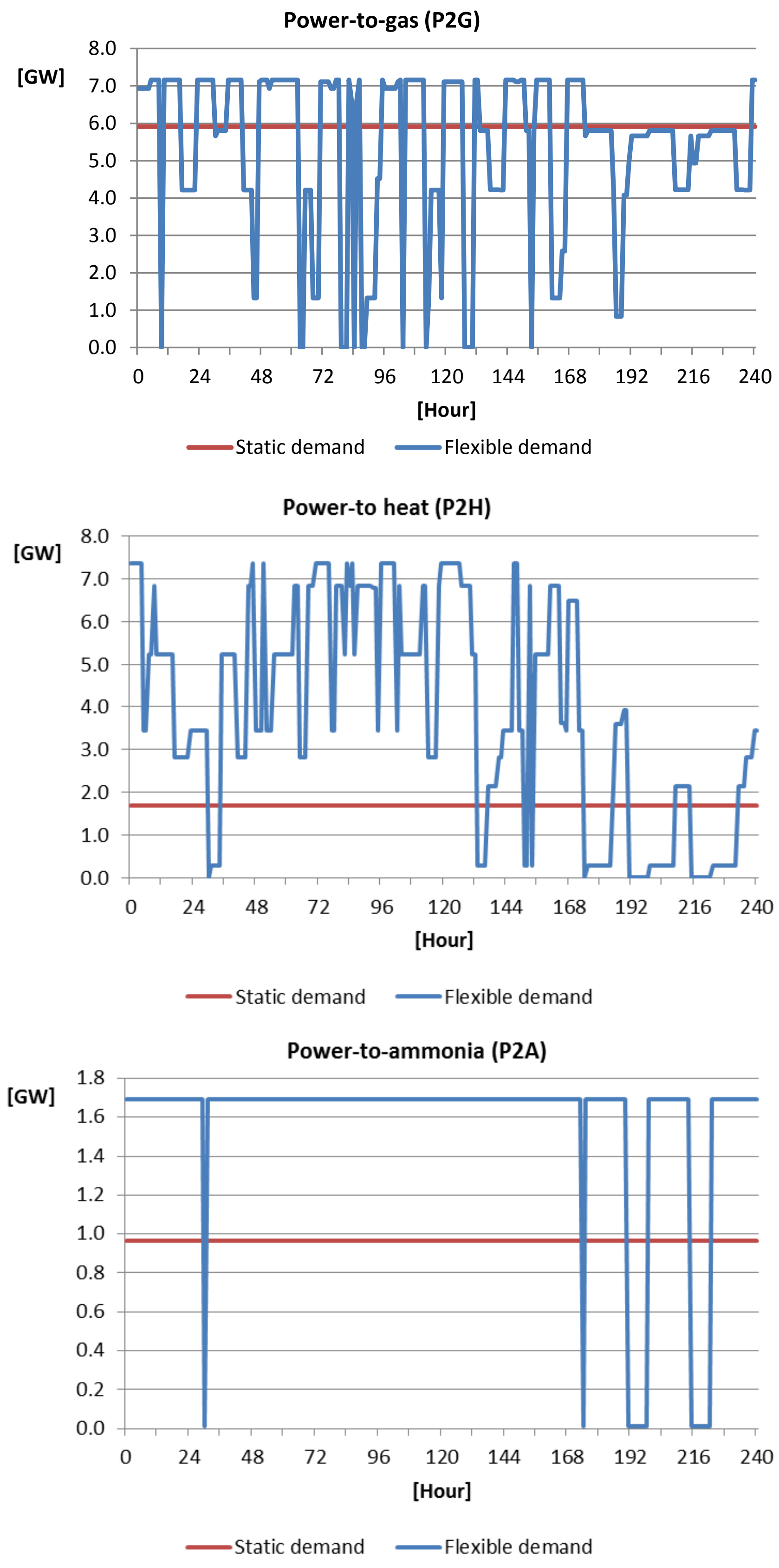
Figure 52 provides an illustration of demand response by the three selected energy conversion technologies during the first ten days (240 hours) of A2050. In each graph, the red line presents the static (inflexible) hourly power demand pattern for each of these technologies – which is assumed to be fully flat – while the blue curve presents the flexible (price-responsive) power demand profile. For all three technologies, the basic demand response condition is that in both demand cases of a technology – i.e. static and flexible demand – its total annual power demand is fixed at the same level. In addition, some specific demand response conditions apply to some of these technologies:

- *Power-to-ammonia (P2A):* Compared to a fully flat (static) input-output pattern throughout the year, P2A is allowed to produce more – or less – across the different (61) time slices of the OPERA model but not within a single time slice in which the hourly input-output level is fixed at the same – average – level. In principle, there is no (technological) limit to the maximum output of a time slice, but the minimum level is set a 1% of the flat (static) profile.
- *Power-to- heat (P2H):* A major condition is that the heat demand profile of industry has to be met. This profile is rather flat and fixed. However, there are several competing technologies – including P2H – to meet the industrial heat demand profile. Hence, the flexible demand profile of P2H is determined by the OPERA model depending on the competitive conditions between these technologies, notably on the fluctuating power prices across the time slices of the model. The demand response of P2H is calculated as the difference between the flexible demand profile and the (assumed) flat demand patterns (similar to the other two selected energy conversion technologies).
- *Power*-to-gas (P2G): Apart from the general (fixed total annual demand) condition, there are no additional, specific demand-responsive conditions for P2G. The OPERA model itself determines when it is most attractive to produce P2G in order to meet the annual demand level.

Figure 52 shows that during the first ten days of A2050 the demand response varies across the three technologies considered. For instance, the (assumed) static demand pattern of P2A is fixed at a flat level of almost 1 GW per hour. During the first ten days of A2050, however, - in which VRE power generation is relatively high and, hence, power prices are relatively low – the flexible power demand profile of P2A is at its economically attractive maximum (input-output) level of about 1.7 GW during most hours of the period considered, while its minimum level is determined, as noted, at 1% of the static demand pattern, applying to a limited number of hours considered (see lower part of **Figure 52**).[34]

[34] Note that **Figure 52** is not representative for the year as a whole as the first ten days of A2050 are characterised by, as remarked, a large supply (surplus) of VRE power generation – notably from wind – and, hence, power prices are relatively low during this period, whereas during other periods of A2050 VRE power supply is relatively low and, so, power prices are relatively high during these periods.

Figure 52: Illustration of power demand response of three energy conversion technologies (P2G, P2H and P2A) during the first ten days (240 hours) of A2050



In the case of P2H, the static demand pattern is fixed at a level of 1.7 GW per hour. On the other hand, the flexible demand profile of P2H is at its economically attractive, relatively high maximum level of approximately 7.4 GW during a limited number of hours of the period considered, while its minimum level amounts to zero during a few hours of this period. During most hours, however, power demand by P2H varies widely between these minimum and maximum levels (see middle part of **Figure 52**).

In contrast, the static demand pattern of P2G is fixed at a flat level of almost 6 GW per hour. Its flexible demand profile, however, varies widely between zero (minimum level) and the relatively low maximum level – i.e. compared to the fixed static level – of 7.2 GW per hour (see upper part of **Figure 52**).

The difference between the fixed static (flat) level and the flexible, economically attractive (minimum/maximum) power demand level of the respective energy conversion technologies depends on the specific competitive, techno-economic conditions of these technologies in the hours (time slices) concerned, including in particular the power price during these hours and the share of (variable) electricity costs versus (fixed) investment costs in total production costs of the technologies concerned, as specified into the OPERA model (see below).

Demand response of electric passenger vehicles

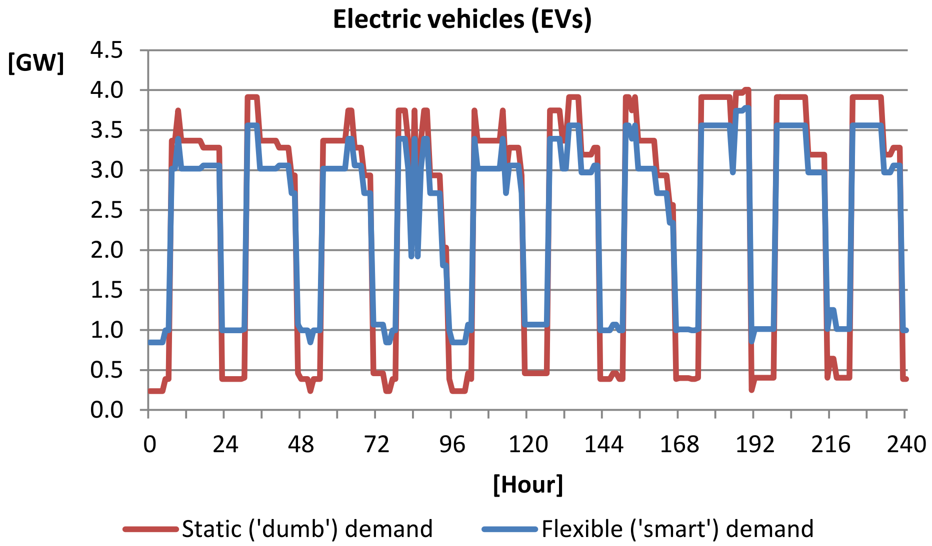
Figure 53 provides an illustration of power demand response of electric passenger vehicles (EVs) during the first ten days (240 hours) of A2050. The red curve represents the static – or better 'dumb' – EV demand profile as developed during the first phase of the FLEXNET project (see report phase 1, notably Appendix A). On the other hand, the blue curve represents the flexible ('smart', 'price-responsive') EV demand profile as assumed and developed during the second project phase.

At the national, aggregated level, the flexible (smart) EV demand profile largely meets the conditions set by the demand-responsive profile used at the regional Liander network level (see Chapter 5, Section 5.3.1 below), although due to the characteristics of the OPERA model this is not fully achievable. In addition, the most important condition for demand response by EVs is that the amount of electricity charged by EVs *per day* in the smart profile should be similar to the daily demand in the dumb profile. Within this overall restriction, however, the smart profile may deviate from the dumb profile – depending on the hourly power price fluctuations – in the following ways:

- If necessary/attractive, within a time slice EV hourly charging in the smart profile may be 75% lower than in the dumb profile.
- If necessary/attractive, within a time slice EV hourly charging in the smart profile may be four times higher than in the dumb profile.

Figure 53 shows that, at least for the hours presented during the period considered, the smart hourly demand profile of EVs varies less widely than the dumb profile (in contrast to the demand profiles of the energy conversion technologies in **Figure 52** where the static demand profile is flat and its flexible profile varies widely). The demand response of EV, however, is defined and calculated similar to the demand response of the energy conversion technologies, i.e. the difference between the hourly flexible demand level and the hourly static demand level. Hence, this demand response can be either positive

Figure 53: Illustration of power demand response of charging electric passenger vehicles (EVs) during the first ten days (240 hours) of A2050



(upwards demand response) or negative (downward demand response), depending on the fluctuating, hourly residual demand conditions (high, low) and, therefore, on the fluctuating, hourly power prices (high, low).

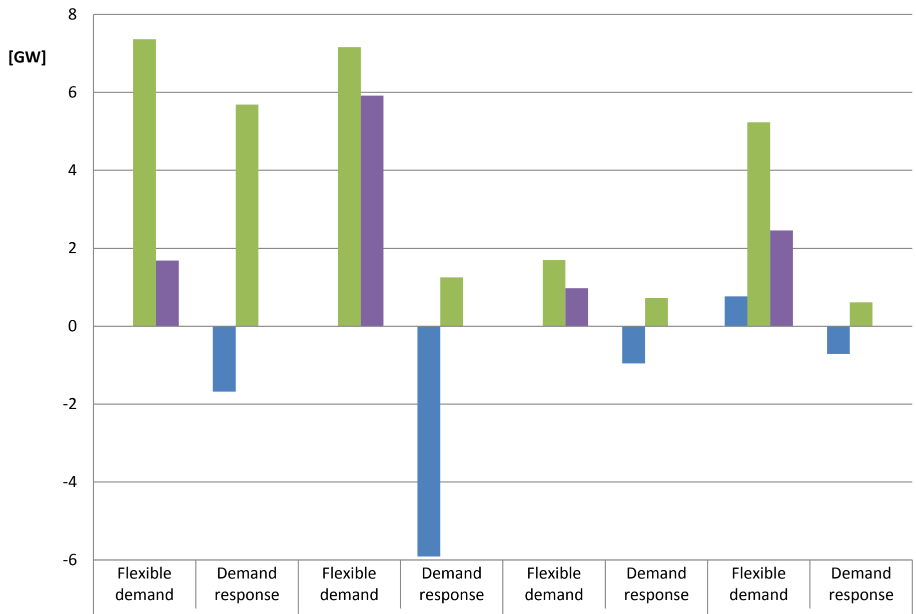
Figure 54 provides a summary of the minimum, maximum and average values of the flexible demand profiles as well as of the hourly demand response of the four above-mentioned technologies in A2050. It shows, for instance, that the flexible hourly demand profile of P2H varies between a minimum level of 0 GW to a maximum level of 7.4 GW, and that the average level of the flexible demand profile amounts to 1.7 GW (which corresponds exactly to the – 'average' - flat level of the static demand pattern of P2H, presented in **Figure 52**).

In addition, **Figure 54** shows that the maximum (upward) hourly demand response of P2H is equal to the difference between the maximum and average value of the hourly demand profile, i.e. 5.7 GW, and that the minimum (downward) hourly demand response of P2H is equal to the difference between the minimum and average values of the hourly demand profile (i.e. 1.7 GW).[35]

Capacity factors of demand-response technologies
Note that the ratio between the average and maximum values of the hourly demand profile (i.e. the ratio between the purple and green bars in **Figure 54**) provides an indication of the capacity factor (or full load hours) of the technology concerned. In case of a flat demand pattern, the maximum hourly demand is equal to the average hourly demand and, hence, the capacity factor of the technology concerned is equal to 1, i.e. its full load hours amount to 8760.

[35] Note that this latter observation also applies to P2G and P2A but not to EVs as the static (dumb) demand profile of EVs differs significantly from the static (flat) demand profile of the three energy conversion technologies (compare **Figure 52** and **Figure 53**).

Figure 54: Minimum, maximum and average values of flexible hourly demand profiles and hourly demand response of selected power demand technologies in A2050



	Power-to-heat (P2H) Flexible demand	Power-to-heat (P2H) Demand response	Power-to-gas (P2G) Flexible demand	Power-to-gas (P2G) Demand response	Power-to-ammonia (P2A) Flexible demand	Power-to-ammonia (P2A) Demand response	Electric Vehicles (EVs) Flexible demand	Electric Vehicles (EVs) Demand response
Minimum	0.0	-1.7	0.0	-5.9	0.0	-1.0	0.8	-0.7
Maximum	7.4	5.7	7.2	1.2	1.7	0.7	5.2	0.6
Average	1.7	0.0	5.9	0.0	1.0	0.0	2.5	0.0

In case of a flexible demand pattern, however, – as, for instance, in the case of P2H – the average hourly demand amounts to 1.7 GW in A2050 and the maximum demand to 7.4 GW (see **Figure 52**). As a result, the capacity factor of P2H amounts to 0.23 in A2050 while the related full load hours of this technology corresponds to about 2000.

Similarly, in case of demand-responsive P2G, the average hourly demand amounts to 5.9 GW in A2050 and the maximum hourly demand to 7.2 GW. Consequently, the capacity factor of P2G in A2050 amount to 0.83 while the related full load hours of this technology corresponds to more than 7200 (see also **Table 9** which provides similar data for the other demand-responsive technologies as well as for two other scenario cases besides A2050, i.e. A2030 and C2050).

Investment versus electricity costs of demand-responsive technologies
A lower capacity factor implies a lower technical efficiency factor of the capacity investment and, hence, higher (fixed) investment costs per unit output accordingly (compared to a capacity factor of 1, i.e. 8760 full load hours). In case of power-demand responsive technologies and fluctuating power prices, however, these higher investment costs may – to a certain level of demand response – be more than compensated by lower (variable) electricity costs (in lower power-priced hours). Hence, the specific demand response level of a certain technology depends – besides demand conditions and other techno-economic constraints – on the ratio between its (variable) electricity costs and its (fixed) investment costs as well as on the difference in the electricity price between higher power-priced hours and lower power-priced hours.

Table 9: Capacity factors and full load hours of selected demand-responsive technologies in A2030, A2050 and C2050

	Capacity factors			Full load hours		
	A2030	**A2050**	**C2050**	**A2030**	**A2050**	**C2050**
P2G	0.41	0.83	0.61	3624	7232	5356
P2H	0.51	0.23	0.23	4485	2000	2000
P2A	1.00	0.57	0.55	8760	5005	4852
EV	0.47	0.47	0.47	4113	4113	4113

Table 10 provides a summary overview of the annual capacities, power demand and related costs of the selected demand-responsive technologies in A2030, A2050 and C2050. It shows, among others, that in A2050 the total annual electricity costs of P2G amount to about € 1500 million while the total annualised investment costs correspond to almost € 340 million. Hence, the ratio between annual (variable) electricity costs and (fixed) investment costs of P2G is relatively high, i.e. about 4.4 in A2050, implying that – in principle – the potential for power demand response by P2G is relatively high, depending on the hourly price fluctuations in the year concerned (besides a variety of other techno-economic constraints).

Table 10: Annual capacities, power demand and related costs of selected demand-responsive technologies in A2030, A2050 and C2050

Tech-nology	Scenario case	Capacity (p.a.)	Capacity unit	Annual power demand [TWh]	Total electricity costs [M€/y]	Other variable costs [M€/y]	Total annualised investment costs [M€/y]	Fixed O&M costs [M€/y]	Ratio electri-city: invest-ment costs	Ratio electri-city: fixed costs[a]
P2G	**A2030**	23.7	PJ	3.9	245.2		54.2	11.3	4.5	3.7
	A2050	157.9	PJ	51.8	1502.1		338.3	70.4	4.4	3.7
	C2050	213.3	PJ	51.8	1502.1		456.7	95.1	3.3	2.7
P2H	**A2030**	208.1	PJ	13.3	839.6		212.6	262.6	3.9	1.8
	A2050	230.0	PJ	14.7	427.1		204.9	253.1	2.1	0.9
	C2050	230.0	PJ	14.7	427.1		204.9	253.1	2.1	0.9
P2A	**A2030**	3.8	Mt NH3	7.6	480.1	37.7	112.7		4.3	4.3
	A2050	6.7	Mt NH3	8.5	245.8	42.0	196.5		1.3	1.3
	C2050	6.9	Mt NH3	8.5	245.8	42.0	202.7		1.2	1.2
EV	**A2030**	2.8	M-EVs[b]	8.4	529.2		8212.6	691.3	0.1	0.1
	A2050	7.2	M-EVs	21.5	623.5		14778.4	1237.4	0.0	0.0
	C2050	7.2	M-EVs	21.5	623.5		14778.4	1237.4	0.0	0.0

a) Million electric vehicles (M-EVs).

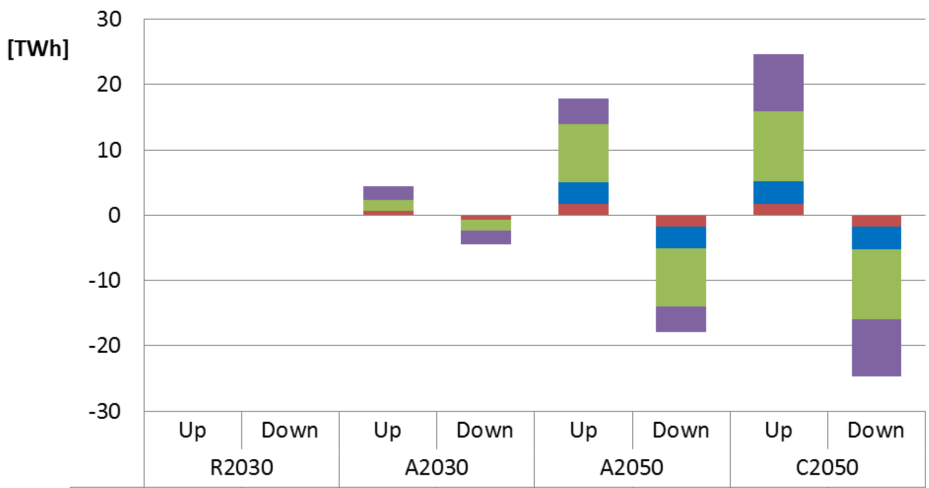
b) Fixed costs include total annualised investment and fixed O&M cost.

Note that in case of EVs, the ratio between the electricity and investment costs is relatively low in A2050 – i.e. close to zero – mainly due to the relatively high investment (purchase) costs of EVs and the relatively low electricity prices in A2050. However, the decision to buy an EV (rather than an alternatively fuelled car) depends less on the ratio between the electricity and investment costs but rather on the *additional* energy versus investment costs of an EV (compared to an alternatively fuelled car), including a variety of other considerations. In addition, the potential power demand response of an EV depends primarily on daily charging conditions and, hence, on daily power price fluctuations once the investment in an EV has been made (including a variety of other considerations and techno-economic constraints).

Total annual demand response

Figure 55 presents the total annual demand response of the four selected technologies, either upwards or downwards, in some selected scenario cases, 2030-2050. The total annual demand response is equal to the aggregated sum of the hourly demand response over a year, either for all hours with an upward demand response or for all hours with a downward demand response, where the hourly demand response is defined as the difference between the hourly flexible demand level and the hourly static demand level, i.e. between the blue curve (flexible demand) and the red curve (static demand) in **Figure 52** and **Figure 53**. Consequently, the total annual *upward* demand response is equal to the area below the blue line and above the red line of these figures, whereas the total annual *downward* demand response is equal to the area below the red line and above the blue line.

Figure 55: Total annual demand response per technology, either upwards or downwards, in selected scenario cases, 2030-2050



	R2030 Up	R2030 Down	A2030 Up	A2030 Down	A2050 Up	A2050 Down	C2050 Up	C2050 Down
P2G	0.0	0.0	2.0	-2.0	3.9	-3.9	8.7	-8.7
P2H	0.0	0.0	1.7	-1.7	8.9	-8.9	10.6	-10.6
P2A	0.0	0.0	0.0	0.0	3.2	-3.2	3.5	-3.5
EV	0.0	0.0	0.7	-0.7	1.8	-1.8	1.8	-1.8

Figure 55 shows, for instance, that the total annual upward demand response of P2H is still zero in the reference scenario case of 2030 (R2030). In the alternative scenario case of 2030 (A2030), however, this response is already 1.7 TWh, while it increases to 8.9 TWh in A2050 and even to almost 11 TWh in C2050. The increase in demand response between R2030 and A2050 is largely due to the increase in the total annual electricity demanded by P2H (see **Figure 51**) and partly due to the increase in volatility of the hourly electricity price resulting from the increasing share of VRE generation in total electricity supply (as illustrated and explained in Chapter 2, notably Sections 2.2.3 and 2.4.1).

On the other hand, the increase in demand response between A2050 and C2050 is solely due to the increase in the hourly electricity price fluctuations resulting from the lower interconnection capacity in C2050, compared to A2050 (as illustrated and explained in Chapter 2, notably Sections 2.2.1 and 2.4.1).

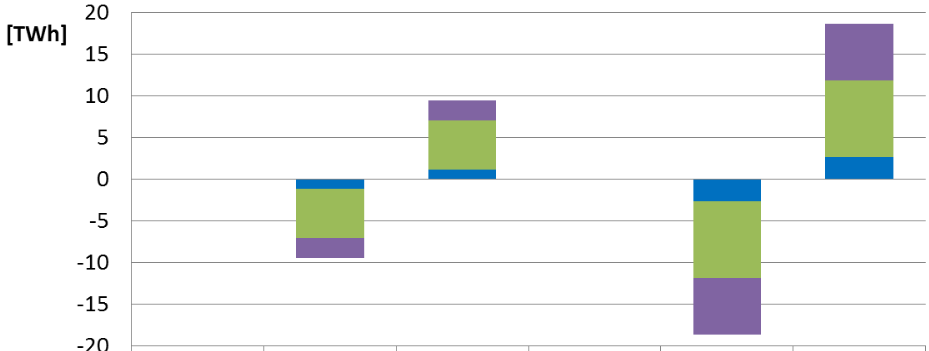
The total annual upward demand response of all four technologies included in **Figure 55** increases from zero in R2030 to 4.4 TWh in A2030, to 18 TWh in A2050 and even to 25 TWh in C2050 (where the total downward demand response shows similar amounts in these scenario cases). As a share of total annual power demand by these four technologies, this corresponds to 13% in A2030, 19% in A2050 and 26% in C2050. As a share of total annual power demand (all sources), these percentages are – of course – lower but still significant, i.e. 3% in A2030, 8% in A2050 and 11% in C2050. On the other hand, as a share of total annual *residual* load (uncurtailed, all sources), these rates are significantly higher, notably in the 2050 scenarios, i.e. 42% in A2050 and even 59% in C2050 (see **Table 11**).

Table 11: Demand response as a share of power demand in selected scenario cases, 2030-2050

	Unit	A2030	A2050	C2050
Total annual demand response by four selected technologies (P2G, P2H, P2A, EV)	[TWh]	4.4	17.9	24.6
Total annual power demand by selected technologies	[TWh]	33.2	96.5	96.5
Total annual power demand (by all sources)	[TWh]	153.2	231.5	230.4
Total annual residual load (by all sources)	[TWh]	96.4	42.8	41.8
Total annual demand response as % of:				
Total annual power demand by selected technologies	[%]	13%	19%	26%
Total annual power demand (by all sources)	[%]	3%	8%	11%
Total annual residual load (by all sources)	[%]	5%	42%	59%

Total annual demand response in VRE shortage and deficit hours
Figure 56 presents the *balance* of the total annual (upward/downward) demand response per technology, distinguished between all hours over a year with a positive residual load (VRE shortage) and all hours with a negative residual load (VRE surplus) in A2050 and C2050. This balance is equal to the aggregated sum of both the upward and downward hourly demand response in all hours with either a VRE shortage or a VRE surplus.

Figure 56: Balance of total annual (upward/downward) demand response per technology, distinguished between hours with a positive residual load (VRE shortage) and hours with a negative residual load (VRE surplus) in A2050 and C2050



	Residual load (A2050)			Residual load (C2050)		
	Total	Positive	Negative	Total	Positive	Negative
P2G	0.0	-2.4	2.4	0.0	-6.8	6.8
P2H	0.0	-5.9	5.9	0.0	-9.2	9.2
P2A	0.0	-1.1	1.1	0.0	-2.6	2.6
EV	0.0	-0.1	0.1	0.0	-0.1	0.1

Figure 56 shows, for instance, that – on balance – the total annual demand response of P2H amount to -5.9 TWh (i.e. downwards demand response) in all VRE shortage hours of A2050 and to 5.9 TWh (upwards demand response) in all VRE surplus hours. These figures are significantly lower than the comparable amounts shown in **Figure 55** (–8.9 TWh and +8.9 TWh, respectively) referring to the total annual demand response, either upwards or downwards, over all hours of the year.

This difference is due to the fact that **Figure 55** aggregates all hours over the year with the same direction of demand response – i.e. either upwards or downwards, but not both – whereas **Figure 56** presents the balance of the total annual demand response, i.e. both upwards and downwards, over either all hours with a VRE shortage or all hours with a VRE surplus. As there are VRE shortage (surplus) hours with either an upward demand response or a downward response, the balance of the total annual demand response over all VRE shortage (surplus) hours will be lower than the aggregated sum of the upward (downward) demand response over all hours of the year.

Nevertheless, as mentioned above, the total annual demand response of P2H is on balance, as expected, significantly negative (-5.9 TWh) in all VRE shortage hours of A2050 (i.e. generally a *downward* demand response in hours with a *positive* residual load and, hence, relatively *high* electricity prices) and significantly positive (+5.9 TWh) in all VRE surplus hours of A2050 (i.e. generally an *upward* demand response in hours with a *negative* residual load and, therefore, relatively *low* electricity prices).[36]

[36] The same observations apply to the other scenario cases and the other technologies included in **Figure 55** and **Figure 56** but in particular to EVs. The latter is due to the fact that demand response by EVs is bound by the condition that the amount of electricity charged by EVs per day in the static (dumb) profile should be similar to the daily demand in the flexible (smart) profile. Hence, if a day is characterised by only VRE shortage (surplus) hours, demand response implies that power demand is shifted upwards in some VRE shortage hours of the day and downwards in other VRE shortage hours of the day. As a result, the balance of the total demand response (both upwards and downwards) over all VRE shortage hours of the day is zero.

In A2050, the total annual demand response of all four technologies included in **Figure 56** amounts to -9.5 TWh in all VRE shortage hours and to +9.5 TWh in all VRE surplus hours. In C2050, these figures amount to almost -19 TWh and +19 TWh, respectively. As a result, both the total VRE deficit and the total VRE surplus in the respective hours of these scenario cases are significantly lower after demand response than before demand response (see **Table 12**).

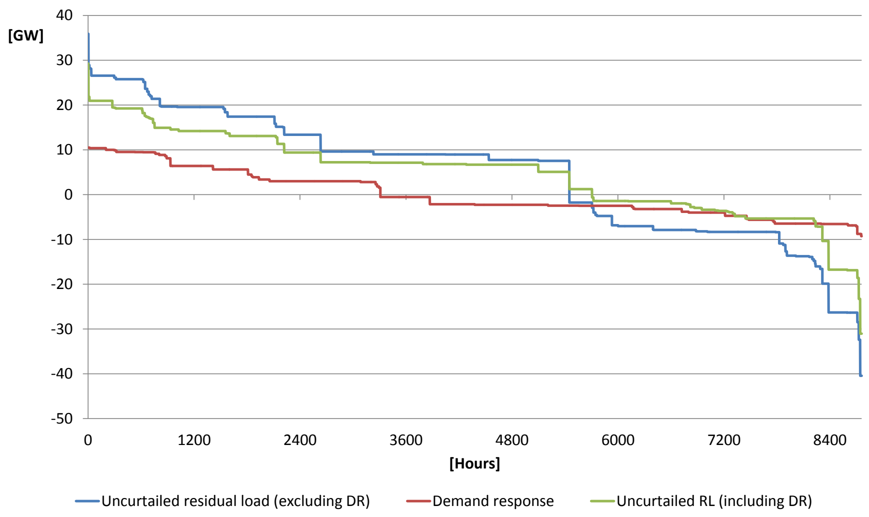
Table 12: Total annual residual load before and after demand response distinguished between hours with a positive residual load (VRE shortage) and hours with a negative residual load (VRE surplus) in A2050 and C2050

		A2050		C2050	
		Residual load		Residual load	
	Unit	Positive	Negative	Positive	Negative
Total annual residual load before demand response	[TWh]	77.4	-34.9	76.4	-34.8
Total annual demand response by four selected technologies (P2G, P2H, P2A, EV)	[TWh]	-9.5	9.5	-18.6	18.6
Total annual residual load after demand response	[TWh]	68.0	-25.4	57.8	-16.2
Total annual residual load after demand response as a % of total annual residual load before demand response	[%]	88%	73%	76%	47%
Total annual demand response as % of total residual load	[%]	12%	27%	24%	53%

Demand response duration curve

Figure 57 presents the demand response duration curve in C2050 (red curve) together with the duration curve of the (uncurtailed) residual load, either excluding demand response (blue curve) or including demand response (green curve). It shows that the hourly demand response varies from about +10 GW (maximum upward demand response) to –10 GW (maximum downward demand response). In addition, it shows that – due to the demand response – the duration curve of the (uncurtailed) residual load including demand response is more flat than the curve of the residual load excluding demand response.

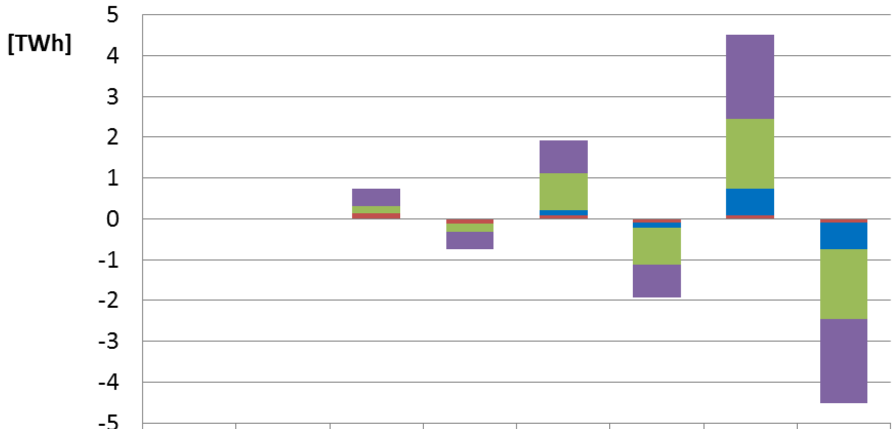
Figure 57: Duration curves of residual load before and after demand response in C2050



Note that the duration curves presented in **Figure 57** show a stepwise pattern rather than a more smooth, gently sloping pattern of the duration curves in Chapter 2 (COMPETES modelling results). This is due to the time slice approach applied by OPERA (as explained in Section 3.1). As a result of this approach, the modelling outcomes for variables such as demand response or residual load become similar for all hours in a certain time slice, leading to the stepwise pattern of the curves presented in **Figure 57**. More specifically, **Figure 57** presents the outcomes of the 61 time slices ('steps') applied in the OPERA modelling analyses of the FLEXNET scenario cases.

Total annual flexibility offered by demand response
Similar to the hourly variations of the flexibility supply options considered in Chapter 2 to meet the flexibility needs due to the hourly variations of the residual load (Section 2.3.3), the hourly variations of demand response can also be considered as an option to meet these needs. **Figure 58** presents the annual supply of flexibility per demand-responsive technology in order to meet the flexibility needs of the Dutch power system due to the hourly variation of the residual load in some selected scenario cases over the years 2030-2050. It shows, for instance, that in A2050 the upward flexibility offered by (the hourly variations of) the demand response by P2H amounts to 0.9 TWh, while in C2050 it amounts to 1.7 TWh.

Figure 58: Total annual flexibility offered per demand-responsive technology in order to meet flexibility needs due to the hourly variations of the residual load in selected scenario cases, 2030-2050



	R2030 Up	R2030 Down	A2030 Up	A2030 Down	A2050 Up	A2050 Down	C2050 Up	C2050 Down
P2G	0.0	0.0	0.4	-0.4	0.8	-0.8	2.1	-2.1
P2H	0.0	0.0	0.2	-0.2	0.9	-0.9	1.7	-1.7
P2A	0.0	0.0	0.0	0.0	0.1	-0.1	0.6	-0.6
EV	0.0	0.0	0.1	-0.1	0.1	-0.1	0.1	-0.1

The total annual flexibility – either upwards or downwards – offered by all demand-response technologies included in **Figure 58** amounts to 1.8 TWh in A2050 and to 4.8 TWh in C2050. As a percentage of total annual flexibility needs due to the hourly variations of the residual load this corresponds to 12% and 32%, respectively (see **Table 13** as well as Section 3.7 below).

Table 13: Total annual flexibility by demand response as a share of total annual flexibility needs due to the hourly variations of the residual load, either upwards or downwards, in selected scenario cases, A2030-A2050

	Unit	A2030	A2050	C2050
Total annual flexibility offered by demand response	[TWh]	0.6	1.8	4.8
Total annual flexibility needs	[TWh]	5.5	15.2	15.2
Total annual flexibility offered by demand response as a % of total annual flexibility needs	[%]	12%	12%	32%

Note: Estimates of total annual flexibility demand and supply have been corrected for the so-called 'time slice effect' (see Section 3.7).

Potential of demand response to meet future flexibility needs
Overall, there seems to be a large potential to meet future flexibility needs of the Dutch power system by means of demand response. This applies in particular to (industrial) power demand activities that are expected to grow rapidly in the coming decades such as power-to-gas, power-to-heat or power-to-ammonia, but also to power demand by means of more smart (flexible) charging of electric vehicles (as analysed above).

To some extent, the demand-response potential of these technologies may be overestimated for two reasons. Firstly, the static demand pattern of the three energy conversion technologies (P2G, P2H, P2A) may be less flat than assumed and, hence, the potential demand response is lower accordingly. Secondly, the flexible demand pattern of these technologies (including EV) may be bound to more techno-economic restrictions than assumed and, consequently, the power demand response of these technologies is lower accordingly.

On the other hand, there may be a large, additional potential for demand response by other power demand activities in other (household/service) sectors, although – to some extent – this potential may be harder to realise depending on the role of aggregators, price incentives, human behaviour, etc. This potential has not been explored in the current study at the national level, but our analyses at the regional Liander network level show that there is a significant potential of demand response at the local (household) level by means of direct load control (DLC) and various pricing mechanisms (see Chapter 5 below).

