Scenarios for the Dutch electricity supply system

A REPORT PREPARED FOR THE DUTCH MINISTRY OF ECONOMIC AFFAIRS (MINISTERIE VAN ECONOMISCHE ZAKEN)

September 2015

Scenarios for the Dutch electricity supply system

Contents

Contents

Scenarios for the Dutch electricity supply system

Executive Summary

The Dutch and other European electricity markets are experiencing fundamental changes. The policy initiatives associated with Europe's green energy transition have significantly influenced the outlook of the whole energy system. First and foremost, power generation from intermittent renewable energy sources as wind or solar power (RES-E) has increased rapidly over the last decade. This development creates challenges for the integration of RES-E into the power system and for the costs for building up the RES-E stock, strengthening grids and keeping back-up capacities.

In addition, market-participants in the Netherlands and in other European countries are discussing whether today's market design that relies on the principles of the energy-only market (EOM), i.e. power generation is remunerated through energy-based payments (€/MWh),[1] is able to guarantee security of supply. Or whether capacity remuneration mechanisms (CRM) that offer remuneration based on capacity payments (€/MW) are required. Some EU member states have decided to introduce or have already introduced CRMs (e.g. France or Great Britain) while other member states, as for example Germany or the Netherlands, have not decided on the introduction of such a mechanism.

At the same time, European power markets become increasingly interconnected and, especially in Central-Western Europe (CWE), national policies also affect the markets in neighbouring countries.

In this report, we analyse the long-term effects of recent and future power market developments on the reliability and affordability of the electricity system in the Netherlands. Furthermore, we to what extent the current market model as a so-called EOM is able to ensure an affordable and sufficiently reliable electricity supply. Therefore, we analyse under which conditions the market offers sufficient stimulus measures for investments in generation capacity, flexibility and system facilities.

Dutch electricity market well positioned to cope with future challenges

Based on our quantitative and qualitative analysis, we conclude that the Dutch electricity system is well positioned to cope with increasing shares of intermittent renewable energy sources.

---

1 Today's electricity market is in reality not an "Energy-only-market". It incorporates substantial and important capacity elements such as contracting of reserve power by the grid operator or back-up contracts between power generators, retailers etc. However, the current market framework is nevertheless often called "EOM" in the public domain – we will stick to this terminology in this report.

- **Short-term overcapacities in the conventional power plant park** – As a result of a dip in power demand and increasing subsidised in-feed of renewable energy sources in Europe, the economics of conventional thermal power generation have deteriorated. Wholesale prices for power will remain low at around 40 EUR (real, 2013)/MWh in the short-term. This development has led to final or temporary retirement of thermal power plant capacity in the Netherlands and elsewhere. The consolidation is a result of changing market conditions and is not signalling any market failure. Therefore, currently low wholesale power market prices are no immediate reason for political interventions. In the medium-term, namely after the nuclear phase-out in Germany (2022), we expect that the supply-demand balance in the market tightens and price signals are provided to re-activate mothballed capacities. Consequently, modelled power prices in 2023 rise by ~20% to above 50 EUR (real, 2013)/MWh in the Netherlands.

- **Market able to integrate increasing share of intermittent renewable energy sources** – The share of renewable energy in electricity supply significantly increase in our analysis from around 12% today to around 50% in 2035. The majority of renewable energy will come from intermittent energy sources, i.e. wind and solar power. These intermittent energy sources require a power system that is sufficiently flexible to integrate the in-feed and that provides back-up in periods of low availability of these resources. Based on our judgement, the Dutch electricity system is well positioned to integrate high amounts of RES-E because

  - flexible gas-plants (including CHP), that can ramp up and down with short lead time, represent the majority of the conventional power plant park;

  - internal congestions of the transmission grid is comparably low; and

  - sufficient interconnection capacities to neighbouring countries are available that allow for international efficiency gains.

  Nevertheless, Dutch politics should not rule out new technological options such as new storage technologies, even if our analysis indicates that those technologies are not necessarily required before 2035.

- **Dutch power market well designed to ensure security of supply** – The current market design in the Netherlands is able to minimise the risk to security of supply that is arising from potential market imperfections. For example, the possibility of external effects in power supply is reduced to a minimum as all market participants, including renewable energy sources, bear balancing responsibility and imbalance prices are set with regard to marginal costs of regulating power. Remaining market risks can be borne by investors and do not need any political intervention.[2]

Possible risks for investors arising from changes to the market framework, i.e. from political intervention, should be minimised. For example, no direct or indirect caps on electricity prices should be introduced even in periods when prices get more volatile and spiky. Climate policy in the power sector should be embedded in the EU ETS and unforeseeable *ad hoc* decisions in the national context deviating from the long term plan should be avoided. Furthermore, uncertainty about the future development of the electricity system could be managed by agreeing on a binding long-term framework (e.g. for 2030 and beyond) for renewable support and targets in an early stage (e.g. 5-10 years ahead). This framework should also address potential distortions between individual investment incentives and system inefficiency arising from implicit subsidies for decentral generation.

Security of supply levels appear to be robust

Our sensitivity analysis suggests that, even under changing market conditions, the supply-demand balance in the Netherlands and a high level of security of supply can be maintained.

- **Changing fuel prices affect costs of generation but not SoS** – The achieved level of security of supply does not rely on certain assumptions regarding the development of fuel prices or CO_2-prices. Our analysis shows that altering these assumptions results in a changing power plant dispatch but not necessarily in changing capacity provision.

- **Less renewable in-feed than expected could be compensated by existing capacities and imports** – No threat to security of supply arises from a variation in the growth of renewable energy sources. For example, a growth path below the current political target for 2023 can be compensated by, for example, gas-fired power plants and especially by imports from neighbouring countries.

- **Capacity markets in Europe affect the Dutch power market but do not represent a threat to security of supply if designed effectively** – The level of available generation capacity in the Netherlands is affected by the definition of capacity requirements in neighbouring capacity mechanisms. Security of supply in the Netherlands, however, is not significantly affected as sufficient import capacities are available to transfer electricity to the

2 In addition, the capacity reserve "Vang-net" could be activated in the case of unforeseen capacity shortage and reduces the risk of external effects further.

Netherlands in case available domestic generation capacity is scarce in certain situations. However, it has to be ensured that electricity is traded and exchanged in an effective and efficient way between EU member states.

Costs of the energy system especially driven by fuel prices and RES-E

Costs of the electricity system will increase in the future. Our analysis shows that the increase in renewable energy sources and the associated investments represent the biggest driver of system costs. Additionally, expected higher fuel and CO_2-prices increase the costs of remaining conventional generation in the medium and long term.

- **Costs of increasing renewable energy sources with significant share of system costs** – The costs of increasing the share of renewable energy sources in the electricity system, i.e. the investment costs and the costs to integrate renewables into the power grid, represent a high share in the costs of electricity generation.

- **Increasing costs to final consumers** – Cost to final consumers, i.e. costs for electricity supply and additional support of renewable energy sources and required grid-enforcement to integrate RES-E will increase by 25% from 2015 to 2035.

  Variable costs of generation have the highest leverage on consumer bills, e.g. higher fuel prices (~40%) increase consumer cost by 6.8% (from 2015-2035). Furthermore, significant cost savings are possible if the envisaged growth of renewable energy sources (especially wind-offshore) is postponed to later years when higher learning effects are realised (-6% from 2015-2035). However, this might mean that the Netherlands has to invest more in other sectors such as the transport sector or to purchase green power abroad in order to meet the current (16% RES share in primary energy consumption in 2023) or any future renewable targets. These costs are not included in our calculations.

- **Significant cost savings for RES-E required for achieving grid-parity** – Intermittent renewable energy sources, i.e. wind-onshore/offshore and solar PV are unlikely to cover their costs based on market revenues until 2035. Depending on the assumed cost development and the technology, there remains a financing gap of 5-22 EUR (real, 2013)/MWh in 2035 (Base Case). Therefore, additional cost savings or higher power prices are required for RES-E to achieve grid-parity.

Flexibility as an important element in the future electricity system

Due to the increasing share of intermittent RES-, the flexibility of the electricity system is an important element of the energy transition. However, as of today, there is substantial flexibility available in the Dutch power market due to flexible gas-fired power plant capacity, flexibility in CHP plants and very substantial cross-border interconnections. Therefore, no immediate action is required to increase flexibility in the short and medium term in the Dutch power system.

In the long term, additional flexibility options such as demand-side-response (DSR) can be further developed. Due to the envisaged Smart Meter roll-out programme in the Netherlands, there will be substantial potential for developing DSR. Clear mechanisms and rules are required to coordinate the use of these decentralised flexibility options for alleviating grid constraints (in particular in the distribution grid) on the one hand side, and for balancing the power system (e.g. to balance fluctuating wind and PV on the system level) on the other hand side. Furthermore, taxes and levies could be designed in a way that electricity is especially used in periods with substantial power generation from renewable sources (high wind, high sun periods).

New power storage technologies such as Compressed-Air-Energy-Storage (CAES) can be further developed. Our modelling does not indicate a significant need to deploy these rather costly technologies on a large scale in the analysed time frame (until 2035). However, developing these technologies in the context of Research and Development (R&D) can offer further flexibility options in the more distant future when even higher shares of power supply may be generated by RES-E.

Integration of internal energy market and harmonisation of national frameworks

Over the past decades, power markets in Europe have become highly interconnected and the need to coordinate national policies has significantly increased in order to reduce market distortions between countries. The Netherlands are characterised as a relatively small country with high interconnection capacities to other member states in Central Western Europe. In order to reduce the risk of market distortions arising from national policies elsewhere, the Netherlands should maintain their engagement in European and regional discussion and coordination groups like the Pentalateral Energy Forum[3] and on the EU-level. Increased ambitions towards a harmonised energy policy framework on European level, especially regarding the support of renewable energy sources and the introduction of capacity remuneration mechanisms, could be addressed e.g. in the course of the Dutch EU Presidency in 2016.

3 The Pentalateral Energy Forum consists of Austria, Belgium, France, Germany, Luxembourg, the Netherlands and Switzerland aims at increasing market coupling and security of supply in Central Western Europe, .e.g. through regular regional generation adequacy assessments.

- **Increasing integration of CWE region** – With increasing interconnection capacity especially to Germany, market integration will increase in the medium-term and prices will almost perfectly integrate in the period 2023-2030.[4]

- **International spill-over effects from CRM possible** – Capacity built under CRMs in neighbouring countries may have an impact on the level of plant capacity in the Netherlands. If, for example, capacity requirements in the French and Belgian CRM do not take the contribution of international interconnections into account, overcapacities in the market region may arise with a negative effect on power generators in the Netherlands. These additional capacities could lead to lower revenues of domestic power generators and therefore to less generation capacity within the Netherlands.

  Therefore, the Netherlands should aim for an adequate definition of capacity requirements in foreign CRMs. Furthermore, cross-border participation in foreign CRMs should be possible, either via participation of generators in neighbouring countries or by participation of interconnectors.

- **Effective internalisation of carbon externality required** – Our analysis shows that higher fuel costs or CO_2-prices increase profitability of renewables and reduce the costs of financing the RES-E growth. Therefore, the Netherlands should aim at strengthening the EU ETS as the central instrument of climate change in Europe.

[4] Our modelling shows a price difference between DE-NL of less than 0.01 €/MWh in more than 90% of the hours.

1 Introduction

The electricity systems in the Netherlands and across Europe are in a period of transition: Due to the sustainability policy in the EU and its member states, the share of intermittent renewable energy sources such as wind and solar is steadily increasing. At the same time, electricity demand and CO_2 prices across Europe are weaker than expected some years ago. Furthermore, physical cross-border interconnection of electricity systems and the integration of power markets are strengthening, leading to stronger impacts of energy policies of neighbouring countries on domestic markets in Europe.

Given these developments, the Ministry of Economic Affairs (MinEZ) wants to understand what long-term effects recent developments may have on the reliability and affordability of the electricity system in the Netherlands. In this context, the ministry commissioned this study to Frontier Economics to analyse the future prospects of the Dutch electricity system regarding affordability and reliability and the potential needs to revise the current market design in the Netherlands to achieve a reliable, affordable and environmental friendly electricity supply system.

In the following, we describe in more detail

- The background and scope of the study (**section 1.1**);
- The approach of the analyses (**section 1.2**); and
- The structure of the report (**section 1.3**).

1.1 Background and scope of the project

The Dutch and European electricity markets are experiencing fundamental changes:

- **Politically driven energy transition**: Europe's green energy transition has implications for the whole energy system: The share of intermittent energy sources such as solar and wind power generation are rapidly increasingly in the Netherlands as well as in neighbouring countries. Some countries such as Germany and Switzerland plan to step out of nuclear power generation. At the same time, new technologies such as smart grids, demand response and new storage technologies emerge.

- **Developments on fuel and CO_2 markets**: Changes in the markets for gas (European market) and coal (global market) have led to relatively high natural gas prices compared to coal in Europe. At the same time, CO_2 prices turned out to be lower than expected in recent years. This, in combination with the massive extension of power generation from renewable sources, has led very low utilisation of gas-fired power plants, and to relatively weak profitability for both, gas and coal fired power stations. Due to these effects, major players in the European electricity market face significant commercial losses in the power generation business.

- **European market and system integration:** The Western European electricity market is becoming increasingly integrated: National policies and regulations have an increasing impact on neighbouring countries and the electricity market in the regions.

At the same time, market participants in the Netherklands as well as in other European countries discuss whether so-called capacity reliability or remuneration mechanisms (CRMs) should be implemented to guarantee security of supply in the electricity sector. The electricity market design in the Netherlands and most of its neighbouring countries is so far based on the principle of an "energy-only market" (EOM). In an EOM, investments for electricity production are primarily financed through energy-based prices (in €/MWh), which incorporate an implicit payment for available capacity.[5] In this context, various market stakeholders wonder whether a market design based on the EOM principle generates sufficient incentives to ensure mid- and long-term security of electricity supply. Some stakeholders have suggested the introduction of a CRM. Through a policial intervention, a CRM would induce explicit capacity payments (e.g. in €/MW per year) that would incentivise additional capacity and thus security of supply. Some of the Dutch's neighbouring countries, for instance Belgium, France or Great Britain, are currently introducing CRMs.

Given this background, the Ministry of Economic Affairs has commissioned the study to analyse,

- what impact these developments have on the reliability and affordability of the electricity system in the long term;
- if and under what conditions the current market model for the electricity market is sufficiently able to ensure an affordable and reliable energy supply; and
- the conditions for which the current market model offers sufficient stimulus measures for economic operators to invest in production capacity, flexibility and system facilities.

5 Today's electricity market is in reality not an "Energy-only-market". It incorporates substantial and important capacity elements such as contracting of reserve power by the grid operator or back-up contracts between power generators, retailers etc. However, the current market framework is nevertheless often called "EOM" in the public domain – we will stick to this terminology in this report.

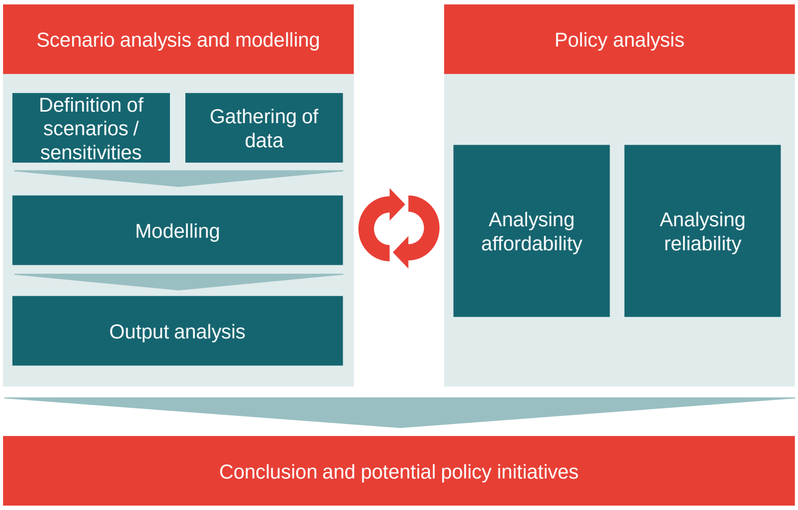
1.2 Approach

Our analysis is based on three main elements:

- **Quantitative power market analysis** – We use our European power market model to analyse the future development of the Dutch electricity sector. Based on one central scenario, which represents the current political framework in the Netherlands and includes the most likely development of the market from our point of view, we analyse the effect of different market factors on (among other things)
  - Investment and divestment decisions in the Netherlands;
  - Development of power generation and power exchange with neighbouring countries; and
  - Development of power prices;
- **Policy analysis** – Based on the results obtained in the power market modelling, we conduct additional quantitative and qualitative analysis regarding the
  - affordability of the system, i.e. the development of total system cost; the economics of intermittent or variable renewable energy sources; and the costs of the electricity system to final consumers; and
  - Reliability of the system, i.e. we analyse the performance of the current (EOM) market design regarding security of supply and address possible market imperfections which may distort the market; in this context, we also discuss potential measures to enhance the reliability of the system.
- **Conclusions and policy initiatives** – Based on the outcome of the analysis above, we assess which additional policy initiatives could be taken in order to enhance the affordability and reliability of the electricity system.

Figure 1 illustrates our approach.

Figure 1. Approach



Source: Frontier

1.3 Structure of the report

The report is structured as follows:

- **Chapter 1 "Introduction"** – We describe the background of the study and the approach of the analysis.
- **Chapter 2 "The current power market in the Netherlands**" – As the starting point of our analyses, we describe the current status of the power market in the Netherlands regarding
  - The historic development of power supply and demand;
  - The development of renewable energy sources in electricity supply;
  - The electricity grid and interconnection capacities; and
  - The current market design of the electricity system.
- **Chapter 3 "Simulation of the future power market"** – We explain the results of our quantitative power market analysis in the following steps:
  - Description of the European power market model;
  - Assumptions and results of the Base Case scenario; and
  - Definition and analysis of relevant sensitivities.

- **Chapter 4 "Affordability of the electricity system"** – We summarise the results of the affordability analysis regarding
  - The costs of the electricity system;
  - The costs to final consumers; and
  - The economics of intermittent renewable electricity supply.
- **Chapter 5 "Reliability of the electricity system"** – We analyse the reliability of the electricity system based on
  - The performance of an ideal EOM;
  - An assessment of the potential market imperfections; and
  - An overall assessment of the future EOM design.
- **Chapter 6 "Policy implications"** – We derive implication regarding the policy design related to
  - The market design of the electricity system; and
  - Renewable energies and other technologies.

2 The current power market in the Netherlands

This section aims at setting the framework for the power market analysis in the chapters to follow. It provides a brief overview of the key characteristics of the Dutch power market. In the following, we describe

- the current status of power generation and supply in the Netherlands based on historical data (**section 2.1**);
- the development of renewable energy sources in electricity supply (**section 2.2**);
- the main characteristics of the transmission and distribution networks including interconnection capacity to neighbouring countries (**section 2.3**); and
- the key market design elements of the Dutch power market (**section 2.4**).

2.1 Power supply and demand

In this section, we provide an overview of the Dutch power sector, focussing on

- the development of power demand (**section 2.1.1**); and
- the development of power supply (**section 2.1.2**);

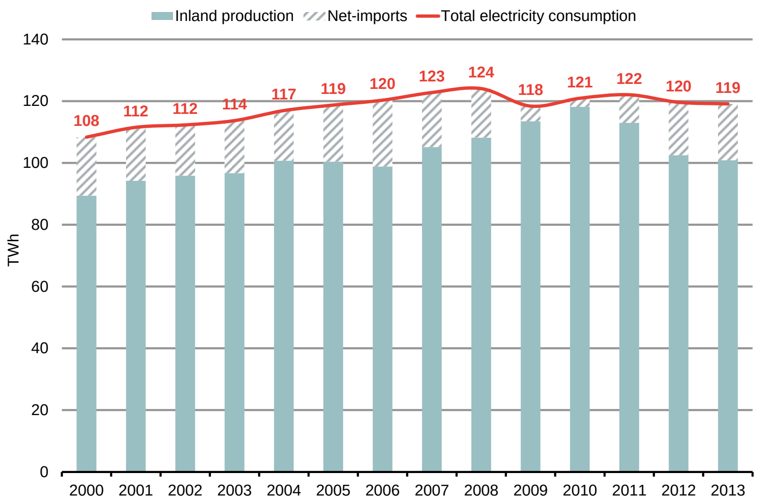
2.1.1 Development of power demand in the Netherlands

Electricity consumption in the Netherlands increased from 2000 until 2008 by an average growth rate of 1.7 % (year-on-year). Historically, electricity consumption has been closely linked to the development of gross domestic product (GDP) of the Netherlands, which has increased on average by 2% (year-on-year) at the same time.

The drop in industrial production and a corresponding significant decrease in GDP (by 3.3%) following the financial and economic crises have reduced electricity consumption by 4.6% from 2008 to 2009. After 2009, electricity consumption and GDP have recovered slightly but experienced negative growth rates in the years 2012 and 2013. Between 2009 and 2013, electricity demand remains around ca. 120 TWh per year.

Figure 2 shows the development of electricity consumption from 2000 to 2013.

Figure 2. Development of gross-electricity consumption, inland production and net-imports



Source: Frontier based on CBS statline

2.1.2 Development of power supply

The Dutch power plant park is characterised by a high share of fossil fuel based generation units. Due to the high availability of natural gas resources in the northern part of the Netherlands and under the North-Sea, the majority of Dutch power plants are gas-fired.[6] Hard coal represents that second largest energy source for electricity generation, driven by the geographical proximity to major European coal import ports (Amsterdam-Rotterdam-Antwerp, ARA). In addition, a significant share of power is produced in combined-heat and power plants (CHP). Due to this supply mix dominated by fossil fuels with high variable costs, the Netherlands have in the past acted as net-importer of power, i.e. imported less expensive power from abroad than exported to neighbouring countries:

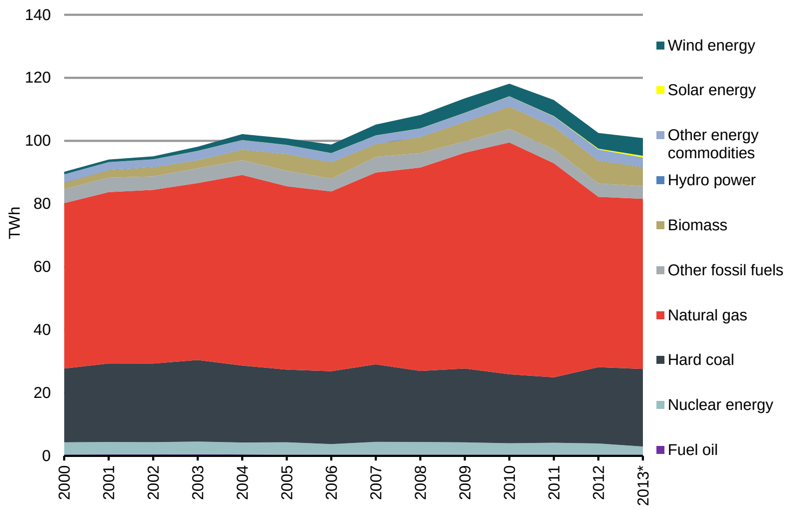
- **High share of fossil fuel based generation –** Gas-fired power generation has accounted for more than 50% of total power generation in the Netherlands in the past decade - with some years reaching a share of more than 60%. Approximately 25% of total inland electricity supply is produced in hard coal power plants. These numbers include power generation from combined-heat and power (CHP) plants (see below). Nuclear energy accounts for 4% in power generation.