3.3 Energy storage

Scope and limits of storage technologies analysed
Some of the energy conversion technologies discussed in the previous section, in particular power-to-gas and power-to-ammonia, can also be regarded as energy storage technologies. In our scenario cases, however, these technologies are not used to generate electricity again at a later stage but rather for a variety of other purposes outside the power system. Hence, from a power system perspective, these technologies cannot be regarded as *electricity* storage technologies but rather as energy conversion technologies – including storage for non-power energy systems and purposes – which

primarily offer flexibility to the power system through hourly variations in the power demanded by these technologies (as analysed in the previous section).

Similarly, batteries of electric vehicles (EVs) can also be used to discharge electricity back to the power system again (and, in practice, some pilot projects are running in this field, such as in Lombok-Utrecht, the Netherlands). In the present study, however, we have not explored this potential electricity storage function of EVs and, hence, the potential flexibility of this technology offered to the power system has been focussed only on the flexible (smart) charging of EVs (as also analysed in the previous section).

The OPERA model, however, includes a wide variety of other, 'pure' electricity storage technologies such as compressed air energy storage (CAES), flywheels, supercapacitors, superconducting magnetic energy storage (SMES) and several types of batteries (conventional, sodium sulphur, lithium ion, flow batteries, etc.).[37] As part of the FLEXNET project, OPERA has analysed the role of these storage technologies as a flexibility option to address the changes and variations of the (hourly) residual load of the Dutch power system in the FLEXNET scenario cases up to 2050.

Major results

A major finding of the FLEXNET-OPERA modelling analyses is that the role of 'pure' electricity storage technologies as a flexibility option to address hourly variations of the residual load of the Dutch power sector is low, i.e. nearly zero, up to 2030 and rather limited beyond 2030. **Figure 59** presents the major OPERA modelling results with regard to the deployment of storage activities (charging, discharging) in order to meet variations in hourly residual load, distinguished between hours with a positive residual load and hours with a negative residual load in the scenario cases A2050 and C2050.

Figure 59 shows that the total charging-discharging activities, excluding storage losses, amount to almost 0.25 TWh in A2050 and 0.21 TWh in C2050, whereas the storage losses amount to 0.11 TWh and 0.09 TWh, respectively.[38] All these activities result from one single technology only, i.e. CAES.

In addition, **Figure 59** shows that, as expected, most of the storage charges take place during hours with a negative residual load (VRE surplus) when electricity prices are usually low. Moreover, also as expected, the balance between storage charges and discharges is generally positive in hours with a VRE surplus and negative in hours with a VRE shortage.

Surprisingly, however, a larger part of storage discharges is used during hours with a VRE surplus than during hours with a VRE deficit. An explanation may be that CAES activities are used only during short-cycle periods (including time frames with only VRE surplus hours) and, more likely, that electricity is discharged during hours in which a (domestic) VRE surplus can be addressed by power exports and, hence, electricity prices are higher accordingly.

[37] For a description and review of these technologies, see DNV Kema (2013). The techno-economic data of these technologies included in the OPERA model have been largely derived from this report.

[38] Storage losses include both the loss of energy needed for charging the storage technology (e.g. the energy used to operate a CAES system) and the losses during the time span between energy charging and energy discharging (e.g. batteries losing part of their energy over time).

Figure 59: Storage activities to meet changes in hourly residual load distinguished between hours with a positive residual load (VRE shortage) and hours with a negative residual load (VRE surplus) in A2050 and C2050

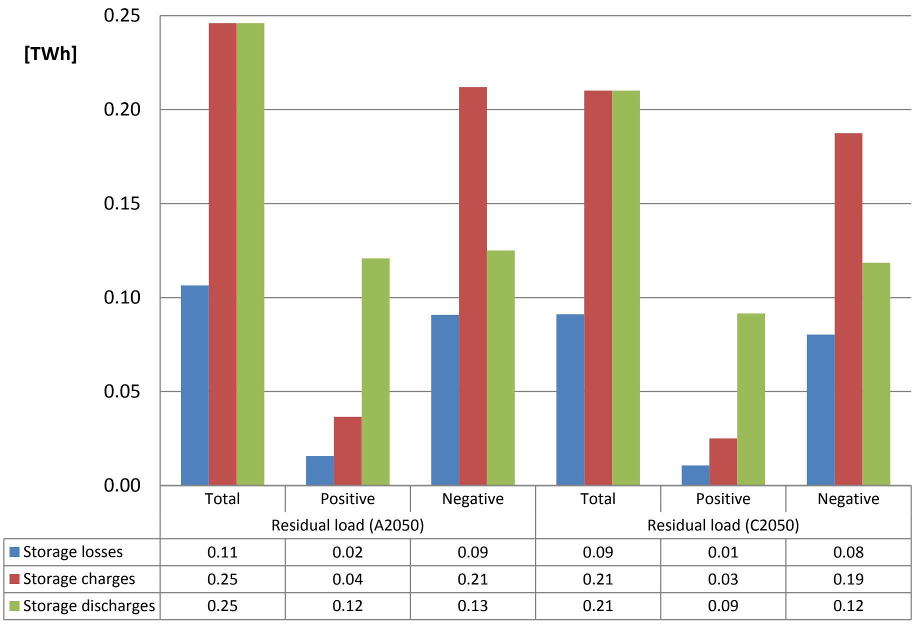


Table 14 presents the CAES storage activities in A2050 and C2050 as a percentage of the residual load, distinguished between hours with a VRE shortage and hours with a VRE surplus. It shows that this share is generally limited, i.e. less than 1% (see also Section 3.6 below).

Table 14: Storage activities as a percentage of residual load distinguished between hours with hours with a positive residual load (VRE shortage) and hours with a negative residual load (VRE surplus' in A2050 and C2050

	Residual load (A2050)			Residual load (C2050)		
	Total	Positive	Negative	Total	Positive	Negative
Storage losses	0.25%	0.02%	0.26%	0.22%	0.01%	0.23%
Storage charges	0.58%	0.05%	0.61%	0.51%	0.03%	0.54%
Storage discharges	0.58%	0.16%	0.36%	0.51%	0.12%	0.34%

Finally, **Table 15** presents the total annual supply of flexibility offered by energy storage (CAES) in order to meet the flexibility needs of the Dutch power system due to the hourly variation of the residual load in A2050 and C2050. It shows that this flexibility amounts to approximately 0.1 TWh in both scenario cases, corresponding to less than 1% of total annual flexibility needs in these cases (see also Section 3.7 below).

Table 15: Flexibility offered by energy storage (CAES)as a share of total annual flexibility needs due to the hourly variations of the residual load in A2050 and C2050

	Unit	A2050	C2050
Flexibility offered by energy storage (CAES)	[TWh]	0.10	0.1
Total annual flexibility needs	[TWh]	15.2	15.2
Flexibility offered by energy storage as % of total annual flexibility needs	[%]	0.6%	0.6%

Sensitivity analyses
As the role of energy storage as a flexibility option turned out to be relatively limited (compared to previous expectations and to what is often suggested by other studies), we have conducted some sensitivity analyses by means of the OPERA model for the scenario case C2050 (which includes the largest part of domestic flexibility options).

In particular, we have reduced the annualised investment costs and the fixed operation and maintenance (O&M) costs of three storage technologies by a factor 10 in C2050, i.e. in the sensitivity runs these costs have been set at 10% of their original, baseline level. These three technologies include (i) compressed air energy storage (CAES), (ii) li-ion batteries, and (iii) superconducting magnetic energy storage (SMES).[39] These technologies represent different energy storage functions within the power system with different underlying techno-economic characteristics (for details, see DNV Kema, 2013).

In the first set of sensitivity runs, we have analysed the impact of the above-mentioned cost reduction for each technology separately, i.e. first we have reduced the cost of one single technology only by 90% and have analysed its effects in terms of storage activities. Subsequently, we have reduced the costs of another single technology by 90% and looked at its impact and, finally, we did so for the third single technology.

The results of these sensitivity runs are summarised in **Table 16**, including the resulting storage activities, costs and flexibility offered by the three selected storage technologies in C2050. The table shows, for instance, that the total annual amount of power charged (and discharged) by CAES amounts to 0.42 TWh in C2050, while the related storage losses amount to 0.18 TWh.[40] These storage activities and the necessary storage capacities result in total electricity costs of € 5.4 million, annualised investment costs of € 0.19 million and fixed O&M costs of € 0.21 million.[41] On the other hand, (the hourly variations of) the CAES activities offer flexibility to the power system amounting to 0.15 TWh per annum, i.e. about 1% of the total annual flexibility needs in C2050 due to the hourly variations of the residual load in the Dutch power system.

For the other two storage technologies (SMES and li-ion batteries), the shares in total annual flexibility needs are slightly higher, i.e. about 2% and 3% (see **Table 16**).

39 As remarked in a previous note, the original techno-economic, baseline data of the storage technologies included in the OPERA model have been derived from a technology review conducted by DNV Kema (2013) as part of the power-to-gas (P2G) project conducted by ECN and DNV Kema (see De Joode, et al., 2014).

40 Note that the storage losses are additional to the power demand due to storage charges.

41 Note that the annualised investment costs and the fixed O&M costs have been set at 10% of their assumed baseline level.

Table 16: Sensitivity analyses: major modelling results with regard to three selected electricity storage technologies in C2050 when their fixed O&M costs and annualised investment costs are reduced by 90% compared to their baseline level

Tech-nology	Storage activity	Capacity [PJ]	Annual power demand [TWh]	Total electricity costs [M€/y]	Other variable costs [M€/y]	Total annualised investment costs [M€/y]	Fixed O&M costs [M€/y]	Total annual flexibility offered [TWh]	As % of total annual flexibility needs
CAES	Losses		0.18	5.26	0.00	0.00	0.00		
	Charges	0.017	0.42	0.14	0.00	0.19	0.21	0.15	1.1%
Li-ion	Losses		0.11	3.16	0.00	0.00	0.00		
	Charges	0.066	1.45	0.48	0.00	64.37	5.22	0.45	3.4%
SMES	Losses		0.10	3.03	0.00	0.00	0.00		
	Charges	0.033	0.94	0.31	0.00	9.70	7.87	0.29	2.2%

However, even in the case that fixed O&M costs and investment cost of these technologies have been reduced by 90%, their shares in power demand and flexibility supply are relatively limited.

In the second set of sensitivity runs, we have reduced the costs of the three technologies mentioned above simultaneously by a factor 10 in scenario case C2050, i.e. the costs of all three technologies have been reduced by 90%, compared to the baseline level, at the same time in a single model run. The major results of this run are presented in **Figure 60**, which shows the aggregated storage activities to address changes in hourly residual load in C2050, distinguished by hours with a VRE shortage and hours with a VRE surplus, assuming that fixed O&M costs and annualised investment costs of the three included storage technologies have been reduced by 90% compared to their baseline level.

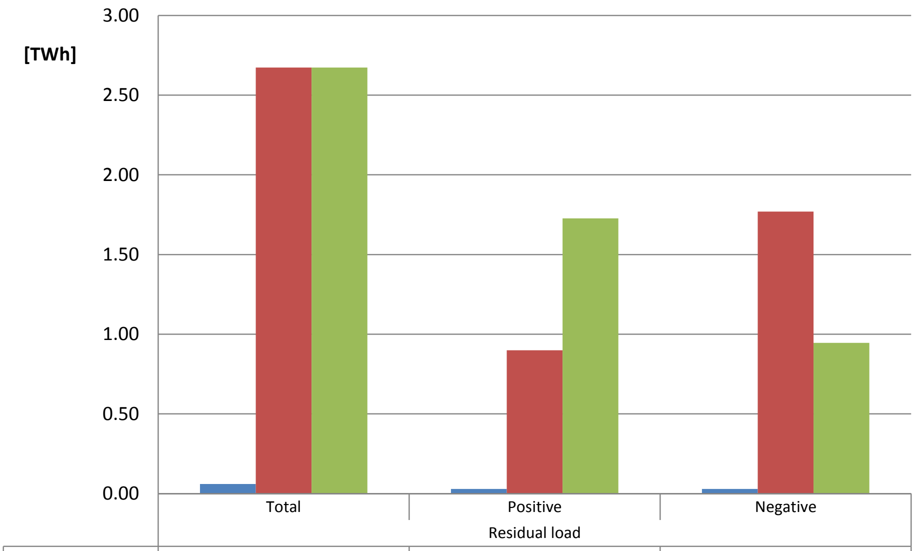
Figure 60 shows that the total annual charges-discharges of the three included technologies amount to 2.7 TWh in C2050, i.e. about 6.4% of the total residual load in that scenario case. All storage activities, however, result from a single technology, i.e. li-ion batteries, while the other two technologies (CAES, SMES) do not turn up in the modelling outcomes.

Figure 60 also shows that, as expected, the balance of storage charges and discharges by the li-ion batteries is positive during hours with a VRE surplus (negative residual load) and negative during hours with a VRE shortage (positive residual load). Overall, the storage activities by li-ion batteries offer flexibility to the power system by an amount of 0.75 TWh per annum, i.e. approximately 5% of the annual flexibility needs due to the hourly variation of the residual load in C2050.

Explanation for the limited role of energy storage

Why is the role of energy storage in meeting future flexibility needs relatively limited (compared to what is generally expected or usually suggested in the literature), even if it is assumed that the cost of energy storage are reduced substantially (by a factor 10)?

Figure 60: Storage activities to meet changes in hourly residual load distinguished between hours with a positive residual load (VRE shortage) and hours with a negative residual load (VRE surplus) with 10% of fixed O&M and annualised investment costs in C2050



	Total	Positive	Negative
Storage losses	0.06	0.03	0.03
Storage charges	2.67	0.90	1.77
Storage discharges	2.67	1.73	0.95

The basic answer is rather simple, i.e. there is a large potential of other, alternative flexibility options that are (much) cheaper to meet these needs, in particular flexibility offered through options such as power trade and demand response, but also – notably in hours with a VRE surplus – by means of VRE curtailment. Besides their volume effect, these options reduce the business case of energy storage technologies through the related price effects in the sense that they reduce the volatility of the electricity price and, hence, reduce the price margin to cover the cost of offering flexibility. This applies particularly for 'pure' electricity storage technologies, such as CAES, SMES or batteries, which have to cover their costs primarily – or even solely – from the price margin earned by this single activity.

Some qualifications, however, may be added to the above observation. Firstly, there are some technologies that – besides their primary function(s) in a more sustainable, low-carbon energy system – can offer flexibility by means of an additional function (energy storage) at relatively low costs to the energy system in general and, to some extent, the power system in particular. This applies notably to energy conversion technologies such as power-to-gas (P2G) and power-to-ammonia (P2A). The power demand by these technologies is expected to grow rapidly in the coming decades as part of the transition to a more sustainable energy system, in particular to meet ambitious carbon reduction targets. As a result, these technologies become more necessary in the future energy system anyhow and, consequently, they can cover the main part of their costs by meeting these primary energy function(s). In addition, they may offer flexibility by means of energy storage functions to the energy system as a whole – and, in specific cases, to the power system as well – at relatively low marginal costs (see, for instance, De Joode et al., 2014). The current study, however, indicates that the potential of the energy conversion technologies, such as P2G or P2A, to offer flexibility to the power system lies primarily in the option to provide demand response rather than electricity storage (as the costs of supplying electricity by means of these technologies are relatively high).

In addition, the above-mentioned qualification applies to some extent also for batteries of electric vehicles (EVs) that may be used to store electricity in order to discharge electricity to the power system again at a later stage. As the costs of this technology are covered predominantly by its primary functions (transport, comfort, etc.), the additional, marginal cost of offering flexibility through electricity storage by this technology are likely low while the benefits may be relatively high. Due to a variety of practical, techno-economic constraints, however, energy storage potential of EVs may be hard to realise while, on the other hand, the potential of this technology to provide flexibility to the power system by means of demand response – through smart charging – seems to be substantial (as analysed in the present study). Therefore, also for this technology the potential to offer flexibility to the power system may be more significant for the option of demand response rather than of energy storage.

A second qualification is that in the OPERA modelling analyses, i.e. in the current chapter, we have focussed our attention on exploring the role of energy storage as an option to meet flexibility needs due to the (hourly) variability of the residual load. Energy storage, however, may be an attractive option to meet other flexibility needs. Although the role and net benefits of energy (battery) storage to address network congestion seems to be limited – and even negative (see Chapter 5 below), energy storage may be an attractive, cost-effective option to address short-term power system balancing issues – e.g. due to the uncertainty ('forecast error') of VRE power generation – notably if this function can be combined with other, additional ('ancillary') services such as voltage support, frequency control or resilience/back up power (see both Chapter 4 and Chapter 5 below).

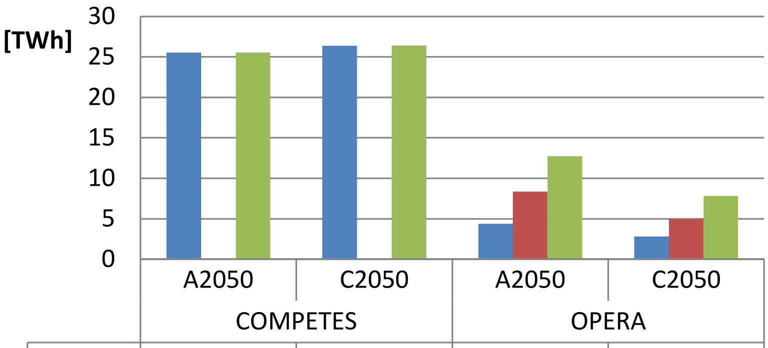
Finally, for geographical reasons hydro pumped storage (HPS) is not a cost-effective flexibility option in the Netherlands. In most EU28+ countries, however, HPS is a major, attractive flexibility options (as outlined in Section 2.2.6 above). Hence, as noted, indirectly the Netherland may benefit from HPS as a flexibility option at the EU28+ level through its power trade relations with neighbouring countries, including Norway, Germany and France.

3.4 Curtailment of VRE power generation

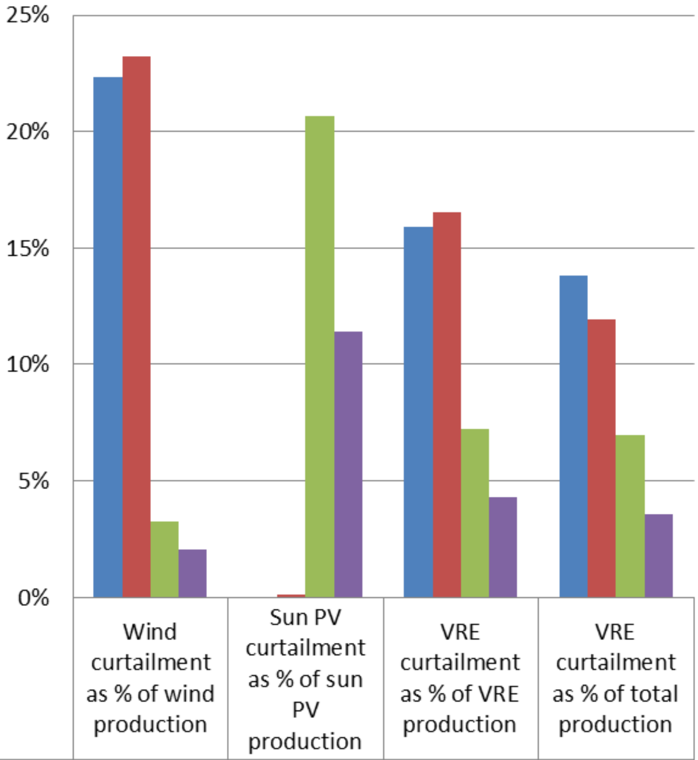
Comparison of COMPETES versus OPERA modelling results on VRE curtailment
Figure 61 presents the OPERA modelling results with regard to the curtailment of VRE power generation in A2050 and C2050 compared to similar results by the COMPETES model (as discussed in Section 2.2.4, notably **Figure 29**). This comparison shows some striking differences.

Firstly, total VRE curtailment in OPERA is significantly lower in both A2050 and C2050 than in COMPETES. This is largely due to the fact that OPERA generates a large amount

Figure 61: Comparison of COMPETES versus OPERA modelling results on VRE curtailment in A2050 and C2050



	COMPETES A2050	COMPETES C2050	OPERA A2050	OPERA C2050
Wind	25.5	26.4	4.4	2.8
Sun PV	0.0	0.1	8.3	5.0
Total	25.5	26.4	12.7	7.8



	Wind curtailment as % of wind production	Sun PV curtailment as % of sun PV production	VRE curtailment as % of VRE production	VRE curtailment as % of total production
COMPETES A2050	22.3%	0.0%	15.9%	13.8%
COMPETES C2050	23.2%	0.1%	16.6%	11.9%
OPERA A2050	3.2%	20.7%	7.2%	7.0%
OPERA C2050	2.1%	11.4%	4.3%	3.6%

of upward demand response as a flexibility option – which reduces the need for VRE curtailment, notably in VRE surplus hours – whereas COMPETES does not include demand response as a potential flexibility option into the model and, hence, the contribution of (upward) demand response in offering flexibility – and, hence, in reducing the need for VRE curtailment – is consequently zero in COMPETES.

Secondly, total VRE curtailment in COMPETES is slightly higher in C2050 than in A2050 (due to the lower interconnection capacity in C2050) whereas in OPERA total VRE curtailment is significantly lower in C2050 than in A2050. This difference in modelling results is due to the fact that in the OPERA modelling results the amount of (upward) demand response is substantially higher in C2050 than in A2050.

Finally, in COMPETES the curtailment of power generation from sun PV is nearly zero, whereas in OPERA it is quite substantial (and even bigger than VRE curtailment from wind). This is due to the fact that in COMPETES the domestic grid is assumed to be a copper plate and, hence, there are no network restrictions to the (local) production and transport of VRE output from sun PV. In such a situation, it is usually easier – and cheaper – to curtail power generation from (centralised) wind than from (decentralised) sun PV.

In OPERA, however, the power grid is specified in the model, including network capacity restrictions (see Appendix D, Section D.3). In case of local (low-voltage) network congestion, OPERA opts to curtail sun PV rather than wind as (offshore) wind generation is usually connected to higher (medium/high-voltage) grid levels. As a result, PV curtailment in OPERA is higher than in COMPETES.

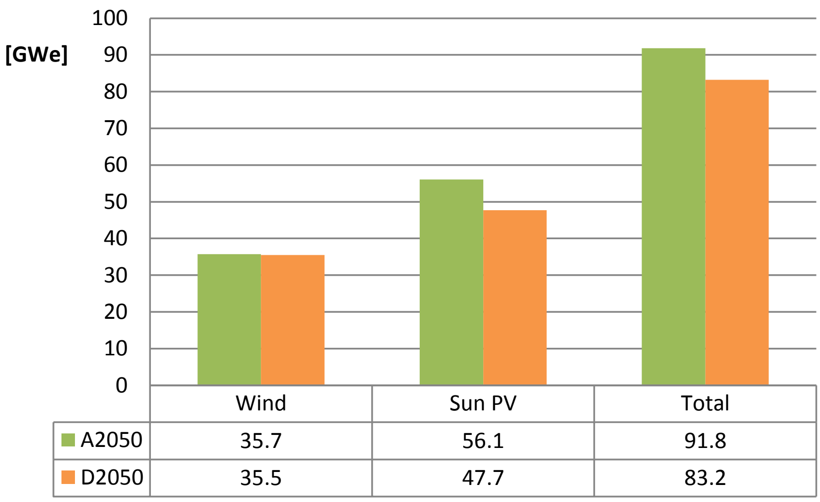
Moreover, in the 2050 scenario cases, the total installed capacity is much higher for sun PV than for wind. Hence, during a peak ('full load') hour, the output from sun PV is much higher than from wind and, therefore, the need to curtail VRE output may be much higher for sun PV than for wind in such an hour.

Alternative VRE capacity scenario case ('D2050')
In the FLEXNET scenario cases, the installed capacity of VRE power generation has been set exogenously, i.e. determined outside the model. Given the substantial amount of VRE curtailment in the 2050 scenario cases, notably in COMPETES but also in OPERA, we have run an alternative A2050 scenario case – labelled 'D2050' – in which the annual curtailed VRE output of wind and sun PV is set at the same output level of A2050, i.e. at 136 TWh and 40 TWh, respectively. Subsequently, the OPERA model determines the optimal level of installed VRE capacity of sun and wind as well as the outcomes of several other variables such as the level of VRE curtailment, flexibility needs, total system costs, etc.

Figure 62 presents the modelling outcomes in terms of installed VRE capacity in A2050 (exogenously fixed VRE capacity) and in the alternative scenario case D2050 (no exogenously fixed VRE capacity but endogenously calculated by the model). It shows that the installed capacity to meet the same level of curtailed VRE output in both scenario cases is substantially (8.6 GWe) lower in D2050 than in A2050, in particular for sun PV (8.4 GWe).

Figure 63 compares the OPERA modelling outcomes on VRE curtailment in A2050 versus D2050. It shows that the level of curtailment is usually significantly lower in D2050 than in A2050, both in absolute terms (i.e. in TWh, see upper part of **Figure 63**) and in relative terms (i.e. as a % of power generation, see lower part of **Figure 63**). For instance, as a percentage of sun PV output generation, PV curtailment amounts to almost 21% in A2050 but to less than 3% in D2050.

Figure 62: Comparison of installed VRE capacity in A2050 (fixed VRE capacity) and D2050 (no fixed VRE capacity)



In addition, the OPERA modelling results of the alternative scenario case D2050 show, among others, that the total annual flexibility needs are approximately 0.7 TWh (i.e. about 5%) lower in D2050 than in A2050, while the total annual energy system costs are about € 230 million lower (0.2%).

3.5 Non-VRE power generation

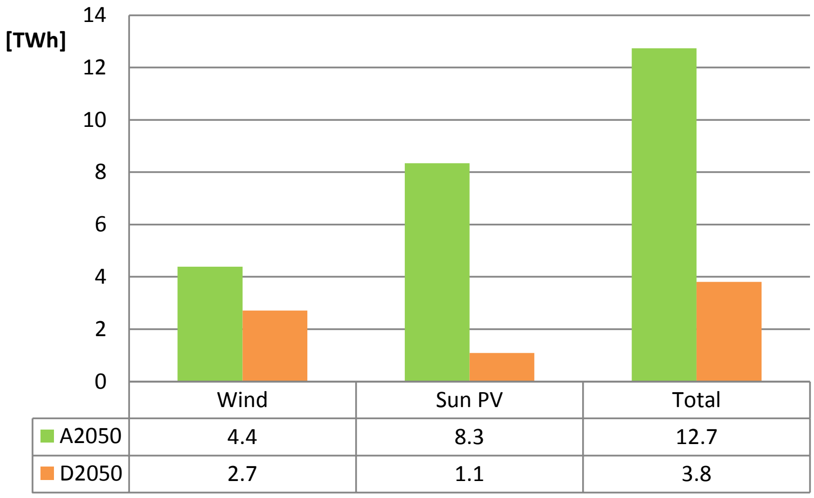
Figure 64 presents the OPERA modelling results with regard to the power output mix from non-VRE sources (coal, gas, nuclear, biomass, etc.) in four selected scenario cases compared to similar outcomes by the COMPETES model (as discussed in Section 2.2.3). For the 2030 scenario cases, the differences in outcomes between the two models are generally remarkably small (given the differences in characteristics of these models). In the 2050 scenario cases, however, there are some major, striking differences in power output between the models in terms of both the total level and the mix of this output.

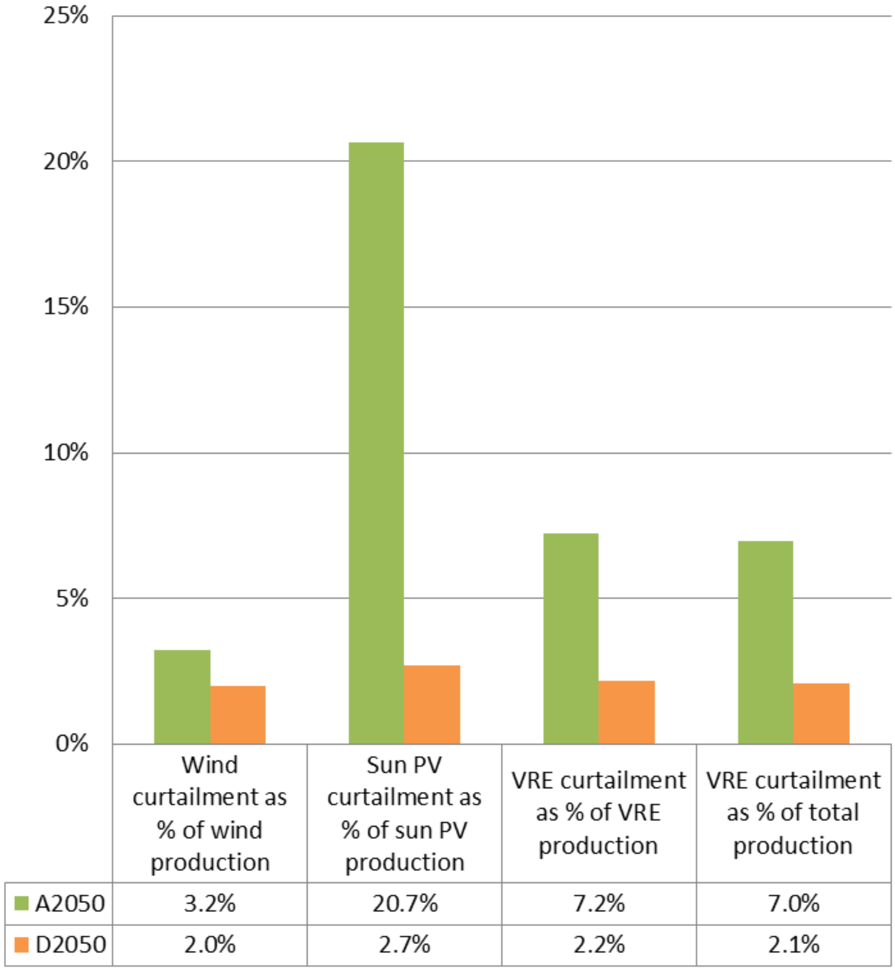
More specifically, compared to OPERA, the non-VRE output level of COMPETES is much higher in both A2050 and C2050. Moreover, the output mix of COMPETES in these scenario cases is quite different in the sense that gas output is much higher whereas the output from other non-VRE sources is much lower than in OPERA, notably in C2050.[42]

These differences in non-VRE output generation between the two models result in particular from the large amount of demand response in the OPERA modelling outcomes in the 2050 scenario cases, especially in C2050, whereas COMPETES does not include demand response as a flexibility option. As a result, the level of VRE curtailment is much lower in OPERA than in COMPETES, notably due to the upward demand response in hours with a major VRE surplus (as observed in the previous section).

42 In OPERA, the relatively high level of other non-VRE supply in C2050 refers to power generation from biomass, waste and geothermic sources.

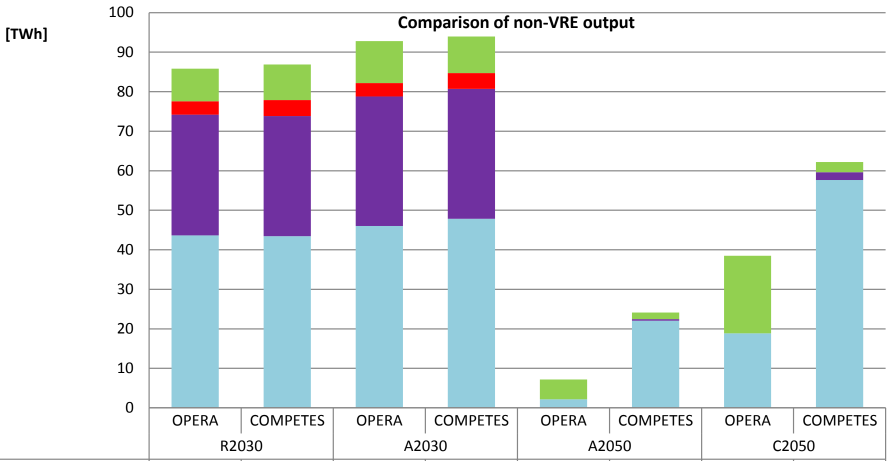
Figure 63: Comparison of VRE curtailment in A2050 (fixed VRE capacity) and D2050 (no fixed VRE capacity)



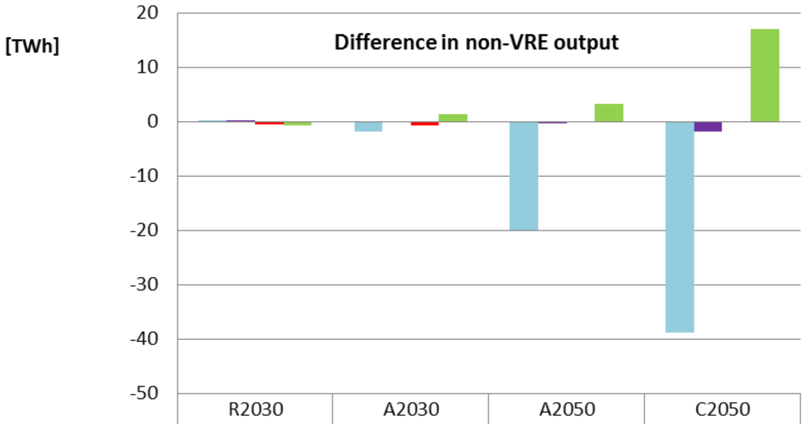


Hence, in these hours – and over the year as a whole – more VRE output becomes available. In addition, due to the downward demand response – notably in hours with a large VRE shortage – less non-VRE output is needed in these hours and, therefore, over the year as a whole.

Figure 64: Comparison of OPERA versus COMPETES modelling results on non-VRE power mix in selected scenario cases, 2030-2050



	R2030 OPERA	R2030 COMPETES	A2030 OPERA	A2030 COMPETES	A2050 OPERA	A2050 COMPETES	C2050 OPERA	C2050 COMPETES
Other non-VRE supply	8.2	9.0	10.6	9.2	5.0	1.7	19.6	2.6
Nuclear	3.4	4.0	3.4	4.0	0.0	0.0	0.0	0.0
Coal	30.6	30.4	32.8	32.9	0.0	0.4	0.0	1.9
Gas	43.6	43.5	46.0	47.8	2.2	22.1	18.9	57.7



	R2030	A2030	A2050	C2050
Gas	0.2	-1.8	-19.9	-38.8
Coal	0.2	-0.1	-0.4	-1.9
Nuclear	-0.6	-0.6	0.0	0.0
Other non-VRE supply	-0.8	1.4	3.3	17.0

Moreover, due to both the upward and downward demand response, the residual load duration curve becomes much flatter in OPERA than in COMPETES (see Section 3.4, in particular **Figure 57**). As a result, there is less need for peak load installations (with relatively high variable costs) – such as gas-fired plants – and more need for mid or base load units (with relatively high investment costs), such as biomass, waste or geothermal installations.

3.6 Net residual power balances

Figure 65 presents the net residual power balances in some selected scenario cases over the years 2030-2050, including a distinction between all hours over the year with a positive residual load (VRE shortage) and all hours with a negative residual load (VRE surplus), according to the OPERA modelling results. This figure resembles a similar set of graphs in Section 2.2.9 above, i.e. **Figure 36**, which presents similar net residual power balances for all FLEXNET scenario cases according to the COMPETES modelling results.[43]

Compared to **Figure 36**, however, **Figure 65** includes also data on demand response (not covered by COMPETES) and energy storage charges – including losses – and discharges (to some extent covered by COMPETES but found to be not feasible, at least in the Netherlands). On the other hand, in **Figure 65** data on non-VRE power generation have been aggregated into one single category (although more detailed, specified OPERA outcomes on the VRE output mix have been provided in the previous section, **Figure 65**).

OPERA modelling results on energy storage activities, however, turned out to be zero in the 2030 scenario cases, whereas they are relatively limited in the 2050 scenario cases (as discussed and explained in Section 3.3). Modelling outcomes by OPERA on demand response, on the other hand, are quite substantial, notably in the 2050 scenario cases.

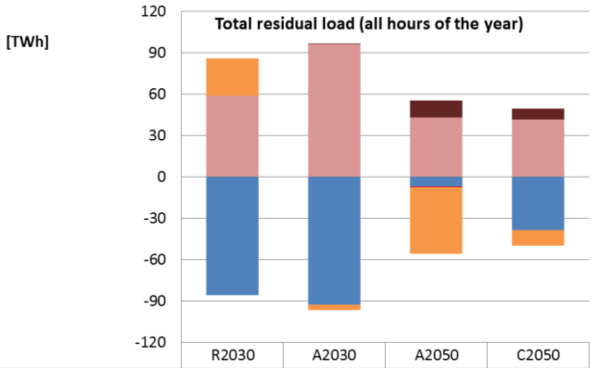
In the upper part of **Figure 65** (all hours of the year), however, total annual demand response is zero. This is due to the condition that in both the static and the flexible demand option the total annual power demand of the technologies concerned is fixed at the same level. As a result, the upward demand response is equal to the downward demand response and the balance of demand response over all hours of the year is zero.