6 The largest share of natural gas production is consumed within the Netherlands and in the power sector, less than 40% of production is exported to other European countries. See IEA (2014a).

Increasing levels of renewable energy sources in electricity generation (RES-E) – The Netherlands exhibit a comparably low share of renewable energy[7] in electricity generation. However, the last decade has seen a constant increase of RES-E generation, mainly driven by an increase of power generation from wind energy and biomass. The RES-E share reached to 10.6% in 2012.

Figure 3 shows the development of inland electricity supply from 2000 until 2013.

Figure 3. Electricity generation by energy commodity



Source: Frontier based on CBS statline
* provisional figure

- **Important role of combined-heat and power generation –** Combined heat and power plants represent around 40% of installed capacity and account for almost 50% in inland electricity generation. The majority of CHP plants are gas-fired, only a small share is fired with hard coal or biomass.[8] The CHP installations can be differentiated into
  - Large central plants, mainly for district heating and industrial heat production; and
  - Small decentral CHP plants, mainly for agriculture, horticulture and smaller industry facilities.

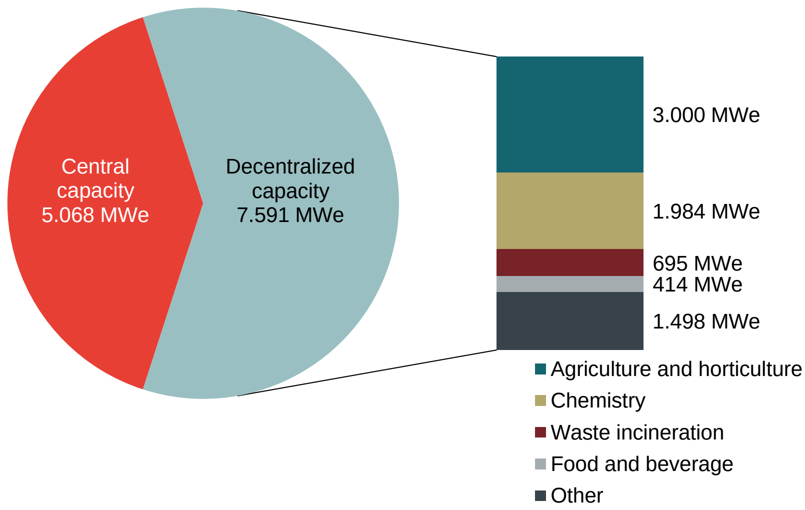
---

7 Electricity generation based on wind energy, solar PV, hydro power and biomass.

8 Around 30-50% of total biomass generation arises from co-firing in coal plants.

The majority of CHP plants (around 60%) can be characterised as decentral power generation capacity (see **Figure 4**).

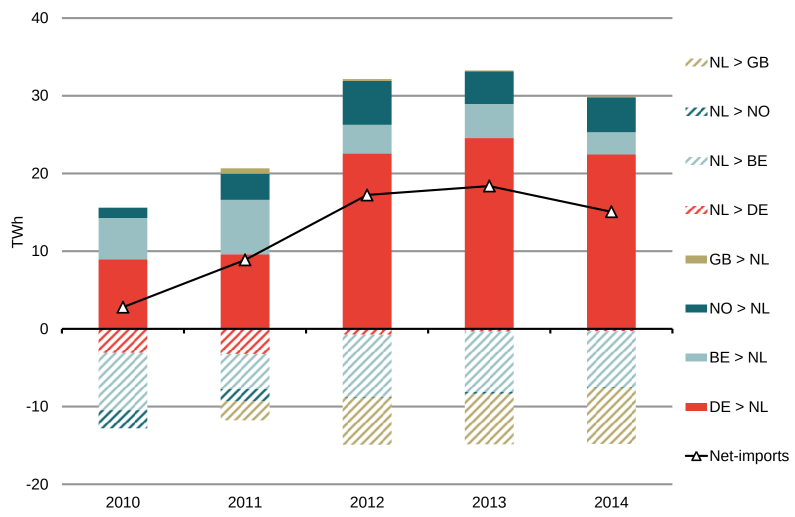
Figure 4. Decomposition of CHP capacities (2013)



Source: Frontier based on CBS statline

- **Netherlands as a historic net-importer of electricity** – As described above, the Dutch power system is characterised by a high share of fossil fuels in power generation which faced relatively high variable fuel costs during the past decade (especially natural gas). Consequently, power prices in the Netherlands have been higher than in neighbouring countries which rely on power generation technologies with lower variable costs (e.g. Germany with large shares of renewables and low-cost lignite generation). Therefore, the Netherlands have recently shown a significant share of electricity imports, mainly from Germany (see **Figure 5**).

Figure 5. Electricity imports and exports



Source: Frontier based on ENTSO-E

2.2 Renewable energy sources in electricity supply

In this section, we provide additional information on the development of renewable energy in the Dutch electricity system. The section is structured as follows:

- Political framework and renewable energy policies (**section 2.2.1**);
- Historic development of RES-E (**section 2.2.2**); and
- The current renewable support scheme (**section 2.2.3**).

2.2.1 Political framework for renewable energy sources

The Netherlands have set the ambitious target to reduce their emission from CO_2 by 80-95% in 2050 compared to 1990 levels. The Climate Letter 2050 formulated by the "Rutte" government in 2011 has identified cornerstones of the transition towards a low-carbon economy:

- CO2- free electricity supply;
- Sustainable use of biomass;
- Energy savings; and
- Introduction of CCS technologies.

The consecutive "Rutte-Asscher"-government has set out the target to achieve a share of renewable energy in the economy of 16% in 2020.[9] This target has been revised in the *Energieakkoord voor duurzame groei* (hereafter Energy Agreement) which was adopted in September 2013[10]. The Energy Agreement sets out the ultimate goal of achieving a renewable share of gross energy consumption of 14% in 2020 and 16% in 2023, compared to 4.4% in 2012. There are no explicit targets regarding the share of renewable energy in electricity supply but the Energy Agreement includes several initiatives that affect the supply of electricity:

- **Wind-offshore:** The Agreement foresees an increase of wind-offshore installation to 4450 MW in 2023;
- **Wind-onshore:** The Agreement foresees an increase of wind-offshore installation to 6000 MW in 2023;
- **Co-firing of biomass:** The Agreement sets an upper limit for biomass co-firing in large coal combustion plants of 25 PJ; and
- **Closure of coal-fired generation units:** The capacity of coal-fired generation units built in the 1980s shall be reduced.[11]

The following sections describe the historic development of and the current support scheme for RES-E.

2.2.2 Development of renewable energy sources in electricity supply

As shown in **Figure 3**, the electricity generation from renewable energy sources (RES-E) has increased significantly since 2000. The largest sources of RES-E are wind-onshore and biomass.

- **Increasing share of RES-E** – The role of renewable energy sources in the Dutch electricity supply has increased significantly in the past. In 2000, only 3% of total electricity consumption has been served by RES-E. The share has more the tripled to 10.6% in 2012.

- **Highest growth rates for wind energy** – Wind-onshore and offshore represent the technologies with the highest growth of electricity generation. The generation from wind-onshore increased from below 1 TWh in 2000 to more than 4 TWh in 2012. This trend is expected to continue in the next years. Wind-offshore represents a less mature technology, shows lower

9 Coalition agreement cabinet Rutte-Asscher: "Building Bridges" (2012).

10 SER (2013).

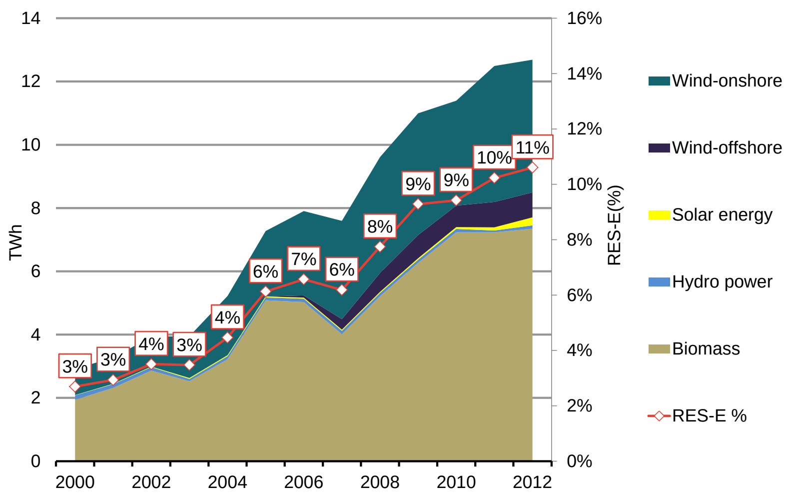
11 Three coal-fired generation units will close at the beginning of 2016, two additional units in mid-2017.

growth rates but is expected to contribute significantly to electricity supply in the future (see **section 3.2.4**).

- **Biomass largest source of renewable energy** – Biofuels such as biomass, biogas and waste represented the largest source of renewable electricity supply in the past. The electricity generation from biofuels has more than tripled from 2000 until 2012, with the highest increase from combined-heat and power generation. Recently, power generation from biomass reached almost 8 TWh/a.

- **Moderate increase in solar photovoltaic (PV) generation** – Electricity generation from solar photovoltaic installations has shown only a moderate increase, especially at the beginning of this decade. From 2010 to 2012, the generation has grown from 60 GWh to 250 GWh. However, solar PV power generation is in absolute terms very minor as of today.

Figure 6. Development of RES-E



Source: Frontier based on CBS statline

2.2.3 Current renewable support scheme

In the Netherlands, the production of renewable energy is mainly supported via the SDE+ (Stimulering Duurzame Energieproductie) scheme[12]. Under the SDE+, renewable energy projects receive a feed-in premium for each renewable kWh produced. The feed-in premium payment is comprised of the gap between

[12] As additional instrument to promote RES-E deployment, reduced interest rates for investments into renewable energies (except for biomass and biogas plants) are available.

the market price of the energy produced and the cost price of the technology. If the market price increases, the premium declines, and vice versa. Ultimately, no subsidy is paid when the market price rise above the cost price and the premium is capped when market prices fall below a threshold (2/3 of the long term energy price).

Producers of renewable energy need to apply for support. The SDE + has a yearly overall budget cap and plant operators applying for support are served on a "first come – first serve" basis. Applications can be made during six stages per period.[13] With each stage the premium, which plant operators receive, increases. In addition, for wind-onshore, the number of full-load hours for which the support is granted, is lower in stages 3-6 than in stages 1 and 2.

The motivation behind the step-wise application process is to foster the deployment of renewable energies with lowest costs while absorbing their rents. Due to the overall cap of support payments, plant operators have an incentive to apply for support during early stages (if possible) in order to be sure to be granted support. In addition, the overall cap for support payments helps to regulate the financial burden tax payer's bear[14].

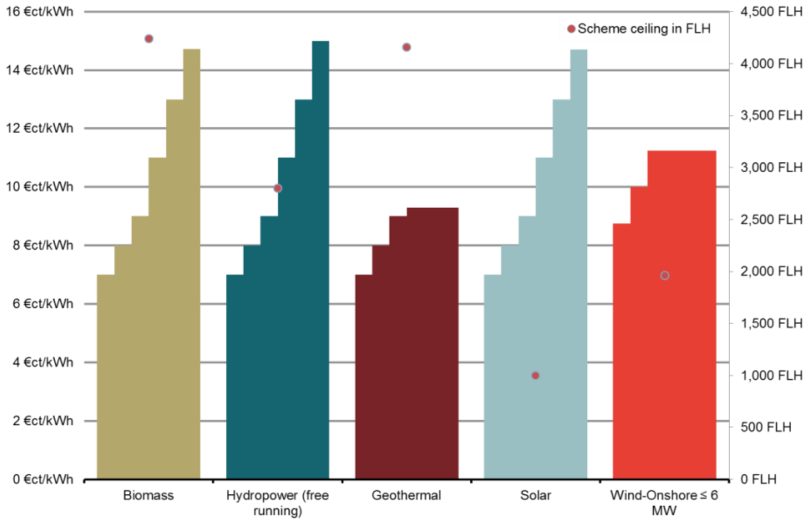
If plant operators are successful with their application, they receive the premium for 15 years (except for operators of biomass, biogas and sewage gas plants who only receive support for 12 years). The premiums are paid from the date onwards, when the plants start to operate. Operators are obliged to start operation within 4 years after the support was granted (within 5 years for wind offshore).

Figure 7 exemplarily shows the maximum basic premium for 5 technologies within the 6 application stages in 2014. In addition, the fixed amount of full load hours is shown. For wind-onshore, the depicted full load hours of 1960 corresponds to stages 3 to 6 (in stages 1-2, support is granted for 2800 full load hours).

13 For example, in 2014, Stage 1 took place from April 1st to May 11th and Stage 6 from November 3rd to December 18th.

14 Costs are covered by the State budget and are passed on to final consumers as levy on electricity consumption. In 2014, the cap was 3.5 billion €.

Figure 7. Market premiums and maximum full load hours that are supported within the 6 stages of the SDE + (in 2014)



Source: Frontier based on res-legal.eu

2.3 Grids and cross-border connection

This section provides an overview of the characteristics of the electricity transmission and distribution grid and the interconnection that exists between the electricity grid of the Netherlands and that of surrounding countries. Following the introduction of the Wet Onafhankelijk Netbeheer (Law Independent System Operations) in 2011 different entities are in charge of generating electricity, operating the transmission and distribution grids, and running the energy retail activities. This section considers only the transmission and distribution systems and their operators.

The section outlines the current status of the system. Investments are considered in more detail in **section 4.1.**

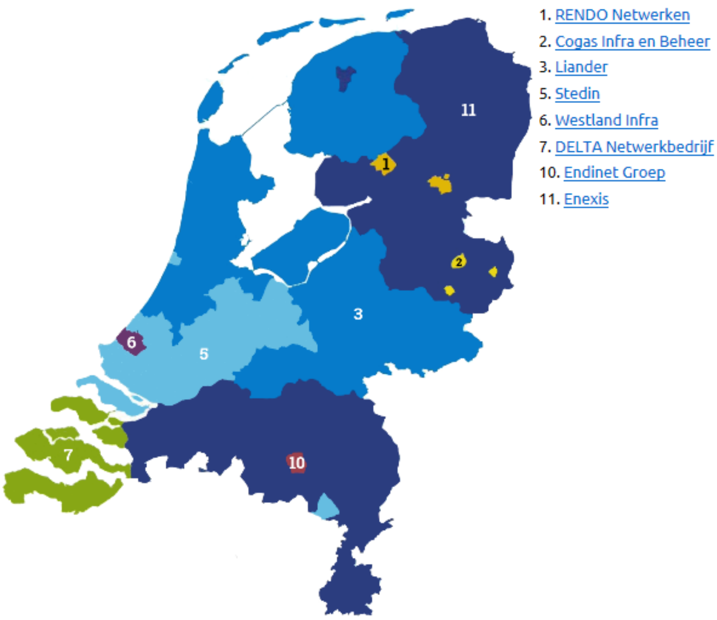
2.3.1 Distribution grid

In total, the Dutch distribution grid is over 325,000 kilometres long, and is almost completely built by underground cables. The Dutch distribution grid performs well on reliability and is improving further. Compared to averages over the period between 2008 and 2012, in 2013 there were 10% less interruptions in the high voltage net (110kV and 150kV) and 4% less interruptions in the middle voltage net (10kV). The average interruption per consumer has decreased by 12% to 23.4 minutes/year[15].

There are currently eight distribution system operators (DSOs) in the Netherlands. All DSOs operate in separate geographical areas (see **Figure 8**). The biggest DSO in the Netherlands is Liander, which operates the distribution system for the provinces of North Holland, Flevoland, Friesland and Gelderland. Liander is the distribution system operator for approximately 3 million households.

The geographical spread of electricity and gas distribution networks does not coincide perfectly, so some households do have different electricity and gas distribution system operators.

Figure 8. Location of distribution system operators in the Netherlands



Source: www.energieleveranciers.nl, retrieved February 2015

2.3.2 Transmission grid

The transmission grid in the Netherlands is operated by TenneT TSO. The company also operates a substantial part of the transmission grid in Germany. TenneT manages networks with a voltage of 110 kV and above. The grid is shown in **Figure 9**.

[15] Source: Netbeheer Nederland, "Betrouwbaarheid van elektriciteitsnetten in Nederland: Resultaten 2013",

Figure 9. Electricity transmission grid in the Netherlands

Source: TenneT, 2014

The Dutch transmission grid is strongly connected to the grids of the surrounding countries. This allows for cross-border trading in electricity and more effective allocation of international supply and demand. Currently, the Netherlands is a net importer of electricity, and mainly imports "low cost" electricity from Germany (see **section 2.1.2**).

An overview of the cross-border connections involving the Netherlands can be found in **section 3.2.6**. Apart from interconnection with Belgium and Germany, TenneT has also created interconnections with the transmission grids of Norway and Great Britain.

- The **NorNED cable** came into operation in May 2008 and is jointly owned by TenneT and the Norwegian transmission system operator Statnett. This connection allows Dutch market parties to import Norwegian renewable hydropower. The connection can also be used to export electricity from the Netherlands, so the connection has improved power trading and security of supply both in the Netherlands and in Norway.

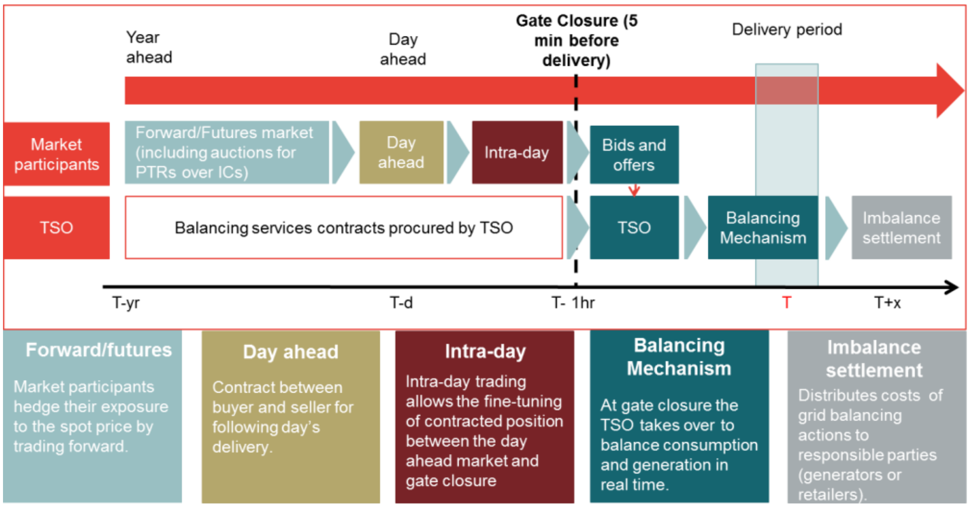
- The **BritNED cable** came into operation in 2011 and is jointly owned by the British transmission system operator National Grid and a subsidiary of TenneT. The cable runs from the Isle of Grain in the UK to the Maasvlakte in the Netherlands.

The future development of interconnection capacity is included in **section 3.2.6**

2.4 The current market design

In the Netherlands, electricity can be traded on power exchanges, via bilateral contracts or via brokers. Electricity trade takes place in several markets (shown in **Figure 10**) that can be differentiated by the time, the trade takes place.

Figure 10. Electricity markets in the Netherlands



Source: Frontier economics.

- **Forward market** – On Forward markets, obligations to physically deliver or buy electricity (physical forward) or obligations for future payments (financial future) are traded up to a few years ahead of actual delivery. These trades are legally binding and do not depend on the availability of, for instance, a power plant or a demand flexibility measure at the time of delivery.

  Many products are standardized – examples are base load products (delivery in all hours of the agreed period) and peak load products (delivery from 8 a.m. to 8 p.m. on all week-days during the agreed period).

  In addition, options that give the right to buy electricity for a pre-defined price (Call-Option) or to deliver electricity at a fixed price (Put-Option) are traded in forward markets. The seller of an option receives a premium for offering the buyer flexibility. Standardised options are traded on power exchanges. Other, more customised options are traded on a bilateral basis, e.g., options that are used to hedge against the risk of a power plant outage or an agreement between a supplier and end-consumers for a potential restricted delivery (e.g. partial shut-down).

- **Day-ahead market** – On day-ahead markets, buyers and suppliers of electricity adapt their positions; buyers adapt their procurement portfolio given more accurate load forecasts and producers optimize their delivery obligations. Depending on their variable costs of electricity production and the market price in each hour, they optimize between buying or producing the electricity themselves (Make-or-buy-decision). For the Netherlands, the Day-ahead market is organized by the power exchange APX. Important market design elements are:
    - Bids for hourly contracts or block contracts can be submitted until 12:00 a.m. on the day before delivery.
    - Based on these bids, market clearing prices and quantities are calculated. Technical price limits are – 500 €/MWh and +3000 €/MWh.
    - The Dutch day-ahead market is coupled with markets in northern, western and southern Europe ("NWE-SWE market coupling"). Therefore, cross-border trade is also taken into account within the efficient determination of the day-ahead market price in the Netherlands.

- **Intra-Day market** – Final adjustment between the amount of electricity procured and effective demand or between the amount of electricity generation already sold and effective electricity generation takes place via continuous trade on the intra-day market.

  At the APX, hourly products and block orders can be traded up to 5 minutes ahead of delivery time. OTC trades, however, can even be nominated ex post. The Dutch intraday market is coupled with Belgium and the Nordic markets. Technical price limits are –100,000 and +100,000 €/MWh.

- **Balancing markets** – Supply and demand has to be balanced at all times. However, imbalances can occur, for instance because of unplanned power plant outages or forecast errors of demand, wind or solar in-feed. To cope with such imbalances at real-time, TenneT TSO uses regulating power.

  All suppliers or consumers connected to the Dutch electricity network have to have their electricity exchange with the grid covered by Balance-Responsible-Parties (BRP), that have to submit so-called E-Programmes to the TSO TenneT the day before delivery. These E-Programmes include information about how much electricity BRPs either plan to feed into the grid or to take out of the grid within 15-minutes intervals on the next day. Small consumers, such as households, do not bear programme responsibility themselves. Suppliers selling electricity to small end-consumers are responsible for organizing balance responsibility for them. Larger consumers and producers are obliged to either become a BRP or find a BRP to carry balance responsibility for their grid connection on their behalf. This is a commercial arrangement. Also renewable energies, in contrast, directly bear programme responsibility in the Netherlands – unlike in many other European countries. However, programme responsibility can also be outsourced to other BRPs that are recognised by the TSO and make nominations on behalf of market parties that originally bear programme responsibility.

If parties deviate from their E-Programme (i.e., if they feed-in or consume more or less electricity than planned), balancing energy has to be used to re-establish a balanced supply and demand in the system to the extent the deviations do not net out. Costs for balancing energy are (partly) financed via imbalance payments[16]; the BRPs, responsible for the imbalance (because their in-feed or take-off does not correspond to their plans submitted via the E-Programmes), have to pay imbalance payments. Thereby, BRPs have an incentive to stick to their plans (e.g., by adjusting their positions on the intraday market if they realize that their actual feed-in or take-off would deviate from their plans).