On the other hand, in the middle part of **Figure 65** (all hours with a VRE shortage) total demand response is highly negative (-18.6 TWh, i.e. downward demand response), implying that in these hours power demand is substantially reduced (corresponding to, on average, about 25% of the – positive – residual load in these hours). In the lower part of **Figure 65** (all hours with a VRE surplus), total demand response is, on the contrary, highly positive (+18.6 TWh, i.e. upward demand response), implying that in these hours power demand is substantially increased (corresponding to, on average, approximately 53% of the – negative, uncurtailed – residual load in these hours).

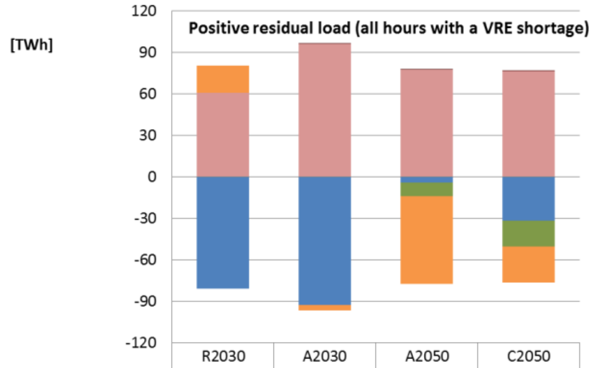
Overall, the differences in the net residual power balances of **Figure 36** (COMPETES) and **Figure 65** (OPERA) are generally small for the respective 2030 scenario cases. In the 2050 scenario cases, however, the differences between the two models are quite substantial. As outlined above, these differences are primarily due to the fact that the OPERA modelling results include a large amount of (upward and downward) demand response, whereas this flexibility option is not covered by COMPETES. As a result, VRE

[43] Note that the (uncurtailed) residual load is generally slightly higher in COMPETES than in OPERA. This is due to differences in model characteristics, notably due to the fact that in OPERA – as an integrated energy system optimisation model – it is harder to fix power demand levels (as this is, to some extent, an output of the model rather than an input).

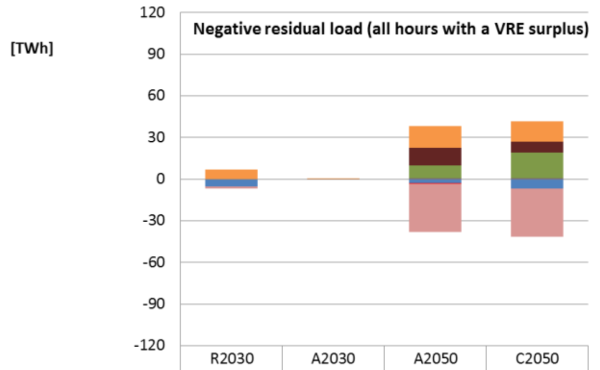
Figure 65: Net residual power balances in some selected scenario cases, 2030-2050, including a distinction between hours with a positive residual load (VRE shortage) and a negative residual load (VRE surplus), according to the OPERA modelling results



	R2030	A2030	A2050	C2050
Net exports	26.7	-3.6	-48.2	-11.0
VRE curtailment	0.1	0.1	12.7	7.8
Residual load (uncurtailed)	59.0	96.4	42.5	41.6
Demand response - total	0.0	0.0	0.0	0.0
Storage - charge (incl. losses)	0.0	0.0	0.4	0.3
Storage - discharge	0.0	0.0	-0.2	-0.2
Non-VRE supply	-85.8	-92.8	-7.2	-38.5



	R2030	A2030	A2050	C2050
Net exports	19.8	-3.8	-63.8	-26.0
VRE curtailment	0.1	0.0	0.0	0.0
Residual load (uncurtailed)	60.7	96.4	77.4	76.4
Demand response - total	0.0	0.0	-9.5	-18.6
Storage - charge (incl. losses)	0.0	0.0	0.1	0.0
Storage - discharge	0.0	0.0	-0.1	-0.1
Non-VRE supply	-80.5	-92.6	-4.1	-31.7



	R2030	A2030	A2050	C2050
Net exports	6.9	0.2	15.7	15.0
VRE curtailment	0.0	0.0	12.7	7.8
Residual load (uncurtailed)	-1.7	0.0	-34.9	-34.8
Demand response - total	0.0	0.0	9.5	18.6
Storage - charge (incl. losses)	0.0	0.0	0.3	0.3
Storage - discharge	0.0	0.0	-0.1	-0.1
Non-VRE supply	-5.3	-0.2	-3.1	-6.7

curtailment is much lower in OPERA than in COMPETES – notably in hours with a VRE surplus and an upward demand response – while non-VRE output is also much lower in OPERA than in COMPETES, in particular in hours with a VRE shortage and a downward demand response.[44]

3.7 Flexibility options to meet hourly variations of the residual load

In Section 2.3.3, we have considered three indicators of flexibility needs due to the hourly variations of the residual power load and, in particular, we have estimated and analysed the supply options to meet the flexibility needs according to these indicators by means of the COMPETES model for all FLEXNET scenario cases. One of these three indicators is the so-called '*total hourly ramps'*, i.e. the total annual amount of hourly variations of the residual load – either upwards or downwards – aggregated over a year and expressed in energy terms per annum (TWh). This is an indicator for the total annual flexibility needs over a year – either upwards or downwards – resulting from the hourly variation of the residual power load.

As part of the OPERA modelling analyses, we have once again estimated the total annual flexibility needs according to the indicator of the total hourly ramps for four selected scenario cases (R2030, A2030, A2050 and C2050) and compared the results with those of the COMPETES modelling analyses (as presented and discussed in Section 2.3.3, notably **Figure 45**).

Due to the *time slice approach* of OPERA – as explained in Section 3.1 – the model, however, is generally inclined to underestimate the hourly variations of (the constituent components of) both the residual load and the residual supply and, therefore, to underestimate the flexibility needs of the power system as well as the options to meet this needs. Consequently, the time slice effect makes it harder to compare the OPERA results with those of the COMPETES model. Therefore, in addition to the OPERA flexibility results including the time slice effect, we have also calculated these results excluding – i.e. correcting for – the time slice effect. This correction is based on the following approach:

- It is assumed that the COMPETES model calculates the total annual demand and supply of flexibility correctly as it calculates the 'truly' hourly variations of the residual demand/supply, based on the hourly power demand and VRE supply profiles as well as on other input values assumed in the FLEXNET scenario cases (rather than on the hourly – 'average' – variations in the OPERA model resulting from the time slice approach). This applies also in particular for the hourly variations of power trade calculated by COMPETES – which is used as fixed input by OPERA before applying the time slice approach – and, hence, for the resulting flexibility offered by this cross-border option as calculated by COMPETES.

[44] Moreover, as noted in Section 3.5, the non-VRE output *mix* is also different between OPERA and COMPETES in the 2050 scenario cases.

- Therefore, in the ‘corrected’ OPERA results, i.e. excluding the time slice effect, the level of the total annual demand/supply of flexibility as well as the flexibility offered by power trade is set at exactly the same level as calculated by COMPETES.
- Within the OPERA results, the (corrected) flexibility offered by power trade is subtracted from the (corrected) total annual supply of flexibility, resulting in the (corrected) total annual *domestic* supply of flexibility.
- The *corrected* total annual domestic supply of flexibility is compared to the *uncorrected* total annual domestic supply (i.e. including the time slice effect). If there is any difference – e.g. if the corrected total supply is 10% higher than the uncorrected total supply – any constituent component , i.e. each domestic flexibility option, of the uncorrected total supply is adjusted by this difference of 10% (so that the total of both categories becomes exactly equal).

Figure 66 presents the total annual supply of flexibility options to meet the total annual demand for flexibility, either upwards or downwards, resulting from the hourly variations (‘ramps’) of the residual power load in the selected scenario cases, according to the OPERA modelling results. The upper part of **Figure 65** shows the estimated total annual supply of flexibility options according to the OPERA modelling results including the time slice effect and the lower part the results excluding – i.e. correcting for – the time slice effect.

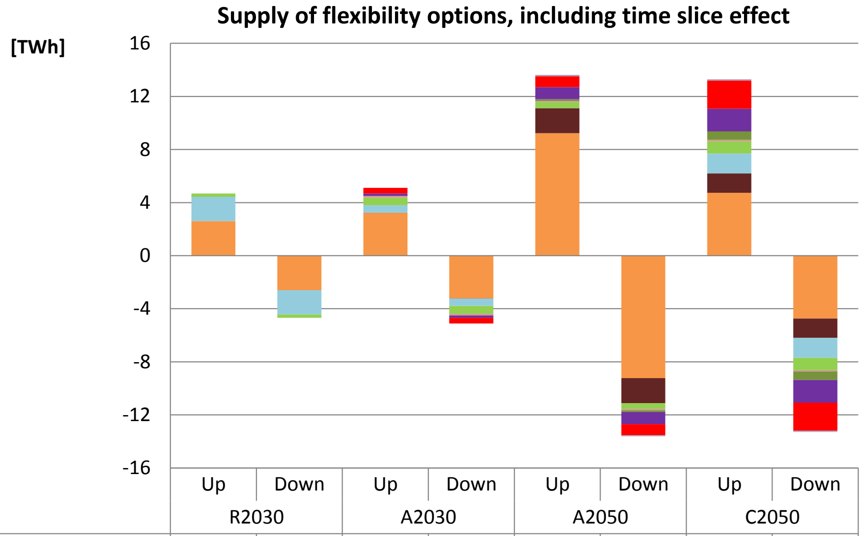
Figure 66 shows that the uncorrected results (i.e. including the time slice effect) are generally 10-30% lower than the corrected results (excluding the time slice effect). For instance, in A2050 the uncorrected (OPERA) result for the upward flexibility offered by (hourly variations in) net imports amounts to 9.2 TWh while the corrected (COMPETES) results amount to 11.1 TWh (+21%). Similarly, the comparable amounts for the total annual supply of upward flexibility in A2050 are 13.6 TWh and 15.2 TWh, respectively (+11%).

Finally, **Figure 67** presents a comparison between the (corrected) OPERA and COMPETES modelling results with regard to the total annual supply of upward flexibility options due to the hourly variations of the residual load of the Dutch power system in four selected scenario cases over the years 2030-2050.[45] Similar to the comparison of the modelling results on VRE curtailment and non-VRE power generation in the sections above, it shows that the differences in modelling outcomes are generally relatively small in the 2030 scenario cases, notably in R2030.

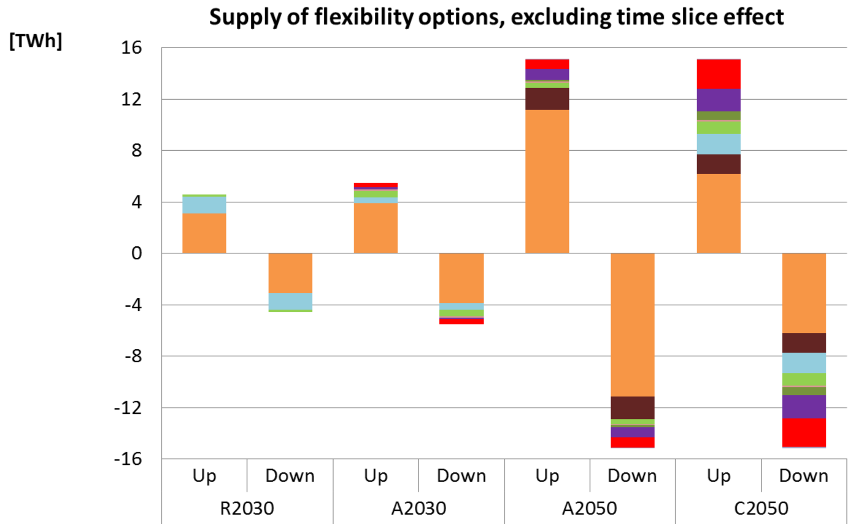
On the other hand, in the 2050 scenario cases – and particularly in C2050 – the differences in domestic flexibility options are quite substantial. For instance, in C2050 the flexibility offered by means of the hourly variations in total demand response (including all four flexible power demand technologies explored in Section 3.2) amounts to 4.8 TWh in the OPERA modelling results, corresponding to almost 32% of total annual flexibility demand/supply – and being the most dominant ‘domestic’ flexibility option in C2050 – whereas it amounts to zero in the COMPETES modelling results (as this option is not covered by this model).

[45] Note that **Figure 67** shows only a comparison of the *upward* flexibility demand/supply as the downward flexibility demand/supply levels are exactly similar to the upward levels (as can be noticed in **Figure 66** and as explained in Section 2.2.3).

Figure 66: Total annual supply of flexibility to meet total annual demand of flexibility due to the hourly variations ('ramps') of the residual load, either upwards or downwards, in selected scenario cases, 2030-2050, according to the OPERA modelling results

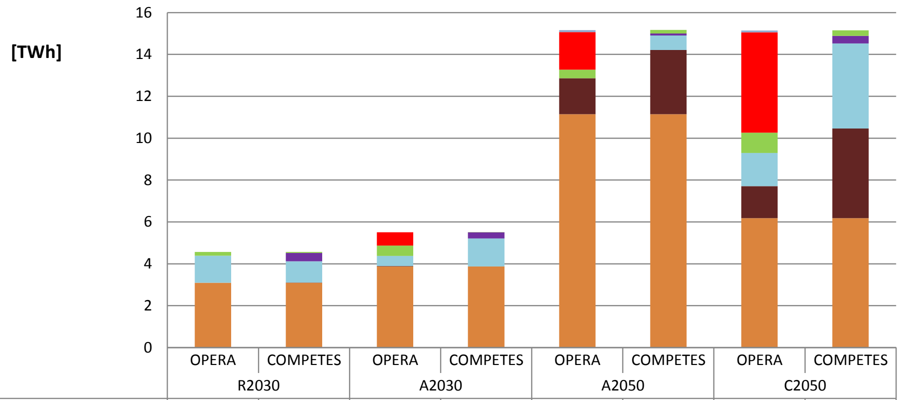


	R2030 Up	R2030 Down	A2030 Up	A2030 Down	A2050 Up	A2050 Down	C2050 Up	C2050 Down
Storage	0.0	0.0	0.0	0.0	0.1	-0.1	0.1	-0.1
Demand response P2G	0.0	0.0	0.4	-0.4	0.8	-0.8	2.1	-2.1
Demand response P2H	0.0	0.0	0.2	-0.2	0.9	-0.9	1.7	-1.7
Demand response P2A	0.0	0.0	0.0	0.0	0.1	-0.1	0.6	-0.6
Demand response EV	0.0	0.0	0.1	-0.1	0.1	-0.1	0.1	-0.1
Other non-VRE supply	0.2	-0.2	0.6	-0.6	0.4	-0.4	0.9	-0.9
Gas	1.8	-1.8	0.6	-0.6	0.0	0.0	1.5	-1.5
VRE curtailment	0.0	0.0	0.0	0.0	1.9	-1.9	1.5	-1.5
Net imports	2.6	-2.6	3.2	-3.2	9.2	-9.2	4.7	-4.7

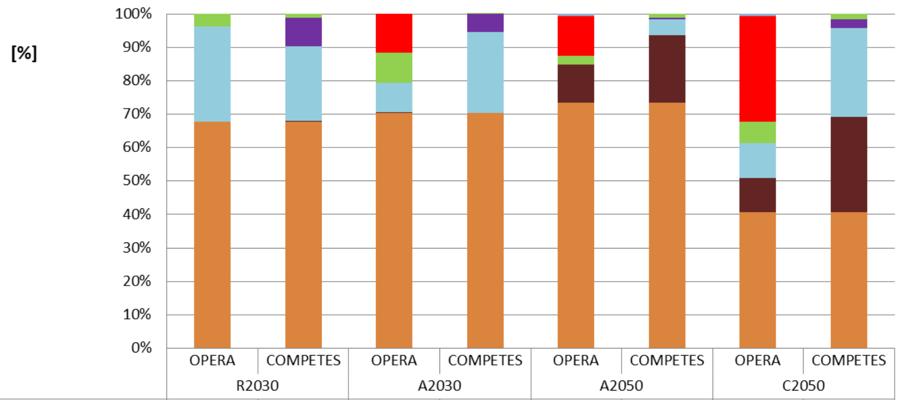


	R2030 Up	R2030 Down	A2030 Up	A2030 Down	A2050 Up	A2050 Down	C2050 Up	C2050 Down
Storage	0.0	0.0	0.0	0.0	0.1	-0.1	0.1	-0.1
Demand response P2G	0.0	0.0	0.4	-0.4	0.7	-0.7	2.2	-2.2
Demand response P2H	0.0	0.0	0.2	-0.2	0.8	-0.8	1.8	-1.8
Demand response P2A	0.0	0.0	0.0	0.0	0.1	-0.1	0.7	-0.7
Demand response EV	0.0	0.0	0.1	-0.1	0.1	-0.1	0.1	-0.1
Other non-VRE supply	0.2	-0.2	0.5	-0.5	0.4	-0.4	1.0	-1.0
Gas	1.3	-1.3	0.5	-0.5	0.0	0.0	1.6	-1.6
VRE curtailment	0.0	0.0	0.0	0.0	1.7	-1.7	1.5	-1.5
Net imports	3.1	-3.1	3.9	-3.9	11.1	-11.1	6.2	-6.2

Figure 67: Comparison of OPERA versus COMPETES modelling results on the total annual supply of upward flexibility options to meet total annual demand of upward flexibility due to the hourly variations ('ramps') of the residual load in selected scenario cases, 2030-2050



[TWh]	R2030 OPERA	R2030 COMPETES	A2030 OPERA	A2030 COMPETES	A2050 OPERA	A2050 COMPETES	C2050 OPERA	C2050 COMPETES
Storage	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0
Total demand response	0.0	0.0	0.6	0.0	1.8	0.0	4.8	0.0
Other non-VRE supply	0.2	0.0	0.5	0.0	0.4	0.2	1.0	0.3
Coal	0.0	0.4	0.0	0.3	0.0	0.1	0.0	0.4
Gas	1.3	1.0	0.5	1.3	0.0	0.7	1.6	4.1
VRE curtailment	0.0	0.0	0.0	0.0	1.7	3.1	1.5	4.3
Net imports	3.1	3.1	3.9	3.9	11.1	11.1	6.2	6.2



[%]	R2030 OPERA	R2030 COMPETES	A2030 OPERA	A2030 COMPETES	A2050 OPERA	A2050 COMPETES	C2050 OPERA	C2050 COMPETES
Storage	0.0%	0.0%	0.0%	0.0%	0.6%	0.0%	0.6%	0.0%
Total demand response	0.0%	0.0%	11.5%	0.0%	11.8%	0.0%	31.7%	0.0%
Other non-VRE supply	3.8%	1.1%	9.1%	0.0%	2.7%	1.1%	6.4%	1.7%
Coal	0.0%	8.6%	0.0%	5.4%	0.0%	0.6%	0.0%	2.4%
Gas	28.4%	22.3%	8.7%	24.2%	0.0%	4.6%	10.4%	26.8%
VRE curtailment	0.0%	0.3%	0.3%	0.0%	11.3%	20.2%	10.1%	28.3%
Net imports	67.8%	67.8%	70.4%	70.4%	73.6%	73.5%	40.8%	40.8%

In addition, **Figure 67** shows that in C2050 the flexibility offered by (hourly variations in) VRE curtailment and gas-fired power generation are significantly lower in the OPERA modelling results than in the COMPETES modelling outcomes (due to the difference in modelling results on demand response mentioned above). For instance, in C2050 the share of VRE curtailment in total annual flexibility supply amounts to 10% in the OPERA results and to 28% in the COMPETES outcomes. For gas-fired power generation, these figures amount to 10% and 27%, respectively (see the last two columns in the lower part of **Figure 67**).

Note that the levels and differences in modelling outcomes between COMPETES and OPERA with regard to the ‘domestic’ flexibility options may be partly due to the assumption that the ‘cross-border’ option (i.e. net power trade) is fixed at the same level in both models (as the power trade output of COMPETES is fixed input into the OPERA model). If the OPERA results on demand response would be fed back into the COMPETES model it may lead to a lower level of the cross-border (power trade) flexibility option and to a similar higher level – and change in the mix – of the domestic flexibility option of non-VRE power generation. This exercise has not been conducted in the present study but may be an interesting topic for follow-up research.

3.8 Summary and conclusions

This chapter has analysed the options to meet the demand for flexibility due to the variability of the residual load in the Dutch power system up to 2050 by means of the NL energy system model OPERA. The major findings of the OPERA modelling results – including, where relevant, a comparison with the COMPETES modelling findings – are summarised below.

Demand response
As part of the OPERA modelling analyses, we have particularly investigated the potential of demand response by some selected power demand technologies as an option to address flexibility needs of the Dutch power system up to 2050. These technologies include electric passenger vehicles (EVs) as well as three energy conversion technologies, i.e. power-to-gas (P2G), power-to-heat (P2H) and power-to-ammonia (P2A).

At present, the power demand by these technologies is still (negligible) small but it is expected that it will grow rapidly in the coming decades and that it offers, in principle, a large potential for demand response as a flexibility option for the Dutch power system, perhaps already – to some extent – in the period up to 2030 but notably in the years beyond 2030.

The major OPERA modelling findings with regard to the role of demand response by the four selected technologies include:

- Total power demand by the four selected technologies increases from almost zero in R2015 to about 33 TWh in A2030 and to 97 TWh in both A2050 and C2050, i.e. more than 40% of total power load in the 2050 scenario cases.

- The total annual *upward* demand response of the four technologies considered increases from zero in R2030 to 4.4 TWh in A2030, to 18 TWh in A2050 and even to 25 TWh in C2050 (where the total *downward* demand response shows similar amounts in these scenario cases). As a share of total annual power demand by these four technologies, this corresponds to 13% in A2030, 19% in A2050 and 26% in C2050.

- As expected, the total annual demand response in the 2050 scenario cases is, on balance, significantly negative in all hours with a VRE shortage (i.e. generally a *downward* demand response in hours with a *positive* residual load and, hence, relatively *high* electricity prices) and significantly positive in all hours with a VRE surplus (i.e. generally an *upward* demand response in hours with a *negative* residual load and, therefore, relatively *low* electricity prices).

- The total annual flexibility – either upwards or downwards – offered by all demand-response technologies considered amounts to 1.8 TWh in A2050 and to 4.8 TWh in C2050. As a percentage of total annual flexibility needs due to the hourly variations of the residual load this corresponds to 12% and 32%, respectively.

Overall, there seems to be a large potential to meet future flexibility needs of the Dutch power system by means of demand response. This applies in particular to (industrial) power demand activities that are expected to grow rapidly in the coming decades such as power-to-gas, power-to-heat or power-to-ammonia, but also to power demand by means of more smart (flexible) charging of electric vehicles (as analysed above).

Moreover, there may be a large, additional potential for demand response by other power demand activities in other (household/service) sectors, although – to some extent – this potential may be harder to realise depending on the role of aggregators, price incentives, human behaviour, etc. This potential has not been explored in the current study at the national level, but our analyses at the regional Liander network level show that there is a significant potential of demand response at the local (household) level by means of direct load control (DLC) and various pricing mechanisms (see below).

Energy storage

In addition to the demand response technologies discussed above – of which some can, in principle, also be regarded as energy storage technologies (notably P2G and P2A) – the OPER model includes a wide variety of other, 'pure' electricity storage technologies such as compressed air energy storage (CAES), flywheels, supercapacitors, superconducting magnetic energy storage (SMES) and several types of batteries (conventional, sodium sulphur, lithium ion, flow batteries, etc.). As part of the FLEXNET project, OPERA has analysed the role of these storage technologies as a flexibility option to address the changes and variations of the (hourly) residual load of the Dutch power system in the FLEXNET scenario cases up to 2050.

A major finding of the FLEXNET-OPERA modelling analyses is that the role of 'pure' electricity storage technologies as a flexibility option to address hourly variations of the residual load of the Dutch power sector is low, i.e. nearly zero, up to 2030 and rather limited beyond 2030.More specifically, the major OPERA modelling results on energy storage include:

- The total charging-discharging activities, excluding storage losses, amount to almost 0.25 TWh in A2050 and 0.21 TWh in C2050, whereas the storage losses amount to 0.11 TWh and 0.09 TWh, respectively. All these activities result from one single technology only, i.e. CAES. As a percentage of residual load, these storage activities are generally rather limited, i.e. (far) less than 1%.

- The total annual supply of flexibility offered by energy storage (CAES) in order to meet the flexibility needs of the Dutch power system due to the hourly variation of the residual load in A2050 and C2050 amounts to approximately 0.1 TWh in both scenario cases, corresponding to less than 1% of total annual flexibility needs in these cases.

As the role of energy storage as a flexibility option turned out to be relatively limited (compared to previous expectations and to what is often suggested by other studies), we have conducted some sensitivity analyses by means of the OPERA model for the scenario case C2050 (which includes the largest part of domestic flexibility options).

In particular, we have reduced the annualised investment costs and the fixed operation and maintenance (O&M) costs of three storage technologies by a factor 10 in C2050, i.e. in the sensitivity runs these costs have been set at 10% of their original, baseline level. These three technologies include (i) compressed air energy storage (CAES), (ii) li-ion batteries, and (iii) superconducting magnetic energy storage (SMES).

The sensitivity analyses show that even in the case of fixed (O&M and investment) costs of the technologies considered have been reduced by 90%, their shares in (residual) power demand and flexibility supply remain relatively limited. For instance, the storage activities by these technologies offer flexibility to the power system by an amount varying between 0.15 TWh and 0.75 TWh per annum, i.e. approximately 1-5% of the annual flexibility needs due to the hourly variation of the residual load.

The main reason why the limited role of energy storage in meeting (future) flexibility needs is basically simple, i.e. there is a large potential of other, alternative flexibility options that are (much) cheaper to meet these needs, in particular flexibility offered through options such as power trade and demand response, but also – notably in hours with a VRE surplus – by means of VRE curtailment. Besides their volume effect, these options reduce the business case of energy storage technologies through the related price effects in the sense that they reduce the volatility of the electricity price and, hence, reduce the price margin to cover the cost of offering flexibility. This applies particularly for 'pure' electricity storage technologies, such as CAES, SMES or batteries, which have to cover their costs primarily – or even solely – from the price margin earned by this single activity.

Curtailment of VRE power generation
Comparing the role of VRE curtailment as a flexibility option in the OPERA versus COMPETES modelling results lead to the following major findings:

- Total VRE curtailment in OPERA is significantly lower in both A2050 and C2050 than in COMPETES. This is largely due to the fact that OPERA generates a large amount of upward demand response as a flexibility option – which reduces the need for VRE curtailment, notably in VRE surplus hours – whereas COMPETES does not include demand response as a potential flexibility option into the model and, hence, the contribution of (upward) demand response in offering flexibility – and, hence, in reducing the need for VRE curtailment – is consequently zero in COMPETES.

- In COMPETES the curtailment of power generation from sun PV is nearly zero, whereas in OPERA it is quite substantial (and even bigger than VRE curtailment from wind). This is due to different modelling assumptions regarding future network capacities, i.e. no domestic network restrictions – 'copper plate' – in COMPETES versus local (low-voltage) grid restrictions in particular hours (with high PV output) in OPERA.

Non-VRE power generation
Comparing the role of power generation from non-VRE sources (coal, gas, nuclear, biomass, etc.) as a flexibility option in the OPERA versus COMPETES modelling results lead to the following major findings:

- Compared to OPERA, the non-VRE output level of COMPETES is much higher in both A2050 and C2050. Moreover, the output mix of COMPETES in these scenario cases is quite different in the sense that gas output is much higher whereas the output from other non-VRE sources is much lower than in OPERA, notably in C2050.

- These differences in non-VRE output generation between the two models result in particular from the large amount of demand response in the OPERA modelling outcomes in the 2050 scenario cases, especially in C2050, whereas COMPETES does not include demand response as a flexibility option. As a result, the level of VRE curtailment is much lower in OPERA than in COMPETES, notably due to the upward demand response in hours with a major VRE surplus.

- Hence, in these hours – and over the year as a whole – more VRE output becomes available. In addition, due to the downward demand response – notably in hours with a large VRE shortage – less non-VRE output is needed in these hours and, therefore, over the year as a whole.

- Moreover, due to both the upward and downward demand response, the residual load duration curve becomes much flatter in OPERA than in COMPETES. As a result, there is less need for peak load installations (with relatively high variable costs) – such as gas-fired plants – and more need for mid or base load units (with relatively high investment costs), such as biomass, waste or geothermal installations.

Net residual power balances
Overall, the differences in the net residual power balances resulting from COMPETES versus OPERA are generally small for the respective 2030 scenario cases. In the 2050 scenario cases, however, the differences between the two models are quite substantial. As outlined above, these differences are primarily due to the fact that the OPERA modelling results include a large amount of (upward and downward) demand response, whereas this flexibility option is not covered by COMPETES. As a result, VRE curtailment is much lower in OPERA than in COMPETES – notably in hours with a VRE surplus and an upward demand response – while non-VRE output is also much lower in OPERA than in COMPETES, in particular in hours with a VRE shortage and a downward demand response.

Flexibility options to meet hourly variations of the residual load
A comparison between the (corrected) OPERA and COMPETES modelling results with regard to the total annual supply of upward flexibility options due to the hourly variations of the residual load of the Dutch power system in four selected scenario

cases over the years 2030-2050 shows that the differences in modelling outcomes are generally relatively small in the 2030 scenario cases, notably in R2030.

On the other hand, in the 2050 scenario cases – and particularly in C2050 – the differences in domestic flexibility options are quite substantial. For instance, in C2050 the flexibility offered by means of the hourly variations in total demand response amounts to 4.8 TWh in the OPERA modelling results, corresponding to almost 32% of total annual flexibility demand/supply – and being the most dominant 'domestic' flexibility option in C2050 – whereas it amounts to zero in the COMPETES modelling results (as this option is not covered by this model).

In addition, the comparison shows that in C2050 the flexibility offered by (hourly variations in) VRE curtailment and gas-fired power generation are significantly lower in the OPERA modelling results than in the COMPETES modelling outcomes (due to the difference in modelling results on demand response mentioned above). For instance, in C2050 the share of VRE curtailment in total annual flexibility supply amounts to 10% in the OPERA results and to 28% in the COMPETES outcomes. For gas-fired power generation, these figures amount to 10% and 27%, respectively.

4

Options to meet flexibility needs due to the uncertainty of the residual load: review of recent studies

In addition to the need for flexibility due to the *variability* of the residual load (expressed on the day-ahead market), there is also the demand for flexibility resulting from the *uncertainty* of the residual load (expressed on the intraday/balancing market). In phase 1 of FLEXNET, we have estimated and analysed the demand for flexibility due to the uncertainty of the residual load in the Dutch power system up to 2050, in particular due to the *forecast error* of wind power generation, i.e. the difference between forecasted and actually realised electricity output from wind energy (see Chapter 4 of the first phase report).

Unfortunately, due to modelling, time and budget constraints we have not been able to model and analyse quantitatively the options to meet the demand for flexibility due to the uncertainty of the residual load up to 2050 as part of the present study. In a previous study, however, ECN has estimated and analysed quantitatively the demand for flexibility due to the wind forecast error in the Dutch power sector over the period 2012-2023 as well as the supply of some flexibility options to meet this demand, using the COMPETES model and comparable input assumptions as in the present FLEXNET study (Koutstaal et al., 2014; see below). Moreover, there are a few other recent studies that have considered potential options to meet (future) flexibility needs resulting from the forecast error of a growing share of wind in total power generation.

In this chapter we will first of all present and discuss the major findings of the previous ECN study mentioned above (Section 4.1). Subsequently, we will review briefly the major findings of a few other recent studies on options to address (future) flexibility needs due to the uncertainty of the residual load (Section 4.2). Finally, we provide a summary of the major findings and conclusions of the present chapter (Section 4.3).

4.1 Previous ECN study on flexibility on the intraday market

In the study '*Quantifying flexibility markets*', ECN has analysed demand and supply of flexibility by the Dutch power sector over the years 2012-2023 (see Koutstaal et al., 2014; see also Özdemir et al., 2015, for a more recent paper based on this study). In this study, a distinction is made between the growing demand for flexibility due to the variability of the residual load – notably due to the variability from wind energy based on the expectations of wind power production on the day-ahead market – and the increasing demand for flexibility in the intraday and balancing markets because of the forecast error of wind power generation.

Due to the forecast error, realized wind power production will differ from the forecasted production on the day-ahead market. Balancing responsible parties will therefore look for flexibility in the intraday market to balance their programs, given differences in wind production compared to their submitted programs. As far as these differences cannot be met on the intraday market, they will have to be addressed by the TSO, i.e. TenneT, who will contract regulating and reserve power in order to ensure system stability. In their study, however, Koutstaal et al. (2014) do not distinguish between the intraday market and the single-buyer balancing market for regulating and reserve power. Instead, they consider the need for flexibility because of wind forecast errors as one market, and refer to it as '*intraday market*'.

4.1.1 Demand and supply of flexibility on the intraday market

Similar to the approach used during phase 1 of FLEXNET (see Chapter 4 of the first phase report), Koutstaal et al. (2014) have assumed the same forecast errors in 2023 as observed in 2012, utilizing the forecasted and realised hourly wind profiles of 2012.[46] Demand for flexibility has been determined by taking the difference between two model runs, one with forecasted wind production and another with realised hourly wind production. It has been assumed that net imports/exports remain fixed at the level based on the day-ahead schedules with forecasted wind power generation and only the generators within the Netherlands are allowed to adjust their production to accommodate wind forecast errors. This gives an estimate of the increased demand for flexibility as a result of wind forecast errors within the Netherlands and the most efficient accommodation from the incumbent generation.

Table 17 presents the resulting total annual demand for flexibility on the Dutch intraday market to accommodate wind forecast errors in the Netherlands. This demand increases significantly with the increasing level of wind generation. More specifically,

[46] Hourly forecasted and actual realised wind data for the Netherlands were acquired from the Wind energy unit at ECN. For more details on the approach used by the respective study, including the assumed input modelling assumptions, see Koutstaal et al. (2014) and Özdemir et al. (2015).

the total annual demand for upward flexibility due to the wind forecast error increases from 0.6 TWh in 2012 to 3.2 TWh in 2023, while the demand for downward flexibility increases from 0.4 TWh to 2.0 TWh, respectively.

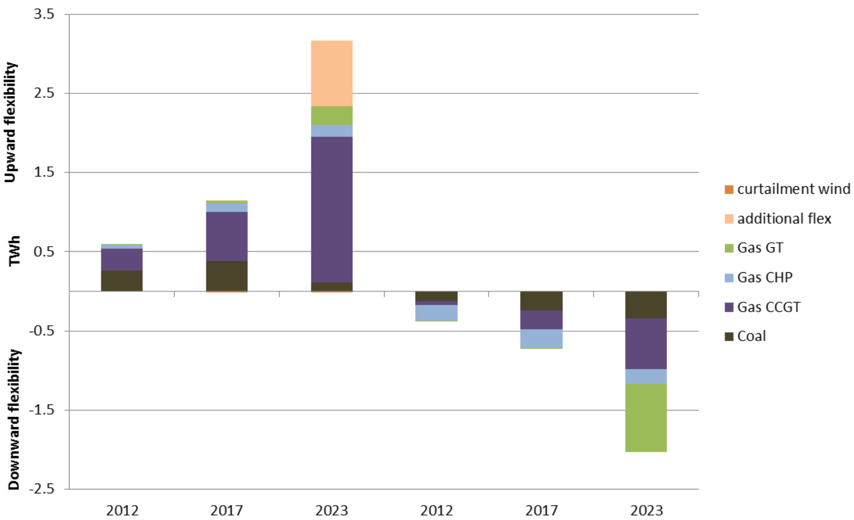
Table 17: Total annual demand for flexibility on the intraday market in order to accommodate wind forecast errors in the Netherlands, 2012-2023 (in TWh)

	2012	2017	2023
Demand for flexibility ramp-up	0.6	1.1	3.2
Demand for flexibility ramp-down	-0.4	-0.7	-2.0

Source: Koutstaal et al. (2014).

Figure 68 shows that the supply of flexibility to balance wind forecast errors is to a large extent from gas units (i.e., CCGTs and gas turbines), which are the most flexible units available in the scenarios considered. Some flexibility is supplied by coal fired power plants, especially by new units which are more flexible than the units in place in 2012. Given the assumption of a national Dutch balancing scheme where cross-border capacity does not contribute in real time balancing, not all demand for flexibility can be met in 2023 from incumbent sources. If balancing prices during hours with unmet demand are sufficiently high, this will provide an incentive for additional new flexibility sources such as flexible generation, storage, and demand response to enter the market or a shift of capacity from the day-ahead market to the intraday market (Özdemir et al., 2015).