Depending on technical characteristics, different reserve products can be distinguished:

- **Primary reserve:** Primary reserve is used automatically to stabilize frequency disruptions within 30 seconds. For example, if thermal power plants supply primary control energy, steam injection to the turbine automatically reacts to grid frequency.

  The Dutch TSO TenneT procures a part of the Dutch requirement for primary control reserve in a joint (weekly) auction with the German TSOs. In 2015, 67 MW will be procured in the Dutch-German auction while the remaining 29 MW that are required will be procured via a separate Dutch auction.[17] Suppliers of primary control reserve receive a capacity price only.

- **Secondary reserve:** If the system balance in the Netherlands tends to one direction (over- or under balanced), TenneT will call energy bid by suppliers of secondary reserve. Secondary reserve may be procured from market participants that can increase supply (or reduce demand) as well as from providers than can decrease supply (or increase demand).

16 The difference between costs for purchasing regulating power (including contracting reserve capacity) by the TSO on the one hand side and imbalance payments by the PRPs is born by electricity consumers via the transmission tariff. This balance can be either positive or negative.

17 www.regelleistung.net

- **Tertiary reserve:** If after 15 minutes, grid frequency has not been re-established, tertiary reserve or minute reserve replaces secondary reserve.

Tertiary and secondary reserve is procured by TenneT within the Dutch regulating/reserve power system. TenneT contracts producers or consumers via annual tenders that then are obliged to bid into the daily auctions for regulating power (non-contracted capacity can still choose to bid into the daily auctions but does not receive a capacity price). Bids are submitted for periods of 15 minutes. The capacity price is a pay-as-bid price while energy prices resulting from the daily auctions (for 15 minute periods) are uniform marginal prices that differ by direction of the balancing measures (upward or downward balancing). Furthermore, large producers and consumers (> 60 MW) are obligated to bid available capacity into the reserve power system, while smaller market participant can choose whether they want to participate.

- **Imbalance settlement** – BRPs that have an imbalanced portfolio will be settled against imbalance prices. If TenneT activates both, negative and positive control reserves within a 15-minutes period, two imbalance prices are set; one for upward and one for downward regulation. The two prices are set equal to the marginal prices of the balancing actions. If TenneT only takes balancing actions into one direction (only up- or down regulation) there is a single price equal to the combined marginal price of all balancing energy activated. In addition, an incentive component is applied that depends on the system performance (and adjusted on a weekly basis). In practice this component is usually zero.

  A specific characteristic of the Dutch balance system is that TenneT publishes the prices of activated balancing energy bids and system imbalance positions close to real time and thereby promotes self-balancing (i.e., BRPs get an incentive to support the TSO in correcting imbalances - "passive contribution"[18]). Imbalance prices are limited to 100,000 €/MWh.

18 "Imbalance Management TenneT Analysis report"

3 Simulation of the future power market

In this section, we describe the results of our model-based analysis of the Dutch power market. The section is structured as follows:

- Description of the power market model (**section 3.1**);
- Assumptions for the base case scenario (**section 3.2**);
- Description and analysis of resulting base case power market trends (**section 3.3**); and
- Definition and analysis of the sensitivities (**section 3.4**).

3.1 The power market model

This section includes a description of the European power market model used in this study. Our combined investment and dispatch model of the European power market is based on a linear optimisation problem[19]. The model optimises the hourly dispatch of the power plants as well as the development of installed capacity based on representative hours and selected photo-years. It is formulated in GAMS, and draws on extensive Excel databases for inputs and outputs. The model has the following characteristics:

- **Objective function –** The objective function is to minimize total costs[20] of the electricity supply in Europe. The model minimizes total costs subject to the following constraints:
  - Energy supply and consumption must be balanced in every hour in every regions;
  - Power exchange between modelled regions is limited by interconnection capacity;
  - Technical and economic constraints for power plants, storages, Demand-Side Response (DSR) as well as renewable energy sources.
- **Investment options** – In order to meet future demand at the least cost, the model can optimises the power plant park in the so-called "core-regions"[21] of our model through either

19 The optimisation problem is solved with the commercial Solver CPLEX.

20 Total costs are minimized as net present value (NPV) today. This includes a discounting of future costs, i.e. comparable to an investment appraisal where short-term profits and costs are treated with higher time preference. We use an interest rate of 5% for the discounting of future costs and profits as well as for the calculation of investment costs of different power plants.

- Investing in new capacities subject to technical and economic parameters and availability different technological options;
- Closing existing power plants in the case of overcapacity; or
- Mothballing a plant and reactivating it at a later point in time in order to save fixed operation and maintenance costs.

- **Temporal resolution** – The model is an integrated investment- and dispatch model. Therefore, the time frame for optimisation follows the technical lifetime of power plants. The time horizon for our analysis is from 2015 until 2035 with an hourly resolution of 4032 representative hours per photo-year.[22]

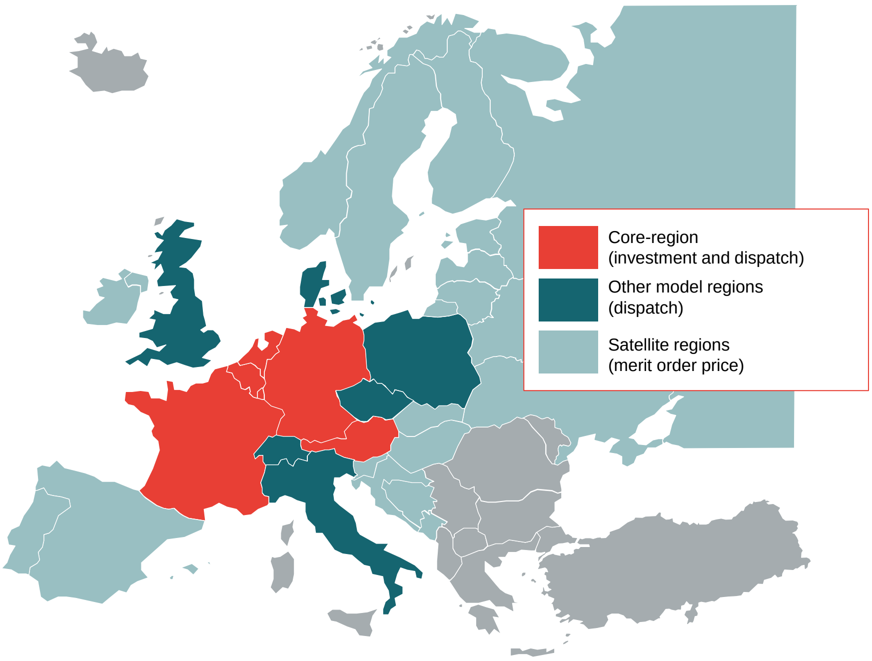
- **Geographical scope –** Our model focusses on Central-Western Europe as core-regions. Other neighbouring countries are included as non-core regions or satellite regions. This differentiation allows to model the power plant park of the core-region on a very detailed (unit-based) basis, but power exchange with other regions that are modelled with lower granularity and level of detail are at the same time included:
  - **Core-regions:** The Netherlands, Belgium, Germany, Austria and France. The power plant park is modelled on a very detailed (unit-based) level, the dispatch of power plants and DSR as well as investment or divestment decisions are taken endogenously (countries coloured in red, **Figure 11**).
  - **Other model regions:** Great Britain, Denmark, Poland, Czech Republic, Switzerland, Italy. The power plant park is modelled as aggregated blocks. Capacity is set exogenously, i.e. investment and divestment decisions are not optimised (countries coloured in dark blue, **Figure 11**).
  - **Satellite regions:** Other adjacent regions - for example South-Eastern Europe, the Noordpool region and Spain - are modelled as satellite regions. Power can be traded with those regions based on an exogenous price (countries coloured in light blue, **Figure 11**).

---

21 The core-regions of our model are the Netherlands, Belgium, Germany, Austria and France.

22 Analysed photo-years: 2015, 2020, 2023, 2030, 2035

Figure 11. Geographical scope of the power market model



Source: Frontier

Security of Supply and Loss-of-load

The hourly energy-balance defines that demand has to be in every hour and in every region. Through system-cost-minimisation, the model derives the efficient development of generation capacities and power plant dispatch (subject to additional technical and economic constraints). In order to fulfil the hourly energy balance, the model can also chose "involuntary load curtailment", i.e. not to meet demand in every hour. This involuntary load curtailment or Loss-of-Load induces additional costs that are included in the objective function, the "Value-of-lost-Load". Hence, we include the possibility that it might be more efficient to not serve all consumers than to build one additional power plant to serve the last consumer.[23]

23 Assumed Value-of-lost-Load: 15.000 €/MWh. Our estimation is based on ENTSO-E (2013); Frontier Economics/Formaet Services (2014).

3.2 Base case assumptions

In this section, we describe the power market assumptions that define our base case scenario for the Netherlands.[24] The base case represents a scenario which is built upon a combination of current market expectations, e.g. regarding fuel prices and CO_2 prices, political targets for example for the development of RES-E etc.. The section is structured as follows:

- Fuel and CO2-prices (**section 3.2.1**);
- Power demand (**section 3.2.2**);
- Power plants and generation capacity (**section 3.2.3**);
- Development of renewable energy source – RES-E (**section 3.2.4**);
- Development of demand-side response (**section 3.2.5**).
- Interconnection capacities (**section 3.2.6**).

3.2.1 Fuel and CO_2-price assumptions

Prices of fossil fuels and CO_2 play an important role in determining the outlook of the power system. The fuel and CO_2 prices affect the variable costs of generation and therefore the power prices and profitability of generation units.

Fuel prices (coal and gas)

We have derived our fuel price assumptions according to the following logic:

- **Short-term** (until 2017) development according to current market expectations – The short-term development is derived from future prices of the trading day 07 January 2015. We have used the prices noted at the Title Transfer Facility (TTF) for gas and CIF ARA prices for coal.[25]

- **Medium- and long-term** based on World Energy Outlook (2014, New Policies scenario) – The oil price projection of the World Energy Outlook (2014, New Policies scenario) serves as the basis for our long-term fuel price development:
  - The medium-term development (2018-2020) price development is modelled as linear interpolation between the last future price (2017) and the first year of price notation based on the WEO (2021).

---

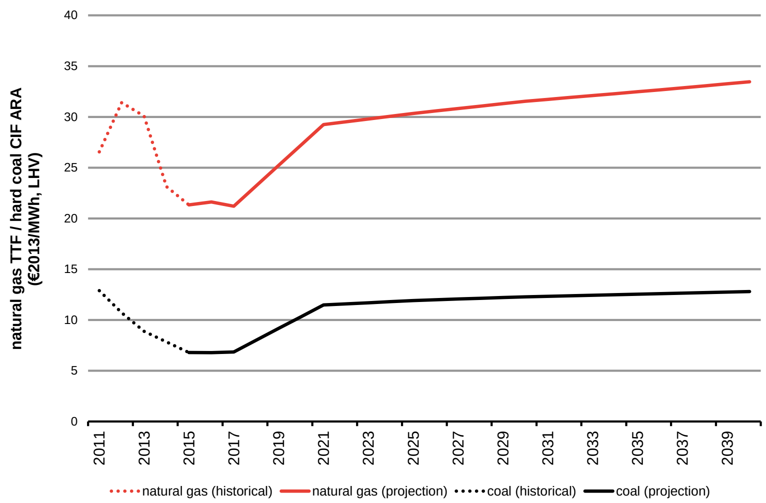
24 Assumptions for other modelled regions are included in Annexe 2.

25 The model includes additional transportation costs for hard coal depending on the transport distance.

- The long-term (after 2021) development of coal and gas prices is derived from oil prices based on expected heat equivalence ratios (oil-to-gas and oil-to-coal)[26]

Figure 12 shows a substantial drop in fuel prices from 2011 to 2015. The latest drop in prices is partly caused by the sharp decline in oil prices observed at the end of 2014/beginning of 2015 from around 100 USD/bbl to ca. 50 USD/bbl (Brent)*)*. We expect that prices will increase again in the next years, which is also reflected in current future prices for oil.[27]

Figure 12. Fossil fuel price assumptions (Base Case)



Source: Frontier
All prices are noted in lower heating values.

Compared to today's low price levels, we expect that gas prices will increase by 11 €/MWh(th) in real terms (base year 2013), which is equal to an increase by 50% from 2015 until 2035. Coal prices are expected to increase from 7 EUR/MWh(th) in 2015 by 80% to 12.5 EUR/MWh(th) in 2035. This implies that coal will get more expensive in heating equivalence terms compared to gas taking into account the low coal price levels observed today.

---

26 Heat equivalence ratios express the price relationship of fossil fuels, converted to EUR/MWh(th). We assume decreasing ratios for gas/oil and coal/oil in the long-run - on the one hand because of the ongoing decoupling of oil and gas prices and higher availability of gas compared to oil (e.g. shale gas and LNG); on the other hand because of the longer resource availability of coal compared to gas or oil and a flatter marginal cost curve for coal than for the other primary energies.

27 World Bank Commodity Price Forecast anticipates increasing oil prices to around 100 USD(nominal)/bbl in 2025.

CO_2-prices

The European Emission Trading Scheme (EU ETS) has been characterised by an "oversupply" of emission certificates in past years. This oversupply can be attributed to a drop of demand due to the financial and economic crisis but also due to higher shares of RES-E in Europe that substitute conventional power generation and in return decrease the demand for emission certificates.[28] As the total supply of certificates in a "cap & trade" system like the EU ETS is fixed by the emission cap, the price has decreased substantially. Nevertheless, we expect that the EU ETS will maintain its role as the central instrument for climate change on the European level. Therefore, we expect the price to rise in the medium- to long-run after market reforms have been implemented.[29]

We derive our CO_2-price assumptions according to the following logic:

- **Short-term** (until 2017) development according to current market expectations – We use CO_2 price futures (trading day 5 January 2015) to derive our short-term price projection.

- **Medium-term** (2018-2030) price development based on the "Nationale Energieverkenning" (National Energy Survey)[30] – We use the CO_2-price assumptions derived in the National Energy Survey in 2014 (scenario "Voorgenomen beleid").

- **Long-term** (after 2030) perspective based on World Energy Outlook (Current Policies Scenario) – For the period after 2030, we use the prices given in the World Energy Outlook 2014 (Current Policies Scenario) and linear interpolation from the last price indicated in the NEV to WEO price in 2040.

Figure 13 shows the assumed CO_2-price development. We expect prices from circa 7 EUR/tCO_2 in 2015 to around 30 EUR/tCO_2 in 2035.

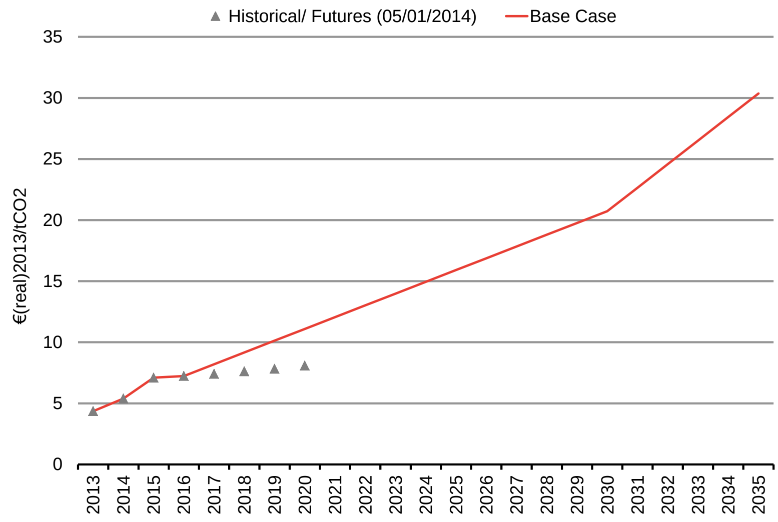
---

28 European Commission (2012).

29 The European Commission will introduce several measures that aim at increasing the CO_2 price and therefore the incentive scheme of the EU ETS. As a temporary measure, a certain amount of certificates has been taken out of the market (so-called "Backloading") and will be fed back into the system at the end of this trading period. The discussed "Market Stability Reserve" represents a possible medium term option (from 2021) to stabilise pricing signals. This option has been backed by the Environment Committee of the European Parliament end of February 2015. (See Press release Consumer/Environment 24/02/2015).

30 ECN/PBL (2014).

Figure 13. CO_2-price assumption (Base Case)



Source: Frontier

3.2.2 Power Demand

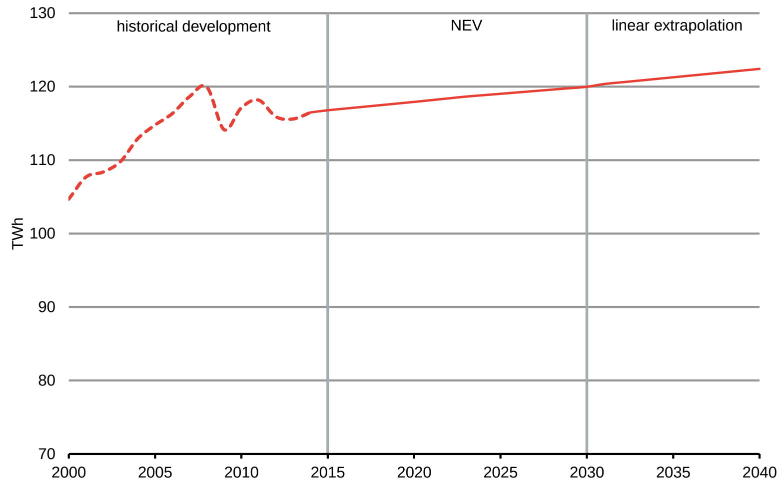
Our assumption for the development of power demand is based on the demand projection used in the National Energy Survey (Nationale Energieverkenning, NEV) published by ECN and PBL in 2014.[31] The NEV assumes a moderate growth of power consumption in the next years. Including network losses, net electricity consumption is assumed to increase from 117 TWh in 2015 to 121 TWh in 2035. This growth reflects the moderate average demand increase in the most recent years and includes two countervailing trends for the future;

- Increased demand due to growth of GDP and
- Increased energy efficiency which leads to a decoupling of the formerly strong relationship between power demand and the GDP.

We base our assumptions on the assumed demand growth of the NEV until 2030 and use linear extrapolation for the years after 2030 (**Figure 14**).

31 Net electricity consumption; "implemented and planned policies" (excluding own-production including grid losses)

Figure 14. Assumed development of electricity consumption



Source: Frontier

3.2.3 Power plants and generation capacity

The Dutch power plant park is characterised by a large share of conventional generation capacities. Based on economic reasoning, our power market model optimises the existing power plant park through

- Retirement of power plants (before end of lifetime if economic);
- Mothballing of power plants;
- Reactivation of mothballed capacity; and
- Investment in new generation capacity.

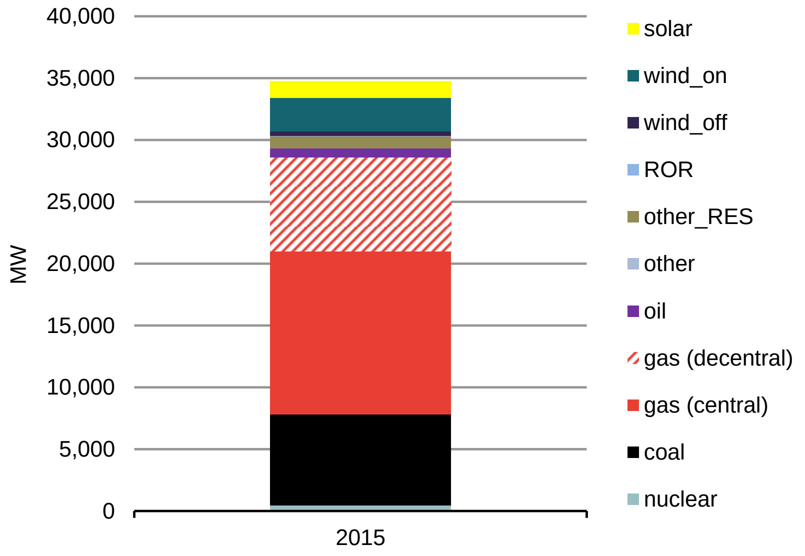
In our modelling, mothballing and reactivation of power plants are associated with costs. Investment costs for conventional power plants are indicated in **Table 1**. Mothballing of power plants reduces the yearly fixed operation and maintenance costs of the power plant by 75%. The reactivation of a power plant is followed by a one-time payment of 25% of the yearly fixed operation and maintenance costs.

Development of thermal generation capacity

Our assumptions regarding the existing power plant park are derived from Platts PowerVision, a commercial database with information on retirements and additions of power plants and other publically available information e.g. on mothballing of specific units. Further adjustments of thermal capacity were derived from the Energy Agreement (regarding closure of coal-fired power plants) and the Monitoring Report published by the Dutch TSO, TenneT.[32]

In 2015, installed generation capacity amounts to ca. 35 GW, of which 29 GW are fossil fuel fired power plants (**Figure 15**).

Figure 15. Installed generation capacity (NL, 2015)



Source: Frontier
ROR = run-of-river hydro power generation

Our modelling takes into account known market entries (investment) until 2020 as well as known mothballing decisions and retirements based on the end of the technical lifetime of power plants as exogenous assumptions.[33] In the short-term (2015-2020), this includes

- Known retirement of 2.6 GW coal-fired generation until June 2017 based on the Energy Agreement;
- Known mothballing of 4 GW of gas-fired capacity;
- Known investment in 2.6 GW of coal-fired power generation capacity.

In addition to those additions and retirements, the model can decide on additional investment, earlier retirement of plants or on additional mothballing and reactivation of generation capacities.

32 TenneT (2014).

33 Our model does not include retrofitting to achieve a lifetime extension but allows for replacement investments.

Possible investment options in the Netherlands

The outlook of the future electricity system in the Netherlands is influenced by the technological development and the availability of new generation technologies, as for example carbon-capture and storage (CCS) for coal and gas plants as well as new storage solutions.[34] We include the following options in our modelling for investments in the Netherlands (**Table 1** – further details on the technologies provided in Annexe 2):

- Hard coal - with and without CCS (as "integrated gasification combined cycle" (IGCC) technology);
- Natural gas – "combined cycle gas turbines" (CCGT) and "open cycle gas turbines" (OCGT);
- Nuclear power;
- Power storages - "compressed air energy storage" (CAES), "advanced adiabatic compressed air energy storage" (AACAES), and power-to-gas (and back to power).

Table 1 shows the assumed investment costs per MW. Beside investment costs, thermal efficiency, if applicable storage volume and other variable costs determine which technologies will be built in the power market model.

[34] Investment costs are derived from multiple source and previous project experience.

Table 1. Investment options in the power market model *)

Technology / Fuel	Available in (year)	Investment cost (EUR/kW)
Hard coal	2015	1,750
Natural Gas (OCGT)	2015	450
Natural Gas (CCGT)	2015	750
Hard coal (IGCC) with CCS	2025	2,750
Natural Gas (CCGT) with CCS	2025	1,200
CAES	2023	806
AACAES	2030	1,300
Power-to-Gas (to-Power)	2030	1,650
Nuclear	2035	4,600

Source: Frontier
*) The investment in RES-E enters the model as exogenous assumption (see **section 3.2.4**). Assumed costs of renewable energy sources are included in **section 4.3**.