Figure 68: Supply of upward and downward flexibility on the intraday market, 2012-2023



Source: Koutstaal et al. (2014).

Figure 68 shows that the upward flexibility offered by non-committed incumbent generators (gas, coal) amount to approximately 2.3 TWh in 2023, whereas the additional upward flexibility from new entrants is about 0.8 TWh. Below, first of all the results on balancing prices and value of flexibility of incumbent generators on the intraday market in 2013 will be presented and, subsequently, the business cases for supplying flexibility by new entrants on this market will be discussed.

4.1.2 Balancing prices and value of flexibility of incumbent units on the intraday market

With increasing levels of renewables in 2023, there is also an increase in price volatility on the intraday market. **Figure 69** shows the monthly prices calculated in 2023 for the day-ahead (spot) market and for the intraday market. It is expected that in those hours where there is an upward demand for flexibility (generation increase) on the intraday market, prices will be higher compared to the day-ahead market, while in those hours where there is a demand for downward flexibility (generation reduction) prices will be lower. On the intraday market, for upward adjustments capacity will be offered that has not been sold on the day-ahead market and, therefore, prices will be higher than on the day-ahead market. For downward adjustments, suppliers will be prepared to pay the balancing party or the TSO, because they will already have sold their energy on the day-ahead market (Abassy et al., 2011).

Figure 69: Average monthly electricity prices on the day-ahead (spot) market and the intraday market, 2012-2023

Source: Koutstaal et al. (2014).

Given the volumes and prices on the intraday market, Koutstaal et al. (2014) determine the value of the flexibility from incumbent generation provided on the intraday market. They assume that upward flexibility is recompensed at the actual market price as realised in the specific hour in which the flexibility is supplied. This price is equal to the variable costs of the marginal production unit at that hour. For downward adjustment, the value equals the difference between the day-ahead prices for the hour under consideration minus the price on the intraday market. Net revenue equals price times volume supplied minus the variable production costs in the case of demand for upward flexibility. Based on these assumptions, **Table 18** shows the net revenues realised by different types of technologies in the Netherlands.

Table 18: Net revenue on the intraday market by generation technology

	2017	*2023*
Coal	2	5
Gas CCGT	1	16
Gas CHP	6	6
Gas GT	0	55

Source: Koutstaal et al. (2014).

The large increase in wind power generation from 2017 to 2023 raises the net revenues on the intraday market, notably for CCGTs and GTs. Besides the incumbent generators, additional upward flexibility could be provided by new generators or by an increase in net imports in the hours in which demand for flexibility cannot be met in 2023.

4.1.3 Business cases for flexibility supply in 2023

Given demand and prices on the intraday market, Koutstaal et al. (2014) analyse the profitability of a new conventional generation or storage unit in providing the flexibility demanded in this market. In their analysis, they concentrate on the intraday market. It should be realized that in practice, investments and generation decisions will take into account all markets on which these assets can be used, from longer term forward markets and day-ahead markets to intraday markets and the provision of ancillary services. Concentrating on the intraday market allows us to analyse the additional opportunities to meet the demand for flexibility. However, they take into account that a plant will also produce on the day-ahead market and, therefore, investment costs do not have to be covered solely on the intraday market.

The analysis by Koutstaal et al. (2014) is concerned with business cases for the investment in a single new plant or facility and investigating their profitability in the intraday market given expected future developments. It is not the purpose of this analysis to derive the optimal capacity mix in the day-ahead or intraday market.

Conventional generation
Koutstaal et al. (2014) have analysed the profitability of a single CCGT and a single GT power plant on the intraday market to accommodate wind forecast errors, taking into account the flexibility constraints for these units. Their calculations indicate that gas-fired power plants, in particular combined cycle gas turbines, will be able to make a profit on the intraday market. They not only replace the old and less flexible incumbent generation but also provide additional flexibility in the hours in which incumbent generators are not able to meet the full demand for flexibility.

Since the efficiency of a GT plant is lower than that of a CCGT plant, its fuel costs are substantially higher. While a GT plant is only just profitable (approximately zero profits), profits for a CCGT plant are about € 25 million in 2023. The positive profit for a CCGT plant indicates that there is room for additional sources of flexibility in those hours in which CCGTs provide flexibility in the hours with unmet demand. Assuming constant net revenues over the whole lifetime of a plant, the internal rate of return for the CCGT plant is high, 47%, while for the GT it is 1%. This difference reflects the operating hours of both plants, where GTs have a much lower load factor.

Storage

Another option to provide flexibility is storage. The storage technologies which can provide volumes useful on the intraday market are mainly pumped hydro storage and Compressed Air Electricity Storage (CAES). Given the focus on balancing in the Netherlands, a business case for a 300 MW adiabatic CAES has been analysed by Koutstaal et al. (2014). In contrast to diabetic CAES, this variant does not need natural gas to expand compressed air, because heat generated in compressing air is stored and used to provide the heat needed in decompressing. Although the investment costs are higher, energy efficiency is also higher compared to diabetic CAES. **Table 19** shows the characteristics and data with regard to this storage option based on DNV KEMA (2013).

Table 19: Input parameters for adiabatic compressed air energy storage (CAES)

Investment costs	600 – 1200 €/kWe
Lifetime	30 years
Capacity	300 MW
Maximum storage capacity	2700 MWh
Discount rate	10%
Efficiency	70%
Annual fixed costs	19 - 38 M €

Source: DNV KEMA (2013) and Koutstaal et al. (2014).

Koutstaal et al. (2014) assume that storage can be used within a day, charging when electricity prices are low and discharging when demand and, therefore, prices are high. The optimal use and the revenues of storage are calculated through modelling of the CAES unit in the intraday market analysed with the COMPETES model. **Table 20** presents the results of this simulation analysis.

Table 20: Business case for adiabatic CAES to provide flexibility in the Dutch intraday market

Yearly charge	788 GWh
Yearly discharge	536 GWh
Revenues	117 M€
Charging costs	45 M€
Yearly fixed costs	19 - 38 M€
Profit	17 - 36 M€

Source: Koutstaal et al. (2014).

Depending on the investment costs, for which current estimates provide a range of 600 - 1200 €/kWe, the business case is positive, yielding a net profit in 2023 of 17 - 36 M€. The increased price volatility is an important driver for the profitability of a CAES storage facility, in particular during scarcity hours which drive up prices to the relatively low assumed VOLL of € 320 per MWh. While CAES mainly provides upward flexibility during scarcity hours reducing unmet flexibility demand, it replaces some of the downward flexibility from CCGT and coal fired power plants. Furthermore, wind curtailment is slightly reduced.

Minimum prices for profitability of new flexible supply

The results of Koutstaal et al. (2014) show that demand on the intraday market for ramping up is high, resulting in periods with high prices, which will incite additional flexibility providers to enter the market. This will bid down the price of flexibility up till the point where entrants will no longer be able to recoup their fixed costs. In equilibrium, prices on the intraday market will therefore include a scarcity rent in peak demand hours up and above the marginal costs of generation; otherwise new generators would not enter the market. As an indication of this scarcity rent, Koutstaal et al. (2014) has calculated the average monthly prices on the intraday market at which the business case for gas-fired units and storage is just positive, or, in other words, at which price these technologies can just recoup their investment costs.

Figure 70 shows the monthly average spot prices, balancing prices on the intraday market, and minimum upward prices required for CCGT, GT, and storage to break even. The minimum price for CCGT is below the day-ahead spot price, illustrating the profitability of a CCGT plant. For GT, the minimum price is more or less equal to the upward adjustment price, illustrating its zero profit at that price. The minimum price for storage is based on the upper limit of investment costs of € 1200 per kWe. Storage requires a higher monthly average price than a CCGT plant, but substantially lower than those of a gas turbine.

Figure 70: Comparison of 2023 intraday market prices and break even prices for flexible power generation and storage

Source: Koutstaal et al. (2014).

4.1.4 Discussion and closing remarks

In a recent study by ECN, it is shown that a higher share of wind power generation does not only increase the need for flexibility to accommodate wind variability, but also leads to an increased demand for flexibility to accommodate wind forecast errors (Koutstaal et al., 2014). In an efficient intraday market, this results in additional revenues and a positive business case for flexible generation and storage providing flexibility for real time balancing. Efficient intraday markets can contribute to accommodating increasing levels of variable and uncertain renewables in the electricity market. These markets will give a price incentive for both flexible generation and other sources of flexibility such as storage to provide the increased need for flexibility. On this market, the most cost-effective options will be selected to compensate higher or lower than forecasted power production from renewable energy sources, thereby reducing overall costs of integrating renewables in the electricity system (Özdemir et al., 2015).

An important requirement for an efficient intraday market is program responsibility for all producers, including renewable energy power generators. Otherwise, renewable power generators will not have an incentive to trade on the intraday market. Without program responsibility for renewable generators, the intraday market will not develop and there will be no incentives to develop new sources of flexibility. Furthermore, there should be an incentive for balancing responsible parties to be active on the intraday market instead of leaving it to the TSO to balance the market. This requires that they bear the full costs of balancing incurred by the TSO. If this would not be the case, for example because part of these costs are socialized or because the price paid for imbalance is based on average costs instead of marginal costs, it would be less costly to leave balancing to the TSO and the intraday market would not develop. In essence, both - the responsibility and the incentives - are part of the current balancing regime in the Netherlands (Özdemir et al, 2015).

In their analysis, Koutstaal et al. (2015) have focussed on a single year based on a scenario for the future development of the electricity market. In actual investment decisions, the business case analysis also includes an analysis of uncertainty and potential risks, taking into account different assumptions for fuel prices, demand and generation mix developments. They therefore have not only focussed on the specific results for the business cases but also looked at the minimum prices needed for a positive business case. These calculations provide a kind of sensitivity analysis, indicating the range of market conditions in terms of prices that allow profitable investments for the supply of flexibility on the intraday market.

While the assumptions by Koutstaal et al. (2014) on future developments have some impact on the results, they are likely to be robust regarding the increased demand for flexibility resulting from increased intermittent renewables generation. Probably the major factor which affects the results is the available capacity relative to net demand on both the day-ahead and intraday markets. Obviously, a situation of overcapacity will not allow all market participants to operate at a profit. However, in such a case it is to be expected that there will be a response of the market, which reduces overcapacity and allows generators to cover all their costs.

Furthermore, Koutstaal et al. (2014) compute optimal dispatch for realized wind production on the intraday market, keeping import and export schedules from the day-ahead market fixed. While intraday markets can be expected to have a higher price due to the higher scarcity of capacity, a very large difference will incite generators to bid more on the intraday market and less on the day-ahead market; thereby increasing prices on the day-ahead market and driving down prices on the intraday market. Moreover, entrants (such as flexible conventional generation, storage and demand side response) are likely to have incentives to provide additional capacity. Although Koutstaal et al. (2014) have not calculated the final equilibrium on the intraday market, the minimum prices determined in the business cases provide some indication of equilibrium prices for individual technologies. A further step in the analysis of the impact of variable and uncertain renewables on day-ahead and intraday markets would be to model these markets explicitly in a dynamic setting in which not only generation but also investments are optimized.

While developments and interactions with other European countries are taken into account for the day-ahead market, the system balancing against wind forecast errors is only analysed for the Netherlands, reflecting current practice in which system balancing takes largely place within countries. However, with further integration of electricity markets, balancing over a larger geographical area can be expected to reduce overall balancing costs by improving the exchange of flexibility. This is also illustrated by the important role of power trade in providing flexibility on the day-ahead market (see previous chapter). It would therefore be valuable to look at the effects of integrating both intraday and balancing markets across country borders (Özdemir et al. 2015).

Furthermore, the analysis by Koutstaal et al. (2014) has been based on hourly data. However, volatility of renewable power generation is continuous. An analysis based on shorter time periods, such as 15 minutes, will probably show an increased demand and a higher value for flexibility.

Finally, as an alternative flexibility option, demand response can potentially provide a cost-effective means to provide some of the flexibility needed to accommodate wind forecast errors. As a result, less flexibility would be needed from supply options such as conventional generation or storage. Demand response, however, has not been considered in the study by Koutstaal et al. to address flexibility needs on the intraday market resulting from wind forecast errors.

4.2 Other recent studies

There is a huge amount of (international) literature on the impact of a growing share of VRE power production on the flexibility needs of the power sector, including the impact of VRE forecast errors on flexibility/balancing needs on the intraday/balancing markets. On the other hand, there is far less literature how these latter needs may be met in the coming decade, let alone serious studies on the (optimal) mix of supply options to address flexibility/balancing needs due to VRE forecast errors in a country such as the Netherlands up to 2030 or beyond.

There are a few (recent) studies available, however, which have considered the potential – or even the business case – of some individual options, such as energy storage or demand response, to address growing flexibility/balancing needs on the intraday/balancing markets in the Netherlands in the coming years (e.g., up to 2023), notably due to the growing share of VRE power generation and the resulting VRE forecast errors in particular. The major findings of these studies are reviewed briefly below.

Bal (2013), Development of the imbalance of the Dutch electricity grid – The impact of high shares of wind and solar generation on imbalance management
The general question of this study is: *How will the balance and imbalance settlement of the Dutch grid change with a high share of wind and solar generation?* One of the more specific sub-questions is: *What is the potential capacity of demand response in households for balancing purposes?* As the focus is on demand response by households other options, such as energy storage or demand response by other sectors (industry, services), are not included in the study. Moreover, to settle imbalance, the study focuses on secondary and tertiary control power, while primary control power is left out of the scope for research.[47]

The major findings of this study include (Bal, 2013):

- Based on data from Germany and Spain, it was found that below a share of 20% of installed VRE capacity, the imbalance share of total power load did not increase. With a higher share of VRE capacity than 20%, however, an increase in imbalance share was noticed, implying that beyond this threshold an increasing share of VRE power generation results in increasing balancing needs.

- The imbalance in the Netherlands is relatively low compared to other countries. It was found that the Dutch imbalance share of total power load is much lower than that from Germany and Spain, i.e. about 1% of total load in the Netherlands compared to 4-6% in Germany and Spain (with a similar share of VRE installed capacity in these countries over a range of 5-10% of total installed capacity. This is most likely the result of the real-time data which is published by the Dutch TSO (TenneT). This provides the possibility to react to imbalance and, therefore, helps 'passively' balance the grid. Since the Netherlands is the only country in Europe that provides this service, this is thought to have a big impact on the low share of imbalance.

- An increased share of imbalance is expected to be settled by an increase of activated control power. In Germany, however, the amount of activated control power has decreased over the past decade due to the cooperation of the German Transmission System Operators (TSOs). The German TSOs have been cooperating since 2008 when the Grid Control Cooperation (GCC) was implemented. The GCC provides the opportunity for TSOs to settle imbalance in their control area with imbalance in the opposite direction with another control area. This results in less

[47] Primary control is used for frequency containment based on automated response within 30 seconds when frequency deviations occur. Secondary control is used for frequency restoration to have the frequency back to its nominal value, after five minutes it is activated automatically. Tertiary control is used to restore the required level of frequency restoration reserves based on manually instructed reserves which take up to 15 minutes to activate (Bal, 2013; See also Van der Welle, 2016).

control power activation for both control areas as they settle imbalance with each other if possible. As a result the amount of activated control power has decreased after implementation of the GCC and, therefore, the imbalance prices have decreased as well.[48]

- The GCC has been transformed into the International Grid Control Cooperation (IGCC) when neighbouring countries of Germany were joining as well. The Netherlands started participating in February 2012. Same as for the German TSOs, the imbalance could be settled with the interconnections for a large part. Only 55% of the current imbalance volume has to be settled with control power from which most of the rest is settled with interconnections through the IGCC. This has resulted in a decreased market for balancing settlement mechanisms, including options such as demand response or energy storage.

- Under the condition that the comfort of living should remain equal, only a limited number of devices in households are suitable for balancing purposes, including in particular freezers, refrigerators, electric water heaters, heat pumps and air conditioners. The potential of these devices for both up and down balancing, however, was found to be relatively large, i.e. there is 100 MW of down regulation and 200 MW up regulation available in the Netherlands while the current (2013) absolute imbalance is around 110 MW.

- Realising the household balancing potential by means of demand response would result in a decrease in imbalance costs of approximately € 30 million annually. This is, on average, € 40 per household annually, which provides a relatively low incentive for the implementation of smart household appliances for balancing purposes. Moreover, the balancing market – which was expected to increase due to increased imbalance resulting from growing VRE generation shares – will likely decrease in the next years because a large part of total imbalance will be settled with the IGCC (or other arrangements to enhance international TSO cooperation and integration of balancing markets over a larger control area). This provides a lower incentive to realise the household balancing potential by means of demand response. Finally, this potential may also be harder to realise due to the competition by other, alternative balancing options such as providing balancing services through energy storage or by VRE generators themselves, which increasingly are technically well suited for being ramped down quickly – when generating electricity – or even to ramp up, when producing below potential output such that some VRE generation is constantly curtailed.[49]

Berenschot et al. (2015), Roadmap Energy Storage NL 2030 (in Dutch)
On behalf of the Top Sector Energy, a consortium consisting of Berenschot, DNV GL and TU Delft has designed a national roadmap for energy storage in the Netherlands up to 2030.[50] As part of this roadmap, they have briefly summarised the potential of energy storage on the balancing market, including the following findings:

48 A similar result was found more recently by Hirth and Ziegenhagen (2015). More specifically, they found that while German wind and solar capacity has tripled since 2008, balancing reserves have been reduced by 15% and costs by 50% (due to TSO cooperation and some other factors). They call this the 'German Balancing Paradox'.

49 This latter option (providing balancing services by VRE generators themselves) is discussed particularly by Hirth and Ziegenhagen (2015).

50 See also the National Action Plan Energy Storage submitted by Energy Storage NL (2016; in Dutch).

- The development of the balancing market up to 2030 is highly uncertain. Compared to the day-ahead/intraday markets, imbalance prices show wider fluctuations – with peak prices running up to 600 €/MWh – although they occur less often. Moreover, the volume of the balancing market is limited, implying that energy storage will meet swiftly competition from other flexibility/balancing options.

- Due to the higher price differences and the number of peak prices per day, the perspectives for some storage technologies are better on the Dutch balancing market than on the Dutch spot market (where variations in electricity prices are not sufficient in 2030 to make longer-term storage attractive). Current regulation, however, may be a potential barrier for storage activities on the balancing market.

- With regard to the market for regulation and reserve power, it is noticed in (international) practice that – besides conventional generators – also energy storage is deployed for offering services on this market, notably by technologies such as flywheels and li-ion batteries that meet the required specifications for these services. Economic analysis shows that with the current price levels and costs for some technologies (flywheels), there is a positive business case for offering primary reserve services. In addition, market consultations show that commercial parties are interested to become active with li-ion batteries in this field.

CE Delft (2016), Market and flexibility (in Dutch)
As part of the study 'Market and flexibility', CE Delft has – among others – considered the potential supply of flexibility options to maintain power system balancing in the Netherlands up to 2023, including the following major findings:

- During hours with a low feed-in by VRE generation, the upward balancing potential in 2023 consists of existing CCGT capacity (1.6 GW) and – newly installed – compressed air energy storage (CAES, 0.3 GW), while the downward balancing potential consists of existing CCGT capacity (5 GW) and CAES (0.3 GW).

- During hours with a high feed-in by VRE generation, the upward balancing potential in 2023 consists of existing conventional capacity (>5 GW) and CAES (0.3 GW), while the downward balancing potential consists of existing conventional capacity (5 GW), CAES (0.3 GW) and demand response by power-to-heat (P2H) in district heating (0.5 GW).

- In general, the available capacity for upward and downward balancing seems to be sufficient to meet balancing needs up to 2023. It should be realised, however, that the balancing needs to correct VRE forecast errors are usually highest during situations of high VRE output levels. During these situations, the availability of conventional options to meet these needs – i.e. gas-fired spinning reserves – will become under increasing pressure. This likely creates the need for the availability of other options such as storage or demand response.

DNV GL (2017) WindStock – Feasibility wind turbines, energy storage and sun PV (in Dutch)
On behalf of Energy Storage NL, Greenchoice and the Dutch association of windmill owners (Windunie), DNV GL has conducted a study in order to investigate feasible business case opportunities of the integration of existing wind turbines with energy

storage and/or sun PV. The major findings of this study include (DNV GL, 2017; Energeia, 2017:

- The business case for the mix of storage and wind turbines can be positive if some conditions are met. First of all, size of the storage system matters. A larger system is relatively cheaper than a small system, but if the storage capacity is bigger than the capacity of the wind park it results in higher connection costs. Hence, a right balance between these two sides has to be found.

- One option is to deploy a cooperative storage system that connects several smaller windmills. In this way, smaller wind parks can also benefit of economies of scale regarding storage size.

- Another condition is that storage has to be used for several purposes to be beneficial. If it is not profitable to use storage only for avoiding imbalance and, hence, to avoid the imbalance costs that windmill owners have to pay. It can be potentially interesting, however, if storage could be used for own consumption of energy. As a result, the network connection of, for instance, farmers or other small-scale wind operators could be smaller and, hence, cheaper. But even then, storage has be meet several conditions (size, consumption profile, additional revenues) to be profitable.

- The study has also investigated the opportunities of using storage to trade on the electricity markets. Trading on the day-ahead (spot) market, however, is not attractive with the current and (expected) future price fluctuations. Trading on the primary reserve balancing market is more interesting with current price levels, but this market is small and prices will become under pressure if more storage is installed.

- The most favourable opportunities seem to exist for using storage to trade electricity on the secondary reserve balancing markets. This market is bigger than de primary reserve market and prices are under less pressure. The best option is to charge a li-ion battery system with electricity from a wind turbine and to deliver to the grid once the imbalance occurs by offering secondary reserve power. If the windmill owner additionally uses part of the electricity from storage for own consumption – and, hence, reduces grid connection costs – a positive business case becomes gradually into existence (DNV GL, 2017; Energeia, 2017).

4.3 Summary and conclusions

In this chapter we have reviewed a previous ECN study on flexibility on the intraday/-balancing market as well as some other recent, medium-term studies (usually up to 2023) that have considered potential options to meet flexibility needs resulting from the uncertainty of the residual power load in general and the wind forecast error in particular. Some of the major findings of these studies include:

- The total annual demand for upward flexibility on the intraday/balancing market is estimated to increase from 0.6 TWh in 2012 to 3.2 TWh is 2023. Most of (the increase in) this demand by 2023 can be met by incumbent, conventional generators (gas, coal) but there is also some room (0.8 TWh) – and even a business case – for new entrants such as conventional generators (notably CCGTs) or storage, in particular compressed air energy storage (CAES; see Koutstaal et al., 2014 as well as Özdemir et al., 2015).

- Under the condition that the comfort of living should remain equal, only a limited number of devices in households are suitable for balancing purposes, including in particular freezers, refrigerators, electric water heaters, heat pumps and air conditioners. The potential of these devices for both up and down balancing, however, was found to be relatively large, i.e. there is 100 MW of down regulation and 200 MW up regulation available in the Netherlands while the current (2013) absolute imbalance is around 110 MW (Bal, 2013).

- Realising the household balancing potential by means of demand response would result in a decrease in imbalance costs of approximately € 30 million annually. This is, on average, € 40 per household annually, which provides a relatively low incentive for the implementation of smart household appliances for balancing purposes. Moreover, the balancing market – which was expected to increase due to increased imbalance resulting from growing VRE generation shares – will likely decrease in the next years because a large part of total imbalance will be settled within the International Grid Control Cooperation (IGCC) between Germany, the Netherlands and some other north-western European countries (or by other arrangements to enhance international TSO cooperation and integration of balancing markets over a larger control area). This provides a lower incentive to realise the household balancing potential by means of demand response. Finally, this potential may also be harder to realise due to the competition by other, alternative balancing options such as providing balancing services through energy storage or by VRE generators themselves, which increasingly are technically well suited for being ramped down quickly – when generating electricity – or even to ramp up, when producing below potential output such that some VRE generation is constantly curtailed. (Bal, 2013; Hirth and Ziegenhagen, 2015).

- The development of the balancing market up to 2030 is highly uncertain. Compared to the day-ahead/intraday markets, imbalance prices show wider fluctuations – with peak prices running up to 600 €/MWh – although they occur less often. Moreover, the volume of the balancing market is limited, implying that energy storage will meet swiftly competition from other flexibility/balancing options (Berenschot, et al., 2015).

- Due to the higher price differences and the number of peak prices per day, the perspectives for some storage technologies are better on the Dutch balancing market than on the Dutch spot market (where variations in electricity prices are not sufficient in 2030 to make longer-term storage attractive). Current regulation, however, may be a potential barrier for storage activities on the balancing market (Berenschot, et al., 2015).

- With regard to the market for regulation and reserve power, it is noticed in (international) practice that – besides conventional generators – also energy storage is deployed for offering services on this market, notably by technologies such as flywheels and li-ion batteries that meet the required specifications for these services. Economic analysis shows that with the current price levels and costs for some technologies (flywheels), there is a positive business case for offering primary reserve services. In addition, market consultations show that commercial parties are interested to become active with li-ion batteries in this field (Berenschot, et al., 2015).

- In general, the available capacity for upward and downward balancing seems to be sufficient to meet balancing needs up to 2023. It should be realised, however, that the balancing needs to correct VRE forecast errors are usually highest during situations of high VRE output levels. During these situations, the availability of conventional options to meet these needs – i.e. gas-fired spinning reserves – will become under increasing pressure. This likely creates the need for the availability of other options such as storage or demand response (CE Delft, 2016).

- The business case of a windmill and energy storage for balancing purposes can be positive if some conditions are met, notably if a certain size of the storage is met – for instance, a cooperative storage system that connects several smaller windmills – and if it is used for several purposes, including (i) avoiding imbalance and, hence, avoiding the imbalance costs that windmill owners have to pay, (ii) trading on the balancing market by providing secondary reserve power, and (iii) using part of the electricity from storage for own consumption and, hence, reducing grid connection costs (DNV GL, 2017).

Overall, it can be concluded that in the coming years the increasing demand for flexibility on the intraday/balancing market due to the increasing share of VRE power generation – and, hence, the increasing uncertainty (forecast error) of the residual load – can be met by incumbent, conventional generators (notably gas) as well as by new entrants, including flexible conventional gas units (particularly CCGTs) but also new, additional flexibility options such as storage, demand response or providing balancing services by VRE generators themselves.

The perspectives of the balancing market in the Netherlands, however, are rather uncertain. In particular, the market for activated control power may grow slowly – or even decline – because a major part of total imbalance may be settled by means of the International Grid Control Cooperation (IGCC) or by other arrangements to enhance international TSO cooperation and integration of balancing markets over a larger control area.

Moreover, it should be realised that most of the studies reviewed cover only a short to medium term period (e.g., up to 2023) and consider usually a single option to address the demand for flexibility on the intraday/balancing market resulting from the forecast error of VRE power production rather than to determine the optimal mix of a set of supply options in the long run. Therefore, it is hard to say which mix and size of supply options will meet the demand for flexibility on the intraday/balancing market due to the uncertainty of the residual load in either the medium or long run.

5

Options to meet flexibility needs due to congestion of the power grid: ANDES modelling results

In phase 1 of the FLEXNET project, a detailed analysis of the impact of the energy transition on the incidence of overloads in the Liander distribution grid has been conducted, indicating the potential demand for flexibility to relieve these overloads.[51] Subsequently, at the Liander distribution grid level, phase 2 has addressed the following research question:

> *What are the options and (net) economic benefits of deploying flexibility for congestion management rather than the traditional solution of grid reinforcement for mitigating network overloads?*

For answering the research question, this chapter provides a detailed, quantitative assessment of the potential and (net) benefits of specific, flexibility-based overload mitigation measures to counteract the impact of the energy transition on overloads in the Liander regional distribution grid. This delivers insights in the extent to which the deployment of these flexibility measures can meet the demand of DSOs for flexibility due to the congestion of their grids.

The analysis focusses on the Liander service area. Although there are differences in grid characteristics between Dutch DSOs, we expect that the Liander analysis is also useful and insightful for other DSOs in the Netherlands (and abroad).

Approach

The methodology of phase 2 at the Liander distribution level consists of five steps:

1. Determine the financial impact of the phase 1 results on expected grid overloads;
2. Determine flexibility-based measures to mitigate regional grid overloads;

[51] See Chapter 5 of the report on phase 1 of the FLEXNET project (Sijm et al., 2017).

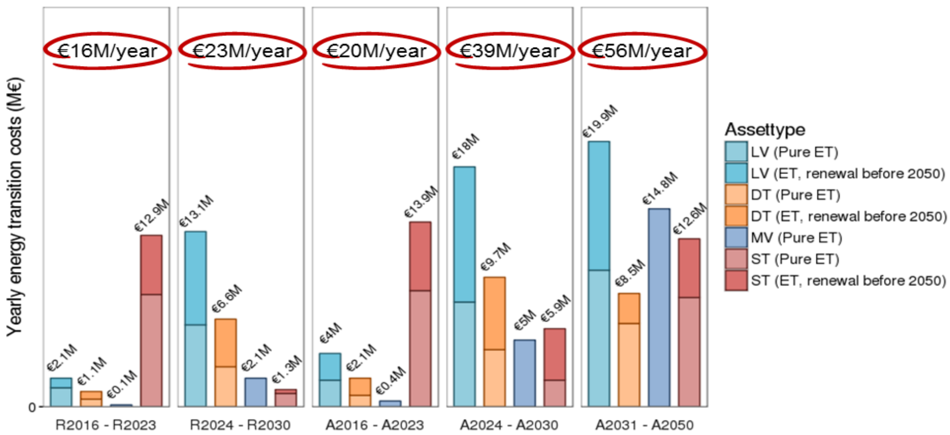
3. Determine peak loading effects of the mitigation measures;
4. Determine overload reduction due to the mitigation measures;
5. Determine net grid investment savings due to the mitigation measures.

The major features and results of these five steps are discussed below in Sections 5.1 up to 5.5, respectively. Finally, Section 5.6 summarizes the main findings and conclusions of the phase 2 analysis on the value of flexibility for congestion management in the Liander service area.

5.1 Financial impacts of phase 1 analysis on grid overloads

Figure 71 summarizes the yearly energy transition costs in million euros per year for two scenarios and for four types of network assets. The scenarios are the reference scenario (R) and the alternative scenario (A) of the FLEXNET project, respectively. The reference scenario runs until the year 2030, while the alternative scenario expands until the year 2050.[52] The time periods have been split in different time spans in order to show the development in energy transition costs.

Figure 71: Increase of average network investments due to the energy transition (phase 1 results)



The four types of networks assets distinguished are:
- Low voltage (LV) cables.
- Distribution transformers (DT) for transforming power from MV to LV level, or the other way around in case local (decentralised) power supply exceeds local demand.
- Medium voltage (MV) cables
- Substation transformers (ST) for transforming power from TenneT's high voltage (HV) networks to MV networks, or the other way around in case regional (decentralised) power supply exceeds regional demand.

52 For more information on the FLEXNET scenarios, see the report of phase 1 of the project.

The cost per asset category are divided into two parts, “*Pure ET*” and “*ET, renewal before 2050*”. Both “Pure ET” and “ET, renewal before 2050” are costs related to assets that become overloaded due to the energy transition (ET), while assets in the category “ET, renewal before 2050” reach their estimated end-of-life within the period up to 2050. Assets that reach their estimated end-of-life time before becoming overloaded are considered non-ET related investments as they will be subject to regular network asset replacement programmes. Besides, the financial model takes into account future load increase up to 2050 when calculating the cost of replacement of an overloaded asset. In this way, double replacement is prevented.

Given these figures the energy transition leads to an estimated increase in yearly grid investments of on average about 2 to 5% up to 2030 for the Liander service area compared to current grid investments in this area (on average € 750 million per year in 2012-2016). The yearly grid investments increase to about 7% on average per year (€ 56 million per year) for the period between 2030 and 2050 (alternative scenario). Total investments for grid reinforcements due to the energy transition are estimated at about € 1.5 billion for the period 2016-2050 in the alternative scenario.

The total amount of grid investments is subdivided among the four types of grid assets;

- 35% of the estimated additional investments is due to reinforcement of the LV grid.
- 26% is contributed by the required substation reinforcement. Up to 2023 the cost for substations are mainly caused by the increase of wind on land.
- 22% is due to additional medium voltage cables.
- Distribution transformers make up for 17% of the sum of grid investment.

As mentioned before, it is important to highlight that the above financial numbers do not include the investment that have to be made as a result of regular asset replacements or ageing assets. The Alliander grid has many older assets and has been heavily extended and reinforced between 1960 and 1980. A wave of replacement due to ageing assets is predicted to occur around 2035.

It should further be noted that the end-of-life of an assets is dependent on many different aspects. It is therefore hard to determine a general number. The chosen numbers for the average life expectancy of transformers and cables have been made based on the most optimistic expectations in literature in combination with (to take into account Dutch conditions) Alliander operational experience (Buchholtz, et al., 2001; Dyba and Goodwin, 1998; Gauthier, 2004; Caronia et al., and Hampton et al, 2007).

The model assumes the following average life expectancy;

- For power transformers: 60 years
- For PILC cables: 90 years (max 70% loading)
- For XLPE cables: 70 years

Assets that become overloaded after they reach the above age are regarded non-ET investments and are not part of the mentions € 1.5 billion.

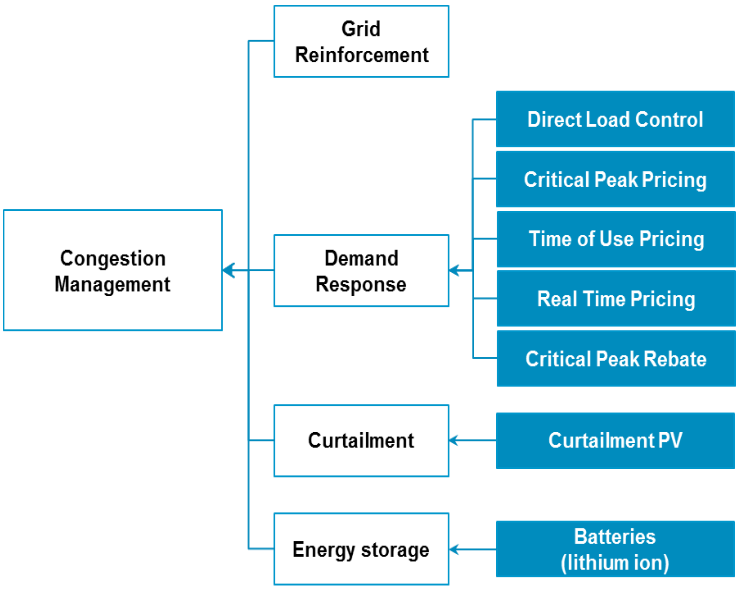
5.2 Overload mitigation measures

In order to limit the required additional grid investments, a number of promising, flexibility-based overload mitigation measures has been selected and assessed (see **Figure 72**). Alternative mitigation measures should be valuated relative to the estimated grid reinforcement investments of Section 5.1

Five different types of demand response measures can be distinguished:

1. *Direct Load control (DLC)* i.e. energy management of EVs and HPs (e.g. smart charging) through a third party (e.g. the network operator or aggregator).
2. *Critical Peak Pricing (CPP)*. During high wholesale market prices or power system emergency conditions, the price for electricity is substantially raised for a specified time period.
3. *Time of Use Pricing (TOU)*. Typically this measure applies to usage over broad blocks of hours where the price for each period is predetermined and constant.
4. *Real Time Pricing (RTP)*. Pricing rates generally apply to usage on an hourly basis.
5. *Critical Peak Rebate (CPR)*. Similar to CPP, the price for electricity during these time periods remains the same but the customer is refunded at a predetermined value for any reduction in consumption.

Figure 72: Considered mitigation measures for overloaded assets



Alternatives for demand response are PV curtailment as well as energy storage. Curtailment implies limitation of the peak output of generation, here specifically PV generation.[53] Concerning energy storage, the focus is limited to the impact of battery systems deployed at either the household level or the distribution transformer level.

[53] Note that when curtailing the power output of wind turbines the loss of energy is relatively high and, therefore, expensive. The current trend in wind energy technology is to increase rotor size, while decreasing generator size to maximize full load hours. This makes wind curtailment even less desirable in the future. Curtailment of wind energy is therefore not considered as a viable option.

For each of the flexibility-based overload mitigation measures the potential peak reduction is determined as shown in **Table 21** below.