Combined-heat and power generation

A large share of electricity supply in the Netherlands is produced in combined-heat and power (CHP) facilities, i.e. power plants with the primary use of heat generation either for

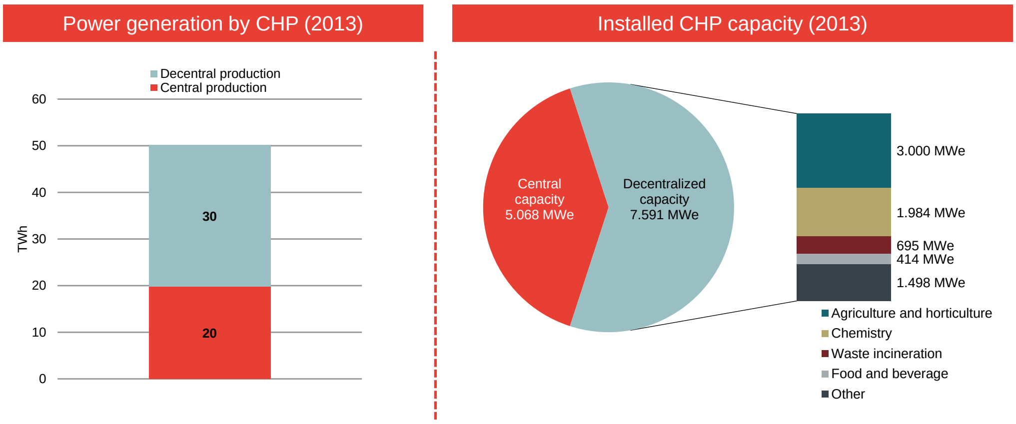
- industrial processes;
- district heating; or
- agriculture and horticulture.

In 2013, around 13 GW of installed generation capacities are characterised as CHP capacities:

- 5 GW central generation capacities (gas and coal) mainly for district heating and industrial heat generation; and
- 7.5 GW of decentralised generation capacities mainly for agriculture and horticulture (green-houses) and industrial heat generation (see **Figure 16**).

Electricity generation from CHP amounted to around 50% of total inland power generation (50 TWh).

Figure 16. Combined heat and power generation and capacities



Source: Frontier based on CBS statline

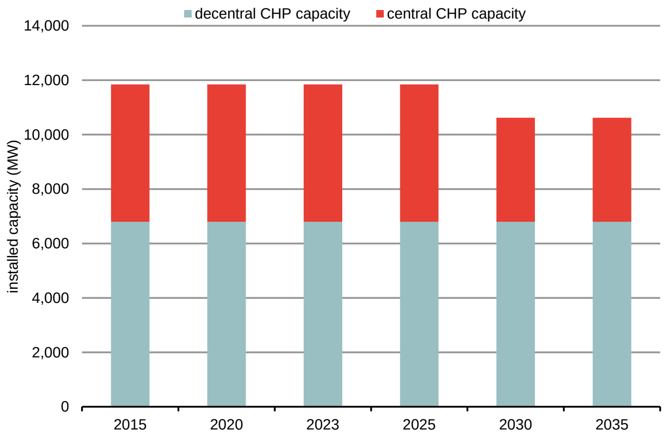
In our modelling of the electricity system, power generation from CHP is treated partly as exogenous generation, partly as dispatched generation. Power generation from CHP follows yearly heat-demand profiles, i.e. power plants have a minimum load derived from heat demand profiles. In addition to the electricity generation arising from heat production, certain CHP plants have flexibility and are optimised like a "regular" power plant. For the future development of conventional CHP generation, we apply the following (simplifying) assumptions:

- **Constant decentral generation:** Electricity supply from decentral CHP capacities, as for example greenhouses, is regarded as bi-product of heat-generation. We assume that the underlying economics of decentral CHP capacities do not change and that generation will remain constant.
- **Slightly decreasing central generation:** Central CHP capacities are influenced by power market economics to a greater extent. We assume that central conventional CHP installations can remain online until the end of their technical lifetime, but may be mothballed or retired beforehand. It has to be noted that we don't model the new built of central conventional CHP installations endogenously since the specific circumstances of heat demand etc. (which are not part of the model) drive the economics of each single unit and therefore the decisions to renew or refrain from renewal of old units. The assumption of absent replacement investments is consistent with results of studies that have

assessed economic situation of conventional CHP plants.[35] Instead, we include the option of new-built gas-plants (OCGT and CCGT).

These assumptions lead to a moderate decrease of combined-heat and power generation from conventional power plants. At the same time, we expect CHP generation from renewable (biomass) plants to increase in the long-run as additional financial support is granted under the SDE (+) support scheme (see **section 3.2.4**).[36]

Figure 17. Assumed development of central and decentral CHP capacity (conventional)



Source: Frontier

3.2.4 Development of renewable electricity supply (RES-E)

The current political targets expressed in the Energy Agreement foresee a significant growth of renewable energy sources in electricity supply. As the development of renewable energy sources in the electricity sector is very much driven by political initiatives and support schemes, we assume an exogenous growth path of RES-E capacities and generation based on:

- Current political targets for RES-E capacity; or
- Secondary sources on future RES-E development in the Netherlands.[37]

In the Base Case, we assume a significant increase of renewable electricity supply from around 14 TWh in 2015 to more than 60 TWh in 2035. This corresponds

35 E.g. CE Delft / DNV GL (2014).

36 ECN/PBL (2014), p. 100.

37 ENTSO-E Scenario Outlook and Adequacy Forecast (SO&AF) RES-E capacities in other modelled countries are derived accordingly based on legal targets and / or secondary sources.

to an increase of the share of renewable electricity of net demand from 12 % in 2015 to ca. 50% in 2035. The development of renewable electricity supply is based on the following assumptions:

- **Wind-onshore** – According to the Energy Agreement, onshore wind power installations are expected to increase to 6 GW in 2020. Thereafter, we assume a yearly growth of wind-onshore installations by 200 MW/a, in line with growth expectations from ENTSO-E SO&AF (2014, Scenario B / Vision 3).

- **Wind-offshore** – The Energy Agreement includes plans to increase the installed capacity of wind-offshore turbines to 4450 MW in 2023. Thereafter, we assume ongoing growth of wind-offshore capacities to 6 GW in 2030 based on ENTSO-E SO&AF (2014, Vision 3).[38]

- **Solar PV** – There are no explicit political targets regarding the development of solar PV installations in the Netherlands. However, solar PV is eligible to the support scheme SDE (+) and, in addition, small scale installations are benefiting from net-metering.[39] Therefore, we assume increasing solar PV capacity based on the following logic:
  - We assume a short-term increase to 5.5 GW until 2020, based on NEV (planned and implemented policies);
  - We assume a moderate increase to 8 GW in 2030 based on ENTSO-E SO&AF (2014, Vision 3) and a linear trend afterwards.

- **Other RES-E (biomass) –** We expect an increase in electricity production from other renewables, especially from biomass in combined-heat and power plants.[40] Our growth path is derived from NEV[41] in the short-term (until 2020) and ENTSO-E SO&AF (2014, Vision 3) in 2030 (linear trend afterwards).

Figure 18 shows the assumed growth of renewable electricity supply.

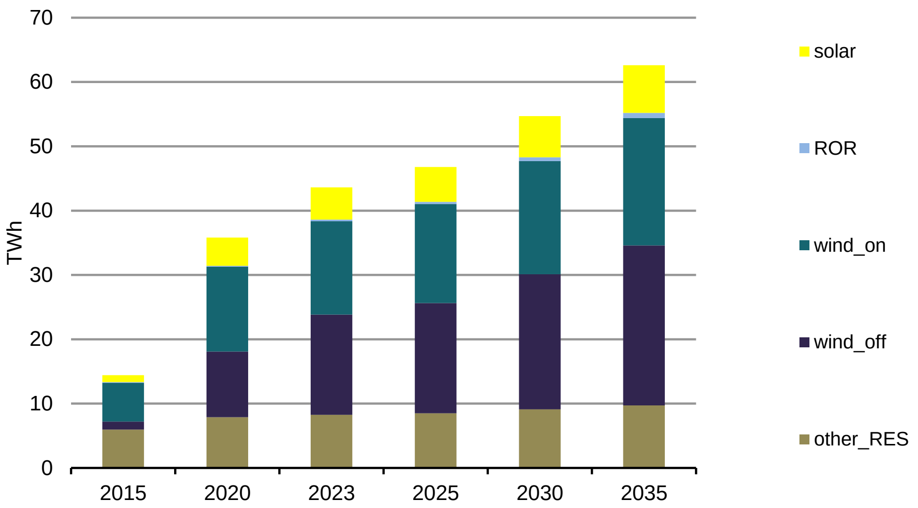
38 Capacity development after 2030 is derived based on a linear trend of the previous years.

39 Net-metering applies to consumers that are connected to the distribution grid and reduces the burden of energy taxes to the amount of net electricity consumption, i.e. no energy taxes have to be paid on the auto-produced electricity.

40 As the majority of electricity supply from biomass is CHP, we model power generation from biomass as exogenous in-feed, based on a typical heat-demand profile and upward flexibility.

41 Capacities are scaled to meet generation according to assumed utilisation of power plants from combined-heat and power production.

Figure 18. Development of renewable electricity supply



Source: Frontier

3.2.5 Demand-Side Response

Beside generating electricity and investing in conventional generation or storage technologies, the model's energy balance can also be met through load reduction, i.e. Demand-Side Response (DSR). In our model, we differentiate between two types of DSR:

- **Load reduction** – Market participants can offer a reduction of the hourly load, i.e. through lowering industrial production or by using emergency generators. We assume that these capacities can enter the market at comparably low costs for information and communication technologies but each unit of reduced load incurs high variable costs, e.g. for foregone value-added of industry.[42] We assume that load reduction capacities are primarily available in the industrial sector.

- **Load shifting** – Market participants can offer to move their consumption of electricity to hours with lower prices. The reduced load must be balanced within in a certain period of time. As the shifted load needs to be balanced, the variable costs of the load shifting itself are small and arise mainly from efficiency losses or loss of use.[43] We assume that load shifting capacities are

42 We differentiate between three discrete cost steps: 500 €/MWh; 1,500 €/MWh; 2,500 €/MWh.

43 We assume that load shifting must be balanced within 24 hours; variable costs of load shifting amount to 2 €/MWh.

for example available in private households, commercial or in the services sector, i.e. from electrical vehicles that can shift their loading or from heat-pumps. The supply of load-shifting depends on the underlying consumption pattern, e.g. load-shifting potentials from heat-pumps in the summer are limited as the heat-pumps are typically more in use in winter times.

Unfortunately, there are no explicit informations available as to how much DSR is participating in today's market. Nevertheless, a number of studies show that participation of demand in the power market is expected to increase. Based on this assumption, we have included increasing investment potentials for DSR in the model[44]:

- **Existing DSR capacities** – According to ENTSO-E[45], 1 GW of DSR is part of today's electricity system in the Netherlands. We assume that these capacities are load-reduction capacities. In addition, we assume that additional 200 MW of load-shifting capacities are available from heat-pumps.[46]

- **Further potential for investment in DSR** – In addition to the already existing DSR capacities, we assume that further investment potential will be available in the future:
  - We assume that additional 700 MW of **load reduction** potential, mainly arising from industry and emergency generation units, could enter the market.[47]
  - We assume that additional 720 MW (de-rated) of load shifting potentials from e-cars[48] and heat pumps[49] will be available in the longer term.

The actual development of future DSR capacities, however, is part of the optimisation of the power market model and therefore dependent on market environment in the specific sensitivities and scenarios. In addition to the voluntary load reduction, the model can choose to curtail load on an involuntary basis at the costs of the "Value-of-lost-Load" (see **section 3.1**).

---

44 De-rated according to assumed availability in peak-period (winter period, Monday-Friday from 17:00 to 20:00).

45 ENTSO-E SO&AF (2014), Scenario B.

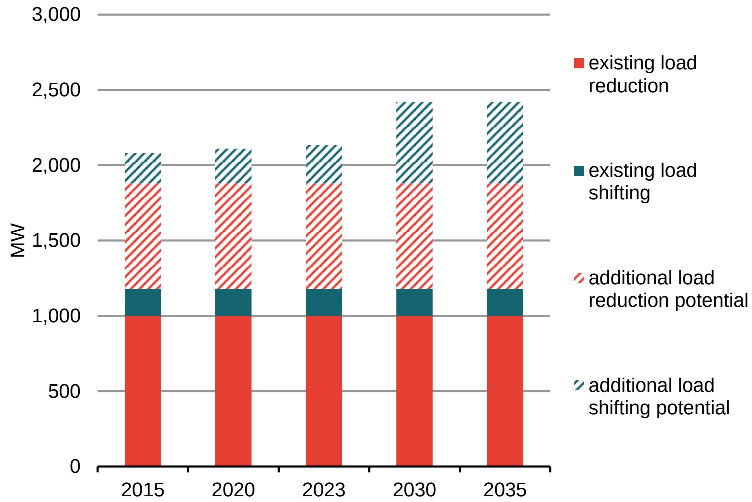
46 CBS statline:. 2500 MW_th capacity in 2012: We convert the thermal capacity to 900 MW electrical capacity using a power-to-heat ratio of 1/3, i.e. heat pumps generate 3 MWh of heat using 1 MWh of power.

47 Deloitte (2004).

48 RVO (2010): 1 mn. e-cars in 2025, we assume that this target will be achieved in 2030 (ca. 4 kW per vehicle, not de-rated).

49 Rijkswaterstaat.nl (2010): Additional 2400 MW electrical capacity in 2030 (not de-rated).

Figure 19. Development of Demand-Side Response*)



Source: Frontier
*) De-rated capacity according to assumed availability in peak-period (winter period, Monday-Friday from 17:00 to 20:00)

3.2.6 Cross-border capacities

Increasing interconnection capacity between countries in Europe is an important cornerstone of the European internal electricity market. Therefore, the development of cross-border connections is an important assumption and influences the outcomes of the power market modelling significantly.

The Netherlands is a country with high interconnection to its neighbouring countries, notably Germany and Belgium Additional interconnections are in place to Great Britain (BritNed) and Norway (NorNed). In 2015, total cross-border capacity from/to the Netherlands amounted to almost 6 GW, approximately one third of peak load.

Based on our assumptions, cross-border capacity will increase further in the next years: Our assumptions regarding the development of interconnection capacity are based on ENTSO-E's Ten-Year-Network-Development-Plan.[50] In addition, we have confirmed the development of power interconnectors to and from the Netherlands with TenneT's monitoring report.[51] **Figure 20** shows the average of import and export capacity to/from the Netherlands[52]:

---

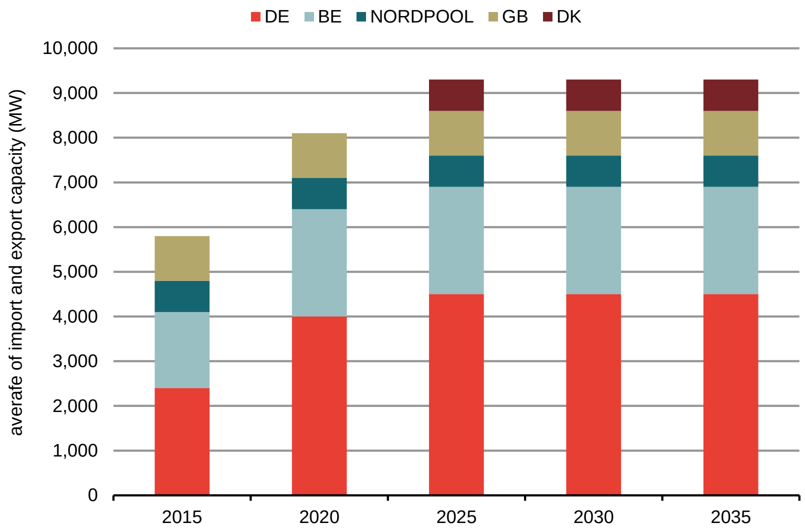
50 We assume that projects that are in the earlier planning phases will come online with a certain delay: "design and permitting" + 2 years; "planning" + 5 years; "under consideration" + 15 years.

51 TenneT (2014).

52 Assumptions regarding interconnectors across Europe are included in Annexe 2.

- Interconnections to Germany will increase in 2018 and 2021 to a total of 4.5 GW in 2021.
- Interconnections to Belgium will increase to 2.4 GW by 2018.
- Interconnection to Denmark (Cobra Cable) will be established by 2021.

Figure 20. Assumed development of interconnection capacity (NL)



Source: Frontier

3.3 Power market outlook – Base Case results

In this section, we present the modelling results for the Base Case scenario with focus on the electricity market in the Netherlands. Information on the development in other modelled regions is included in Annexe 2. The section is structured as follows:

- Development of generation capacities and power generation (**section 3.3.1**);
- Development of Demand-Side Response (**section 3.3.3**);
- Electricity imports and exports to and from the Netherlands (**section 3.3.3**); and
- Development of power prices (**section 3.3.4**).

Main results of the power market study (Base Case)

- **Energy transition does not pose threat to Dutch power market and Security of Supply** – Our base case shows that - even in a system with high shares of renewable electricity in the system - the Dutch power market is able to ensure security of supply. We don't expect scarcity of generation capacities to take effect in the Netherlands in the foreseeable future, as previously mothballed capacity is reactivated in the medium-term (until 2023) and new investments take place in the long-run (until 2035).

- **High electricity supply from renewable energy sources increases exports to neighbouring countries** – The assumed growth of RES-E to 47% of Dutch power demand increases exports to neighbouring countries, especially Germany. In the medium-term (after 2023), we expect that the currently observed net-import position of the Netherlands will be reversed to a net-exporting position.

- **Growing participation of demand side in the market** – Increasing potentials of demand side response (load reduction and load shifting) can be expected to enter the market in the long-run (after 2030).

- **Increasing power prices in the medium-term** – In line with the assumed medium-term development of fuel and CO_2-prices, we observe increasing electricity price levels in Central-Western-Europe in the medium term. In the long-term (after 2030), power prices increase only moderately, due to higher renewable electricity generation and interconnection capacity between regions.

- **Price convergence between Germany and the Netherlands** – With increasing interconnection capacity between Germany and the Netherlands, we observe growing price convergence between the two countries. In the medium-term, hourly prices are almost fully integrated.

3.3.1 Power generation and development of generation capacity

In the base case, we observe the following trends regarding power generation and capacity development:

No scarcity of generation capacity expected

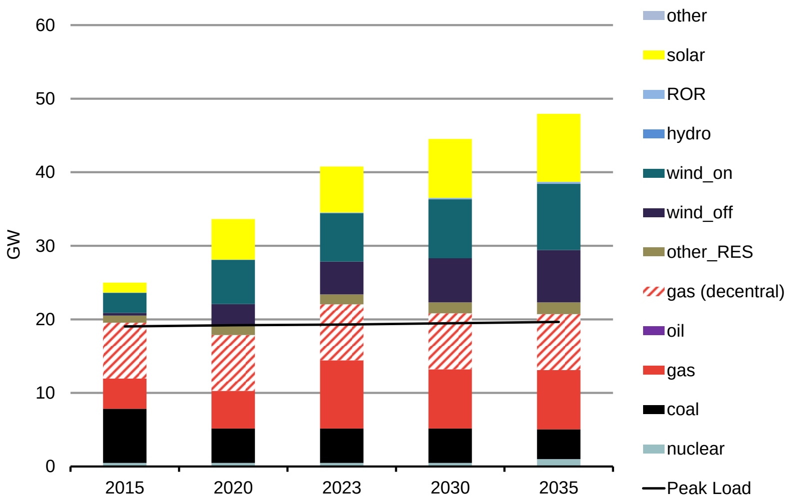
With increasing shares of intermittent renewable energy, total installed generation capacity grows in the long-run:

- **Increase in RES-E and decreasing conventional power generation capacities** – As outlined in **section 3.2.4**, we assume a significant increase in renewable power production in the Netherlands. At the same time, conventional generation capacities are reduced compared to (very high) current levels:

- Assumed increase of RES-E capacities from 4 GW in 2015 to more than 26 GW in 2035;
- Decrease of operational conventional generation capacity from 29 GW in 2015 to 20 GW in 2035.

Figure 21 shows the development of operational generation capacity in the Netherlands from 2015 until 2035. Operational generation capacity compared to installed capacity does not include a total of 7.5 GW of mothballed capacities from 2015 until 2019.[53]

Figure 21. Development of operational generation capacity (NL)



Source: Frontier

- **Additional mothballing and retirements in the short-run** – Based on the assumed capacity development from 2015-2019, we observe additional retirements and mothballing of conventional power plants in the Netherlands:
  - In total, 11.8 GW of conventional generation capacities are closed down temporarily or permanently from 2015 to 2019. In addition to the already known retirements and mothballing decisions, this includes

53 The 7.5 GW include 4 GW of plants that are mothballed until 2015.

earlier retirement of old oil and gas-fired plants (2 GW) and additional mothballing of 3.5 GW gas-fired generation capacity;

- At the same time, 2.6 GW of (known) new coal fired generation capacities enter the market.[54]

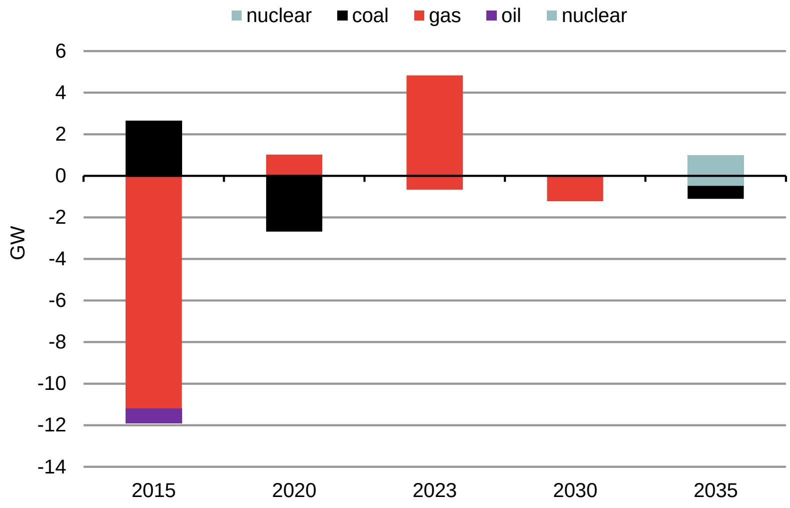
However, this net-decrease of generation capacity does not pose a threat to generation adequacy in the Netherlands, as the current capacity situation is very comfortable in the Netherlands, mothballed capacity is reactivated when needed (see below) and sufficient interconnection capacity to neighbouring countries is available.

- **Reactivation of mothballed capacities and replacement investment for nuclear in the medium to long-term** – Based on the assumed growth path for renewables, the continued availability of CHP plants and the increase in interconnection capacities with neighbouring countries, the need for new power plant investments in the Netherlands is limited in the medium and longer term. At the same time, mothballed power plants are reactivated:
  - In the medium to long-run, we observe that previously mothballed capacity re-enter the market until 2030 (ca. 1 GW in model-period 2020 and ca. 5 GW in model period 2023);
  - In addition, the retired Borssele nuclear power plant could be replaced with a new investment in 2035 according to the model results.

Figure 22 shows the development of conventional generation capacity, i.e. investment and reactivation are marked as positive values, retirements and mothballing as negative values.

54 Known entries until 2016: Maasvlakte 2 (1.1 GW); Eemshaven (1.5 GW).

Figure 22. Development of conventional generation capacities

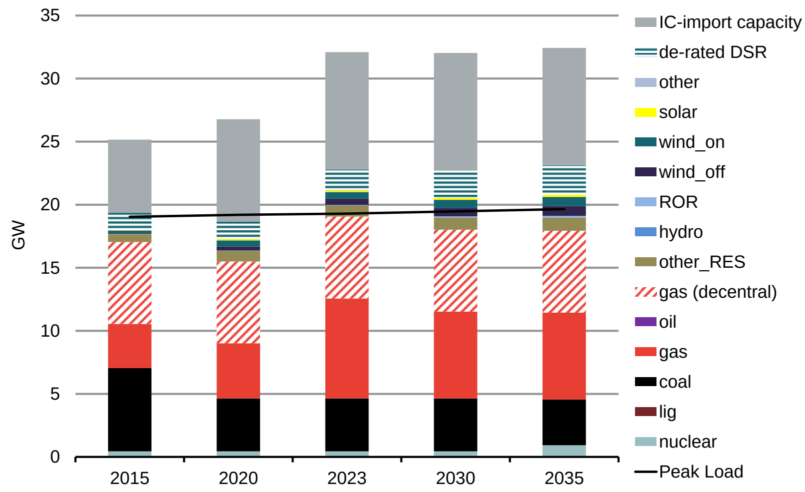


Source: Frontier

- **No threat to security of supply** – Capacity levels decrease in the short-term due to mothballing of gas-fired power plants. The adequacy reserve margin in 2020 amounts to -0.5 GW excluding import capacities and to 7.5 GW including import capacities.[55] Nevertheless, there is sufficient capacity available to guarantee security of supply in the short-term long-term (based on indicative capacity balance, **Figure 23**), as mothballed plant could be re-activated. In addition, no involuntary load-reduction ("Loss-of-Load") is pursued. In the long-run, adequacy reserve margins are positive, even without taking into account import capacities.

55 ARM= Peak-Load – derated capacity (De-rating factors according to availability in peak-period; see Annexe 2).

Figure 23. Capacity balance (de-rated), Base Case



Source: Frontier
Used de-rating factors can be found in Annexe 2.

Moving towards a higher share of RES-E power generation and net-exports of power

The Base Case shows the following trends in power generation:

- **Increasing generation of wind-onshore and offshore push RES-E** – We assume the highest increase in generation from renewable energy sources coming from wind-onshore and wind-offshore installations:
  - Generation from wind-onshore increases to 21 TWh in 2035; and
  - Generation from wind-offshore increases to 27 TWh in 2035

  In addition, we assume that in-feed from solar PV installations will increase to 8 TWh and from biomass installations to 10 TWh in 2035. In total, this leads to an increase in the share of renewable electricity in the system[56] from 13% in 2015 to 54 % in 2035.

- **Decreasing generation from conventional power plants** – Electricity supply from conventional thermal power plants today amounts to around 90% of total power supply in the Netherlands. Due to increasing generation from RES-E, the share of conventional generation will decrease to 55% in the long-run (2035). We expect

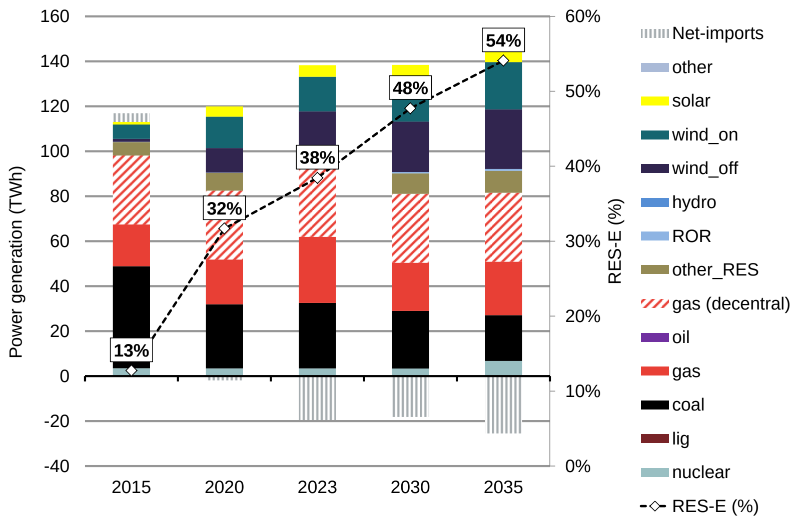
56 RES-E (%) share of net-demand.

- decreasing generation from coal-fired power plants (-55% from 2015-2035) as retired coal plants are not replaced;
- a small increase of generation from gas-fired power plants (decentral and central + 10% from 2015 until 2035)[57]; and
- an increase in nuclear electricity supply after the replacement of Borssele nuclear plant with 1 GW new built nuclear capacity in 2035.

- **The Netherlands will be net-exporter of power in the medium-term –** With increasing electricity supply from renewable energy sources and high share of efficient gas-fired power plants, the Netherlands will develop from net-importing to net-exporting of power in the medium-term:
  - Net-imports in the short-term until 2020;
  - Net-exports of power after nuclear phase-out in Germany from 2023 (see **section 3.3.2**)

Figure 24 shows the modelled power generation in the Netherlands.

Figure 24. Development of power supply in the Netherlands



Source: Frontier

- **Reduction of carbon dioxide emissions from electricity supply in the Netherlands by 30% –** CO_2-emissions of power generation decrease over time from 54 mn. tCO_2 in 2015 to 37 mn. tCO_2 in 2035:

57 The majority of gas-fired generation is produced in CHP plants. We assume that total CHP decreases moderately from 50 TWh in 2016 to 46 TWh in 2035.

- Emissions increase slightly by 3 mn. tCO_2 to 45 mn. tCO_2 from 2020 to 2023. This increase occurs with the reactivation of mothballed gas-fired power plants and the German nuclear phase-out which results in higher exports of power (see **Figure 24**).
- After 2023, CO_2 emissions decrease constantly to 37 mn. tCO_2 in 2035.

Side note: German Energy Transition (Energiewende)

The German power market is subject to a significant transformation process which affects the whole Central Western Europe market area.

- **Renewable energy law** – Since coming into effect in 2000, the renewable energy law (EEG) has very effectively increased the share of renewable energy sources in electricity supply[58] from below 10% to around 25% in 2013 (ca. 150 TWh). The goals of the current EEG (2014) are to increase the renewable share to
  - 40-45% in 2025,
  - 55-60% in 2035; and
  - 80% in 2050.

  The current legal framework includes technology specific targets for installed renewable capacity:
  - **Wind-onshore** shall increase by 2.4 - 2.6 GW per year;
  - **Wind-offshore** capacities shall amount to 6.5 GW in 2020 and 15 GW in 2030;
  - **Solar PV installations** shall increase by 2.5 GW per year, until a support cap of 52 GW is reached.

  The modelled development of the power market is based on these assumptions. We further assume that the support for solar PV and the respective capacities grow only moderately afterwards.

- **Nuclear phase-out until 2022** – Following the nuclear power accident in the Japanese nuclear power station of Fukushima in 2011, the German government had decided on a temporary moratorium of nuclear power generation in Germany. Subsequently, the German parliament decided on the phase-out of nuclear power generation until 2022.

Fundamental change of the power plant park

The increase in renewable energy sources to almost 100 GW of installed capacity in 2015 has lowered utilisation of conventional thermal power plants. In combination with low prices for fuels and CO_2, profitability of thermal generation is weak. As a result, various power plant operators have announced or pursued temporary or final retirement of power plants.

---

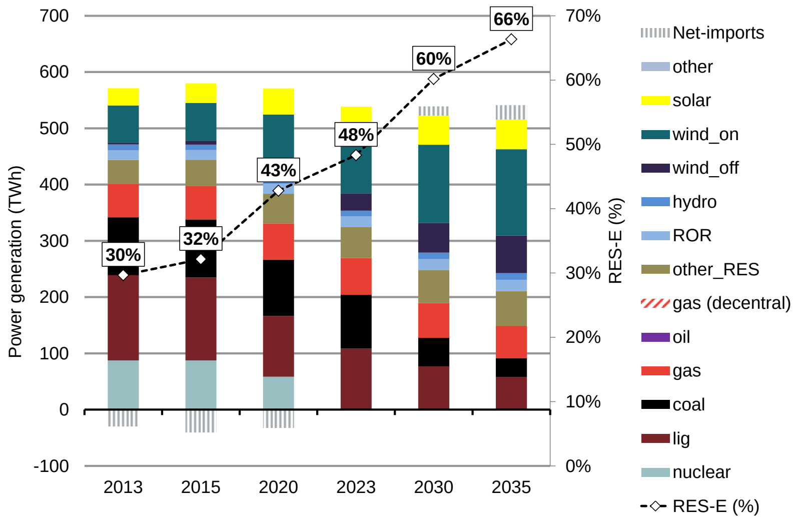
58 Share of renewable electricity generation of gross-inland power consumption.

- **Decreasing share of conventional generation** – The developments described above have the following effects in our modelling: Operational thermal generation capacities decrease from around 90 GW in 2013 to 60 GW in 2020 and further to 32 GW in 2030. Consequently, the share of fossil fuel generation at net power demand declines from 74% in 2015 to 28% in 2035:
  - Retirements of coal and lignite fired plants as well as increasing prices for carbon dioxide emissions lower power generation from coal and lignite-fired plants by 60% from 250 TWh in 2015 to 92 TWh in 2035.
  - Power generation of gas-fired power plants increases in the short-term from 60 TWh in 2015 to 66 TWh in 2023 but decreases again afterwards to the levels of 2015.
- **High levels of renewable energy sources** – According to the assumptions described above, in-feed from subsidised renewable energy sources (including hydro power) increases significantly from 180 TWh in 2015 to more than 360 TWh in 2035.
  - Wind-onshore alone will be accountable for around 150 TWh of generation;
  - Wind-offshore generation increases to 67 TWh; and
  - In-feed from solar PV to 53 TWh in 2035.

  In sum, this corresponds to an increase the RES-E share of net power demand to 66% in 2035.
- **Net-exports of power until 2023, net-imports after completion of the nuclear phase-out** – Despite decreasing levels of conventional generation, Germany remains net-exporter of power with a power-balance surplus of 30 TWh in 2020. In 2015, nuclear generation amounts to approximately 90 TWh, after completion of the phase-out in 2023, net-exports decrease significantly to 2 TWh. In the long-run (2030-2035), higher CO_2-prices lower utilisation of the remaining lignite and fired-power plants. As a result, Germany develops from a net-exporting country to a net-importing country (+24 TWh in 2035) in the long-run.

Figure 25 shows the development of power generation in Germany in the Base Case.

Figure 25. Development of power generation in Germany (Base Case)



Source: Frontier
RES-E (%) expressed as share of generation of net-demand

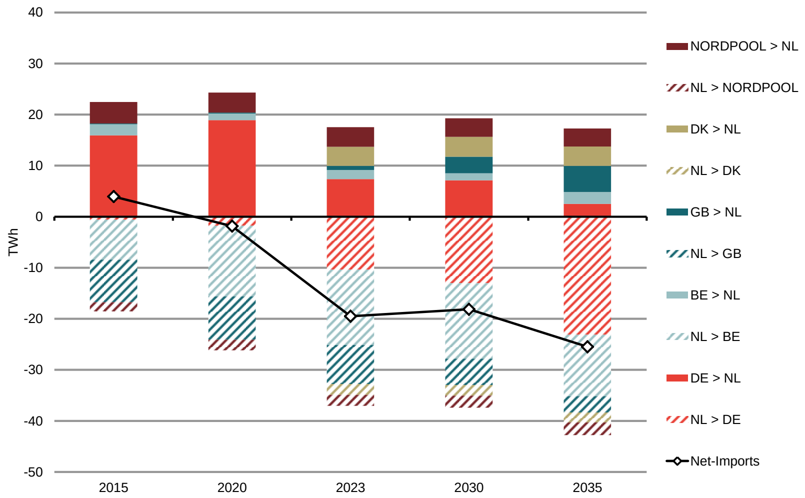
3.3.2 Power exchange with neighbouring countries

As described above, the Netherlands develop from a net-importing country in the short-term to a net-exporter of power in the long-run. This change is driven by two main trends:

- Increase of RES-E in the Netherlands in the long-run increases supply in-land of electricity; and
- Increasing import requirements of neighbouring countries such as for example Belgium and Germany (in Germany especially after the nuclear phase-out in 2023).

In 2015, the Netherlands import 23 TWh, mainly from Germany, and export 17 TWh, mainly to Great Britain and Belgium. In the long-run, imports decrease to 17 TWh while exports increase to 43 TWh in 2035. **Figure 26** shows the development of annual net-imports (positive values) and exports (negative values) of the Netherlands with neighbouring countries.

Figure 26. Power flows to/from the Netherlands



Source: Frontier

3.3.3 Demand Side Response

We assume increasing potential for demand side response (DSR) which can be activated if economic under market conditions in the model (see **section 3.2.5**). In the base case, substantial amounts of load reduction and load shifting are realised:

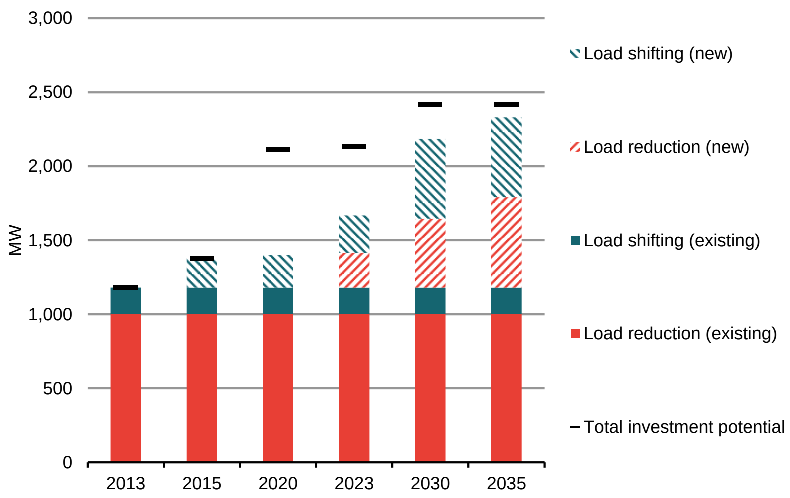
- **Load reduction capacities with low variable costs enter the market** – We observe that load reduction capacities increase in the long-run, especially in 2035. Those capacities are assumed to have rather low upfront investment costs e.g. for information and communication technologies but high variable costs if called. We observe that until 2030, only load reduction capacities with variable costs of 500 €/MWh enter the market. Capacities with variable costs of 1.000 €/MWh participate only in 2035, and capacities with even higher variable costs of load reduction are not activated. Load reduction potential is especial available in the industry with high energy intensity.

- **Increasing utilisation of load-shifting potentials** – In contrast to load reduction capacities, load shifting potential are characterised by comparably higher specific investment costs[59] but lower variable costs for load shifting. Load shifting includes reducing load in one hour and increase hour at a later point in time, i.e. not charging an e-car in hours with high scarcity on

59 Higher specific investment costs for information and communication technologies for load shifting potentials arise from the smaller unit size.

wholesale level The Base Case includes increasing utilisation of load-shifting capacities, the de-rated capacity increases to the assumed maximum of investment potentials (540 MW).

Figure 27. De-rated*) DSR capacity



Source: Frontier
*) de-rated according to assumed availability in peak-period

3.3.4 Development of electricity prices

Power prices in the past 5 years fluctuated around 50 EUR/MWh but decreased recently to levels below 40 €/MWh. This drop in prices can be explained with decreasing fuel prices for conventional generation (see **Figure 12**), weak electricity demand due to the economic crisis in Europe, increased in-feed from renewable energy sources in Central-Western-Europe as well as the low levels of CO_2-prices. In this section, we describe the model results regarding future development of electricity prices for the Netherlands.

Increasing price levels in the medium- to long-term

Based on the base case assumptions, we observe the following development of power prices:

- **Price levels remain low in the short term (2015-2020)** – We expect prices to increase from today's low level of 38 EUR (real, 2013)/MWh[60] to 46 EUR (real, 2013)/MWh in 2020.

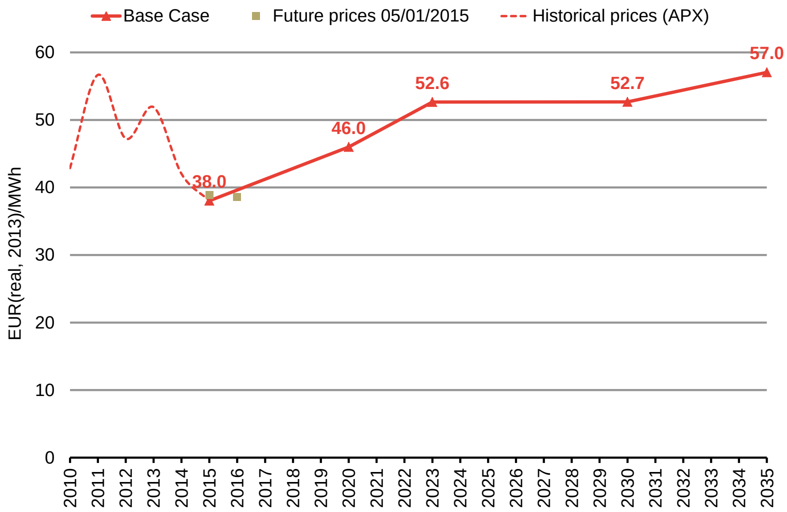
---

60 This development is in line with current market expectations and future prices which were noted below 40 €/MWh for 2015 (Trading day 05/01/2015).

- **Increasing power prices in the medium-term (2020-2023)** – We expect increasing prices for electricity in the Netherlands to 46 EUR (real, 2013)/MWh in 2020 and 52.6 EUR (real, 2013)/MWh in 2023. Main drivers of this development are:
  - Higher fuel and CO_2-prices that increase the short-run marginal costs of thermal power generation;
  - The completion of the German nuclear phase-out in 2023 decreasing generation capacity availability in Germany;
  - General reduction of overcapacity in Central-Western-Europe through retirement and mothballing of conventional generation capacity leading to increasing prices in European power markets.
- **Moderate price increase in the long-run (2030-2035)** – In the longer term, we expect that price levels will remain constant until 2030 and increase moderately until 2035 (57 EUR (real, 2013)/MWh). Further assumed increases in fuel and CO_2-prices drive the upward trend of wholesale power prices. This effect, however, is (over)-compensated by the following developments:
  - Higher in-feed from renewable energy sources in Europe, especially Germany;
  - More interconnection capacity to neighbouring countries and generally across Europe allows to run of the European electricity system more and efficient and therefore to reduce costs; and
  - Reactivation of mothballed capacity strengthens the supply side of the market.

Figure 24 shows the development of prices in the Netherlands.

Figure 28. Power prices (yearly average, NL)



Source: Frontier
Modelled years: 2015, 2020, 2023, 2030, 2035

Increasing price volatility and high price spikes in the long-run

Based on increasing in-feed from intermittent renewable energy sources in CWE, we expect that volatility of prices will increase significantly in the longer term. Increasing shares of RES-E in the electricity system affects the prices in two ways:

- high prices in times of low in-feed from RES-E, especially wind and solar PV – prices peak especially in a low number of hours with low RES-E in-feed and high electricity demand. For example in winter times in the early evening when in-feed from solar PV is very low but demand increases with high domestic consumption of electricity; and
- very low prices in times of high in-feed from RES-E, for example at night on very windy week-end, i.e. when demand is comparably low but in-feed from wind-power is high.

In the model, we observe this effect in the Netherlands especially after 2030, with price spikes above 2,000 EUR (real, 2013)/MWh in 2030 and above 3,300 EUR (real, 2013)/MWh in 2035 but also negative prices caused by very high much RES-E supply in the system.[61] **Figure 29** shows the price duration curve of

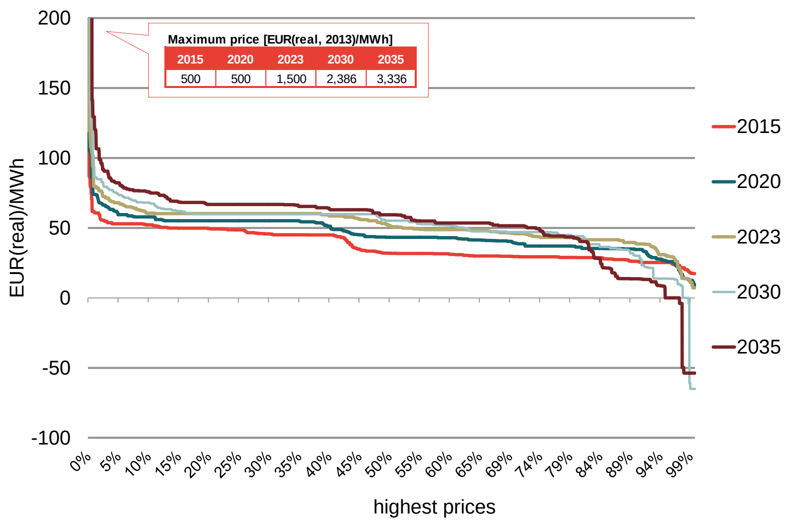
---

61 Price peaks in specific hours will only be paid by a very limited number of market participants: Consumer prices are in most cases fixed prices that means wholesale price peaks are not passed-on to many consumers on a real-time basis. Furthermore, electricity retail companies and large industrial consumers buying power on the spot market can hedge against price peaks e.g. by buying

the Netherlands for the modelled years (hourly prices ranked from the highest hourly price to the lowest hourly price):

- Price curves in later years are shifted upward reflecting higher overall price levels due to higher fuel costs for thermal generation;
- Higher share of hours with very high prices and with very low prices resulting from higher RES-E shares in Europe.

Figure 29. Price duration curve (NL)



Source: Frontier

The changing price pattern affects also the daily structure of wholesale electricity prices:

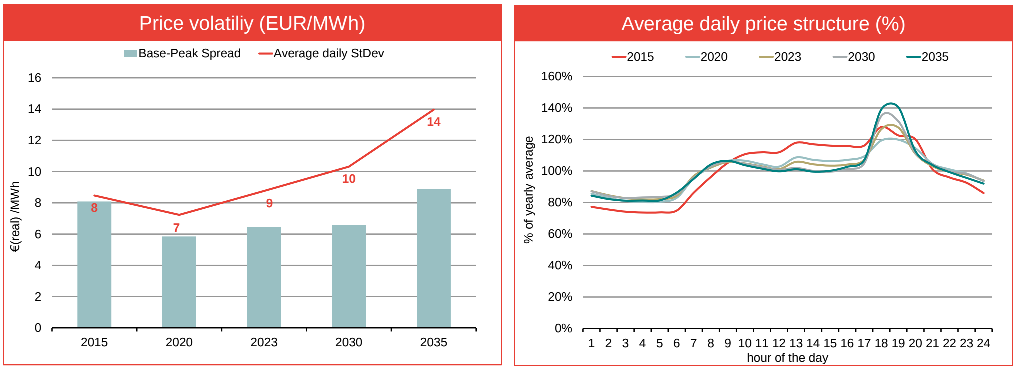
- Lower price peaks during the day (at noon) due to higher in-feed from solar PV;
- Increasing price spikes in peak load hours in the early evening (18h-19h); and
- Activation of demand side response (load shifting) and storages across Europe increase prices in off-peak periods.