Table 21: Potential peak reduction of selected overload mitigation measures

Type of mitigation measure	Potential peak reduction
Direct Load Control (DLC)	25% (HP), 75% (EV)
Critical Peak Pricing (CPP)	31%
Time of Use Pricing (TOU)	16%
Real Time Pricing (RTP)	12%
Critical Peak Rebate (CPR)	20%
Curtailment PV	21%
Energy Storage (Batteries)	-

Source: Alliander and McKinsey (2013), Faruqui and Sergici (2009), Faruqui et al. (2012), and Stromback et al. (2011)

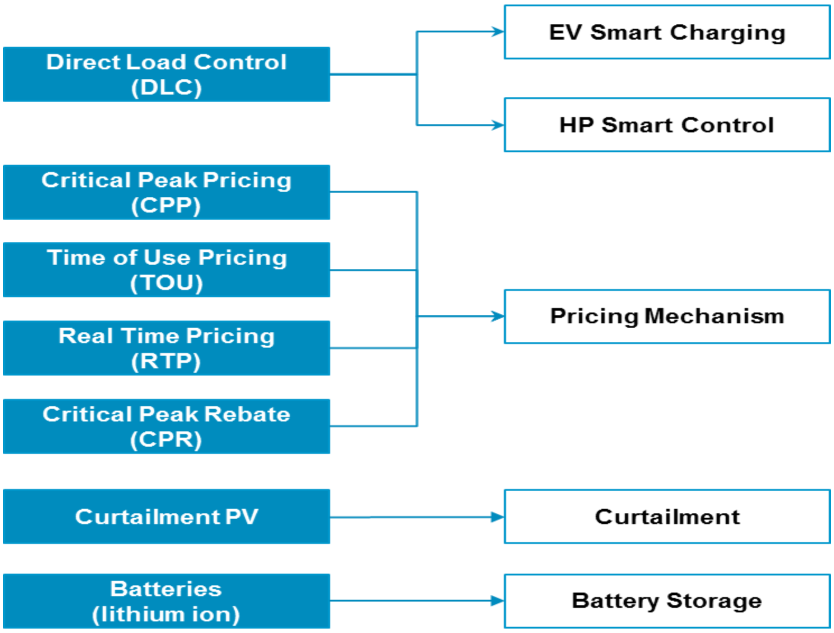
The potential peak reduction by deployment of specific technologies such as heat pumps (HPs), electric vehicles (EVs), and PV curtailment is the maximum reduction of additional load caused by the respective technology, while peak reduction of total residual load will be dependent on other loads as well. **Table 21** indicates that peak load of heat pumps can only be reduced by 25% to maintain adequate comfort. CPP is available up to 80 hours (about 20 events) per year.[54] The maximum peak reduction of TOU, RTP and CPR is only achievable in combination with smart/intelligent devices. Additionally, for achieving the maximum peak reduction of CPR sufficient marketing and communication efforts are a prerequisite. In line with current German regulation curtailment of PV is limited to 30%, although from a technical perspective higher curtailment percentages are possible. Average peak PV output is about 70% of installed capacity due to varying orientation. Estimation of peak reduction is, hence, 0.7 x 30% curtailment ≈ 21%. Finally, the potential peak reduction of batteries depends on the system size, since the return on investment depends on system cost.

5.3 Modelling methods for determining effects of mitigation measures

The effects of mitigation measures on the reduction of grid overloads are determined by using five modelling methods, which are shown in **Figure 73** and discussed below.

[54] Based on CPP pilot programs at USA based utility companies such as DTE, PG&E, and SDG&E.

Figure 73: Modelling methods to determine effects of overload mitigation measures



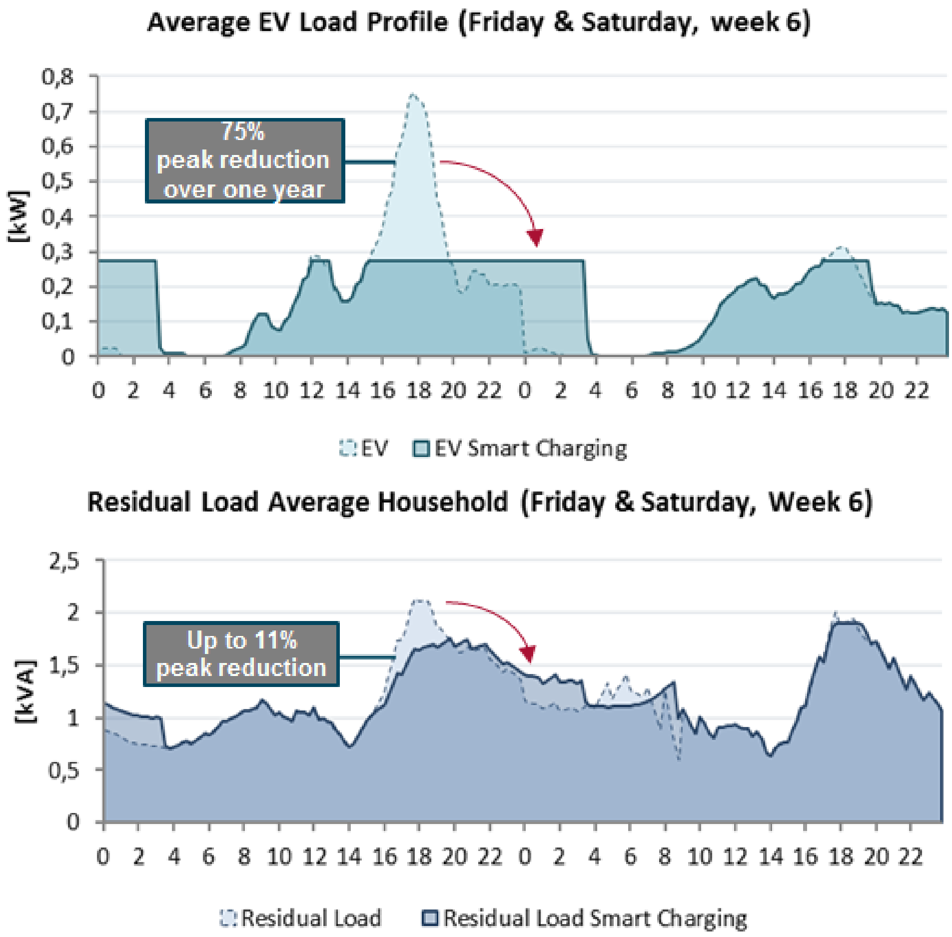
5.3.1 EV smart charging

EV smart charging is modelled by limiting the peak load with 75% compared to the original maximum peak load over a one-year period. A load balancing scheme is assumed i.e. peak load is reduced by shifting load in time, while the total consumption in kWh remains the same over the course of a day. Required charging is allowed to take at maximum 4 times longer, while load shift is kept minimal. Peak load is limited to a collective maximum, but not zero since for the remaining peak load of 25% it is assumed that charging cannot be controlled. As a result, a flattening of the load profile can be observed in **Figure 74**. This graph clearly shows the difference in EV charging and the resulting demand for smart charging between a week-day and a weekend-day.

Please note that the shown EV load profile is an estimation of the average load profile for a group of 3.7 kW home EV charging points and therefore is only applicable for an aggregated group of households, not a single household. Assuming an EV is charged once every 2 days, 80% of EVs charges between 16 and 20h, and assuming a simultaneity factor of 75%, the maximum average peak load for a 3.7 kW charging point is estimated at 3.7 * 50% * 80% * 75% = 1.1 kW.

The impact of smart charging on the residual load profile of an average household with a conventional yearly energy use of 3300 kWh is illustrated in the lower part of **Figure 74.** It shows that EV smart charging alone will reduce the residual peak load of an average household profile by up to 11% over a one-year period.

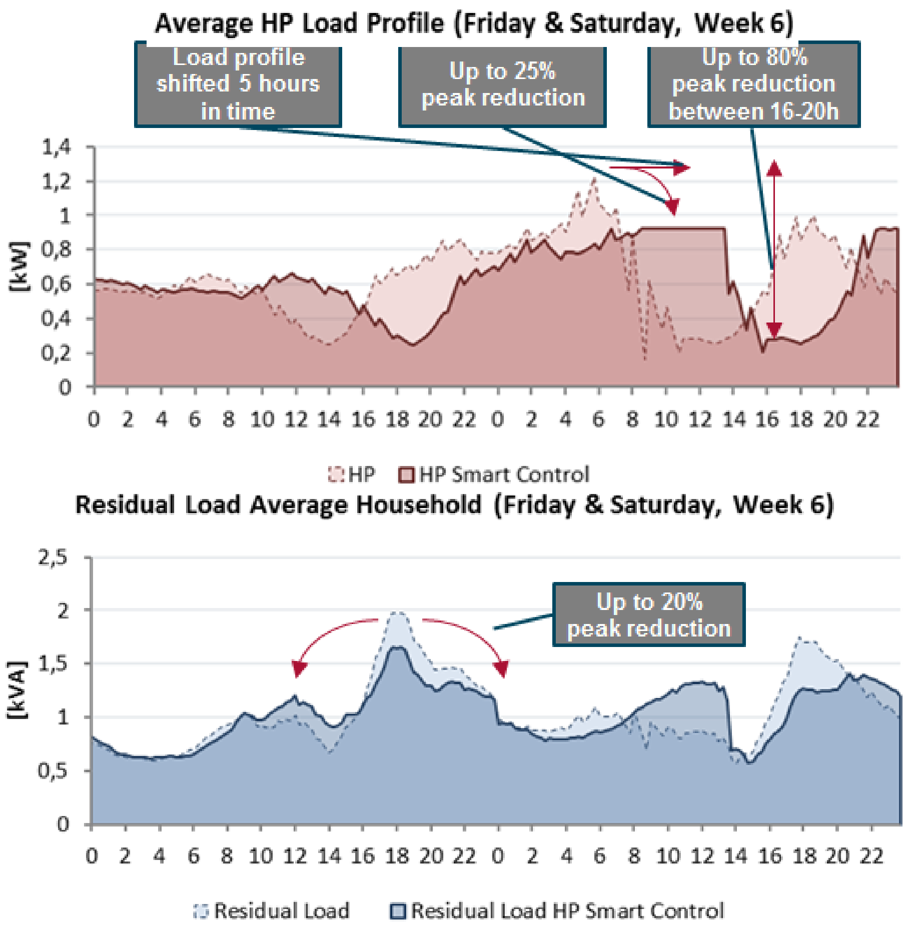
Figure 74: EV load profile and resulting residual load profile with smart charging



5.3.2 HP smart control

HP smart control is modelled assuming the comfort level of the user must not be affected. Therefore the peak load is only limited with 25% compared to the original maximum peak load over a one-year period. Peak load is reduced by shifting load in time, assuming the total demand in KWh remains the same over the course of a day. The average HP load profile is based on an estimated mixture of different types of heat pumps per scenario case. For modelling purposes the HP load profile is shifted 5 hours in time, in this way HP loading is at its minimum during the 18h peak in the residual load. Load shift can be achieved by either pre-heating the house or storing heat in an appropriately sized buffer tank. In this way, a potential peak reduction of up to 80% can be achieved between 16 and 20h as shown in **Figure 75**. Please note that this HP load profile shows the estimated load profile as used in the alternative 2050 scenario where the mixture consists of 50% air-source heat pumps and 50% ground-source heat pumps.

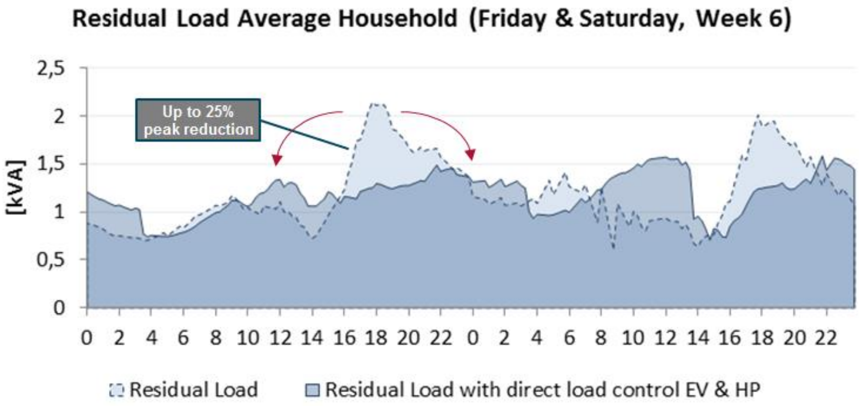
Figure 75: HP load profile and resulting residual load profile with smart control



The impact of smart HP control on an average household residual load profile, with a conventional yearly energy use of 3300 kWh, is illustrated in the lower part of **Figure 75**. HP smart control alone will reduce residual peak load of an average household profile by 20% over a one-year period.

If EV smart charging and HP smart control would be combined this reduces the residual peak load further. As shown in **Figure 76**, combining the two direct load schemes results in a reduction of the residual peak load of an average household profile by 25% over a one-year period. Again, this peak reduction is only applicable on the average of an aggregated group of households, implying the actual instantaneous peak reduction at a single household can be either higher or lower.

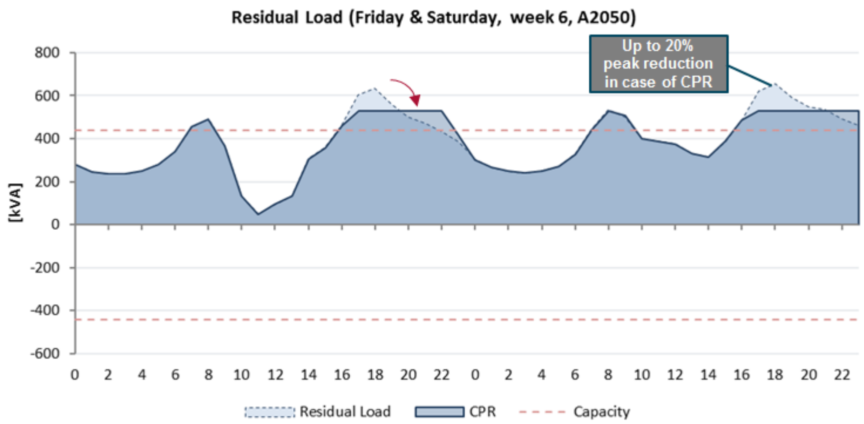
Figure 76: Resulting residual load profile with both EV smart charging and HP smart control



5.3.3 Pricing mechanisms

For the demand response measures CPP, TOU, RTP, and CPR, pricing mechanisms are modelled by limiting the maximum peak residual load over a one-year period according to their estimated peak reduction percentages. As shown before, peak reduction rates are 31%, 16%, 12%, and 20% for these demand response measures, respectively. Similar to the other modelling methods, peak load is reduced by shifting load in time, minimum load shifting is assumed, and the total demand or consumption in kWh remains the same over the course of a day. As stated before, CPP is only applied in case the number of overloads per year is less than 20 per year. **Figure 77** shows the impact of CPR at a distribution transformer.

Figure 77: Impact of CPR on the residual load profile of a distribution transformer

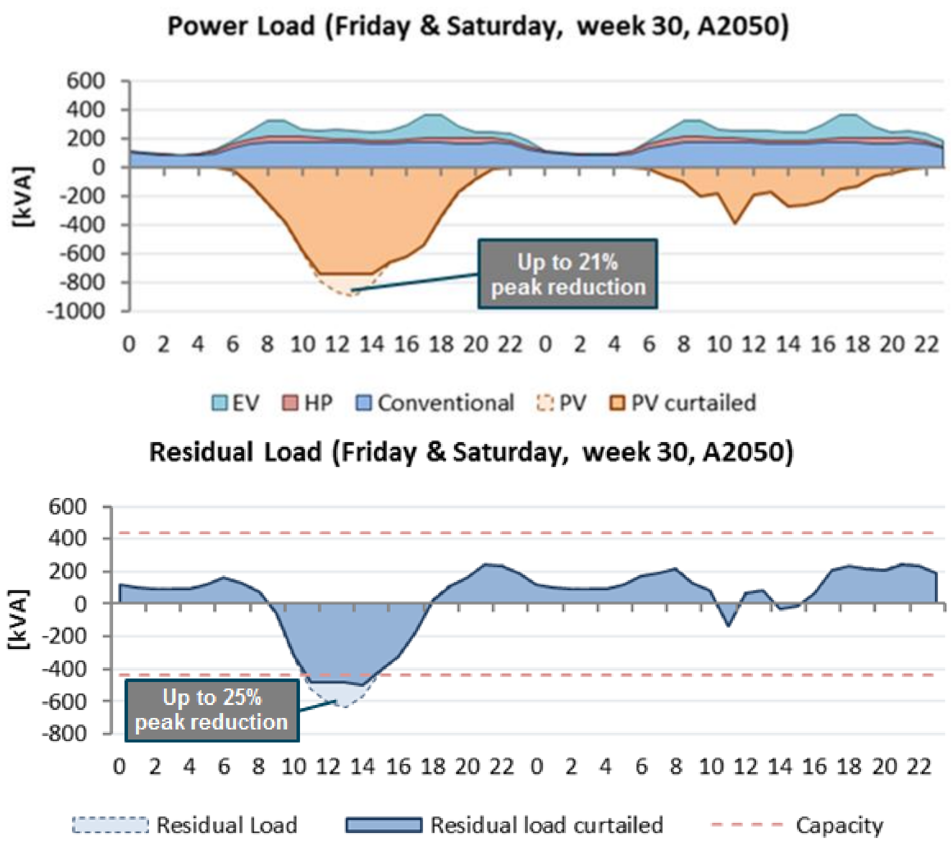


5.3.4 PV curtailment

For modelling curtailment of PV, two cases are simulated: 0% and 30% curtailment. Curtailment of 30% is achieved by installing an inverter with a maximum output of 70% of the rated capacity of the feed-in system.

Since the orientation of PV modules differs, the average peak PV output is about 70% of installed capacity. As a result, average peak reduction at 30% PV curtailment is estimated at 21% of the original maximum peak feed-in over a one-year period. The impact of 30% curtailment is visualized in **Figure 78**. According to internal Liandon research validated with actual real-life measured data (and confirmed by SMA amongst others), this results in a loss of annual yield of about 2 to 3% at 30% curtailment.

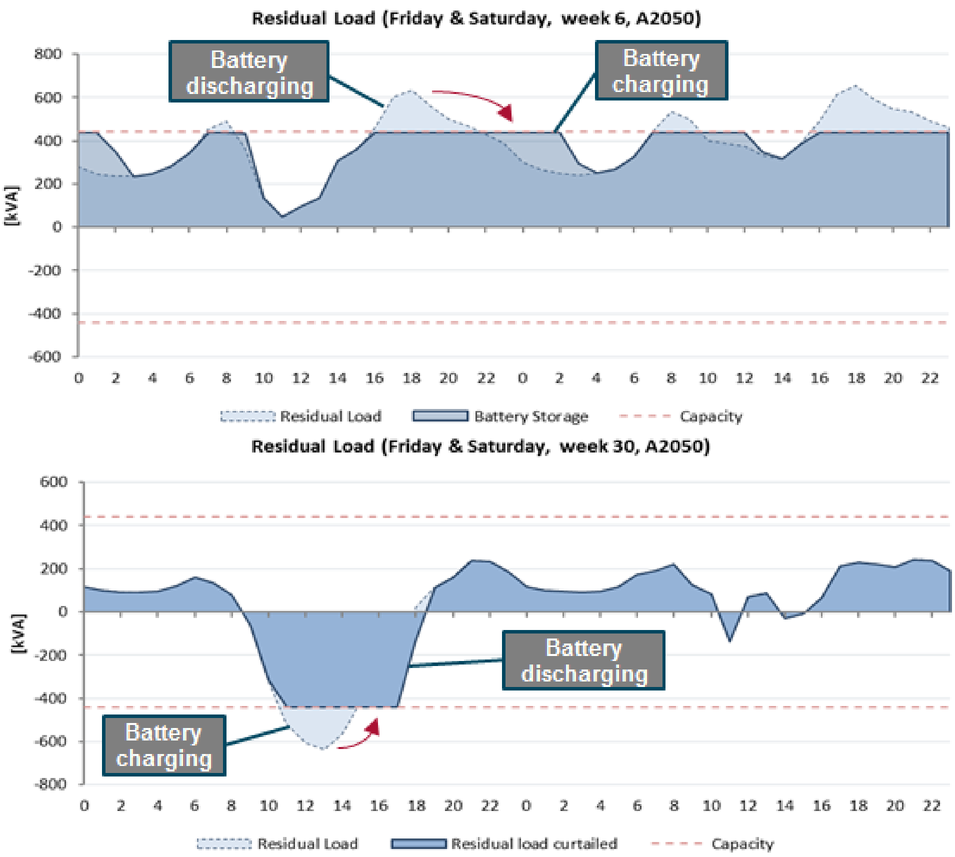
Figure 78: Impact of 30% PV curtailment at a distribution transformer



5.3.5 Battery storage

Battery Storage is modelled by limiting the maximum peak residual load to the capacity limit of the asset concerned. Similar to earlier described modelling methods, peak load is reduced by shifting load in time. In order to determine the size of the battery, the maximum daily excess energy (kWh) from a grid overload perspective has been calculated. It has been assumed that the battery optimizes the peak load in a one-day period, i.e. load is not shifted in time for more than 24 hours. It is expected that once this assumption does not hold, the battery will not be feasible anyway, because of the required storage capacity. Battery storage has only been investigated on distribution transformer level as this is currently the most advantageous location for Liander to install battery storage for congestion management. Two examples of the reduction of peak load by deployment of battery storage are shown in **Figure 79**.

Figure 79: Example of battery storage modelling at a distribution transformer

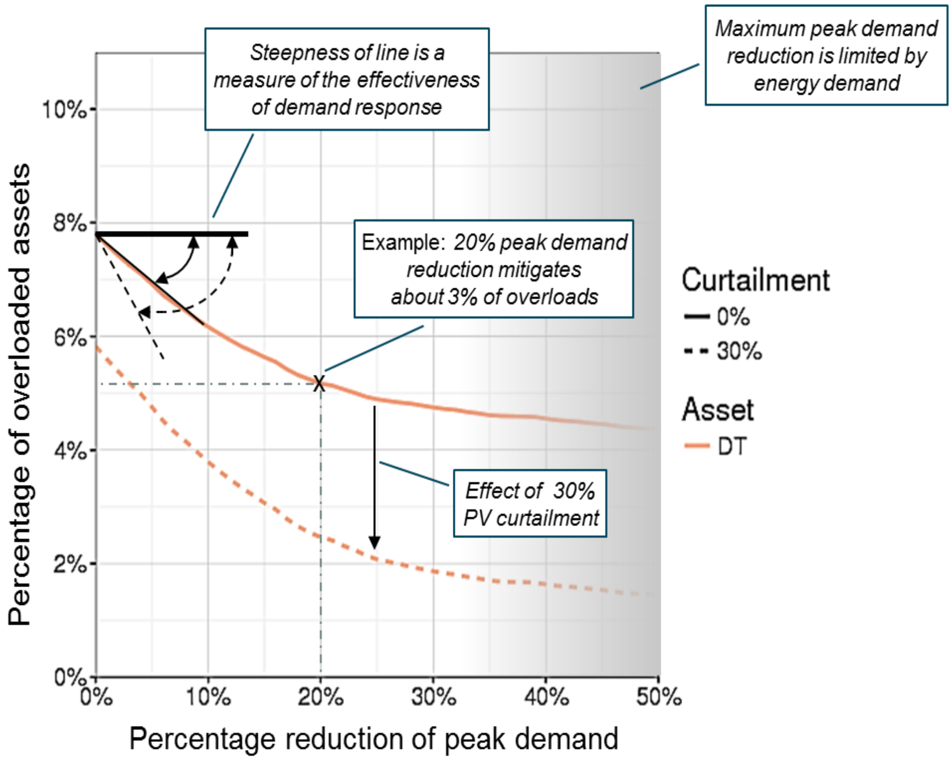


5.4 Overload reductions

Application of the modelling methods elaborated upon above results in overload reductions per modelling solution and per scenario. First, the relationship between peak reduction and mitigation of overloads is illustrated in **Figure 80** below.

Overloads can be caused by both demand and feed-in. Peak demand can be reduced by the demand response measures elaborated above, while peak feed-in can be reduced by (PV) curtailment. The size of the overload reduction is of course limited by the energy demand. The solid line shows the relation between peak demand reduction and mitigation of overloads of distribution transformers without curtailment while the dotted line shows the relation with 30% curtailment. The steepness of the line provides an indication of the effectiveness of peak demand reduction by demand response. A level line indicates that remaining overloads are caused by peak feed-in. Further reduction of peak demand therefore becomes ineffective. Above 30% peak demand reduction, it becomes more and more unrealistic that the level of reduction can be achieved in practice. The graph is therefore greyed out. As explained before, the peak reduction of feed-in by 30% PV curtailment is estimated at 21% due to the variations in system orientation.

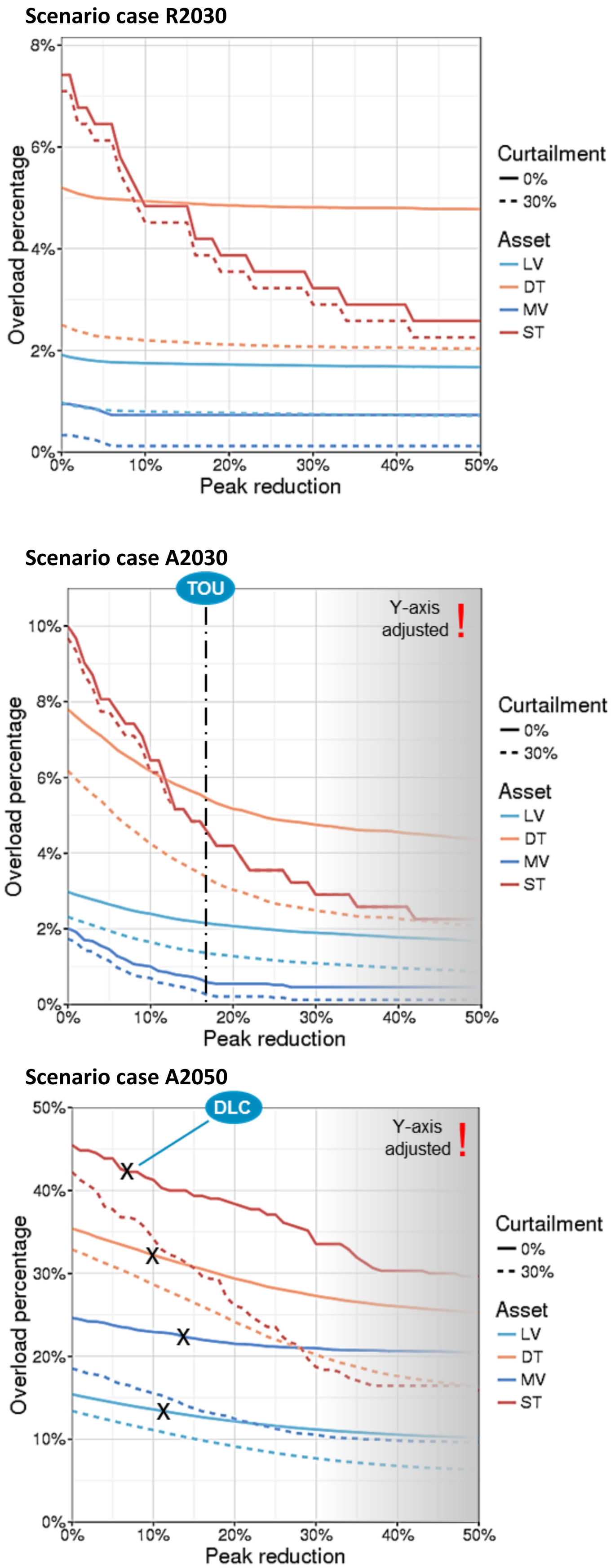
Figure 80: Illustration of relationship between peak reduction and mitigation of overloads



Given these relationships, the reduction of overload percentages of the different scenarios can be determined. The upper part of **Figure 81** shows the reduction of overload percentages due to curtailment and demand response for the four asset categories of the R2030 scenario. It can be seen that the effect of curtailment at substation level is limited, as demand of large scale consumers is still dominant. At the same time, the relatively high steepness of the substation line indicates that demand response is most effective at substation level. For the other asset categories holds that curtailment is very effective, given the broad adoption of PV by households, while adoption of EV and HP is still limited.

The reductions of overload percentages in the A2030 scenario are shown in the middle part of **Figure 81**. The higher adoption of EV and HP compared to R2030 increases the number of overloads due to power demand and thus limits the effect of PV curtailment. Demand response is still most effective at substation level. At lower level, the effectiveness of demand response is increased by applying curtailment (steepness of line increases), see for instance the effect on distribution transformers.

Figure 81: Percentage of grid asset overloads in selected scenario cases



The lower part of **Figure 81**shows the reductions of overload percentages in the A2050 scenario. In the A2050 scenario the electrification of medium and large scale consumers will increase significantly. As a result, curtailment becomes more effective at substation level. To effectively mitigate overloads, a combination between demand response and curtailment is most optimal and hence preferred.

5.5 Potential grid investment cost reductions

5.5.1 Yearly cost reductions per scenario and solution

Grid overloads can be addresses by either flexibility-based mitigation measures or grid reinforcements (or a mix of both options). Overload mitigation measures can substantially reduce the capital expenditures (CAPEX) i.e. investments in grid reinforcements.[55] In terms of CAPEX reduction, low-voltage (LV) cables show the most potential savings in the reference scenario until 2030. Curtailment can significantly reduce yearly costs at low-voltage (LV) and distribution transformer (DT) levels, while demand response is ineffective in this scenario case. The upper part of **Figure 82** shows the yearly cost per asset category for the scenario period R2023-R2030, both for the case with and without PV curtailment and TOU demand response, while the upper part of **Figure 83** shows the total yearly cost for both cases, i.e. the sum of the yearly costs for the four asset categories over the period R2023-R2030. Please note that in these and next figures, the yearly cost sometimes increases at higher peak reduction rates. This is caused by postponement of investments from the previous period to the next period.

Compared to R2030, in the alternative scenario up to 2030 the effectiveness of TOU demand response is increased significantly compared to the R2030 scenario case due to the higher adoption of HPs and EVs. PV curtailment still has a significant potential, although effectiveness is reduced due to higher adoption of HP and EV (see middle part of **Figure 82** and **Figure 83**).

In the alternative scenario (period A2031-A2050), due to electrification of medium and large scale consumers, especially investments at medium-voltage (MV) and substation level increase significantly. Investments at the LV level increase to a minor extent, while investments in distribution transformers decrease. The significant increase of PV compared to the A2030 scenario case limits the effectiveness of demand response. Except for the LV level, demand response without curtailment is not effective in this scenario, especially at MV level. The effectiveness of demand response (as indicated by the steepness of line) increases with PV curtailment (see lower part of **Figure 82** and **Figure 83**).

[55] Note that the costs of implementation and operation of flexibility-based mitigation measures are not part of the analysis in this section.

Figure 82: Yearly grid investment cost per asset during different scenario periods

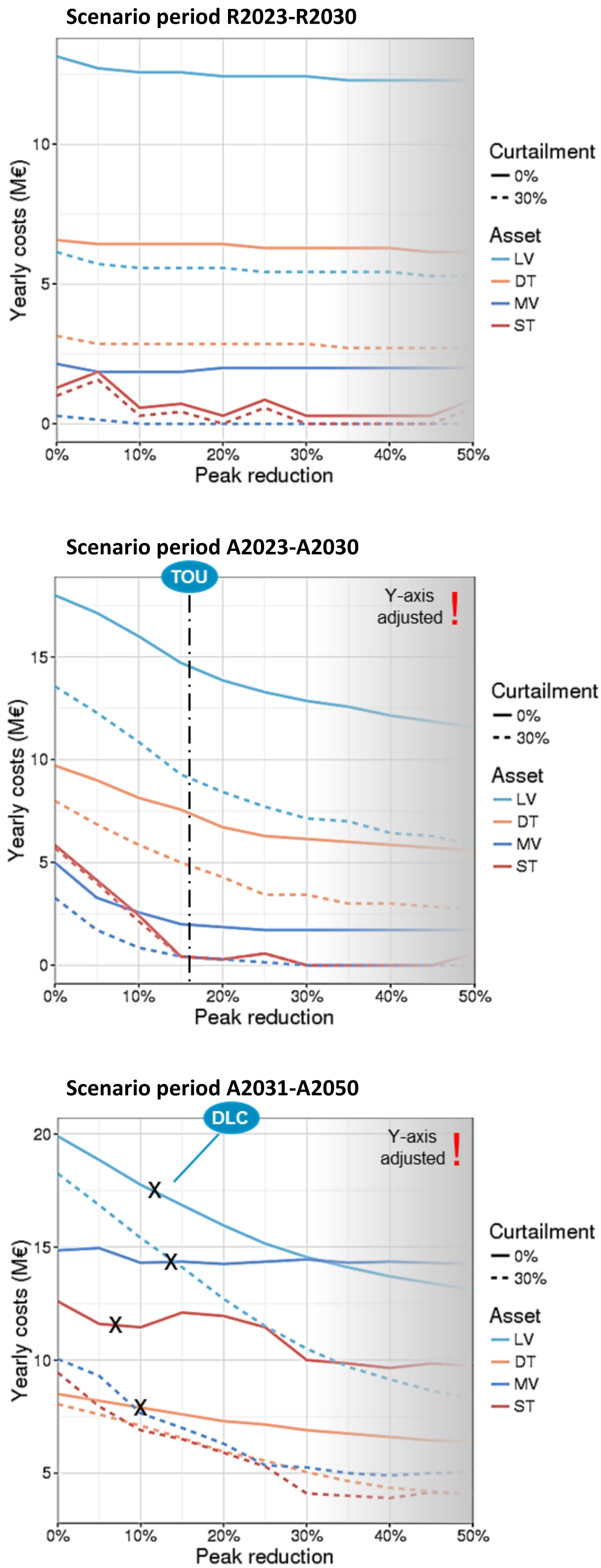
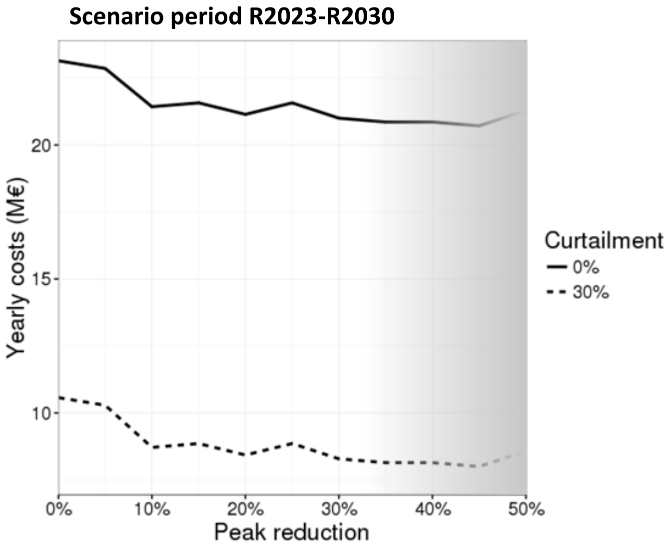
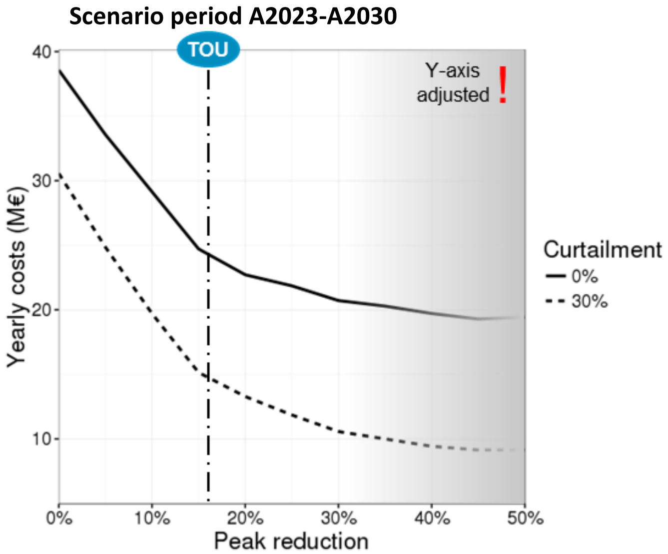
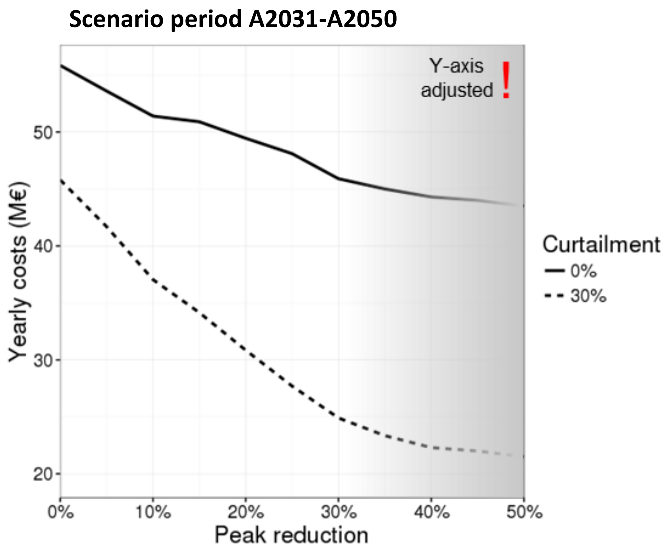


Figure 83: Total yearly grid investment cost during different scenario periods







5.5.2 Cumulative cost reduction per scenario and solution

As a next step the grid investment costs can be summed up over years in order to obtain cumulative costs. In the upper part of **Figure 84**, the cumulative costs are shown for the R2030 scenario. PV curtailment alone can save up to € 100 million in energy transition related grid investments, while time-of-use (TOU) pricing, for instance, can only save up to € 50 million. A mix of PV curtailment and TOU pricing can save up to € 150 million.