Figure 30 shows the daily price structure expressed as average hourly prices divided by the annual average power price (right-hand side of **Figure 30**). The

power on the forward market, by purchasing options or by backing up procurement with own generation capacities or demand flexibility. These risk hedging contracts can form constant revenue streams for power plant operators and are therefore important for the market. Only market participants which have not hedged against price risks will face potential short term price peaks.

left-hand side graph provides two volatility measures, the base-peak spread[62] and the average daily standard deviation of prices. Both measures indicate an increase of price volatility in the long-run.

Figure 30. Price volatility and daily price structure



Source: Frontier

Increased integration of Dutch and German power prices after 2020

We expect an increasing convergence of prices in Central-Western-Europe (CWE) and especially between the Netherlands and Germany:

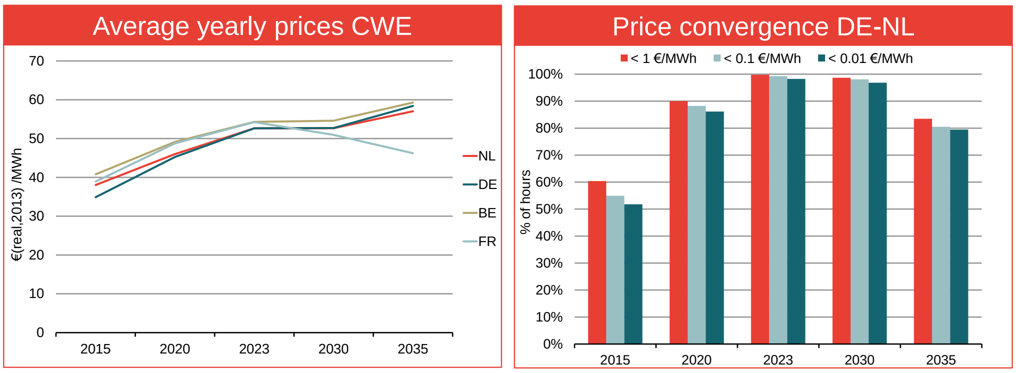
- **Belgium faces the highest prices in CWE, France the lowest prices in the long-run**
  - We expect that Belgian power prices (beige line, **Figure 31**) are the highest in CWE, induced by the tightest supply situation regarding generation capacities.
  - German wholesale power prices are the lowest in the short-term but increase after 2020 due to the completion of the nuclear phase-out and increasing fuel and emission costs especially for coal and lignite power generation (dark blue line, **Figure 31**).
  - Prices in France (light blue line, **Figure 31**) increase until 2023 but decrease afterwards to levels significantly below the other countries. This can be explained by the assumed development of generation capacity subject to the French capacity mechanism as well as by increasing power generation from renewable sources lowering wholesale market prices.

62 Peak period: Weekday, hours 9-20.

- **Medium-term convergence of Dutch and German power prices** – The completion of the interconnector expansion between the Netherlands and Germany as well as an increasing convergence of the power plant parks (higher wind power capacity in NL, decommissioning of nuclear and coal plants in Germany) lead to a significant price convergence between the two countries: The hourly price differences between Germany and the Netherlands are below 1 €/MWh
  - in 55% of the modelled hours in 2015;
  - in 85% of the modelled hours in 2020;
  - in 99% of the modelled hours in 2023 and 2030; and
  - 84% of the modelled hours in 2035. (**Figure 31**). The weaker price correlation from 2030 to 2035 is caused by lower prices in the Netherlands in off-peak periods due to new base load power generation coming into operation (nuclear power plant).

It has to be noted that our assumptions only include known interconnector projects. With increasing price differences in the future, additional interconnectors could be built in the very long-run. For example, in the model French electricity prices diverge significantly in the very long term. This is due to the fact that the power generation mix across the countries is still changing significantly whereas no major x-border transmission grid extensions are assumed after the year 2030. In practice, it can be expected that additional interconnectors beyond known projects as well as the implementation of flow-based market coupling in the CWE region will increase convergence also in the long-run.

Figure 31. Price development in CWE



Source: Frontier

3.4 Power market outlook – Sensitivity Analysis

In this section, we summarise the results of the power market simulations for variations of selected input parameters. We have defined six sensitivities, in which we modify assumptions for fuel and CO_2 prices; the development of generation capacities outside the Netherlands and for the demand response potential. The sensitivities represent possible developments of these parameters but do not represent the most likely outcome based on our reasoning.

The sensitivity analysis aims at identifying the impact of the parameters on the market outcomes (electricity prices, x-border power flows, investments and power generation) and therefore their impact on the costs of the electricity supply system. This analysis allows us to understand how the electricity system reacts to specific exogenous developments.

The sensitivities can be characterised as follows:

- **Sensitivity 1a "low CO_2-prices"**: effect of substantial lower CO_2-prices (**section 3.4.1);**
- **Sensitivity 1b "high CO_2-prices"**: effect of substantial higher CO_2-prices than in the Base Case (**section 3.4.2)** ;
- **Sensitivity 2 "High fuel prices"**: effect of substantial higher fuel prices for coal and gas-fired power plants (**section 3.4.3);**
- **Sensitivity 3 "Slow growth of wind power"**: effect of lower growth of wind-energy in the Netherlands (**section 3.4.4);**
- **Sensitivity 4 "Increased foreign capacity"**: effect of higher installed capacities in Belgium and France e.g. due to higher capacity procurement in capacity mechanisms (**section 3.4.5**); and

- **Sensitivity 5 "Higher demand side response (DSR) potential"**: effect of higher load shifting potentials in the Netherlands (**section 3.4.6).**

Main results of the sensitivity analysis

The sensitivity analysis aims at identifying the impact of the parameters on the market outcomes. It allows to understand how the electricity system reacts to a set of specific exogenous developments:

- **Lower CO_2-prices decrease electricity generation in the Netherlands** – Low prices for carbon dioxide emissions reduce power generation in the Netherlands (especially gas-fired power generation), as emission-intensive generation for example from German lignite plants becomes more economical. Furthermore, we observe higher levels of coal-fired capacity in the Netherlands and other regions.

- **High CO_2-prices beneficial for electricity generation in the Netherlands** – High prices for carbon dioxide emissions on the other hand induce higher power generation in the Netherlands since the Dutch power plant mix has a relatively high share of low-emission gas-fired plants. As a result, more electricity is exported to other regions. Furthermore, mothballed power plants (natural gas) are reactivated earlier in the Netherlands.

- **Higher fuel prices more beneficial for coal-fired plants** – Higher fuel prices for gas and coal are more favourable for coal-fired generation than for gas if the price increase holds for both primary energies equally in relative terms. Gas-plants are affected more from the price increase due to a higher variable-to-fixed cost relation compared to coal plants. The outcome is more coal-fired plant capacity and higher net-imports into the Netherlands. Furthermore, wholesale power prices would be substantially higher in the Netherlands than in the base case.

- **Lower shares of renewable electricity in the Netherlands would be substituted primarily by imports** – If the envisaged growth of wind power generation until 2020 is lower than expected, the lack of generation would be substituted with imports from Germany and a moderate increase of gas- and coal-fired power generation in the Netherlands. The effect on wholesale power prices, however, is limited compared to the previous sensitivities.

- **Spill-over effects from foreign capacity mechanisms may decrease capacity in the Netherlands** – Foreign capacity remuneration mechanisms (CRM) can have an adverse effect on capacity provision in the Netherlands, if the foreign capacity mechanisms lead to overcapacities in the region (e.g. if foreign countries didn't take contributions from interconnected capacities into account in the capacity balance). However, due to sufficient levels of cross-border interconnection capacity to its neighbours, we don't expect a threat to the security of supply of the Dutch electricity sector in this case. In addition, higher capacities in the region lead to lower electricity price levels on the energy market. This in return, is beneficial for Dutch consumers, who do no bear the additional costs of financing the additional capacities built under the foreign CRM (see **section 4)**.

- **Limited impact of additional demand response potential** – Additional DSR potential, especially load shifting, does not substantially affect the installed power plant capacity in the Netherlands. However, the power price volatility is reduced due to the increased availability of demand side flexibility. Therefore, market conditions become more favourable for base-load generation, i.e. coal-fired plants, compared to gas-fired plants.

3.4.1 Sensitivity 1a "low CO2-prices"

In this section, we describe the assumptions and the main results for sensitivity 1a "low CO_2-prices".

Motivation and assumptions

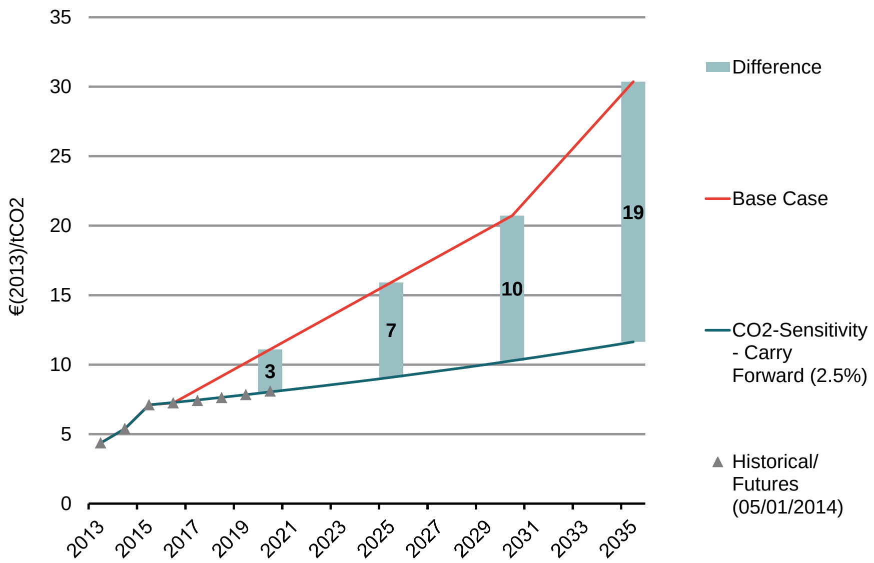
The European Union has implemented the EU ETS as the central climate policy instrument. In the Base Case, we assume that the EU ETS will remain the central instrument of climate change in the European Union. Therefore, we assume that prices for carbon dioxide emissions will increase to 30 EUR (real, 2013)/tCO_2 in the long-run.

In the sensitivity, we explore how the electricity system reacts to CO_2-prices that are substantially lower than in the Base Case. Low prices for carbon dioxide emissions reduce the incentives to reduce CO_2 emissions inside the EU ETS. However, future CO_2 prices are highly uncertain and depend on a magnitude of factors. For example, currently discussed reforms of the EU ETS may not be implemented or could turn out to only have limited effects on CO_2 prices. In this case, the EU ETS will only provide limited incentives to avoid CO_2 emissions in the future.

Lower CO2 prices can occur due to other reasons e.g. if CO2-abatement costs are lower than expected due to technological progress, the inclusion of other industry sectors in the EU ETS (with lower abatement costs), weaker economic growth than expected (which at the same time less economic activity and therefore means lower emissions), stronger growth in RES-E capacities in the system etc.

We assume in this sensitivity that prices will remain below 12 EUR (real, 2013)/tCO_2 (**Figure 32**).[63]

Figure 32. CO_2-price assumption sensitivity 1a "low CO_2-prices"



Source: Frontier

Lower CO_2-prices more favourable for coal-fired power generation

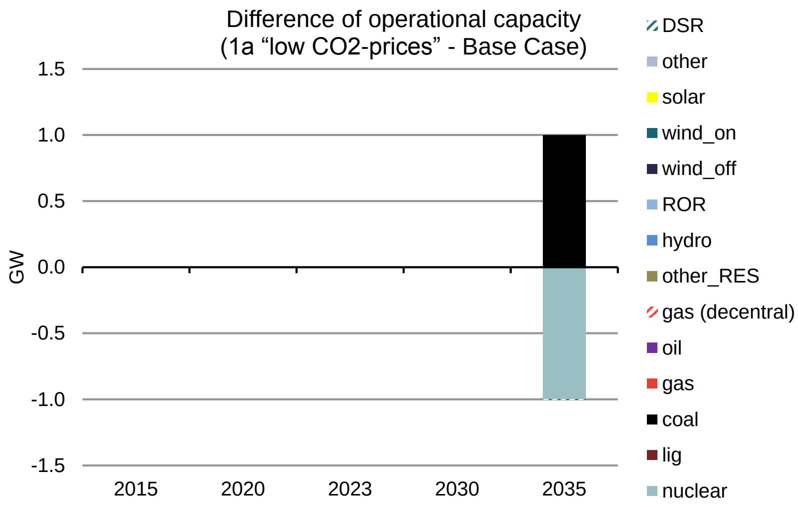
Lower costs for carbon dioxide emissions are more favourable for fuels with high emission factors, i.e. hard coal and lignite compared to natural gas. In the simulation, we observe the following effects on investment decisions and power plant dispatch in the Netherlands and Europe:

- **Long-term investment in nuclear power plant replaced with coal-fired investment** – In the Base Case, investment in a nuclear power plant can be observed in year 2035 in the model. In the sensitivity, this investment is replaced by hard-coal fired generation capacities. Apart from that, we do not observe other major effects on the capacity development in the Netherlands. However, in neighbouring countries, we observe slightly higher coal-fired capacity on the expense of gas-fired power plants.

  Figure 33 shows the difference of installed capacity in the Netherlands compared to the Base Case (negative values indicate less capacity for a specific fuel type).

63 The CO_2 price of the sensitivity has been derived according to a carry-forward logic (based on interest rate of 2.5%).

Figure 33. Sensitivity 1a: Impact on capacity (NL)



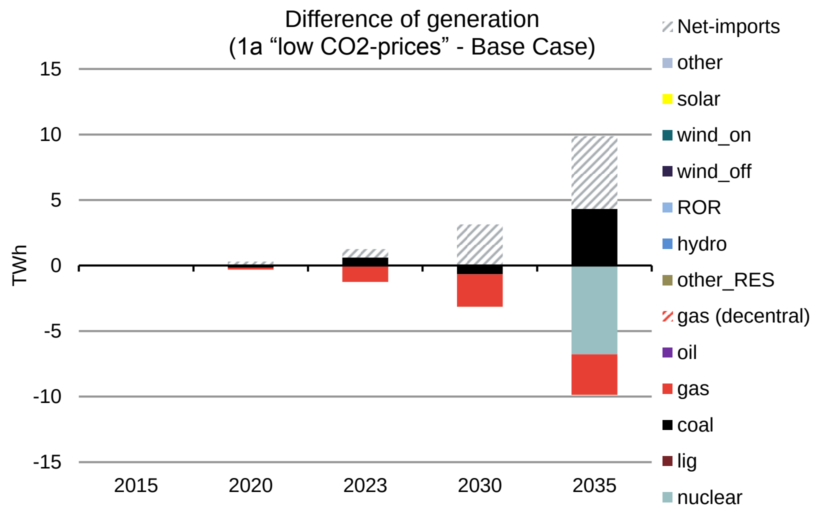
Source: Frontier

- **Less gas-fired generation and more coal-fired generation in the long-run** – Compared to the Base Case, power generation from gas-fired power plants in the short-term is lower and generation from coal-fired plants in the long-run is higher. In addition, imports to the Netherlands are higher due to an increase in low-cost lignite power generation in Germany.

  In the model, we observe an increase in coal- and lignite fired power generation in region by 8% in 2035 compared to the Base Case.

  Figure 34 shows the difference of power generation in the Netherlands compared to the Base Case (negative values indicate less generation from a certain fuel type).

Figure 34. Sensitivity 1a: Impact on power generation (NL)



Source: Frontier

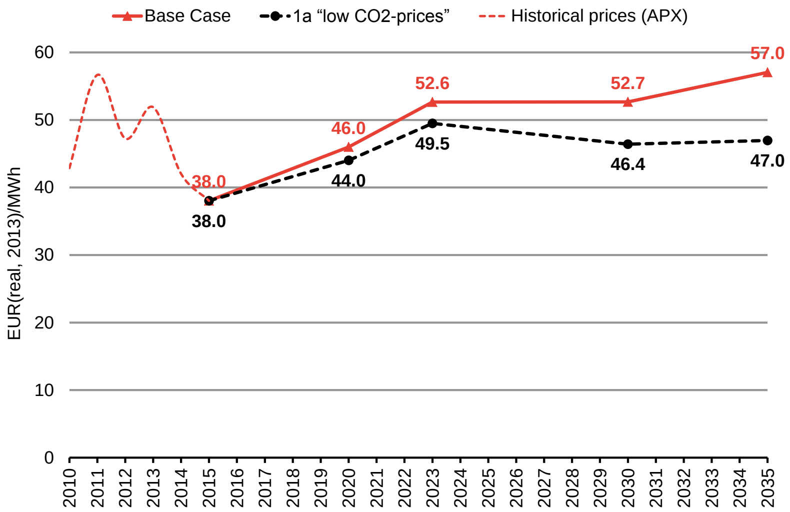
- **Higher CO_2-emissions in Europe –** With higher generation from carbon-intensive technologies, total CO_2-emission increase compared to the Base Case (+1.3% in total from 2015-2039). Emissions in the Netherlands, however, increase only slightly due to higher imports of power (0.1% from 2015-2039).

- **Lower wholesale prices in the Netherlands** – Lower CO_2 prices can induce downward pressure on power prices in two ways; firstly, generation cost of all conventional plants are reduced and therefore power prices decrease. Secondly, the market environment becomes more favourable for power plants with low variable costs but high emission factors (fuel switch).

  In the sensitivity, we observe

  - a moderate price effect in the short- to medium term (until 2023); but
  - a significant price effect in the long-run with price reduction of more than 10 EUR (real, 2013) in 2035 due to the emission costs.

Figure 35. Sensitivity 1a: Impact on power prices (NL)



Source: Frontier

3.4.2 Sensitivity 1b "high CO2-prices"

In this section, we describe the assumptions and the main results for sensitivity 1b "high CO_2-prices".

Motivation and assumptions

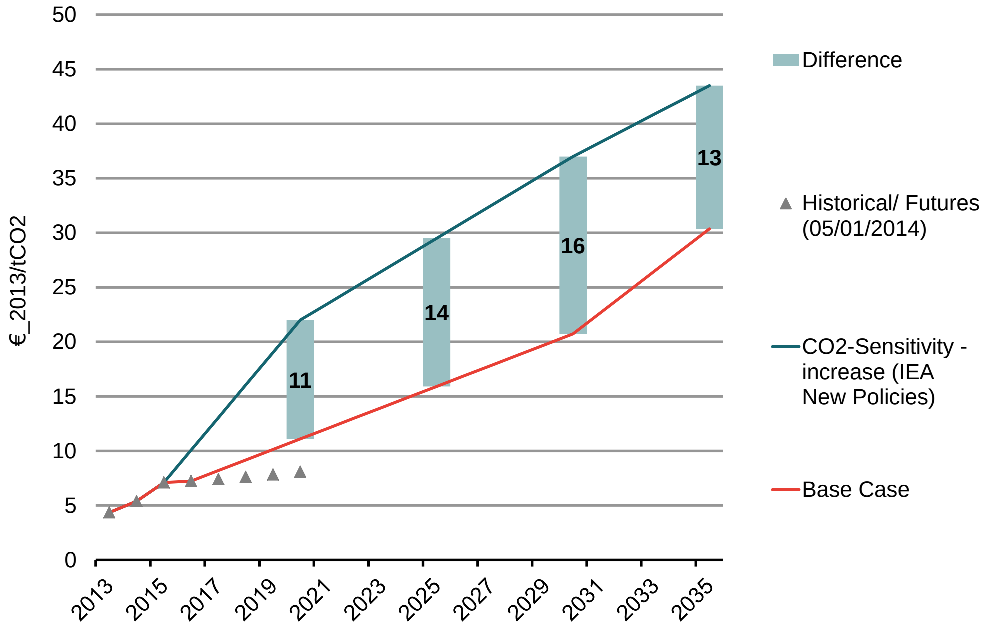
In this sensitivity, we examine the effect of higher prices for carbon dioxide emissions within the EU ETS. A steep increase in prices for emission allowances could be the result of a sudden increase in demand for EUA, following a strong recovery after the financial crisis. On the supply side, structural reforms of the EU ETS could include higher reduction factors in order to achieve the reduction targets and therefore less supply of certificates in the short term.

In this sensitivity, we explore how the market reacts to higher prices for emission allowances than in the Base Case, especially to what extent investment and divestment decisions are influenced by the CO_2-price development. Furthermore, in section 4.3, we will examine the effect of this variation on the profitability of renewable energy sources, as their costs are not directly affected.

We have based the assumptions of the sensitivity on the CO_2-price projection of the World Energy Outlook's "New Policies" scenario. We assume a significant increase of CO_2 prices in the short-term (2020) to 22 EUR (real, 2013)/tCO_2. In the long-run (2035), prices are assumed to increase to 43 EUR (real, 2013)/tCO_2 in 2035, i.e. 13 EUR (real, 2013)/tCO_2 above the Base Case.

Figure 36 shows the CO_2-price assumption in this sensitivity as well as the absolute difference to the Base Case.

Figure 36. CO_2-price assumption sensitivity 1b “high CO_2-prices”



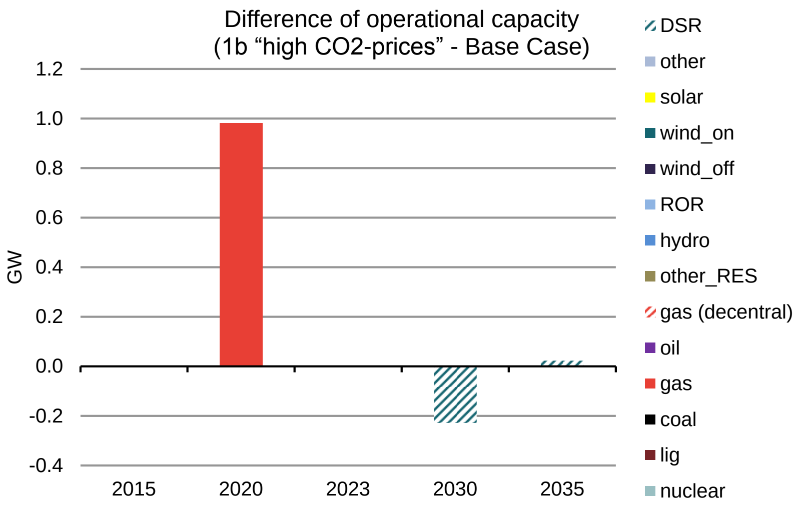
Source: Frontier

High CO_2 prices more favourable for gas-fired generation

High costs for carbon dioxide emissions are detrimental for technologies that have benefited from low carbon prices in the previous sensitivity, i.e. coal-fired power generation. Accordingly, we observe higher levels of gas-fired generation than in the Base Case. In detail, the main effects of the sensitivity can be summarised as follows:

- **Reactivation of mothballed capacity in the Netherlands takes place earlier** – Mothballed power plants are reactivated earlier than in the Base Case in the Netherlands. In total, additional gas-fired capacity of approximately 1 GW is operational in 2020. Furthermore, load-reduction capacities enter the market later in 2035.

Figure 37. Sensitivity 1b: Impact on capacity (NL)

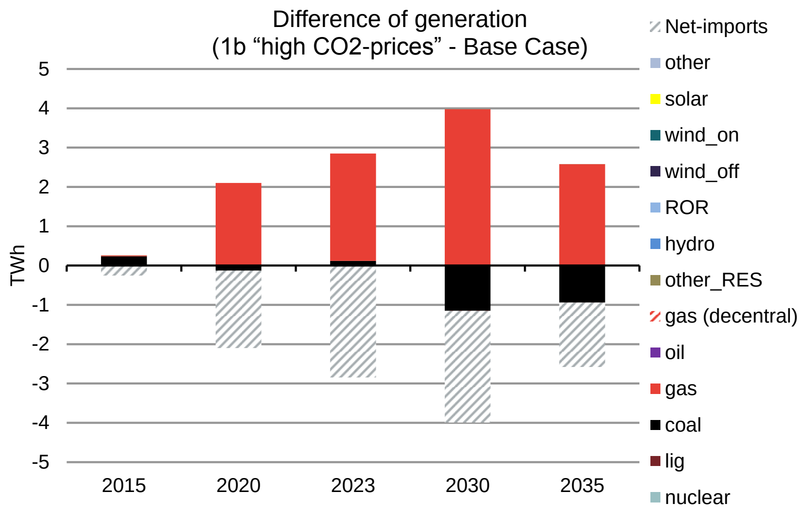


Source: Frontier

- **Higher gas-fired power generation and exports** – With higher costs for carbon emissions, natural gas plants achieve a cost advantage over coal-fired plants in the short term power plant dispatch (fuel-switch):
  - Gas-fired generation in the Netherlands increases by 11% and across all regions by 12% in 2035; while
  - Coal-fired plants in the Netherlands decreases by 5% and across all regions by -10% (coal and lignite).

  The increase of gas-fired generation is used almost entirely to export power to other regions, especially to Germany with its high share of emission-intensive power plants that are affected most from higher CO_2-prices.

Figure 38. Sensitivity 1b: Impact on power generation (NL)



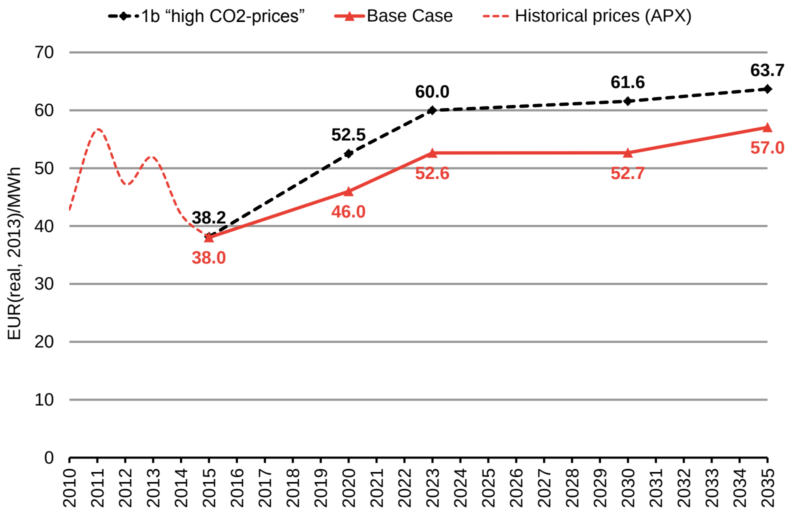
Source: Frontier

- **Additional generation increases total emissions in the Netherlands** – Due to a less carbon-intensive power plant park; electricity supply in the Netherlands becomes less costly than e.g. in comparison to Germany. As described above, this leads to higher exports of power to foreign countries in the long-run and therefore to moderately higher carbon dioxide emissions within the Netherlands (+1.4%; 2015-2039).

  However, the net-effect in all modelled regions is negative as total emissions from electricity supply decrease compared to the Base Case due to higher CO_2-prices (-3.3%; 2015-2039).

- **Price increase due to higher cost for carbon emissions** – Higher costs for carbon dioxide emissions increase the variable costs of power generation. Consequently, power prices in the Netherlands increase to
  - levels above 50 EUR (real, 2013)/MWh already in 2020;
  - reaching more than 63 EUR(real, 2013)/MWh in the long-run (2035).

Figure 39. Sensitivity 1b: Impact on power prices (NL)



Source: Frontier

3.4.3 Sensitivity 2 "High fuel prices"

In this section, we describe the assumptions and the main results for sensitivity 2 "High fuel prices".

Motivation and description

In this sensitivity, we examine the effect of higher primary energy prices, i.e. fuel prices for gas and coal-fired power plants. As described in section 3.2.1, we have derived our Base Case fuel price assumption from the World Energy Outlook oil price projection. The WEO foresees a moderate increase of oil prices in the long-run. This translates in moderately increasing prices for natural gas and coal in the Base Case (see **section 3.2.1**).

The future development of primary energy prices is highly uncertain. Therefore, we analyse the impact of a potential significant variation in future fuel prices on the Dutch power market in this sensitivity. For this purpose, we use the oil-price projection of the U.S. Energy Information Administration (Annual Energy Outlook 2014, "high-price scenario") instead of the World Energy Outlook (New Policies scenario). EIA's Annual Energy Outlook "high-price scenario" assumes a significant increase in oil-prices in the long-run due to increased industrial oil-demand, e.g. from the chemical industry,[64] reaching 180 $ (2010)/bbl in 2035 (ca. 120 $ (2010)/bbl in the Base Case)

64 EIA (2014), AEO MT-3.

Based on this oil price assumption, we derive the following fuel price development for sensitivity 2 “High fuel prices”:

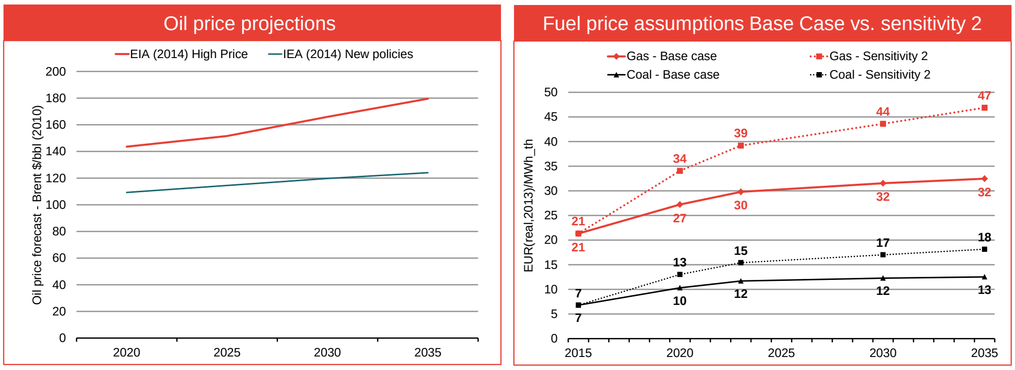
- Gas prices increase to 34.1 EUR (real, 2013)/MWh(th) in 2020 and to 46.9 EUR (real, 2013)/MWh(th) in 2035; and

- Coal prices increase to 13 EUR (real, 2013)/MWh(th) in 2020 and to 18.1 EUR (real, 2013)/MWh(th) in 2035.

For both fuel types, this represents an increase of fuel prices of around 45% in 2035 compared to the Base Case. It should be noted, that the fuel prices for gas and coal are both increased by the same amount in relative term (as a %-change) compared to the Base Case. This allows us to examine to which extent different technologies are influenced by variable costs compared to fixed costs.

Figure 40 shows the different oil price projection (left-hand side) and the resulting fuel price assumptions (right-hand side).

Figure 40. Sensitivity 2 “High fuel prices”



Source: Frontier

High fuel prices more favourable for coal-fired generation

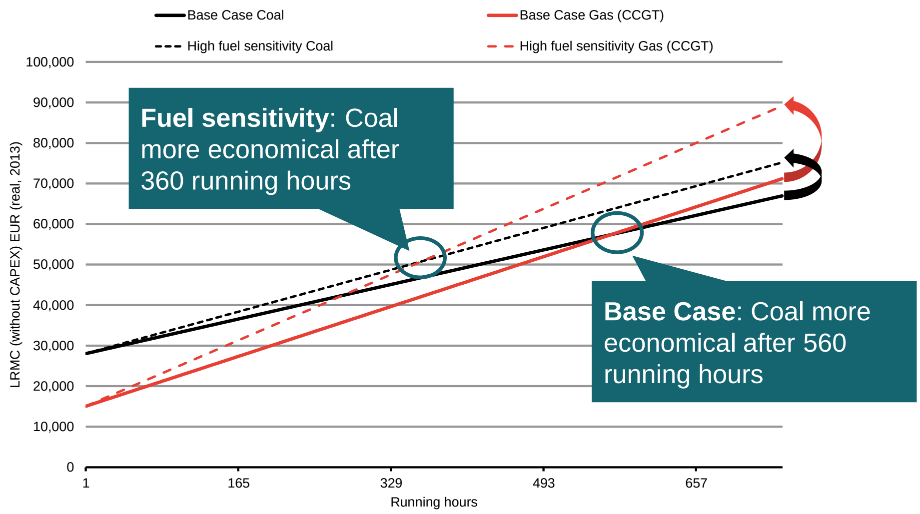
Even though fuel prices for gas and coal are both increased by the same amount in relative terms compared to the Base Case, the new fuel price relationships are more favourable for coal-fired generation as variable costs of power generation represent a higher share of total cost for gas plants compared to coal plants.

Figure 41 illustrates this effect based on an exemplary long-run marginal cost (LRMC) of power generation from coal and gas plants for 2030.[65] The LRMC (y-axis) are calculated in dependence from the full load hours/running hours (x-axis) of the plants in the example year. In the Base Case, coal-fired power plants

65 The calculated LRMC are based on short-run marginal costs of power generation (i.e. fuel costs and costs of CO_2) plus fixed operation and maintenance costs.

are more economic than gas plants if the plant runs more than 560 hours. In the sensitivity, coal-fired power plants are more economic than gas plants if the plant runs more than only 360 hours: The intersection of the LRMC curves of coal and gas, i.e. coal being more economical than gas, is located more to the left, i.e. with less running hours than in the Base Case.

Figure 41. Exemplary LRMC calculation "High fuel prices"



Source: Frontier

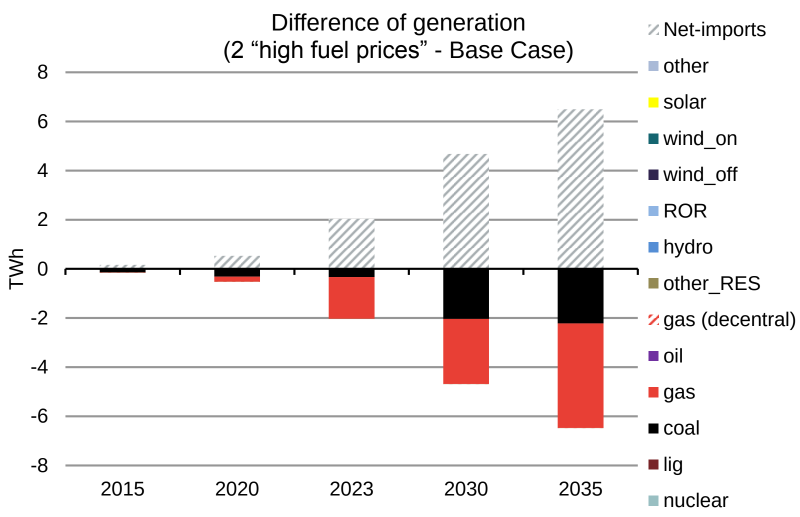
- **Limited effect on generation capacity in the Netherlands** – Based on **Figure 41**, we have shown that coal plants achieve a comparative advantage over gas plants from higher fuel prices if both prices are increased to the same extent (in relative terms). However, the effect on the development of generation capacity in the Netherland is insignificant.

  In the CWE region, gas-fired generation capacity decreases by 3.6 GW in 2035, and coal-fired generation capacity increases by 5.2 GW in 2035 compared to the Base Case.

- **Increase in net-imports in the Netherlands** – The Dutch electricity market is characterised by a relatively high share of fossil fuelled power generation capacities. Therefore, dispatch of the power plants is significantly affected by the fuel price increase:
  - With increasing fuel prices over time, power generation from gas- and coal-fired plants in the Netherlands decreases by around 6 TWh in 2035;
  - At the same time, exports of power decrease while imports increase (**Figure 42**).

In all modelled regions, gas fired power generation decreases by 7% in 2035 and coal and lignite fired power generation increases by 5 % compared to the Base Case.

Figure 42. Sensitivity 2: Impact on power generation (NL)

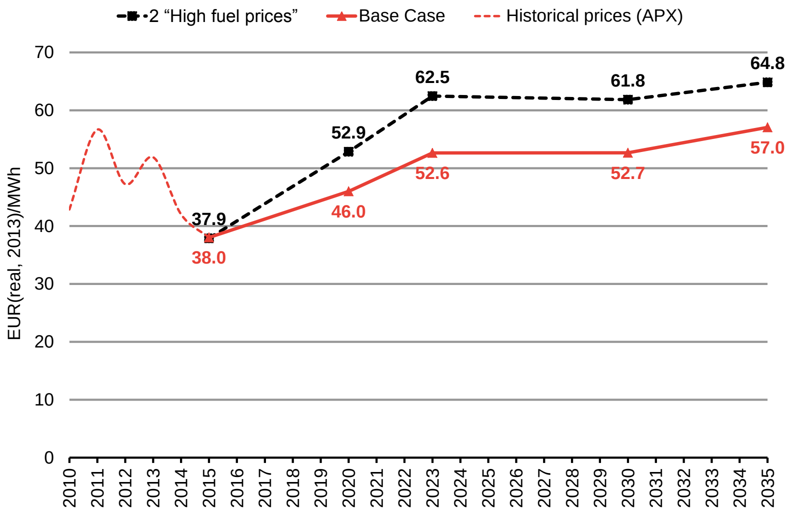


Source: Frontier

- **Less carbon dioxide emission in the Netherlands** – Due to decreasing domestic electricity generation, CO2-emissions decrease in the Netherlands by -3% in total from 2015 to 2039. On the other hand, total CO_2 emissions in all regions increase by 0.4% (2015-2039) as coal generation is more economic than natural gas.

- **Higher fuel prices increase wholesale prices for electricity –** We observe increasing electricity prices due to higher variable costs of conventional power generation in the sensitivity. Compared to the Base Case, prices increase
  - by 15% to 53.3 EUR (real, 2013)/MWh in 2020; and
  - by 13% to 65.4 EUR (real, 2013)/MWh in 2035 (**Figure 43**).

Figure 43. Sensitivity 2: Impact on power prices (NL)



Source: Frontier

3.4.4 Sensitivity 3 "Slow growth of wind power"

In this section, we describe the assumptions and the main results for sensitivity 3 "Slow growth of wind power".

Motivation and assumptions

In the Energy Agreement, ambitious targets for the growth of wind-onshore and off-shore capacity are outlined. Goals are to increase

- wind-offshore capacity to 4.5 GW in 2023; and
- wind-onshore capacity to 6 GW in 2020.

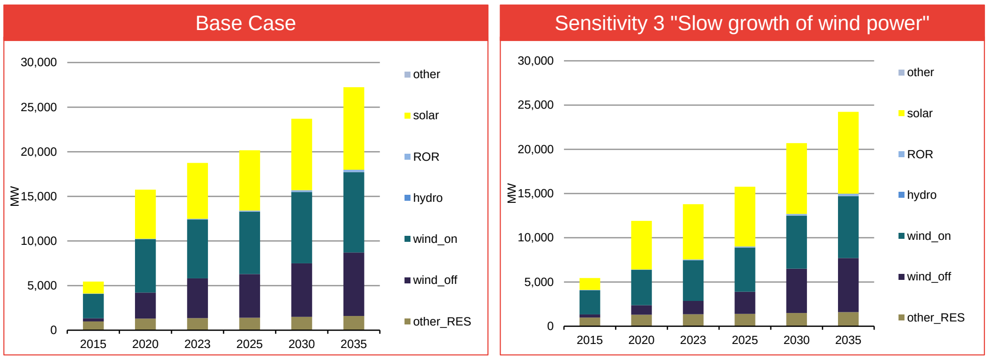
Future growth in RES-E power production depends on a number of factors such as e.g. the availability of sufficient sources for financing, future decisions on the RES-E support system and the duration of permitting procedures. Therefore, the increase in RES-E power generation is uncertain which may have a significant impact on the whole electricity system. Therefore, we examine the effect of a slowed-down expansion of wind power on the Dutch electricity system in this sensitivity.

We assume that the targets laid down in the Energy Agreement will be met only with a delay of 7 to 10 years. For the sensitivity, we derived the assumptions for RES-E (wind onshore and offshore) from the Nationale Energieverkenning (NEV) which analyses the growth of wind power in dependence from the implementation of different policy measures.[66] In detail, we assume in the sensitivity

- wind-offshore capacity to reach 1.5 GW in 2023; and
- wind-onshore capacity to reach 4 GW in 2020.

Targets for wind power outlined in the Energy agreement will be reached in 2030.

Figure 44. Development of installed capacity (RES-E) Sensitivity 3



Source: Frontier

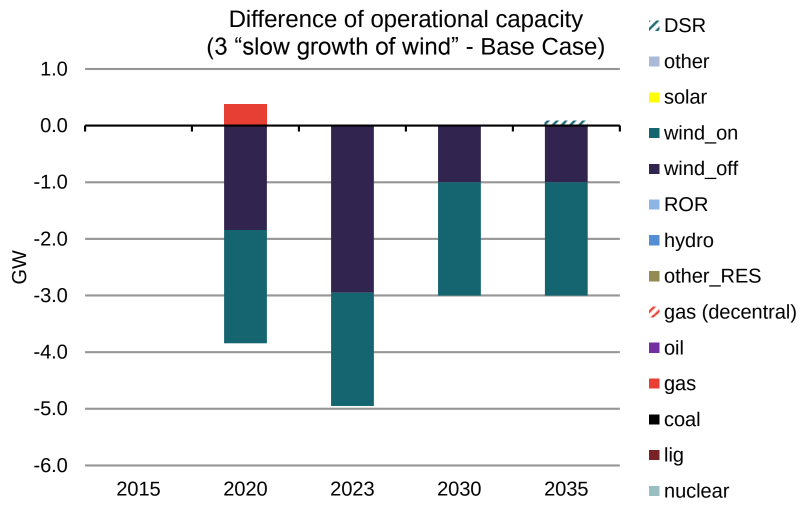
Reduced wind energy compensated with imports

Less wind-power has the following effects on the power market:

- **Reduction of wind power capacity with limited effect on conventional capacity in the NL** – The assumed reduction of exogenous wind capacity does not affect the investment and mothballing decisions in the Netherlands significantly, as sufficient interconnection capacity is available. 400 MW of gas-fired generation are reactivated in earlier (2020) than in the Base Case.

66 ECN/PBL (2014), p. 60-61.

Figure 45. Sensitivity 3: Impact on capacity (NL)



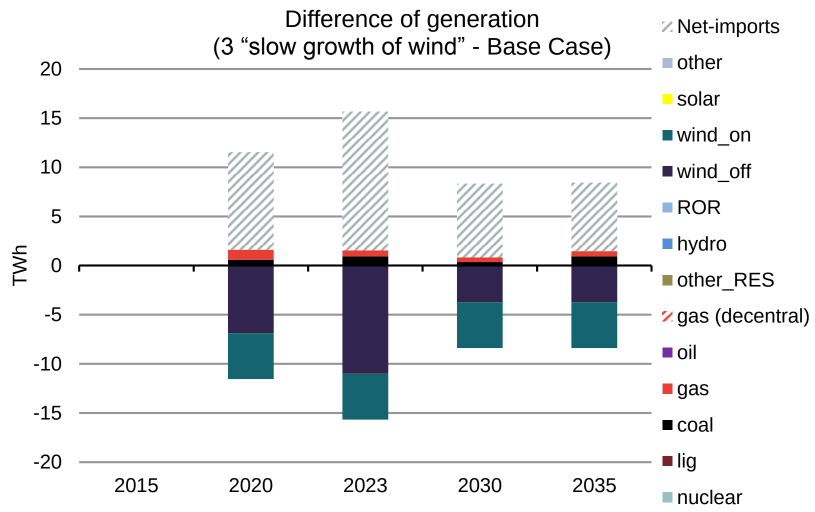
Source: Frontier

- **Lower wind power production compensated by higher imports** – As described above, lower wind capacity does not affect the capacity development in the Netherlands significantly. Instead, imports to the Netherlands increase compared to the Base Case and the Netherlands become net-exporter in 2023. In particular, net-imports
  - increase by 10 TWh in 2020 compared to the Base Case, especially from Germany (7 TWh); and
  - by 7.3 TWh in 2030.[67]

  Electricity generation within the Netherlands, especially generation from gas and coal-fired plants, increases slightly by 2 TWh in the short-term (2020).

67 Additional information on the imports/exports is included in Annexe 2.

Figure 46. Sensitivity 3: Impact on power generation (NL)

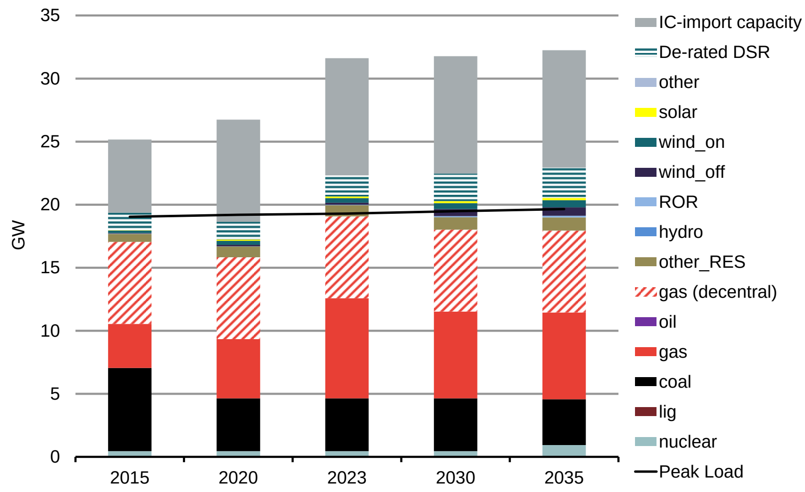


Source: Frontier

- **Security of supply not affected by lower wind-energy** – The reduced wind-power capacity does not affect the de-rated capacity balance of the Netherlands to a great extent, because of
  - Reactivation of mothballed plants that takes place earlier; and
  - The high de-rating of wind-capacity,

  The indicative adequacy reserve margin decreases only by small amount and remains positive in the long-run. As in the Base Case, no involuntary load-curtailment takes place (**Figure 47**).