In the alternative scenario, PV curtailment alone can save up to € 70 million in energy transition related grid investments, while TOU pricing can save up to € 140 million. A combination between PV curtailment and TOU pricing can save up to € 230 million in grid investments up to 2030 (see middle part of **Figure 84**).

For the A2050 case, PV curtailment or TOU pricing alone can save up to about € 250 million in energy transition related grid investments. Energy transition related investment costs do not include the investments required as a result of ageing assets. A mix of PV curtailment and TOU pricing can save up to € 700 million in energy transition related grid investments. Thus the savings for the 2031-2050 period are € 470 million (700 – 230 million euro for the period 2023-2030; see lower part of **Figure 84**). Potential investment deferral is, however, very much dependent on the considered scenario.

5.5.3 Net benefit of flexibility solutions

The numbers provided above do not include any additional costs required to implement and operate each of the selected mitigation measures. Therefore, for a high level estimation of the additional costs has been made to determine the potential net benefits of deployment of these mitigation measures. The main goal of this section is to emphasise that the above illustrated grid investment reductions do come at a cost.

Curtailment of PV

The benefits of PV curtailment consist of an estimated 20% avoided ET grid reinforcement investments for the A2050 case. However, when taking into account the cost of PV curtailment in terms of lost revenue, the net benefit is about 10% (**Figure 85**).[56]

The total revenue of PV is calculated by using the installed capacity per scenario case in the Liander service area, the assumed PV generation profile and the hourly APX price per scenario case. APX prices (wholesale market) have been calculated by ECN using the COMPETES model and the FLEXNET scenarios, net metering is not taken into account. In the A2030 scenario case, the gross revenue of PV (5 GWp)[57] based on hourly APX prices is estimated at € 250 million/year. For the A2050 scenario case, the gross revenue of PV (20 GWp) is estimated to be between € 330 million and € 450 million per year depending on the available interconnection capacity.[58]

[56] Curtailment is defined as the application of an inverter with a rated output of 70% of the installed PV capacity.

[57] Yearly yield in the Netherlands is about 850kWh/kWp.

[58] Increased interconnection capacity results in a lower average APX price, while limited interconnection capacity leads to a higher price volatility (see Chapter 3)

Figure 84: Reduction of cumulative grid investment costs during different scenario periods

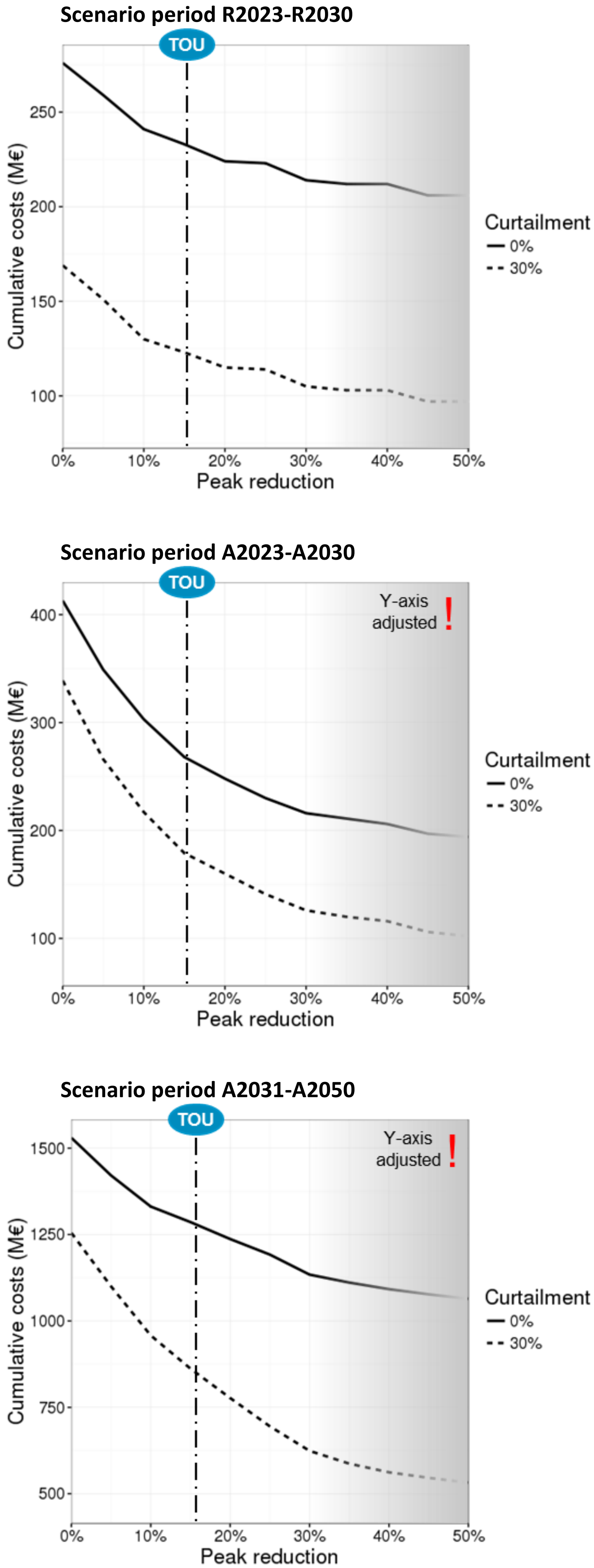
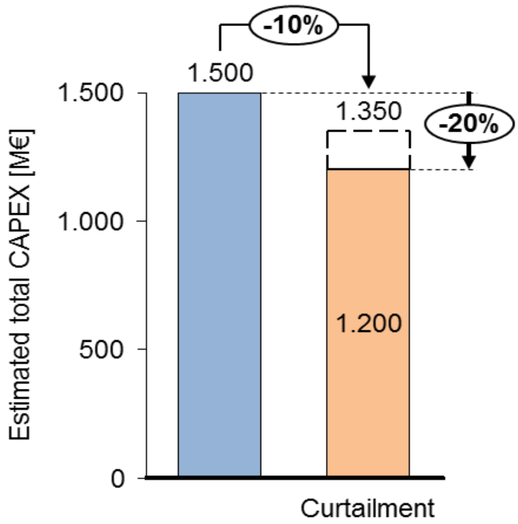


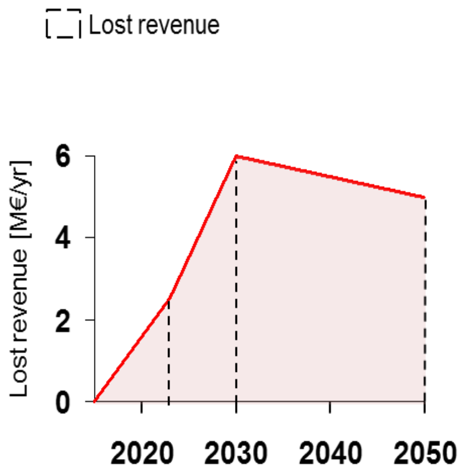
Figure 85: Net benefits of PV curtailment



The lost revenue of PV curtailment is estimated for the alternative scenario cases by comparing the lost energy (±3% assumed ≈ 500 GWh in A2050) to the hourly APX prices when these losses are incurred.

By applying linear interpolation between the scenario cases, an estimation of the total lost revenue of systematic PV curtailment up to A2050 can be obtained (see **Figure 86**).

Figure 86: Lost revenue for PV owners due to PV curtailment

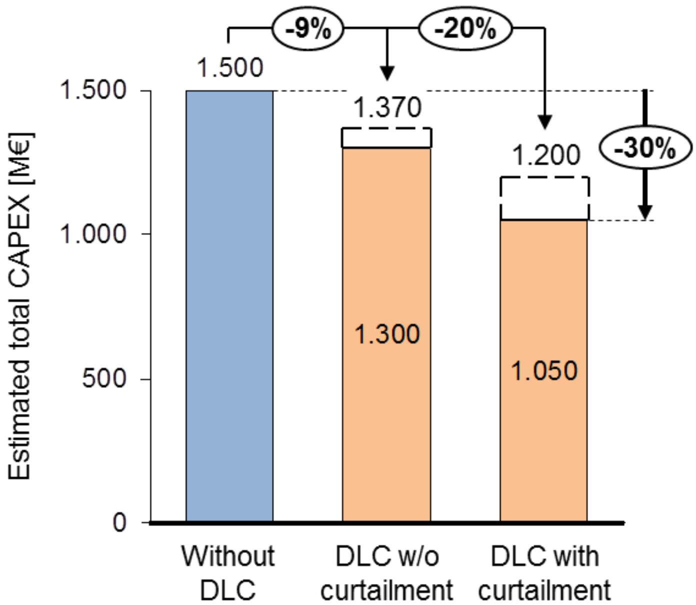


The total lost revenue on the wholesale market is estimated to be about € 150 million for the Liander Service Area up to A2050 and the net result of curtailment would thus be about € 150 million up to 2050 in avoided investments for the Liander service area. This is, on average, about 1% per year of the total grid investments in this area up to 2050. Similar to other solutions, these amounts do not take into account additional grid losses as a result of deferred or avoided investments. In the A2050 scenario, these additional operational costs are estimated at an amount of € 55 million per year.

Direct load control (DLC)

As shown in **Figure 87** DLC can potentially avoid 13-30% of grid reinforcement investments in the alternative scenario i.e. € 200 million alone and € 450 million when combined with curtailment respectively. Direct load control without curtailment is estimated to be able to prevent the overloading of about 1000 distribution transformers in the A2050 scenario case. In combination with curtailment, this number increases to about 2500 distribution transformers. Each distribution transformer supplies on average about 100 consumers. Assuming an adoption rate of EV and WP of about 70%, DLC needs to be implemented at about 70.000 to 175.000 EVs and HPs.

Figure 87: Net benefits of direct load control without and with PV curtailment



Initial IT investment is estimated at € 20 million per technology[59] plus an additional € 20 to €70/year[60] per controlled device (equivalent to the number of controlled EV, HP, PV). Assuming a cost of €20 per controlled device, the annual cost in A2050 is about € 1.4 million per year without curtailment and about € 3.5 million per year with curtailment per technology.

Assuming a linear development in cost (rough estimation), the total costs of implementation and operation will be about € 70 million without curtailment and about € 110 million with curtailment up to A2050. These costs figures do not include a possible penalty for DSOs for not meeting contractual capacity (kW) agreements or additional grid losses, which are expected to be higher for DLC compared to grid reinforcement. Furthermore, the assumption is made that no additional investments are required in grid digitization/measurements besides the smart meter. On the other hand, since restoring power after an outage to a region with a high adoption of HP and/or EV can lead to high currents and overloads, investments in DLC might already be made for power restoration reasons, decreasing required DLC investments for congestion management purposes.

59 Alliander and McKinsey (2013), McKinsey estimation.

60 Lower value from Alliander and McKinsey (2013), higher value based on Energex (2014).

Based on above analysis and the FLEXNET alternative scenario, the net result of DLC would be about € 130 million without curtailment and about € 200 million with curtailment (including lost revenue PV) up to 2050 for the Liander service area at most. This is, on average, around 1% per year of the total grid investments in the Liander service area up to 2050.

Pricing mechanisms

Pricing mechanisms (CPP, TOU, RTP, CPR) alone can potentially avoid up to 18% of grid reinforcement investments in the alternative scenario, while the combination with curtailment may result in savings of 48% of grid reinforcement investments. For several reasons, however, the net savings of pricing mechanisms are likely to be smaller..

First of all, research shows that the percentage of peak reductions used in this analysis can only be achieved if local devices such as, for instance, washing machines can be automatically controlled. This requires investments from either consumers in home automation or from market participants in an IT platform which controls devices in a certain area. Although part of the cost may be attributed to deployment of flexibility for portfolio optimization and balancing purposes, assuming pricing mechanisms do not levy any costs on flex deployment for congestion management is a strong assumption.

Furthermore, the grid operator should have sufficient insight in the (near) real-time load in the controlled area to effectively use pricing mechanisms for congestion management. Smart metering may fulfil this requirement, although additional investments in grid digitization or measurements might be required.

In addition, net benefit figures do not include a possible penalty for DSOs for not meeting contractual kW agreements, while additional grid losses, which are expected to be higher for pricing mechanisms compared to grid reinforcement, have not been taken into account. These grid losses may result in additional operational costs of € 55 million per year in the A2050 scenario.

Besides, the unpredictable behaviour of customers makes it unlikely that the indicated net benefits as shown in **Figure 88** can be achieved in practice as grid operators will need some security margin in their grid design. Especially at the lower grid levels, the number of controlled devices will be limited and the risk of relying on pricing mechanisms to prevent overloads for DSOs is higher.[61]

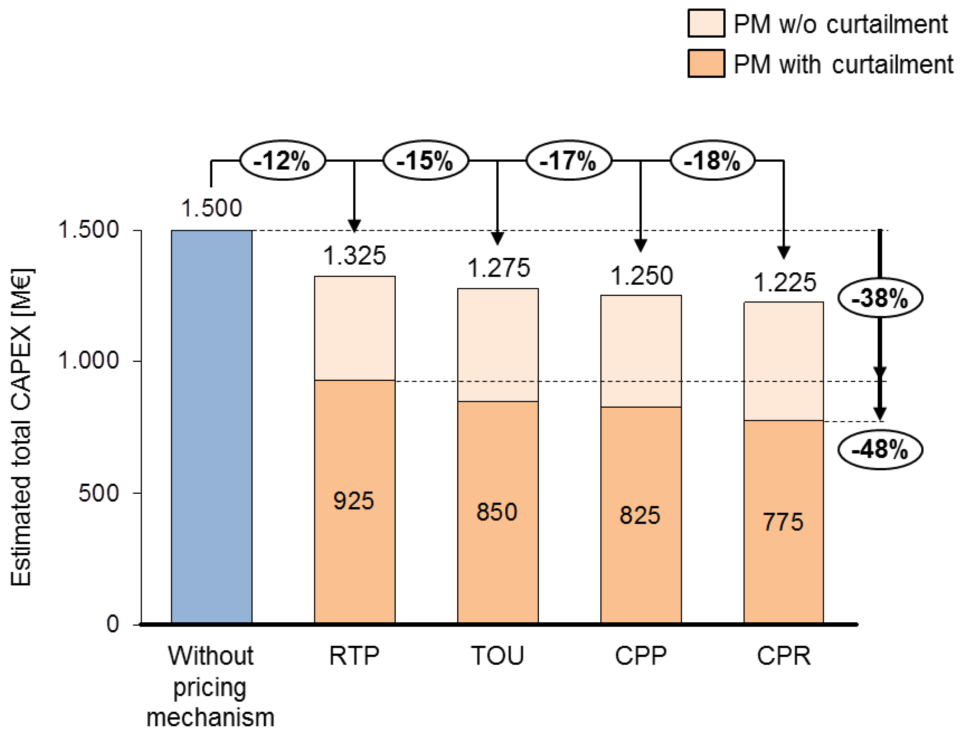
Considering the above, the net result of pricing mechanisms is estimated to be less than 1% per year of the total grid investments in the Liander service area.

Energy storage (batteries)

Figure 89 shows the benefits of several battery systems of different size. The number of overloaded distribution transformers that can be mitigated is dependent on the size of the battery system. Net benefits are not shown as the benefits of the use of a battery system for mitigating overloads do not outweigh the costs, as explained below.

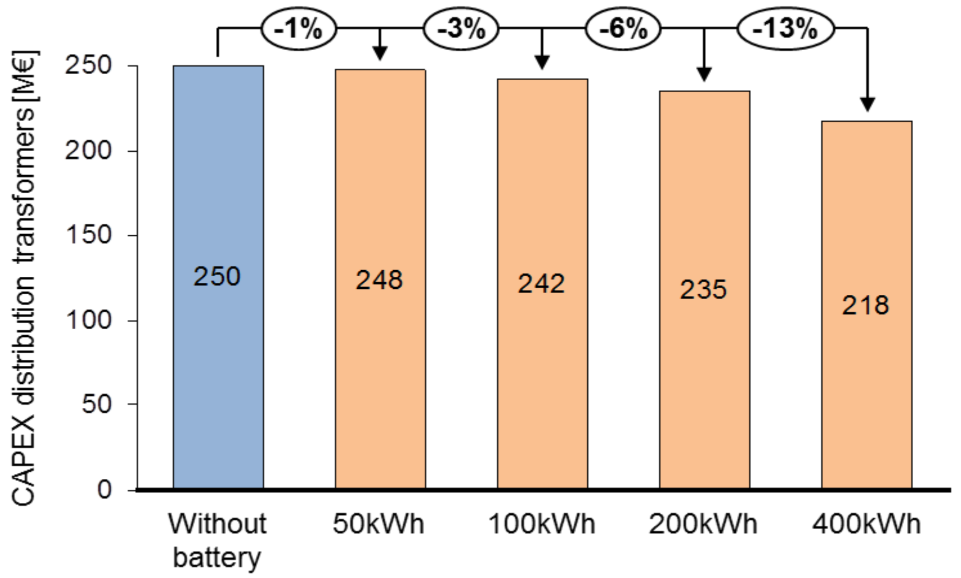
[61] Additionally, it is assumed that the average price per kWh supplied remains the same. However, it is unclear which implications this could have.

Figure 88: Net benefits of pricing mechanisms without and with PV curtailment



For batteries (lithium ion) holds that costs are estimated at 200 to 400 €/kWh (excluding cost of installation), with a life-expectancy of ± 5000 cycles ≈ 15 years; round trip efficiency is assumed to be 90%. The cost estimation is based on current cost of Tesla Powerwall 2.0, which is estimated at € 7,000 fully installed (± € 1,500 for installation).

Figure 89: Benefits of batteries



Relatively large battery capacities are required to mitigate the overloads. In order to determine the size of the battery, the total amount of energy (kWh) in the overload during a day has been calculated. A battery of 50 kWh can mitigate about 400 of the estimated overloaded distribution transformers in the A2050 scenario, 100 kWh solves approximately 1200, 200 kWh solves about 2300, and 400 kWh solves about 5000 on a total of about 38,000 distribution transformers.

Assuming the cost of a battery system is equal to the lowest value of the cost bandwidth provided above i.e. € 200/kWh per 15 years, and a distribution transformer reinforcement of around €35,000 per 45 years, the maximum size of the battery system, if only based on avoided CAPEX up to 2050, is about 50 kWh.[62]

Taking into account the required OPEX, the additional losses, and the added complexity and therefore higher operational risk, it is safe to assume that the use of a battery system at DT-level in comparison to DT reinforcement purely for the purpose of mitigating an overload is only economically feasible for a very limited number of cases at most. The use of a battery system might be more profitable in case the same system could provide other services such as for instance voltage support, energy trading, frequency support, or resilience/back up power.

5.6 Summary and conclusions

Benefits of deployment of flexibility as alternative for grid reinforcements
Based on the results of the ANDES model and the FLEXNET scenario cases, it is estimated that additional investments in grid reinforcements of 2 to 5% per year up to 2030 and about 7% per year in the period from 2030 to 2050 are required to prevent overloads in the Liander grid due to the increased deployment of PV, EV and HP. Given current annual grid investments in the Liander service area of, on average, € 750 million in 2012-2016, this corresponds to a cumulative grid reinforcement investment of € 1.0-1.5 billion up to 2050 (alternative scenario).

In terms of CAPEX savings, it is estimated that curtailment (assuming a 30% peak reduction in PV production) or time-of-use (TOU) pricing (assuming a 16% peak demand reduction) alone can save up to about € 250 million (cumulative) in energy transition related grid investments up to 2050 (in the alternative scenario). A combination of PV curtailment and TOU pricing can save up to € 700 million of these type of grid investments up to 2050. This € 700 million is an indication of the value of flexibility for network planning by Liander.

The effectiveness of curtailment versus demand response depends on the adoption levels of PV versus EV and HP. In the reference scenario (up to 2030), curtailment is more effective in reducing reinforcement costs than demand response, due to the fact that in this specific scenario, PV production creates more congestion problems than the

62 Costs of a battery system of 50 kWh over a time period of 45 years sum up to 50 * 3 * € 200 = € 30,000, while the (uniform) distribution transformer reinforcement costs amount to 35,000 euro over the same time period.

adoption of EV and HP. The alternative scenario shows that the higher adoption of EV and HP increases the effectiveness of demand response significantly.

Net benefits of deployment of flexibility as alternative for grid reinforcements
The numbers provided above do not yet include additional costs required to implement and operate each of the selected mitigation measures. The net benefits of deployment of flexibility as alternative for grid reinforcements are therefore significantly lower. Given estimates for additional costs, net benefits for PV curtailment, direct load control, and pricing mechanisms are determined.

PV curtailment
The benefits of PV curtailment consist of an estimated 20% avoided ET grid reinforcement investments for the A2050 case i.e. € 300 million, but when taking into account the cost of 30% PV curtailment in terms of lost revenue, the net benefit is about half of this amount i.e. € 150 million.

The lost revenue on the wholesale market is calculated by estimating the lost energy in the A2050 scenario and multiplying this amount by the corresponding hourly APX price. Subsequently, the total lost revenue up to 2050 is obtained by linear interpolation between scenario cases. Similar to other solutions, these amounts do not take into account additional grid losses as a result of deferred or avoided investments, which are estimated at € 55 million per year in the A2050 scenario.

Direct load control
Direct load control can potentially avoid 13-30% of grid reinforcement investments in the alternative scenario i.e. € 200 million alone and € 450 million when combined with curtailment respectively. Assuming a linear development in cost (rough estimation), the total costs of implementation and operation will be about € 70M without curtailment and about € 150 million with curtailment for the A2050 scenario. The net result of DLC would be about € 130 million without curtailment and about € 300 million with curtailment (including lost revenue PV) up to 2050 for the Liander service area at most. This is, on average, around 1% per year of the total grid investments in the Liander service area up to 2050.

These costs figures do not include a possible penalty for DSOs for not meeting contractual capacity (kW) agreements as well as costs of additional grid losses, which according to Liander estimates amount to 55 million euro per year. Furthermore, the assumption is made that no additional investments are required in grid digitization/measurements besides the smart meter. On the other hand, since restoring power after an outage in a region with a high adoption of HP and/or EV can lead to high currents and overloads, investments in DLC might already be made for power restoration reasons, decreasing required DLC investments for congestion management purposes.

Pricing mechanisms
Pricing mechanisms (CPP, TOU, RTP, CPR) alone can potentially avoid up to 18% of grid reinforcement investments in the alternative scenario, while the combination with curtailment may result in savings of 48% of grid reinforcement investments. In absolute terms this amounts to € 275 million and € 725 million respectively. For several reasons, however, the net savings of pricing mechanisms are likely to be smaller.

First of all, research shows that the percentage of peak reductions used in this analysis can only be achieved if local devices such as, for instance, washing machines can be automatically controlled. This requires investments from either consumers in home automation or from market participants in an IT platform which controls devices in a certain area. Although part of the cost may be attributed to deployment of flexibility for portfolio optimization and balancing purposes, assuming pricing mechanisms do not levy any costs on deployment of flexibility for congestion management is a strong assumption.

Furthermore, the grid operator should have sufficient insight in the (near) real-time load in the controlled area to effectively use pricing mechanisms for congestion management. Smart metering may fulfil this requirement, although additional investments in grid digitization or measurements might be required.

In addition, grid losses which are expected to be higher for pricing mechanisms compared to grid reinforcement, have not been taken into account. According to Liander estimates, these grid losses may result in additional operational costs of € 55 million per year in the A2050 scenario.

Besides, the unpredictable behaviour of customers makes it unlikely that the indicated net benefits can be achieved in practice as grid operators will need some security margin in their grid design. Especially at the lower grid levels, the number of controlled devices will be limited and the risk of relying on pricing mechanisms to prevent overloads for DSOs is higher.

Considering the above, the net result of pricing mechanisms is estimated to be less than 1% per year of the total grid investments in the Liander service area.

Energy storage (batteries)
For energy storage, no net benefits are calculated since the benefits of the use of a battery system for mitigating overloads do not outweigh the costs. Relatively large battery capacities are required to mitigate overloads of distribution transformers. Given (i) the accompanying cost of a battery system, (ii) the required operational costs (OPEX), (iii) the additional losses, and (iv) the added complexity and, therefore, higher operational risks, it is safe to assume that the use of a battery system at DT-level in comparison to DT reinforcement purely for the purpose of mitigating an overload is only economically feasible for a very limited number of cases at most. The use of a battery system might be more profitable in case the same system could provide other services such as for instance voltage support, energy trading, frequency support, or resilience/back up power.

Overall conclusions
In contrast with some earlier studies and expectations beforehand, based upon a comprehensive quantitative analysis the current study shows limited net benefits of deployment of flexibility solutions by DSO Liander in order to prevent traditional grid reinforcements. However, a rough comparison of the ANDES modelling results of Liander with modelling outcomes of DSO Stedin indicates more overloads in 2050 in the Stedin service area and, therefore, a higher demand for flexibility, although this seems partially due to differences in network topology as well as differences in input

assumptions, notably on the allocation of technology adoption to grid levels, and differences in load profiles.

Given the Liander analysis, some policy recommendations can be inferred. DSOs should be cautious in claiming flexibility for congestion management purposes as, *in general*, the scope and benefits of deploying flexibility for congestion management seems to be limited. Moreover, flexibility could have a higher value for purposes such as portfolio optimization or system balancing. Flexibility providers should be aware that flexibility generally has relatively a limited scope and limited net benefits for DSOs, implying no large payments for flexibility can be expected from network operators.

At the same time it should be noted that in *specific* situations deploying flexibility for congestion management may offer a significant potential and relatively high net benefits for DSOs, resulting in a concomitant high value of flexibility and associated benefits for flexibility providers. In which type of situations and how frequently these situations could occur is a subject for further research.[63]

[63] See also the report of phase 3 of the FLEXNET project, focusing on the development of a societal framework for the trade-off between grid reinforcement versus deployment of flexibility for congestion management.

6

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Appendix A. Description of the EU28+ electricity market model COMPETES

A.1. Model overview

COMPETES is a power optimization and economic dispatch model that seeks to minimize the total power system costs of the European power market whilst accounting for the technical constraints of the generation units, the transmission constraints between European countries as well as the transmission capacity expansion and the generation capacity expansion for conventional technologies.[64] The COMPETES model consist of two major modules that can be used to perform model simulations for two types of purposes:

- A transmission and generation capacity expansion module in order to determine and analyse least-cost capacity expansion with perfect competition, formulated as a linear program to optimize generation capacity additions in the system using a two-period approach.
- A unit commitment and economic dispatch module to determine and analyse least-cost unit commitment (UC) and economic dispatch with perfect competition, formulated as a relaxed mixed integer program taking into account flexibility and minimum load constraints and start-up costs of generation technologies.

The formulation of generation capacity expansion and economic dispatch is based on complementarity and optimization modelling (Özdemir et al., 2013). The unit commitment formulation is based on the relaxed UC formulation of Kasina et al. (2013). The model is coded in AIMMS and uses the Gurobi solver.

A.2. Model formulation

Generation and transmission capacity expansion model

The generation expansion formulation of COMPETES endogenously calculates the least cost transmission capacity and the conventional generation capacity additions taking

[64] The COMPETES model has been developed by the Energy research Centre of the Netherlands (ECN), in cooperation with Benjamin F. Hobbs, Professor in the Whiting School of Engineering of The Johns Hopkins University (Baltimore, USA) as a scientific advisor of ECN.

into account generation intermittency (e.g., wind, solar) and RES-E penetration in EU member states. The renewable and nuclear installed capacities are assumed to be exogenous since capacity developments of these technologies are mainly policy driven. The model also decommissions the existing conventional power plants that cannot cover their fixed costs.

The model uses a two-stage optimization approach as described in Özdemir et al. (2013). Investment decisions regarding a mix of new technologies are determined in the first stage (i.e. 2020), while the generation of electricity per technology and per country in future electricity markets is set in the second stage (i.e. 2030). It can also be used with a multiple recursive period approach which is essentially performing a series of a two-period optimization model with the aim to reflect the transition of the system.

Özdemir et al. (2016) shows that, under the assumption of perfect competition, the two-stage competitive equilibrium of generation and transmission investments in energy-only electricity markets or electricity markets with a forward capacity market can be found by solving an equivalent optimization problem (i.e., a linear program). Thus, the dynamic COMPETES model is still formulated as a linear program in which the objective function minimizes the overall investment and system operating costs. The investment costs include annual investment costs of new transmission capacity (i.e., HVDC lines) between countries as well as the annualised investment costs of conventional generation, whereas the system operation costs consist of the annual generation operating cost and the cost of energy not served (i.e., 3.000 €/MWh; Stoft, 2002).

The model minimizes total system cost under electricity market constraints such as:

- *Power balance constraints:* These constraints ensure demand and supply is balanced at each node at any time.
- *Generation capacity constraints:* These constraints limit the maximum available capacity of a generating unit. These also include derating factors to mainly capture the effect of planned and forced outages to the utilization of this plant.
- *Cross-border transmission constraints:* These limit the power flows between the countries for given NTC values.

Given the specific levels of demand, the solution of the COMPETES expansion model specifies the least-cost/social welfare maximizing investments of generation and transmission capacity as well as their allocation in all the countries, whereas the competitive prices calculated at each node represent the locational marginal prices. The least-cost allocation of production implies that the conventional generation technologies and the flexible renewable technologies (e.g., biomass and waste) are dispatched according to their marginal costs and positions in the merit order for each country.

Unit commitment and economic dispatch model

The COMPETES unit commitment (UC) model is used to find an optimal generation schedule for the problem of deciding which power generating units must be committed/uncommitted over a planning horizon at minimum cost, satisfying the forecasted system load as well as a set of technological constraints. These constraints include the flexibility capabilities of different generation technologies as well as the lumpiness in generator start-up decisions, a feature not considered in most continent-wide electricity market models. The model also includes hourly profiles of wind and solar generation that are intermittent in nature.

Unit commitment problems are considered to be difficult to solve for systems of practical size due to their complexity of finding integer solutions. To overcome this, the exact formulation of a Mixed Integer Linear Programming (MILP) is used for the units in the Netherlands, while an approximation of MILP is formulated for the other countries/regions. The corresponding approximating problem proposed by Kasina et al. (2013) aims to solve large scale systems within a reasonable time while capturing the most of the characteristics of a unit commitment problem.

To summarize, the unit commitment formulation of COMPETES minimizes total variable, minimum-load and start-up costs of generation and the costs of load-shedding in all countries subject to the following electricity market constraints:

- *Power balance constraints:* These constraints ensure demand and supply is balanced at each node at any time.
- *Generation capacity constraints:* These constraints limit the maximum available capacity of a generating unit. These also include derating factors to mainly capture the effect of planned and forced outages to the utilization of this plant.
- *Cross-border transmission constraints:* These limit the power flows between the countries for given NTC values.
- *Ramping-up and -down constraints:* These limit the maximum increase/decrease in generation of a unit between two consecutive hours.
- *Minimum load constraints:* These constraints set the minimum generation level of a unit when it is committed. For the Netherlands, every unit is modelled with minimum generation levels and the corresponding costs. For other countries, this constraint is approximated by a relaxed formulation since the generation capacities and the minimum generation levels represent the aggregated levels of the units having the same characteristics (e.g., technology, age, efficiency etc.).
- *Minimum up and down times (only for the units in the Netherlands):* These constraints set the minimum number of hours that a unit should be up or down after being started-up or shut-down.

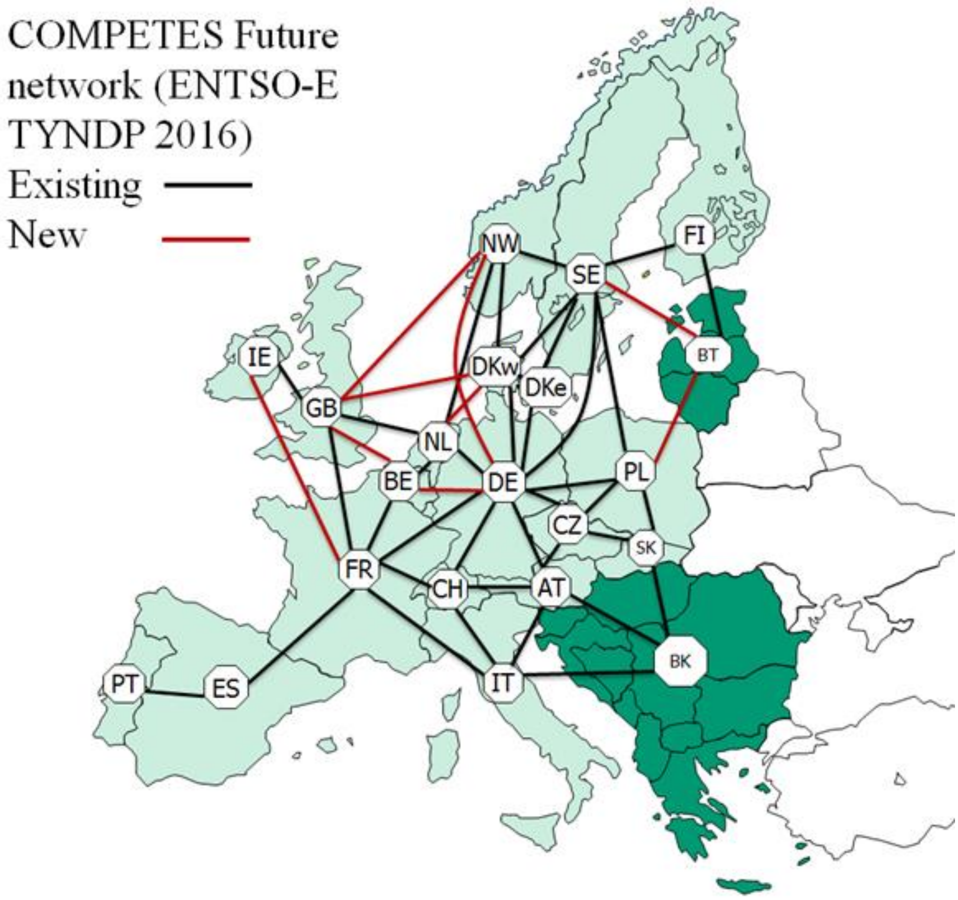
The incorporation of start-up costs, ramping rates and minimum load levels allows a better representation of the system flexibility to accommodate the variability and forecast errors of electricity from variable renewable energy (VRE) sources such as sun or wind. In addition, the model also includes the flexibility decisions related to the operation of storage. The long-term planning decisions in the form of adequate generation capacity and cross-border import capacity are part of the scenario and thus exogenous to the model.

A.3. Model characteristics

Geographical and temporal scope

The COMPETES model covers 28 EU Member States and some non-EU countries (i.e., Norway, Switzerland, and the Balkan countries) including a representation of the cross-border transmission capacities interconnecting these European countries. Every country is represented by one node, except Luxembourg which is aggregated to Germany, while the Balkan and Baltic countries are each aggregated in one node, and Denmark is split in two nodes due to its participation in two non-synchronous networks (See **Figure 90**). The model assumes an integrated EU market where the trade flows between countries are constrained by 'Net Transfer Capacities (NTC) reflecting the Ten-Year Network Development Plan (TYNDP) of ENTSO-E up to 2030 (ENTSO-E, 2016). The model has time steps of one hour. In this study, the target (focal) years of the FLEXNET scenario cases are optimised over all 8760 hours per annum.

Figure 90: Geographical coverage in COMPETES and the (future) representation of the cress-border transmission links according the Ten-Year Network Development Plan of ENTSO-E



Electricity demand

The demand represents the final electricity demand in each country. The hourly load profiles of demand are based on the latest historical hourly data given by ENTSO-E.

Electricity supply characteristics

The input data of COMPETES involves a wide-range of generation technologies summarized in **Table 22**. There are 14 types of fossil-fuel fired power plants – which can operate with CCS or as a combined heat and power (CHP) plant – as well as nuclear, geothermal, biomass, waste, hydro, wind and solar technologies, in particular detailed out with unit by unit generation in the Netherlands. For the other countries, the units using the same technology and having similar characteristics (i.e., age, efficiencies, technical constraints, etc.) are aggregated. The generation type, capacity, and the location of existing generation technologies are regularly updated based on the WEPPS database UDI (2012).

Table 22: The categorisation of electricity generation technologies in COMPETES

Fuel	Types	Abbreviation
Gas	Gas turbine	GT
	Combined cycle	NGCC
	Combined heat and power	Gas CHP
	Carbon capture and storage	Gas CCS
Derived Gas	Internal combustion	DGas IC
	Combined heat and power	DGas CHP
Coke oven gas	Internal combustion	CGas IC
Coal	Pulverized coal	Coal PC
	Integrated gasification combined cycle	Coal IGCC
	Carbon capture and storage Combined heat and power	Coal CCS Coal CHP
Lignite	Pulverized coal Combined heat and power	Lignite PC Lignite CHP
Oil	Oil	
Nuclear	Nuclear	
Biomass	Co-firing	
	Standalone	
Waste	Standalone	
Geo	Geothermal power	
Solar	Photovoltaic solar power	
	Concentrated solar power	
Wind	Onshore	
	Offshore	
Hydro	Conventional	
	Pump storage	

The main inputs for electricity supply can be summarized as:

- Operational and flexibility characteristics per technology per country:
  - Efficiencies
  - Installed power capacities

- o Availabilities (seasonal/hourly)
  - o Minimum load of generation and minimum load costs
  - o Start-up/shutdown costs
  - o Maximum ramp-up and down rates
  - o Minimum up and down times (only for the units in the Netherlands)
- Emission factors per fuel/technology
- Fuel prices per country, ETS CO_2 price, (national CO_2 tax)
- Hourly time series of VRE technologies (wind, solar etc.)
- RoR (run of river) shares of hydro in each country
- External imports from Africa (optional)
- Overnight costs for conventional generation (Euro/MW)
- Transmission capital expenditures (CAPEX; Euro/MW).

The flexibility assumptions for conventional units are assumed to differ with the type and the age of the technology as summarized in **Table 23**.

Table 23: Flexibility assumptions for conventional technologies in COMPETES

Technology	Time of being commissioned	Minimum load (% of maximum capacity)	Ramp rate (% of maximum capacity per hour)	Start-up cost[a] (€/MW installed per start)	Minimum up time	Minimum down time
Nuclear	<2010	50	20	46 ±14	8	4
	2010	50	20	46 ±14	8	4
	>2010	50	20	46 ±14	8	4
Lignite and Coal PC/CCS	<2010	40	40	46 ±14	8	4
	2010	35	50	46 ±14	8	4
	>2010	30	50	46 ±14	8	4
Coal IGCC	<2010	45	30	46 ±14	8	4
	2010	40	40	46 ±14	8	4
	>2010	35	40	46 ±14	8	4
NGCC/Gas CCS	<2010	40	50	39 ±20	1	3
	2010	30	60	39 ±20	1	3
	>2010	30	80	39 ±20	1	3
GT	<2010	10	100	16 ±8	1	1
	2010	10	100	16 ±8	1	1
	>2010	10	100	16 ±8	1	1
Gas CHP	<2010	10	90	16 ±8	1	1
	2010	10	90	16 ±8	1	1
	>2010	10	90	16 ±8	1	1

a) Warm start-up costs are assumed for all technologies but OCGT. For OCGT, a cold start is assumed.

Source: Brouwer et al. (2015).

Overnight costs for conventional generation for capacity expansion model represent engineering, procurement and construction plus owners costs to develop the project and is taken from different sources (see **Table 24**).

Table 24: Overnight investment cost of generation technologies

Fuel new	Fuel type new	2030 (Euro/MW)
Biomass	Co-firing	1600
Biomass	Standalone	1900
Coal	CHP	1350
Coal	PC	1350
Coal	IGCC	1925
Coal	CCS	3200
Derived gas	IC	825
Gas	CCS CHP	1250
Gas	CCS CCGT	1250
Gas	CCGT	700
Gas	CHP	700
Gas	GT	400
Geo	-	2450
Hydro	CONV	2300
Hydro	PS	2300
Lignite	PC	1550
Lignite	CHP	1550
Nuclear	-	3000
Oil	-	725
RES-E	Others	2800
Sun	PV	1600
Sun	CSP	3500
Waste	Standalone	1900
Wind	Onshore	1100
Wind	Offshore	2625

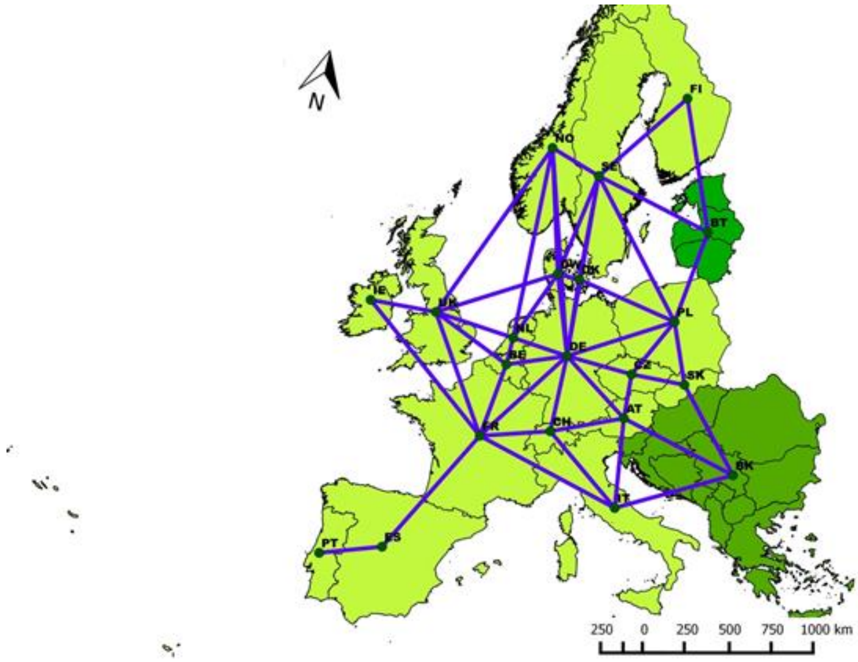
Sources: ECF (2010), IEA (2010a), IEA (2010b), IEA (2010c), TCE (2010), and ZEP (2011).

Transmission (interconnection) investments

In order to avoid the difficulty of an integer modelling problem (and to have a linear programme instead), investments in transmission (interconnection) are simplified, i.e. investment costs are assumed to be continuous and in proportion to the MWs of the transmission capacity expansion. In COMPETES, investments in high-voltage, direct current (HVDC) assets are considered to be an overlay network (see **Figure 91**). Furthermore, it is assumed that HVDC cables can be utilized in two directions, i.e. from AC to DC and from DC to AC. Hence, both at the beginning and at the end of the line two HVDC converter stations are needed. Costs per line are calculated based on the per unit HVDC line costs (in €/MW) and the distance between the nodes of the two countries concerned (in km) in line with the overlay network presented in **Figure 91**, including the costs of four HVDC converter stations for bipolar HVDC cables (i.e. AC/DC conversion in two directions).[65] More specifically, the unit investment costs of the

[65] The distances of the overlay network between the nodes of the countries concerned have been determined by means of the Quantum Geographic Information System (GIS) and are in line with the distances between the nodes presented in **Figure 91**.

Figure 91: HVDC overlay network in the COMPETES transmission investment module



overlay network are assumed to be 800 €/MWkm for HVDC cables and 96.000 €/MW for HVDC converter stations (expressed in euros of 2010; IRENE-40, 2012; ACER, 2015).[66]

VRE power generation

The maximum hourly power generation from solar and wind depends on the hourly load factors and the installed capacities of these technologies that are inputs to the model. The hourly load factors - representing the variability of wind and solar - are calculated based on the historical hourly generation data of the climate years under consideration provided by ENTSO-E (2016) and the TSOs of different countries.[67] Especially for Northwest Europe this dataset is more or less complete for 2012 -2015. For countries for which the hourly data is not available, correlations from the TradeWind (2009) data set of the year 2004 are used to indicate which country-specific time series were applicable to represent the wind time series of neighbouring countries.[68] For solar, only full datasets of 2005 and 2015 are available to represent

[66] The figure of 96.000 €/MW for HVDC converter stations represents the upper value provided by ACER (2015), i.e. 103.566 €/MVA, expressed in euros of 2014. Since COMPETES calculates with costs and prices expressed in euros of 2010, this figure is converted to approximately 96,000 €/MW (assuming that power line rating is equal to 1).

[67] Wind times series from 2006-2014 for a few EU countries are given by Bach (2015) and of 2012 for the Netherlands by ECN (2014). Also Energinet (2015), Nordpoolspot (2015), Terna (2015), 50Hertz (2015), Amprion (2015), TenneT (2015), TransnetBW (2015) and Eirgrid (2015) provide hourly wind data.

[68] In case there is a strong positive correlation between two countries, it indicates that the countries generally show the same wind patterns. For example, data for Spain was available but not for Portugal. Since TradeWind data shows a strong correlation between Portugal and Spain (±80%), the wind profile of Portugal in 2012 and 2013 is represented by the profile of Spain. In case there was a weak correlation, the wind patterns of the two countries are generally not alike. Then, TradeWind data of the year 2004 was used.

hourly solar production (ENTSO-E, 2016 and SODA, 2011).[69] Since there is a seasonal correlation between wind and solar – e.g. summer is relatively more sunny and less windy - but not necessarily an hourly correlation, it is acceptable to use wind and solar profiles of two different years to represent a future year.

Hydro conventional generation

Hydro production can be divided between conventional hydro, run-of-river (ROR) and reservoir storage. Hourly hydro conventional generation is calculated prior to the actual runs with the COMPETES model and assumed as an input to the model. Hourly Run-of-River (RoR) generation is determined by using data on annual hydro generation, the share of RoR per country, and monthly data on the RoR production. In order to calculate hourly hydro storage production, RoR is assumed to be must-run or inflexible generation, and the dispatch of flexible generation from hydro storage is assumed to depend on the residual demand hours (demand minus variable RES-E generation). Since the highest prices are expected in the high residual demand hours, hydro storage is assumed to produce in the highest residual demand hours in a certain year. The underlying idea for this approach is that there is a positive correlation between residual demand and prices. The generation from hydro storage is distributed over the year in such a way that the sum of the hourly generation is equal to the assumed annual hydro production for that year.

Storage

For the purpose of providing flexibility on timescales of an hour and more in sufficient volumes, we mainly focus on the bulk electricity storage technologies such as hydro pumped storage (HPS) and compressed air energy storage (CAES). These electricity storage technologies are modelled to operate such that they maximize their revenues by charging and discharging electrical energy within a day. By doing so, they are able to increase or decrease system demand for electricity and contribute to the flexibility for generation-demand balancing. The amount of the power consumed and produced in the charge and discharge processes and the duration of these processes depend on the characteristics of the storage technology such as efficiency losses and power/energy ratings which are input to the model.

Modelling outputs

The COMPETES model calculates the following main outputs for the EU28+ as a whole as well as for the individual EU28+ countries and regions:

- Investments in cross-border transmission (interconnection) capacities (capacity expansion module output).
- Investments in conventional generation capacities (capacity expansion module output);
- The allocation of power generation and cross-border transmission capacity;
- Hourly and annual power generation mix – and related emissions – in each EU28+ country and region;
- The supply of flexibility options, including power generation, power trade, energy storage and VRE curtailments
- Hourly competitive electricity prices per country/region;
- Power system costs per country/region.

[69] Solar hourly load factors were calculated on the basis of the sunset time, sunrise time, their evolution throughout the year and solar irradiation values in 118 nodes distributed in Europe (SODA, 2011).

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Appendix B. COMPETES model assumptions and inputs

In addition to the general description of the COMPETES model in Appendix A, this appendix provides a further, more specific explanation of the major assumptions and inputs used by COMPETES to determine the outcomes of the FLEXNET scenario cases.

B.1 Baseline scenario: Installed generation capacities

Since investments and other changes in (flexible) capacity – i.e. investments in new capacity and decommissioning of existing power plants – are part of the modelling output and discussed in the main text of this report (see Chapter 2), we consider here only the major assumptions and inputs of the baseline scenario with regard to the installed generation capacities in the Netherlands and the EU28+ as a whole. In brief these assumptions and inputs include:

- Installed VRE (wind/sun) generation capacities in the Netherlands are in line with the FLEXNET scenario assumptions of phase 1 of the project (R1, Section 2.2). Non-VRE generation capacities are in line with the National Energy Outlook 2016 (ECN et al., 2016).
- For the other EU28+ countries, generation capacities in the baseline scenario for 2015 and 2023 is in line with scenario A of ENTSO-E (2015). For 2030, these capacities are in line with Vision 4 ('Green revolution scenario') of TYNDP/ENTSO-E (2016a). For 2050, renewable energy generation capacities are based on extrapolation of trends over the years 2025-2030 up to 2050, whereas conventional generation capacities are assumed to be equal to 2030 levels.
- Storage capacities refer to hydro pumped storage (HPS) only.

Based on these assumptions and inputs, the resulting installed generation capacities in the baseline scenario for the Netherlands and the EU28+ are presented in **Figure 92** and **Figure 93**, respectively.

Figure 92: Baseline scenario: installed generation capacity in the EU28+, 2015-2050

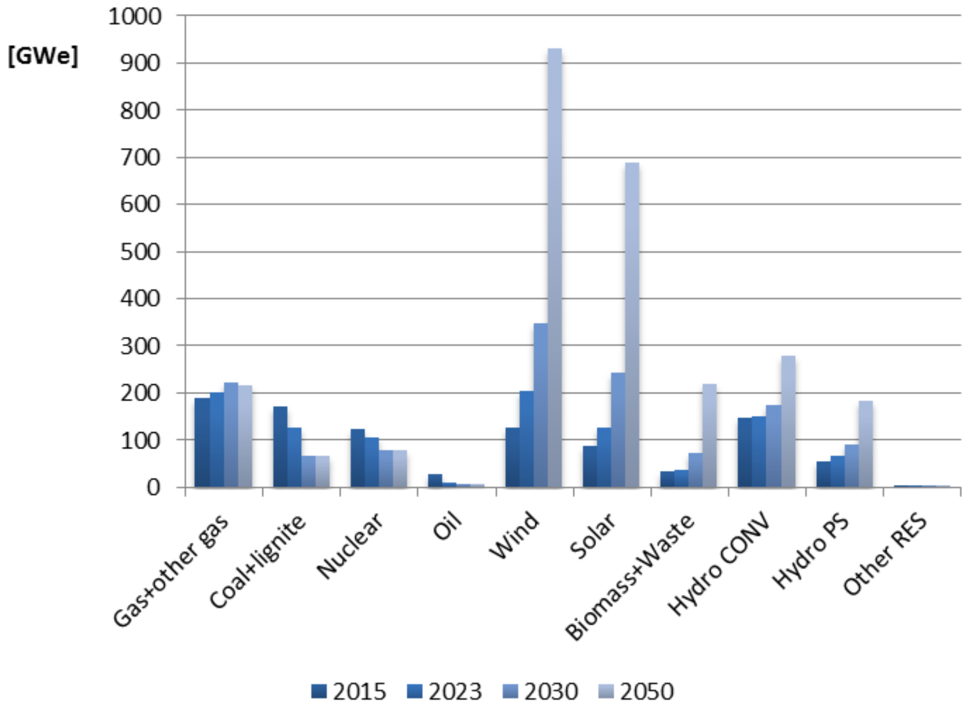
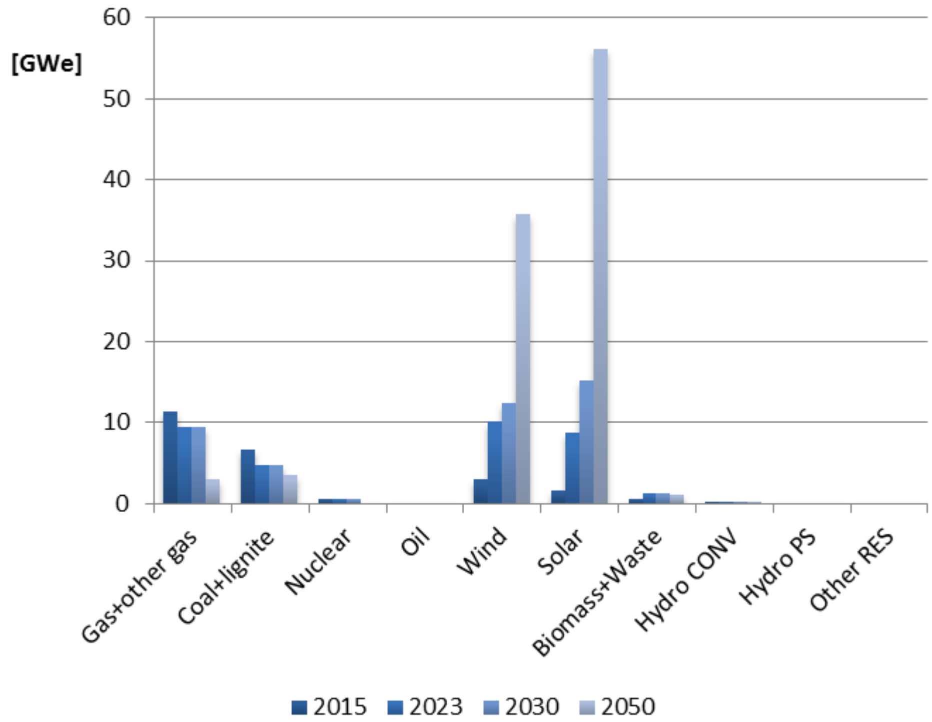


Figure 93: Baseline scenario: installed generation capacity in the Netherlands, 2015-2050



B.2 Baseline scenario: installed transmission (interconnection) capacities

The baseline scenario for transmission capacity is assumed to represent cross-border trading capacities in Europe. For the EU28+, these capacities are based on the Ten-Year Network Development Plan (TYNDP) 2016, which provides a robust dataset for transmission capacity expansion plans throughout Europe up to 2030 (ENTSO-E, 2016a, as presented and discussed in Section 2.2). For the Netherlands the relevant interconnection expansion projects and their status have been consulted with the national TSO, i.e. TenneT (see **Table 25**).

Table 25: Baseline scenario: interconnection capacity of the Netherlands, 2015-2030

Project	Export capacity NL [MW]/Year of commissioning
Current capacity	**5850**
Expansion projects:	
• Doetinchem (NL) – Wesel (DE)	+1500/2017
• COBRA cable (NL – DK)	+700/2019
• Internal reinforcement Belgium	+700/2023
• Meede (NL) – Diele (DE)	+500/2019
• Project 'Spaak' and internal reinforcements NL	+550/2030
Total export capacity in 2030	**9800**

B.3 Baseline scenario: Electricity demand

Electricity demand in the baseline/FLEXNET scenario cases is based on the following assumptions and inputs:

- For the Netherlands, total power load and hourly electricity demand profiles are in line with phase 1 of FLEXNET (R1, Section 2.3).
- For the other EU28+ countries, the increase in total (conventional) electricity demand is in line with the 'Green Revolution scenario' of ENTSO-E (2016a). Hourly load profiles have been obtained from ENTSO-E (2016b) for the same climate year as the hourly profiles for the Netherlands (i.e. 2014).
- For the other EU28+ countries, only the additional demand for charging electric passenger vehicles (EVs) is included (but not for household heat pumps or other means of additional electrification of the energy system). For 2020, EV targets of the other EU28+ countries are based on the Global EV Outlook of the IEA (2016). For 2030 and 2050, these targets are similar to the assumed EV penetration rates in the Netherlands, i.e. 32% and 75%, respectively. For the other EU28+ countries, the same (normalised) hourly load profile of EV charging is used as for the Netherlands developed during the first phase of FLEXNET (R1, Section 2.3 and Appendix A).

The resulting electricity demand for EV charging up to 2050 across the major EU28+ countries is presented in **Figure 94**, whereas the total electricity demand in the EU28+ over the years 2015-2050 is shown in **Figure 95**.

Figure 94: Electricity demand by electric vehicles in major EU28+ countries in the alternative FFLEXNET scenario cases, 2015-2050

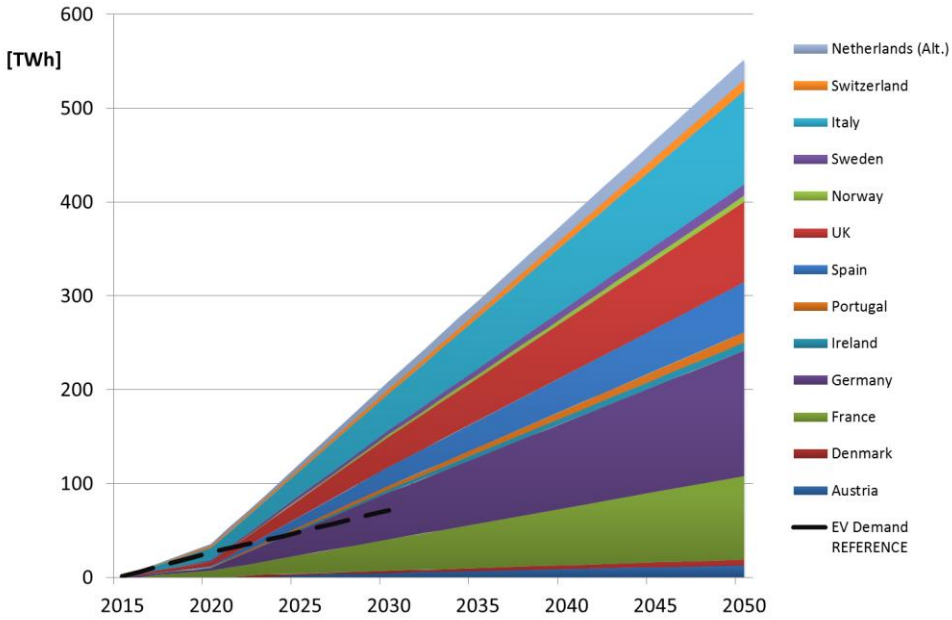
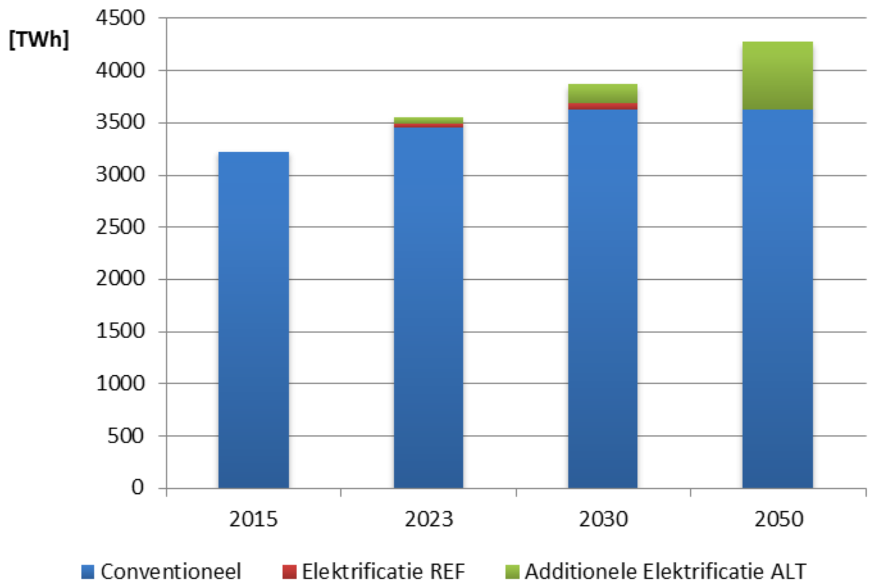


Figure 95: Total electricity demand in the EU28+. 2015-2050



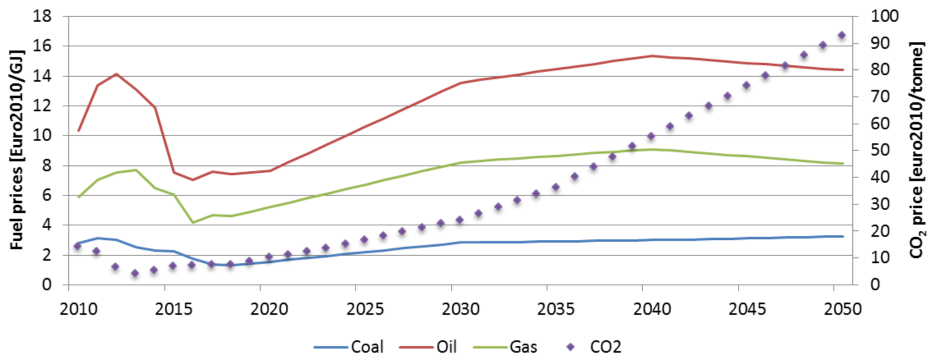
B.4 Hourly profiles for power supply from wind and sun

The maximum hourly power generation from solar and wind depends on the hourly load factors and the installed capacities of these technologies that are inputs to the model (see Appendix A.3.). For the other EU28+ countries, the increase in full load hours (FLH) is in line with the FLH assumptions for the Netherlands during phase 1 of FLEXNET (R1, Section 2.2). Moreover, in order to account for the correlations between countries concerning either wind patterns or sun patterns, the same climate year as assumed for the Netherlands during phase 1 of the project has been taken to represent either hourly wind profiles or hourly sun profiles for the other EU28+ countries, i.e. 2012 for wind and 2015 for sun PV.

B.5 Fuel and CO_2 prices

Figure 96 presents the assumed trends in fuel and CO_2 prices over the years 2010-2050. Up to 2030, these trends are in line with the assumptions of the National Energy Outlook 2016 (ECN et al., 2016), whereas after 2030 they are based on the New Policies Scenario of the World Energy Outlook 2015 (IEA, 2015).

Figure 96: Fuel and CO_2 price assumptions, 2010-2050

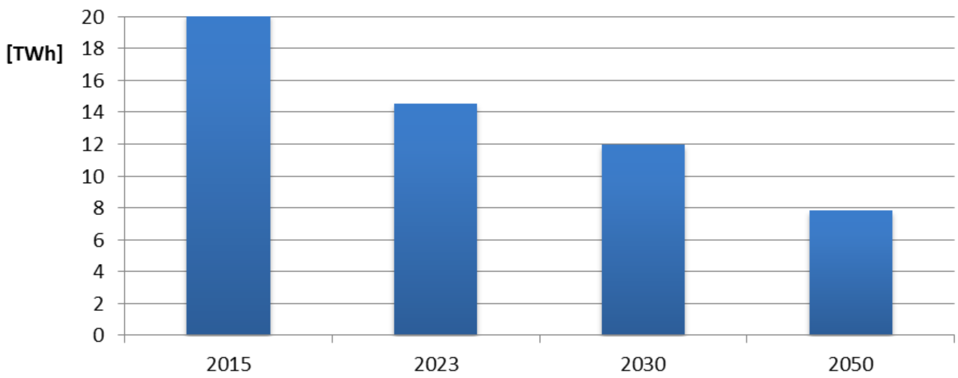


Source: IEA (2015) and ECN et al. (2016).

B.6 Decentralised CHP in the Netherlands

For the Netherlands, the dispatch of decentralized, combined heat and power (CHP) generation is modelled by ECN's bottom-up energy demand and decentralized CHP model for the Dutch agricultural sector and industrial sector. Electricity prices of the Optimal Power Flow (OPF) version of COMPETES are used to calculate the dispatch of decentralized CHP. For the FLEXNET reference and alternative scenario cases, the resulting CHP generation of electricity is the same in the respective focal years – see **Figure 97** – and used as fixed input into the COMPETES model.

Figure 97: Total decentralised CHP output of electricity in the Netherlands, 2015-2050



B.7 Generation investments

The major assumptions regarding investments in power generation capacity include:

- Investments in power generation capacity are simultaneously optimised with investments in power transmission (interconnection) capacity (see Appendix A).
- Investments in nuclear power generation are largely policy driven. Hence, besides assumed capacities in the baseline scenario, no new investments in nuclear energy are postulated.
- Investments in CCS (of coal- or gas-fired power generation) are an option in all EU28+ countries.
- Only Italy, Poland and the Czech Republic have a positive attitude towards coal-fired power generation. Therefore, only in these countries possible new investments in coal-fired generation is assumed, whereas such investments are not possible in all other EU28+ countries.
- Investments in new storage capacity are – in theory – possible, assuming a daily cycle, but – in practice – generates too low revenues for units to cover their costs (additional to the hydro pumped storage capacity assumed in the baseline scenario, i.e. about 100 GWe in 2030 and approximately 200 GWe in 2050 for the EU28+ as a whole; see Appendix A, **Figure 92**).

B.8 References

ECN, PBL, CBS and RVO.nl (2016), Nationale Energieverkenning 2016, Energy research Centre of the Netherlands, Policy Studies, Amsterdam (in Dutch).

ENTSO-E (2015), Scenario Outlook & Adequacy Forecast, Brussels.

ENTSO-E (2016a), Ten-Year Network Development Plan (TYNDP), Brussels.

ENTSO-E (2016b), Statistical database, https://www.entsoe.eu/data/data-portal/Pages/default.aspx.

IEA (2015), World Energy Outlook, Paris.

IEA (2016) Global EV Outlook, Paris.

Appendix C. Expansion of interconnection capacities across EU28+ countries in A2030-2050

In Section 2.2.1, we have discussed the expansion of the interconnection capacity in the EU28+ as a whole and between the Netherlands and its neighbouring countries in particular (see Chapter 2, notably **Figure 18** and **Figure 19**). In this appendix, **Figure 98** presents a more detailed picture of the additional High Voltage Direct Current (HVDC) transmission investments between individual EU28+ countries in A2030 (and C2050), while **Figure 99** provides a similar picture in A2050.[70] The thickness of the lines in these figures is an indication for the level of the transmission expansion between the countries concerned. In A2030 (C2050), no additional transmission investments are needed between most countries (besides the baseline capacity), whereas in those cases where an interconnection expansion is needed it is generally limited. The major exceptions are the transmission expansion between France and Italy (+5.6 GW) and between France and Spain (+3.8 GW).

In A2050, on the contrary, substantial transmission expansions are needed between several EU28+ countries (compared to the baseline capacity in 2030). This applies particularly for the interconnection capacity between France and the UK (+65 GW), between France and Spain (+ 51 GW) and between Italy and the Baltic region (+ 28 GW). These large expansions are needed partly because total electricity demand across the EU28+ increases significantly up to 2050 – due to the further electrification of the energy system (see Appendix B) – but mainly because of the large increase in VRE generation output, resulting in relatively low electricity prices across EU28+ countries. Consequently, there are hardly any investments in expanding non-VRE generation capacity (as discussed in Chapter 2, Section 2.2.1) but indeed substantial investment needs to expand interconnection capacity.

70 Additional HVDC transmission investments means additional to the baseline interconnection capacity projected for 2030 in the TYNDP of ENTSO-E (2016). Note that, as explained in Section 2.2.1, the expansion of the interconnection capacities across the EU28+ in C2050 is similar to the expansion in A2030. Therefore, **Figure 98** presents additional HVDC transmission investments across the EU28+ for both A2030 and C2050.

Figure 98: Additional HVDC transmission investments in the EU28+ in scenario case A2030 (and C2050)

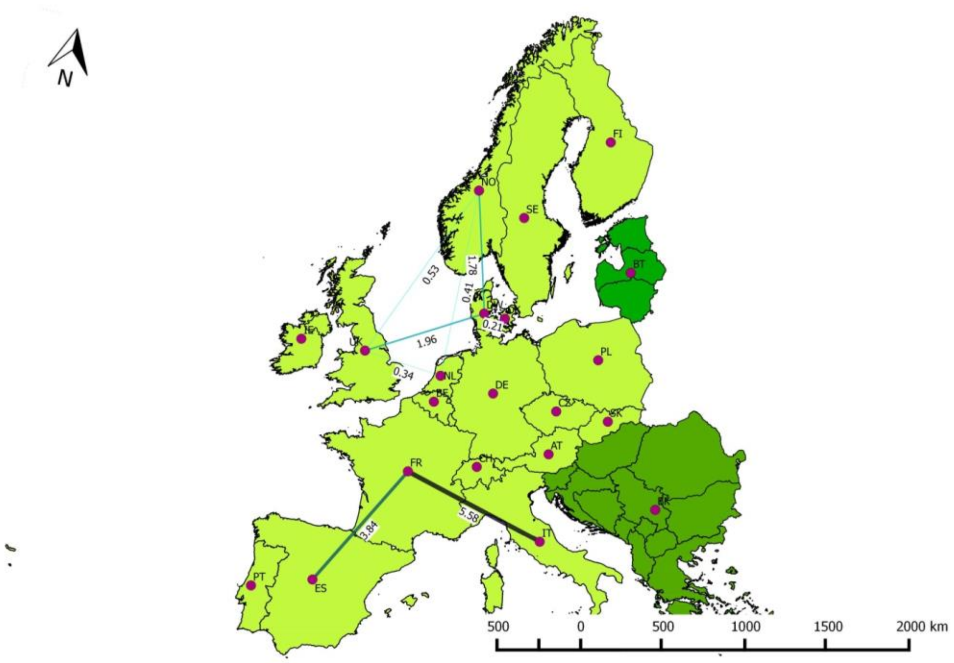
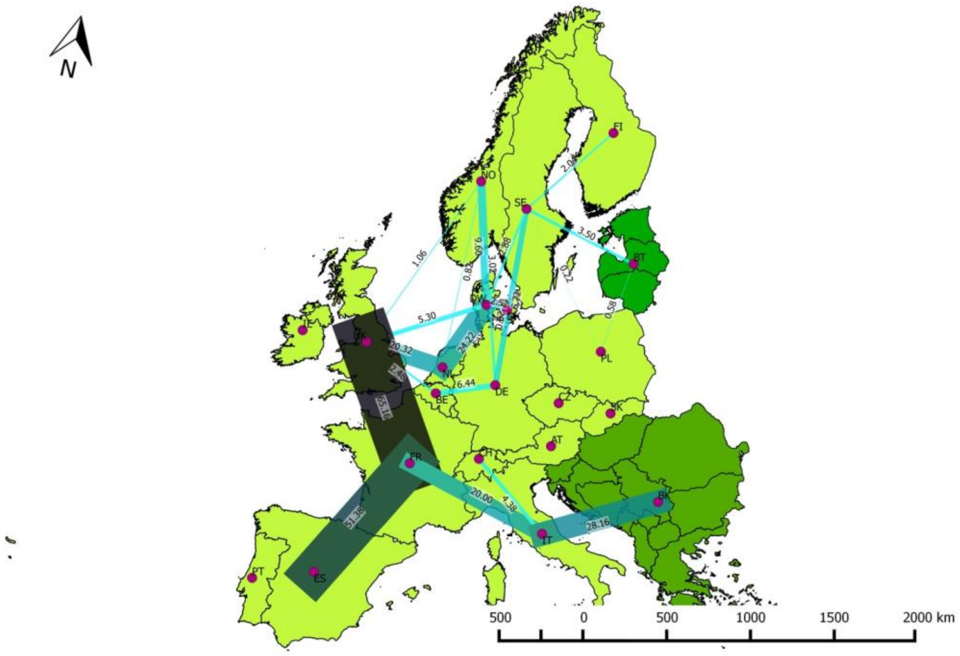


Figure 99: Additional HVDC transmission investments in the EU28+ in scenario case A2050



Appendix D. Description of the NL energy system model OPERA

D.1 Introduction and model overview

OPERA (*Option Portfolio for Emissions Reduction Assessment*) is an integrated optimisation model of the energy system in the Netherlands developed by ECN. It is a bottom-up technology model that determines which configuration and operation of the energy system – combined with other sources of emissions – meet all energy needs and other, environmental requirements of the Dutch society, whether market-driven or policy imposed, at minimal energy system costs. These requirements generally include one or multiple emission caps. In addition to energy related technologies and emissions, the model is capable to include technologies and emissions that are not energy-related as well.

For the choice of technologies (technology options), OPERA draws upon an elaborate database containing technology factsheets, as well as upon data on energy and resource prices, demand for energy services, emission factors of energy carriers, emission constraints and resource availability. The technology fact sheets for electrolysis, methanation and electricity storage used in the OPERA model are based on the findings of the techno-economic assessment by DNV KEMA (2013).

In addition, for the baseline scenario, OPERA derives various baseline data from the Dutch Reference Outlooks and, more recently, from the National Energy Outlooks (see, for instance, ECN et al., 2016). These data provide a baseline scenario based on extrapolation of existing and proposed policies. Among others, the baseline includes the demand for energy services that must be met (e.g. the demand for space heating, lightning, transport, products, etc.). OPERA uses the baseline to compare its results with the outcomes of alternative (policy) scenarios in terms of additional emission reductions, changes in energy demand and supply, changes in energy system costs, etc.

The baseline scenario is represented by a technology portfolio based on the complete energy balances of the Netherlands as reported in MONIT (www.monitweb.nl). These energy balances distinguish between energetic energy use, non-energetic use (feedstock in e.g. the petro-chemical industry) and other energy conversions (e.g. cokes ovens or refineries). Energy service levels are also derived from the baseline, whether as energy demand (electricity and/or heat) or as a projected activity level expressed in physical units (e.g. iron and steel, ammonia, ethylene, passenger road transport, freight road transport).

Emissions currently covered in OPERA are the greenhouse gases CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and SF_6. In addition, the model is complemented with air pollutants such as sulphur dioxide (SO_2), nitrogen oxides (NO_x), ammonia (NH_3), particulate matter (PM10 and PM2.5) and non-methane volatile organic compounds (NMVOC). Thereby, both climate targets as well as air pollutant targets and effects can be analysed.

Being a flexible and versatile tool, OPERA may incorporate any other target pollutant or substance, given that they are accompanied by factsheets that contain the required information on their effects.

D.2 Energy system representation

The model covers both the demand and supply side of the Dutch energy system, as well as the energy networks connecting the various parts of the energy system.

The energy supply sectors covered are:
- *Electricity*: including both fossil-fuel and renewable-based technologies at the central and decentral (local) level;
- *Gas*: including both natural gas as well as biomass-based gas, with both possibly combined with carbon capture and storage (CCS);
- *Heat*: including both fossil-fuel and renewable-based technologies at the central and decentral (local) level;
- *Hydrogen*: including technologies based on fossil fuels (without and with CCS), renewables and electricity at the central and decentral (local) level;
- *Grids*: including differentiated voltage levels and electricity storage technologies;
- *Energy conversion*: including refineries, liquid fuels from fossil and biomass sources (without and with CCS).

Energy technology representation
The model database contains traditional technologies describing the actual energy system on supply and demand sides, as well as existing and future alternatives. Generally, the alternatives are favoured over traditional technologies as emission constraints get tighter. More specific limiting constraints, such as additional technology or energy limitations (e.g. limits on nuclear expansion or CCS or biomass availability) will limit the role of the directly affected technologies and technologies linked to these, while favouring the position of other technologies that fulfil the same functions.

Constraints imposing minimal values (e.g. a target to meet a certain amount of wind or solar energy) favour the affected technology while placing competitors at a disadvantages. There are various ways in which technologies influence each other: technologies may compete with each other, but they may also favour each other. For example, a lot of intermittent renewable energy may favour the position of storage and peak load technologies, and a lot of electricity supply – i.e., with low electricity prices – is likely to favour the position of technologies that convert electricity to other energy carriers.

For all end-use demands, at least one alternative technology is available. In most cases a small portfolio of technologies drawing upon different energy sources (e.g. fossil, biomass, solar) is present, that all satisfy the same demand. In this way, the model does not contain biases towards the one or the other energy source.

Table 26 provides a list of the different technology options modelled by OPERA in the energy value chain.

Table 26: Broad overview of technology options included in the energy value chain as modelled by OPERA

Production/supply	Conversion	Infrastructure	Demand
• Centralised electricity (and heat) plants based on: - coal - gas - biomass (without and with CCS) - nuclear - renewables: wind on shore and off shore - hydrogen FC • Decentralised electricity plants (CHP) based on: - Gas - Biomass - Hydrogen - Solar PV	• Fossil fuel conversion: - Refineries (without and with CCS) • Biomass conversion (without and with CCS): - Into gas - Into liquid fuels • Hydrogen production based on: - Electricity - Natural gas (without and with CCS) - Biomass (without and with CCS)	Electricity and heat network Natural gas network Hydrogen network	• Boilers based on fossil fuels (without and with CCS): - Coal - Liquids - Gas • Boilers based on biomass (without and with CCS): • Boilers based on hydrogen • Industrial processes: - Iron and steel - Ammonia - Ethylene • Electric appliances • Saving technologies: - Heat based - Electricity based - End use technologies like different vehicle types

GHG emission reduction sources

GHG emission targets are an important issue in explorations of future energy systems. Basically, there is a limited range of primary resources for GHG emission reduction: end use energy savings, CHP, nuclear energy, CCS, biomass, other renewables (e.g. wind, solar, geothermal), fuel switch and reduction options for other greenhouse gases. All categories are represented in OPERA. Individual technologies may exploit only a single source (e.g. nuclear energy) or multiple sources (e.g. biomass based CHP with CCS). Generally, the technologies that directly exploit a primary resource produce energy in a form that can be directly applied (biofuels, biogas, electricity, heat, hydrogen).

However, there seldom is a perfect match between supply and demand. Therefore, secondary transformations are required to deliver energy in form that is directly applicable for the various end-use sectors (e.g. electricity to hydrogen, electricity to heat, biogas to heat, biogas to electricity).

Generally, the small scale end-use sectors such as the built environment and the transport sector have less often direct access to primary resources, while the large scale end-use sectors and the energy supply sectors have more direct access (see **Table 27**). As a consequence, transformation technologies such as power-to-gas (P2G) may play an import role in decarbonizing the energy system, as they convert carbon free energy harvested in the energy supply sector into a form which better meets the requirements of some end-use applications.

Table 27: Availability of energy related GHG emission reduction primary resources in sectors (direct application only)

Sector	Energy supply	Industry	Agriculture	Built environment	Transport
Savings	+	+	++	++	++
CHP	++	++	++	+	
Nuclear	+++				
CCS	+++	+++			
Biomass	+++	+++	++	+	
Other renewables	+++	+	++	++	
Fuel switch	++	+			++

+++: large, ++: medium, + small

P2G/hydrogen value chain representation

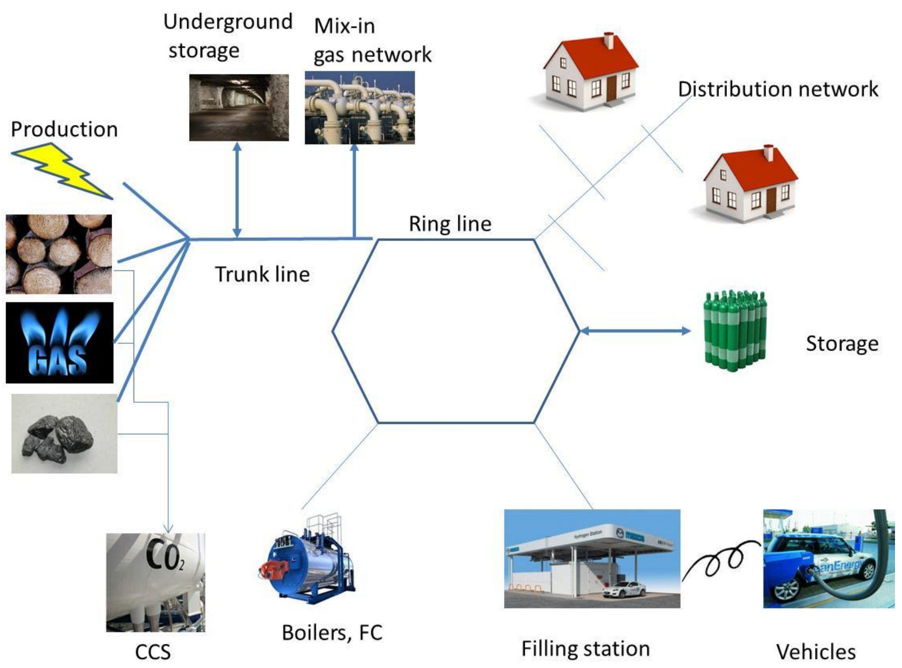
For power-to-gas (P2G), the representation of hydrogen and a possible lay-out of a hydrogen network has received specific attention in OPERA. The old, former representation, with only some production technologies (SMR and electrolysers) has been expanded with transport, distribution, conversion and various demand technologies. **Figure 100** illustrates the hydrogen infrastructure in the OPERA model.

Hydrogen can be supplied by different technologies based on the input energy carrier (electricity, natural gas, biomass, fossil fuels). The network representation is kept deliberately simple as explained above: a trunk line feeds in a ring line around large demand centres (e.g. Rotterdam area, Randstad) which on its turn disperses in medium (industry, filling stations for transport) and low pressure distribution lines (households, service buildings) to end-users.

The hydrogen may be consumed as such in fuel cells (both stationary as mobile), boilers etc. or mixed in the natural gas grid. The tool can apply varying maximal shares for mixing-in. Another possibility is the further conversion into methane (methanation process; not illustrated), which couples hydrogen with CO_2 from capture units. This can be used in all traditional and new natural gas applications.

In order to enhance flexibility of the hydrogen flow, several storage options are taken into account: large underground storage (similar to underground gas storage) is envisaged on the trunk line level, while local or regional storage can be achieved at the ring line level.

Figure 100: Schematic illustration of the hydrogen infrastructure represented in OPERA



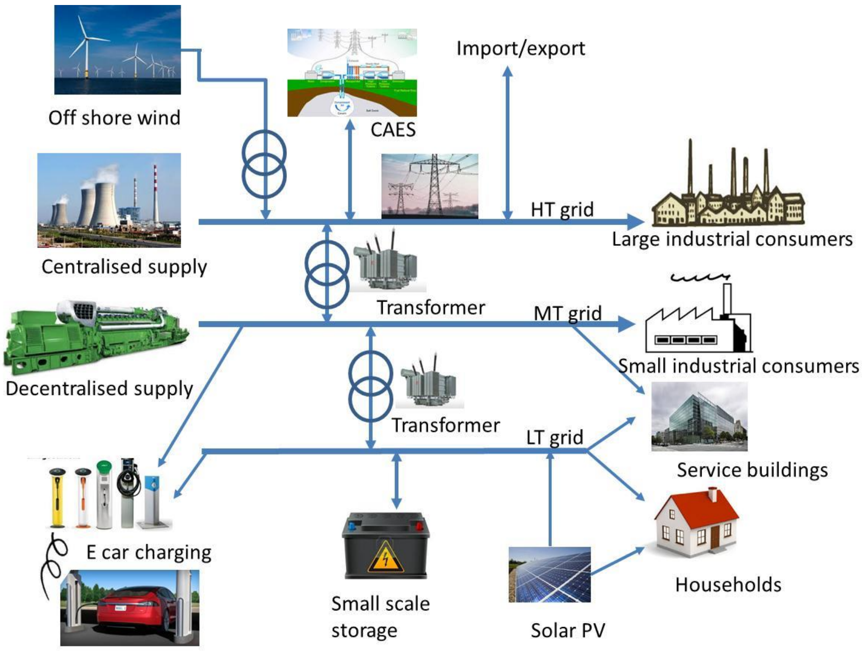
D.3 Representation of infrastructure

Given the diversity of levels of demand (households consume low voltage electricity, industry medium or high voltage), it is important to take into account that energy, electricity, and gas, is not directly consumed at the suppliers site. To transport energy from the suppliers to the end-users, a network capable of transmitting sufficient amount of energy at any moment is required.

A stylised representation of the different grids is included in the model (see **Figure 101**). The electric network is differentiated in three voltage levels (high, medium, low) with on each level the appropriate supply options as well as the main categories of electricity end-users.

In order to be able to convey energy at different grid levels, electric transformers are included as well. They can ensure the flow of electricity between the voltage levels, in both directions. As has been explained by the stakeholders in the power-to-gas (P2G) project, the grid capacity is not the limiting element, it is the capacity of the transformers. Therefore, in addition to an estimated existing capacity in transformers (based on Liander and Enexis data), several expansion transformers (different MVA/kVA) are included in the database. OPERA may choose to invest in these transformers if the required peak flows between two voltage levels exceeds the existing capacity.

Figure 101: Schematic illustration of the electric supply, infrastructure and demand



In addition, a number of specific elements have been included in the electricity network representation in the model:

- On the high voltage level, there is the possibility to make use of compressed air energy storage (CAES);
- Off shore wind electricity may be connected at the high voltage grid, with a dedicated off-shore grid which is connected to the land grid by special transformers. These three elements (turbine-grid-transformer) are connected but not rigidly: the model can choose each capacity independent of the other: this allows for instance that, in order to avoid high investments in transformers to convey peak production to the land grid, the model can chose to limit this capacity investment and to perform curtailment if this would be more cost-effective. Thus, the capacity of the transformer is sufficient for the baseload/bulk output of the wind turbines, but not always for the peak load.
- On the low voltage grid, stationary end users may use solar PV to provide (part of) their electricity demand and in the case of excess production, deliver into the grid;
- Also on low voltage, small scale storage is possible, mainly by means of battery technologies (see DNV KEMA, 2013 for an overview of options and technologies);
- The model includes charging stations for pure electric or hybrid cars.

For the natural gas grid, the model applies a similar but much simpler representation, as it is expected that any imbalance between demand and domestic production, both from traditional gas extraction as from biomass sources (green gas), will be covered by imports or additional production.

The gas grid has different pressure levels, similar to the electricity voltage levels: a high pressure with most production facilities feeding in as well as the hydrogen mixing-in. The medium pressure grid and a distribution network serve most end users. Between the pressure level, connectors are modelled which reduce pressure from high to low. In contrast with electricity no pressurising from a lower to a higher pressure is envisaged as this interferes with the quality assurance of the gas on the different levels (e.g. odorisation and dilution with N_2 to maintain low caloric quality for most end users vis-a-vis high caloric gas consumption by a growing number of industrial end users). Distribution and transmission system operators generally expect the existing capacity of the gas grid to be sufficiently large for meeting current and future demand for gas, as the projected gas demand in the built environment is expected to show a stagnant or declining trend (related to the adoption of energy efficiency measures).Therefore, increases do not require expansion technologies, but do result in increased energy consumption for pressurizing the transported amount of gas.

D.4 Representation of time units and relevant demand and supply profiles

OPERA explicitly deals with needs to achieve a match between supply and demand at any moment. In order to do so within acceptable computation times, the OPERA model applies a so-called '*time slice approach'* , in which the 8760 hours of the years are attributed to separate time slices. OPERA adopts an innovative approach in utilizing most relevant patterns in energy demand and supply covering the 8760 hours of the year, while not explicitly modelling each of these hours separately.

The basic approach is to smartly group together those hours of the year that have very similar characteristics with respect to the (time sequence of) energy demand and supply. Energy supply and demand exhibits particular patterns over the hours of the day, over the week, across seasons etc. Based on historical hourly data on all relevant supply and demand patterns (i.e. wind and solar profiles, heat and electricity demand profiles), time slice algorithms smartly combine those hours of the year that are (most) similar, and take account of the sequence of a particular hour relative to the daily peak in demand. In this way, model simulations can capture the different energy system balances throughout the year, while not putting to heavy requirements upon computing power capacity. The approach is flexible as the desired amount of time slices (and associated computing time per scenario run) can be varied in the OPERA interface.

Explanation of the adopted time slice approach
Demand and (variable) supply profiles are input into the OPERA model with hourly resolution. This means that there are 8760 values per profile input into the model. Such a high temporal resolution with a large number of technologies and other input variables would lead to excessive runtime and memory use of the computer model. It was therefore decided to decrease the number of time periods used in the optimization loop by grouping the hours of the year into sets, called *time slices*. The methodology and algorithms to allocate the hours of the year into time slices have been devised to meet the following requirements:

- The set of time slices should enable the identification of significant time periods where supply and demand vary (e.g. seasonal variations, daily variations);

- The set of time slices should enable the identification of periods with shortage/excess of supply versus demand;
- The user should have full flexibility in choosing the number of time slices in order to achieve the desired compromise between runtime and temporal resolution;
- The user should have full flexibility in choosing what the underlying criterion for the time slices allocation is:
  - Fixed time periods (seasonal and/or daily);
  - Variations in the demand patterns for electricity, heat or total;
  - Variations in the supply patterns for electricity, heat or total;
  - Variations in the excess/shortage of supply vs. demand patterns for electricity, heat or total, and the possibility of using storage.

For each of these four criteria a set of special *allocation indicators* has been built in the model. In the P2G project (de Joode, *et al*, 2014) several tests were executed and it was concluded that the fourth criterion yields the most valuable output for that project. Therefore the next sections will focus exclusively on the description of the set of allocation indicators for this particular criterion.

However, during the FLEXNET project it appeared that solely applying the fourth criterion results in some undesirable allocation of time slices and in an underestimation of extreme situations. Two additional requirements have therefore been added in the FLEXNET project:

- The resulting time slice allocation should result in a distribution of hours that avoid non-logical production and demand patterns;
- The user should have the opportunity to allocate extreme situations into separate hours. For example, the most windy hours;

The last two sections will explain in some further detail those additional requirements.

VRE supply profiles

Hourly variable supply profiles concern electricity from wind energy and electricity and heat from solar energy. They are further specified per year (*y*), region (*r*), and option (*o*): $s(y,h,r,o_w)$ for wind profiles and $s(y,h,r,o_s)$ for solar profiles.

An aggregated wind (solar) supply profile per year is created by summing and normalizing all separate wind (solar) profiles:

$$s_w(y,h) = \frac{1}{N_w}\sum_{r,o_w} s(y,h,r,o_w)$$
$$s_s(y,h) = \frac{1}{N_s}\sum_{r,o_s} s(y,h,r,o_s)$$

where N_w and N_s are the normalization factors.

An overall aggregated supply profile is then created using the following equation:

$$s(y,h) = \frac{1}{N}\sqrt{s_w^2 + s_s^2}$$

where *N* is a normalization factor.

It is important to remark that the aggregated supply profile does not represent a physical quantity. It is used to construct the desired indicator. If new, or additional supply profiles are input in the model, the aggregated profile will change and this will influence the final indicator.

Energy demand profiles

Hourly demand profiles for electricity and heat are provided per year and sector. Following an analogous procedure as for the supply, aggregated profiles for electricity and heat demand, d_e and d_h respectively, are created by summing over the sectors and normalizing. An overall aggregated demand profile, d, is then created by taking the square root of the sum of squares and normalizing.

Allocation indicators

Based on the aggregated demand and supply profiles described above, the following allocation indicators have been created:

$$\Delta sd_e(y,h) = s(y,h) - d_e(y,h)$$
$$\Delta sd_h(y,h) = s(y,h) - d_h(y,h)$$
$$\Delta sd(y,h) = s(y,h) - d(y,h)$$

The first two indicators represent a probability of having an excess (positive values) or shortage (negative values) of supply versus demand of electricity and heat, respectively. The last indicator represents the probability of having an excess or shortage of overall supply versus demand.

Allocation algorithm

Figure 102: Illustration of the Δsd indicator

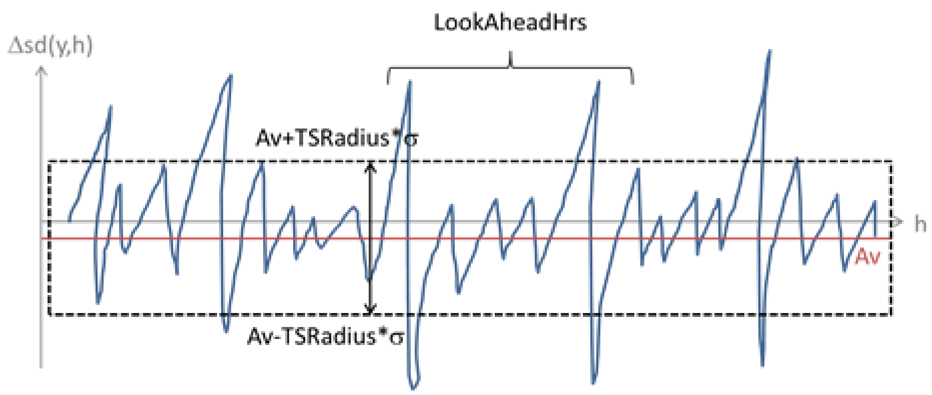


Figure 102 shows a sketch of the Δsd indicator and the parameters that are used by the algorithm to perform the time slices allocation. The meaning of the different parameters and the procedure steps are briefly summarized in the following bullets:

- Av = Average of Δsd.
- σ = Standard deviation of Δsd.
- *TSRadius* controls the height of the black dashed rectangle; initial value = 1. The values outside the rectangle correspond to extreme situations. Maxima, or *peaks*, are likely excesses of intermittent supply. Minima, or *valleys*, are likely shortages of intermittent supply versus demand.

- *LookAheadHrs* controls how many hours to look from a maximum (peak outside the rectangle) to find a minimum (valley outside the rectangle); initial value = 24 hrs.
- The algorithm selects all peaks (valleys) outside the rectangle, and find all valleys (peaks) within *LookAheadHrs* (-*LookAheadHrs*) hours. These valleys and peaks are then stored in the first half of the time slices, in ascending order depending on the value of AVDiff (hence first the valleys then the peaks). The remaining hours are stored in the rest of the time slices, in ascending order depending on the value of AVDiff.
- All parameters can be adjusted in the model via the user interface, at the page 'TS Indicators - overview'.

The algorithms allows to isolate the hours where an excess of intermittent supply is likely to occur and a use for this excess is likely to arise in the near future. Analogously, the algorithm isolates the hours where a shortage of intermittent supply is likely to occur and this shortage can be "filled" with an excess supply from the near past. Depending on the degree of likely excess (shortage) and on the total number of time slices, these hours are allocated within a certain time slice.

Avoidance of non-logical supply and demand patterns
During the FLEXNET project it appeared that, after zooming into the results per hour, there was significant solar PV production during the night. For example, during the night hours in January there was a non-negligible amount of solar PV. This effect is a consequence of looking at the difference between VRE supply and conventional demand. This difference might well be the same for an hour with a modest VRE production and a modest demand as for an hour with high VRE supply and high demand. If the difference is similar, they will fall into the same time slice. Next to this non-logical production of solar PV, extremes are more averaged out. This problem has been tackled by forcing hours that belong to certain periods in the day together:

- Sleeping hours: hours 1-7 and hour 24 of each calendar day
- Office hours: hours 8-17
- Evening hours: 18-23

This excludes, for example, midnight hours to be in the same time slices as afternoon hours.

In particular for solar energy there is a large difference in solar irradiation for summer days and winter days. Therefore a seasonal split has been applied as well. Since a split of the day in 3 periods needs to be applied for each separate season, summer and spring have been combined and winter and autumn have been combined. The forced daily and season split results in 2x3=6 temporal, exclusive, subsets for time slices.

Allocation of extreme hours in separate time slices
Even with the allocation improvements as described in the previous section, it is unavoidable that extreme situations are averaged out to some extent. The following situations are considered to be important extreme situations:

- The hours where the wind is blowing strongest
- The hours where the wind is absent or very low
- The hours where solar irradiation is strongest

In the FLEXNET project an allocation of extreme wind hours (both strong and absent) was separately done for day and seasonal splits as described in the previous section. This results in 2x2x3=12 additional time slices. Allocation of extreme solar irradiation has been restricted to hours that fall within office hours and in the spring-summer season.

D.5 References

DNV KEMA (2013), Systems analyses Power to Gas: A technology review, Report GCS 13.R.23579.

ECN, PBL, CBS and RVO.nl (2016), Nationale Energieverkenning 2016, Energy research Centre of the Netherlands, Policy Studies, Amsterdam (in Dutch).

Appendix E. Description of the Liander regional grid model ANDES

E.1 Introduction

ANDES stands for Advanced Net Decision Support and aims to give invaluable insight into future grid load patterns. It is an all-encompassing model that looks at the short- medium- and long-term (0-40 years ahead) from the LV-grid up to the HV-grid. The model has been developed by Liander, one of the major Distribution Network Operators (DNO) in the Netherlands. It is responsible for the electricity and gas grids in roughly a third of the Netherlands and serves approximately 3 million customers. The Liander electricity grid consists of 700 HV/MV-substations, 50.000 MV-cables, 45.000 MV/LV-substations and 180.000 LV-feeders.

E.2 Method

The ANDES model calculates the impact of technologies on the electricity network using a bottom-up approach. The method used is different from other energy transition impact studies in which load forecasts are made based on average linear relations and the electricity grid is treated uniformly. In contrast, the ANDES model uses the potential for specific technologies at the household level and couples this with the specific grid situation of the Liander grid.

In the ANDES model technological developments are included using predictions on household level. The main advantages of the ANDES model is that discrepancy between geographical areas are taken into account and the model is able to forecast the load on all the components in the electricity network. The large scale approach of the model leads to huge data volumes and big-data techniques, such as in-memory computing, are used to ensure the required performance.

The model can be divided in several main steps that will be explained in more detail below.

High-level adoption scenarios
First, scenarios are made for the adoption of electric vehicles, heat pumps and solar panels. Alliander expects that these technologies will have the largest impact on the

load of the electricity network. To generate the scenarios a strategic analysis is carried out, including the regulations, the vision of the government and the incentives to buy a technology. Subsequently, S-shaped curves are generated that predict the total amount of a technology in the entire Liander-area in a specific year. For each technology a low, medium and high scenario is modelled.

Technology dispersion

Second, the expected total amounts from the first step are used to find the penetration of a technology for each customer. External and internal socio-demographic data are coupled to the customers. The present-day location of a technology combined with the socio-demographic data is used to construct statistical models. For example, a logistic regression model calculates the probability that a household will possess a solar panel for each coming year and a regression with an arc sinus transformation is used to calculate the probability that a household will possess an electric vehicle for each coming year. Together the probability and the total amount from the S-shaped curve are used in a Monte Carlo simulation to find the penetration of a technology for each household in the scenarios in all the years.

Technology profile generation

In the third step, load profiles for the three technologies are generated based on measured data. More specific, sensor data is used to find an average year profile based on quarter hour values. Consequently, the customers to which a technology is allocated are coupled to an expected technological load profile.

Customer profile generation

Fourth, the ANDES model calculates a present-day load profile for every customer. For large costumers measurement data is available and this is used to generate their profile. For smaller customers, including households, an average profile is combined with the average year consumption of that specific customer to generate the load profile. The load profile of customers is based on quarter hour values.

Future profile generation

Fifth, the future load profile for each customer is generated. This new load profile is calculated by combining the current load profile with the load profile of new expected technologies. A bottom-up approach is used to connect the customers to the electricity network. A network trace, starting at the customer and ending at the HV/MV-substation, defines the whole Liander grid. The load profiles of the customers connected to a certain asset are added to each other such that an expected load profile on all the assets arises. Besides the current load and the expected load of the technologies also urban developments and customer prospects are added to the asset load profiles at the HV/MV-substation level.

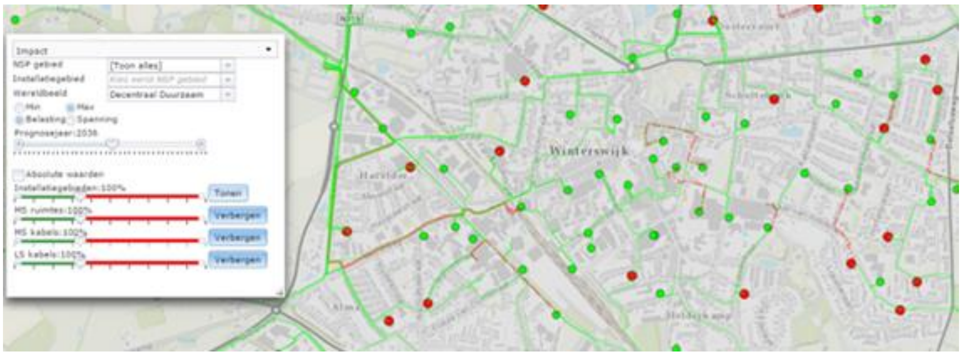
Result assessment and visualisation

Finally, the load profiles are used to determine congestion problems in the electricity network. More specific, the maximum and the minimum load of the yearly load profile are used and compared with the capacity of the assets. In other words, the usage and local generation of electricity are compared with the capacity of the assets. To provide easy access to the load forecast of a certain asset, an interactive, web-based, geographical interface is available.

E.3 Results

The whole area of Liander is present in the model, including 700 HV/MV-substations, 50.000 MV-cables, 45.000 MV/LV-substations and 180.000 LV-feeders. The adoption of energy transition effects, such as electrical vehicles, solar PV and heat pumps, is modelled for each of the 3 million customers individually. An interactive geographical visualization has been build where the resulting loads in the grid can be assessed given a certain year and scenario. See **Figure 103** for a snapshot of this visualisation. Also the change of the peak load over time can be shown for each modelled asset. These resulting load forecasts are an important part of the long term grid development plans. Based on these forecasts, the optimal route of investments can be determined for a certain energy transition scenario.

Figure 103: Snapshot of the interactive geographical visualisation part of the ANDES model



Note: Shown are MV/LV-substation (dots) and MV-cables (lines). The color represents whether the asset is overloaded (red) in the selected year/scenario.

In order to identify the differences between a bottom-up approach versus the traditional approach and to evaluate the added value of the ANDES-model for Grid Capacity Planning, a standard HV/MV-substation in Winterswijk, situated in the East of The Netherlands, is considered. To do so this paper performs two kinds of comparisons, namely; a) Comparing the forecasted substation load profile from the ANDES-model with the current load profile and b) evaluate the insights of the peak load forecast.

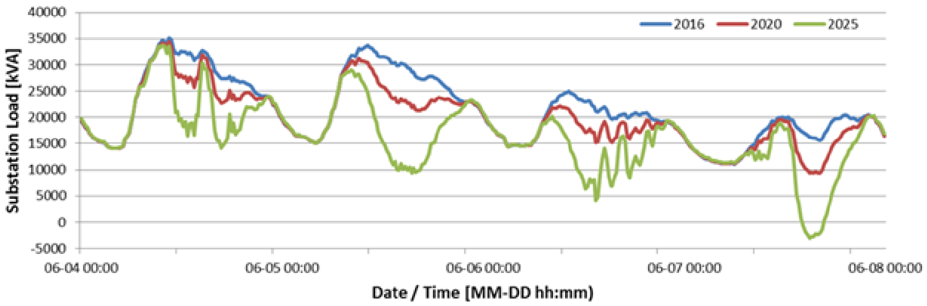
Future load profile generation

In the traditional capacity planning approach, historical data is extrapolated to find the future peak load of an asset. Because only the peak load is used, changes in the load profile are not visible. Visualizing the present-day 15-minute load profile for a certain period (June 4th – June 8th) in **Figure 104** (blue line), a clear daily profile is visible. When adding the expected amount of solar panels, heat pumps and electrical vehicles expected at this substation in the years 2020 (red) and 2025 (green) and keeping the meteorological circumstances the same, we observe a clear change in the load profile.

On the one hand we observe a small reduction in the maximum peak, whereas the peak moment stays the same. On the other hand, the most significant impact is visible on the minimum peak, where a sunny moment leads to a shift in the peak moment and to a surplus of locally generated energy. These are insights which cannot be derived from the traditional load forecast approach and lead to insufficient awareness of the effects of locally produced energy.

These new load profiles are also important input for the evaluation of future asset degradation. The results for HV/MV-substation Winterswijk show that the future profile is more volatile than the current profile. The larger amount of installed Solar PV leads to large load swings, even at the substation level. It can be expected this has an impact on the lifetime of the voltage regulator at the HV/MV-transformer.

Figure 104: Example of generated load profile for HV/MV substation Winterswijk in the years 2016, 2020 and 2025

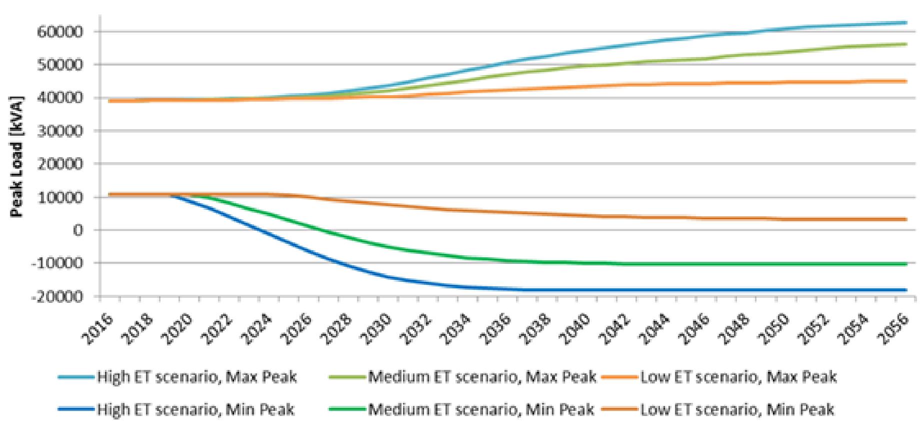


Peak load forecast

The difference between the peak load and the total capacity of an HV/MV-substation gives information about the capacity available for urban developments and customer prospects. However, in the traditional grid planning method, effects of the energy transition on the peak load are neglected, and potential future capacity problems are overlooked.

With ANDES it is possible to evaluate the future peak loads as a result of solar panel and heat pump installations and electrical mobility. **Figure 105** shows the peak load forecast for the HV/MS-substation Winterswijk, the same substation under consideration in the previous section. The forecast consists of the minimum load and maximum load occurring within each year for 40 years ahead. The results are shown for three scenarios: low, medium or high adaptation of the three energy transition technologies.

Figure 105: Forecast of the yearly maximum and minimum loads for three transition scenarios



What can be observed from this figure is that regardless the scenario, the peak load at the substation will increase. Another notable insight is that the difference between the minimum and maximum load increases, resulting in fluctuations of the available substation load. In the medium and high scenarios, the minimum load of the substation will go into negative numbers. This means there will be moments within the year that the substation actually delivers power to the above HV-grid.

The ANDES-model generates these peak load forecasts not only at the HV/MV-substation level, but also for every MV-cable, MV/LV-substation and LV-feeder. This means that also at the lower grid levels detailed forecasts of future peak load and the impact of the energy transition are available.

The resulting forecasts can be taken into consideration within the grid planning process. Therefore they make it possible to design grid expansions suitable for a situation with a certain adaptation of electrical vehicles, solar PV and heat pumps. This will ultimately lead to better grid investment decisions.

E.4 Closing remarks

A bottom-up load forecasting tool like ANDES can provide new insights on the effects of the energy transition. The new approach developed for the ANDES-model is more flexible and allows detailed exploration of potential future developments like electrical vehicles, solar PV and heat pumps. Because the entire grid topology is taken into consideration, the impact of these new techniques can be evaluated at every level within the grid, from the LV-feeder up to the HV/MV-substation. Therefore it provides new understandings of the changes in typical load profiles at the LV- and MV-grid levels that were not under consideration before.

Due to the extensive temporal scope (1 to 40 year ahead) the model can be used for both short term grid planning (where new urban developments and customer prospects cause the dominant growth) as well as for long term strategical grid planning (where the energy transition effects are responsible for the dominant changes). This means that when designing grid expansions and replacements, they can be designed for their whole lifespan of typically 40 years.

Despite a lot of potential for the outcomes of the ANDES-model is foreseen, it is still too early to conclude when this new approach will entirely replace the traditional process of grid planning. More time and experience with the results is needed to perform extensive validation and to quantify its impact.

E.5 Reference

Van de Sande, P., M. Danes, and T. Dekker (2017), ANDES: Grid capacity using a bottom-up profile-based load forecasting approach, CIRED, Glasgow, 12-15 June, Paper 1071.

Appendix F. Approach to estimate network resistive losses

The calculated load duration curve of the substation transformers was used to determine the network resistive losses on these transformers. A mathematical model was used to estimate these losses (see below). The total substation power losses were shown to increase with 80% in the A2050 scenario. Substation transformers account for approximately 20% of the total network losses. The yearly cost of the technical resistive losses is currently € 70 million per year. In A2050 this increases to € 126 million per year. Therefore, in A2050 the additional operational costs due to network resistive losses are estimated at € 55 million per year.

The main assumptions of the above-mentioned calculation include:

- The other network levels have a similar load profile;
- The electricity price will not change;
- The substation voltage will not change significantly;
- The substation transformers and network topology will not change;
- The losses are calculated on an hourly basis.

Mathematical model used to assess network resistive losses

$$I = \frac{P}{U}$$

P: Transformer load (known)
U: Transformer voltage
I: Transformer current

$$E_{\text{yearly}} = \sum_{x=1}^{t} \sum_{y=1}^{n} I_{x,y}^2 \cdot R_{\text{y}}$$

E_{yearly}: Yearly resistive power losses (kWh)
R_{y}: Transformer resistance of transformer y (Ohm)
t: Number of hours considered, in this case 8760
n: Number of transformers considered

$$I = \frac{P}{U} \quad \Rightarrow \quad I^2 = \frac{P^2}{U^2}$$

$$E_{\text{yearly}} = \frac{1}{U^2} \cdot \sum_{x=1}^{t} R_{\text{y}} \sum_{y=1}^{n} I_{x,y}^2$$

$$100\% \cdot E_{2015} = x \cdot E_{2050}$$

Now R and U can be eliminated:

$$x = \frac{100\% \cdot \sum_{n=1}^{i} \sum_{m=1}^{t} P_{n,m,2016}^2}{\sum_{n=1}^{i} \sum_{m=1}^{t} P_{n,m,2050}^2}$$

x: New total power loss (%), solving yields $x = 180\%$
i: number of transformers
P_{2016}: Power load in 2016
P_{2050}: Power load in 2050

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