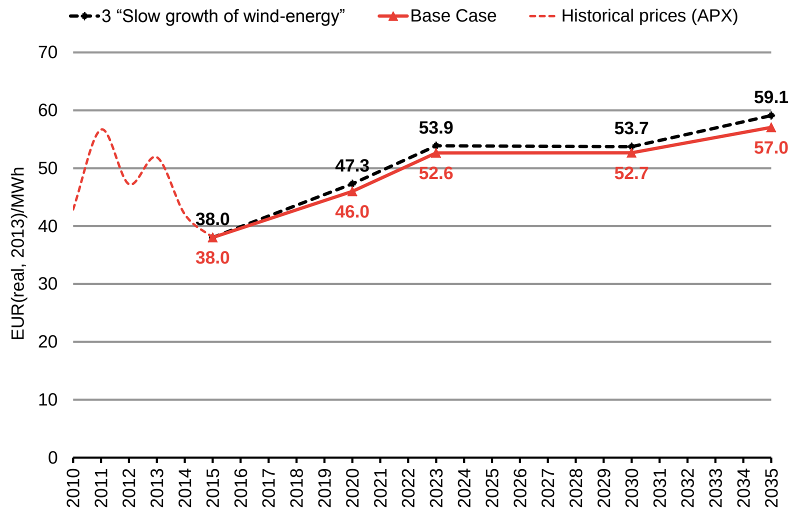
Figure 47. Capacity balance (de-rated), Sensitivity 3



Source: Frontier

- **Increase of emissions due to lower wind power generation** – Due to less RES-E power production with zero emissions, the utilisation of conventional power plants increases. Consequently, in the sensitivity, carbon dioxide emission are slightly higher than in the Base Case:
  - CO_2-emissions in the Netherlands (2015-2039) increase by 1.2% in total; and
  - Overall CO_2-emissions in all modelled regions increase by 1 % (2015-2039).
- **Limited effect on wholesale power prices** – Wholesale power prices are higher in the sensitivity than in the Base Case due to lower in-feed from wind installations in the Netherlands. However, the increase of between 1 and 2 EUR (real, 2013)/MWh is rather minor compared to the CO_2 price and fuel price sensitivities since the variable costs of price-setting power generation technologies remain unchanged (**Figure 48**).

Figure 48. Sensitivity 3: Impact on power prices (NL)



Source: Frontier

3.4.5 Sensitivity 4 "Increased foreign capacity"

In this section, we describe the assumptions and the main results for sensitivity 4 "Increased foreign capacity".

Motivation and assumptions

The introduction of capacity remuneration mechanism (CRM) is discussed in in a number of European countries. CRMs aim at controlling the national amount of power generation capacity in the respective country, or at least at increasing incentives to invest in new power generation capacity (including demand flexibility) and/or to keep existing plants in operation. This, in return can affect investment and power plant dispatch in interconnected or neighbouring countries, especially if substantial additional power plant capacity is built due to the CRM compared to a market design without a CRM. The effect on investment and power plant dispatch crucially depends on the extent to which the CRM affects the total capacity in the market. For instance, if vast capacity is procured in context of the CRM, i.e. with a high additional adequacy margin (potentially leading to significant over capacities), power prices are inclined to decrease in all affected countries.[68]

Some EU member states have already taken the decision or already have introduced some sort of capacity mechanism across Europe, for example:

68 See **section 5.2.4** for the evaluation of international spill over effect.

- **France** is introducing a mechanism that obliges all electricity suppliers to secure their supply with so-called "capacity-certificates". These certificates can either be purchased from capacity owners or be self-procured in vertically-integrated entities.[69]
- **Belgium** has introduced a strategic reserve by contracting a certain amount of additional capacity which is not taking part in the energy market but can be made available in periods of extreme scarcity.[70]
- The **United Kingdom** has introduced a comprising CRM in which total capacity is procured in central auctions.[71]

In the Base Case, we have taken the French capacity mechanism into account as an additional capacity constraint in the model; installed capacity in France shall not be lower than peak-load, corrected by de-rated interconnection capacity. For the definition of capacity requirements in a CRM, it is crucial to take interconnection and available foreign generation capacity into account. Otherwise, the contribution of foreign capacities to domestic security of supply is underestimated leading to over capacities in the market.

In order to analyse the potential impact of variations in the design of foreign CRMs on the Dutch electricity market, we vary the calculation of the capacity requirements in the French CRM. Furthermore, we assume a potential future comprehensive CRM in Belgium (e.g. similar to the CRMs in France or UK). It has to be noted that these variations are hypothetical and arbitrary and serve only to illustrate potential x-border effects on the Dutch power market:

- **Implicit contribution of foreign capacity in the Base Case** – According to the French TSO, approximately 50% of installed interconnection capacity is included in the calculation of the overall level of capacity obligations (capacity requirements).[72] Therefore, we have reduced the capacity demand (peak load) by half of installed interconnection capacity. This leads to a long-term decrease of capacity requirements as more interconnection capacity is built in the future:
  - 95.2 GW in 2020; and
  - 93.3 GW in 2035.

69 RTE (2014).

70 Elia (2014).

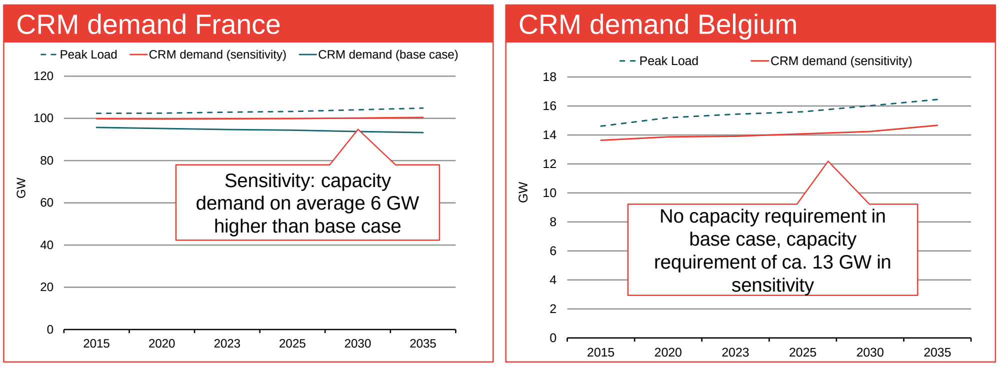
71 This CRM is not included in the model as capacity development is an exogenous assumptions for the UK.

72 RTE (2014) p. 94; Additional information on the parameterisation of CRM is included in the Annexe 2

- **Implicit contribution of foreign capacity in the sensitivity** – In the sensitivity, we assume that the contribution from foreign capacity to security of supply in France is reduced to 20% of installed interconnection capacity in the calculation of the CRM capacity requirements. This results in an additional capacity requirement of
  - 4 GW in 2020 (99.2 GW); and
  - 7 GW in 2035 (100.3 GW).
- **Capacity demand in Belgium (sensitivity 4)** – The capacity requirements of the assumed (and hypothetical) CRM in Belgium are calculated similar to the logic for France.: The capacity requirement is calculated as peak-load minus implicit contributions of interconnection capacity of 20% of installed interconnection:
  - 13.9 GW in 2020; and
  - 14.7 GW in 2035.

Figure 49 shows the definition of capacity requirements in France (left-hand side) and Belgium (right-hand side).

Figure 49. Definition of CRM capacity requirements (Sensitivity 4)



Source: Frontier

Increased capacity requirement in other countries reduce capacity in the Netherlands

Assuming higher capacity requirements in France and Belgium has the following effects on the Dutch electricity market:

- **Higher retirement and later reactivation of gas-fired plants in the Netherlands** – Higher capacity requirements in France and Belgium have an adverse effect on capacities in the Netherlands. In the sensitivity, we observe (compared to the Base Case)

- 500 MW of gas-fired that are mothballed in the Base Case are decommissioned in the sensitivity; and
- Mothballed gas-fired capacities are reactivated in later years: In the Base Case, most mothballed power plants re-enter the market in the model-period of 2023. Higher capacity requirements in Belgium reduce the need to reactive mothballed capacities in the Netherlands:
  - In the Base Case, ca. 6 GW are reactivated until the model period 2023 (representing the years 2023-2029); whereas
  - In this sensitivity, only 3 GW re-enter the market in the same timeframe (until the model period 2023) while the remaining 2.5 GW are reactivated later.[73]

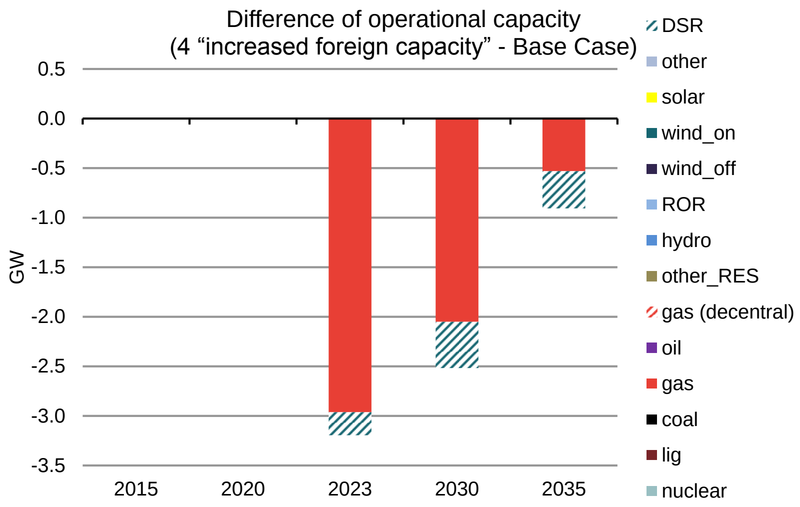
In total, operational gas capacity in the Netherlands is lower by up to 3 GW (peaking in year 2023). The difference disappears in the long-run, after reactivation of mothballed power plants.

Furthermore, slightly less investment takes place in DSR (load reduction) in the Netherlands since price volatility and price peaks in the wholesale power market are lower in the sensitivity than in the Base Case due to additional power plant capacity abroad (**Figure 50**).

Across all modelled countries, we observe a positive net-effect on capacity in the range of 5 to 9 GW (arising from more capacity in France and Belgium).

[73] It has to be noted that we do not assume technological limits related to the possible duration of power plant mothballing.

Figure 50. Sensitivity 4: Impact on installed capacity (NL)

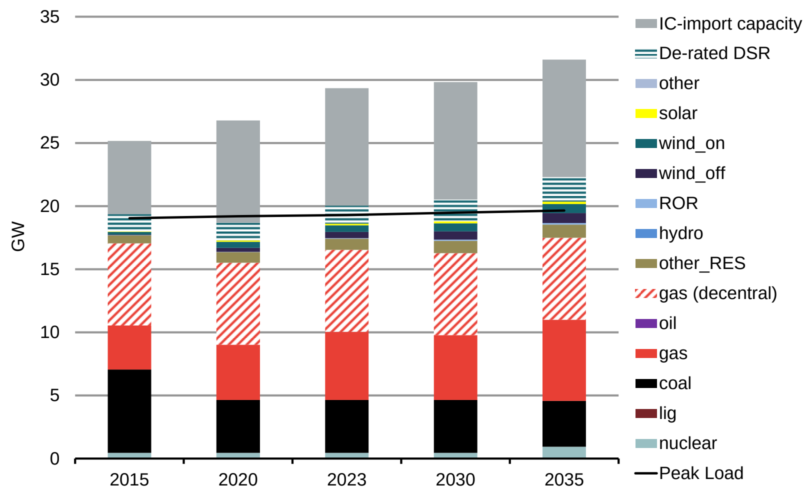


Source: Frontier

- **Lower reserve margins in the Netherlands but no threat to security of supply** – Higher capacity levels in Belgium and France lead to more decommissioning and motballing of power plants (see above). As this does affect the Dutch system only after 2023, the short-term reserve margins are not affected. In 2023, however, the reserve margin (without import-capacity) decreases from 3.5 GW to 0.7 GW. Taking into account interconnection, the margins remain highly positive (**Figure 51**).

  Therefore, this reduction of operational capacity does not signal a major threat to security of supply, as the mothballed capacity could still be reactivated and sufficient import capacities are available. As in the Base Case, no involuntary load-curtailment takes place.

Figure 51. De-rated capacity balance (NL), Sensitivity 4

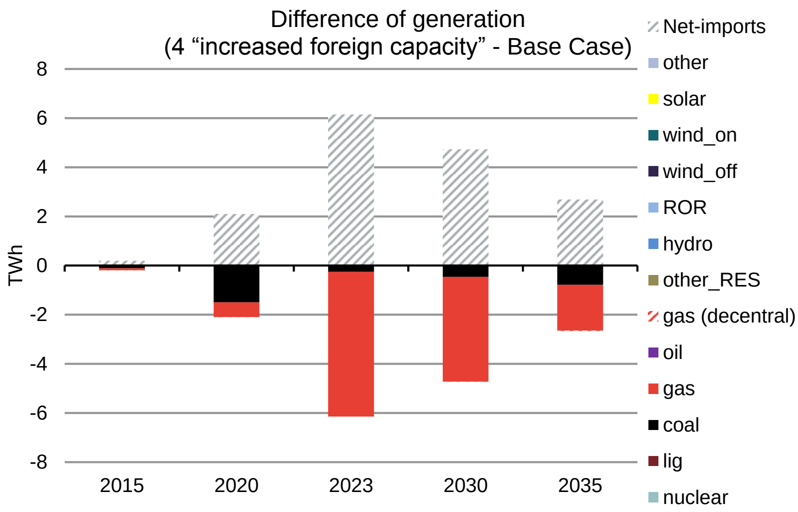


Source: Frontier

- **Increasing imports due to higher foreign capacity** – Even in the case of higher capacity requirements in neighbouring countries, the Netherlands would be able to ensure security of supply due to high levels of interconnection capacity. However, electricity generation within the Netherlands decreases and is substituted by foreign generation:
  - Power generation from gas and coal-fired plants decreases by 6 TWh (10%) in 2023.
  - More imports and less exports to/from Belgium take place (see Annexe 2 for details).

  Furthermore, access to foreign generation capacities has to be ensured also in potential periods of scarcity.

Figure 52. Sensitivity 4: Impact on power generation (NL)



Source: Frontier

- **Lower carbon dioxide emissions in the Netherlands** – Due to lower power generation within the Netherlands, CO_2 emissions decrease by 3.3% (2015-2039) compared to the Base Case. The net-effect across all modelled regions, however, is slightly positive, with an increase of 0.2%, because of more coal-fired power generation in Belgium.

- **Lower prices in the long-run due to surplus capacity** – The short-term effect of higher generation capacities in France and Belgium on Dutch wholesale power prices is limited. In the long-run, however, prices differences increase:
  - Prices are lower by less than 1 EUR (real, 2013)/MWh until 2023;
  - The differences increase to -1.3 EUR (real, 2013)/MWh) in; and
  - The impact is highest in 2035 with -4.9 EUR(real, 2013)/MWh due to the absence of very high prices in Belgium which could be observed in the Base Case to to a tight supply-demand balance.

3.4.6 Sensitivity 5 "Higher demand side response (DSR) potential"

In this section, we describe the assumptions and main results for sensitivity 5 "Higher demand side response (DSR) potential".

Motivation and assumptions

In the Base Case, an increasing potential for DSR (load reduction and load shifting) is assumed. However, the future potential for DSR is very uncertain especially in the long term.

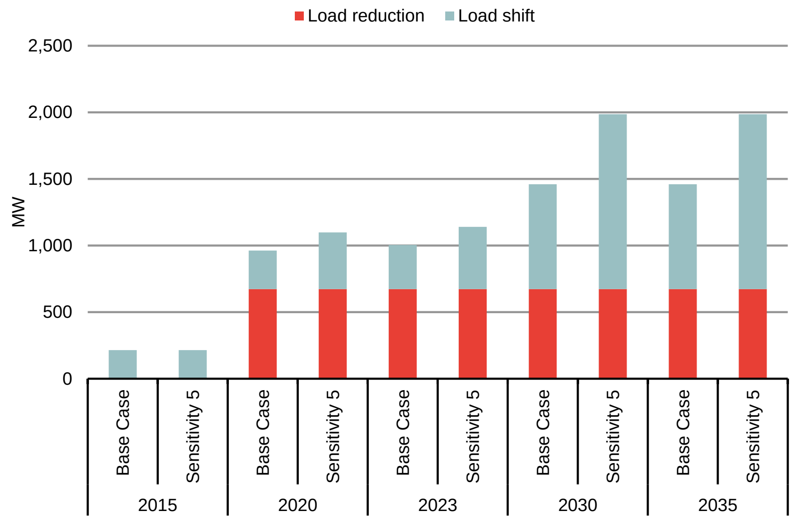
In order to analyse the effect of variations in the long term DSR potential on the Dutch electricity market, we model exemplary the effect of a higher potential for demand side response in the long term. Compared to the Base Case, the load shifting potential, i.e. heat-pumps and e-cars, is increased by 2 GW in 2020 and additional 1 GW in 2030.[74] The availability of DSR capacities in the model depends on assumed hourly availability factors that are based on typical consumption patterns for the different technologies (e.g. flexibility from heat-pumps is only available in winter periods). The 3 GW assumed additional investment potential (which is realised in the model only if it turns out to be economic) expressed in "installed capacities" correspond to ca. 500 MW of capacities de-rated according the average availability throughout the year.

The options to invest in load reduction capacities remain unchanged. **Figure 53** shows the development of the assumed DSR investment potential in the Base Case and in the sensitivity.

---

74 Installed capacity,

Figure 53. Development of DSR investment potential (de-rated capacity, excl. existing capacities)



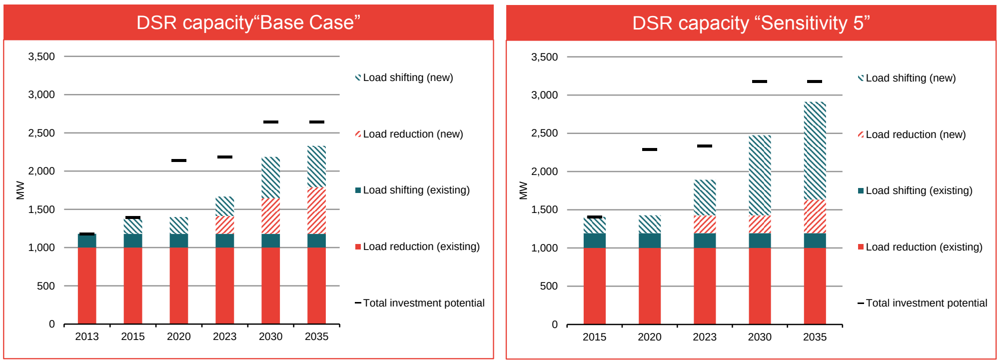
Source: Frontier

Higher Demand Side Response potential with limited effect on power market

In this sensitivity, higher potentials to invest in load shifting capacities are assumed the model. The sensitivity captures uncertainties around the medium and long term demand side flexibility potential in the Netherlands. Load-reduction potentials that exhibit lower investment but higher variable costs than load-shifting remain the same. Assuming higher investment potentials for DSR (load shifting) has the following effects on the power market:

- **Higher investments in DSR –**As a result of the optimisation, the model decides to invest more into the increased load-shifting flexibility and less into load-reduction capacities (in the long-run). Based on the average availability of those capacities throughout the year
  - 500 MW additional load-shifting capacities enter the market; while
  - Investment in load-reduction capacities decreases by 140 MW(**Figure 54**).

Figure 54. Sensitiviy 5 – impact on DSR investments*) (NL)



Source: Frontier
*) de-rated capacity according to assumed average yearly availability

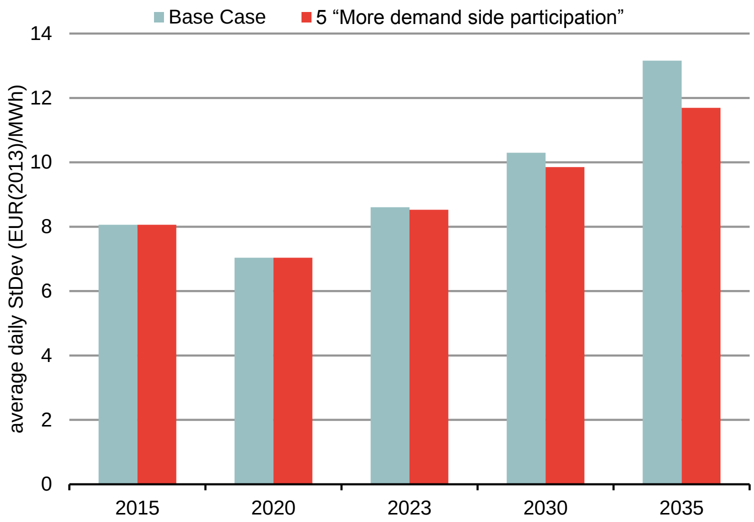
- **Limited effect on power plant capacity and generation in the Netherlands** – Higher demand side response is not affecting installed power generation capacity in the Netherlands since the assumed additional DSR potential are not used to the full extent and because investment in load reduction capacities decreases.

  Power generation in the Netherlands is affected to a small extent. The additional load shifting capacities reduce load in peak times and move consumption to off-peak time. Therefore we observe

  - Less gas-fired power generation (- 240 GWh in 2030) and
  - higher imports (+180 GWh) and coal-fired power generation (+ 90 GWh) in the Netherlands.

- **Additional demand-side participation reduces price volatility** – Increased demand side response to wholesale power price signals decreases the volatility of power prices: With more DSR capacity operational in the long-run (2035), the average daily standard-deviation of Dutch wholesale power prices decreseases from 13.2 EUR (real, 2013)/MWh to 11.7 EUR (real, 2013)/MWh. Wholesale power price levels remain unchanged.

Figure 55. Sensitivity 5: Impact on price volatility (NL)



Source: Frontier

4 Affordability of the electricity system

In this section, we summarise the results of the analyses regarding the affordability of electricity supply. The analysis is largely based on the quantitative market modelling described in the previous chapter and further analyses. We identify key cost-drivers in the electricity system and examine the effect of these cost-drivers on the costs to consumers and the profitability of intermittent renewable energy sources and their development over time.

In the following, we describe the:

- The development of costs of the electricity system (**section 4.1**);
- The payments of consumers for the electricity supply and renewable support (**section 4.2**); and
- The economics of renewable energy sources in the electricity system (**section 4.3**).

4.1 Costs of the electricity system

In this section, we provide estimations for the total system cost of the electricity supply system in the Netherlands. The section aims at identifying the main cost drivers in the electricity system. In this context, the results obtained in the sensitivity analysis allow to analyse the impact of different power market developments on the costs of the system.

It has to be noted that this analysis does not include all possible cost elements in the power sector. For example, we do not take into account cost incurred by enforcement or replacement investment in the distribution and transmission network that are not directly linked to the growth of renewable energy sources.

The section is structures as follows:

- Definition of costs of electricity generation (**section 4.1.1**);
- Definition of grid costs related to RES-E growth (**section 4.1.2**); and
- Quantitative analysis of system costs under different sensitivity assumptions and the Base Case (**section 4.1.3**).

Main results of the system costs analysis

- **RES- E main future cost driver under the influence of Dutch politics** – Costs of intermittent renewable energy sources represent the highest share of the analysed system costs. Across the modelling period, investment costs and fixed operation and maintenance costs of RES-E amount to 39 bn. EUR (real, 2013)[75] which corresponds to 50% of total costs from 2015 until 2039.

Assuming less investment in RES-E in the short-term reduces total system significantly by 10% (8 bn. EUR (real, 2013)). These savings could, however, be (partially) offset by investments in other sectors or by "green energy imports" from abroad required to meet the current or future targets regarding the share of renewable energy in primary energy consumption.

- **Highest RES-E related grid-costs in the first years** – Our indicative grid cost estimation shows that the highest level grid costs related to renewable expansion are incurred in the first years with the highest investment RES-E.

- **Cost share of conventional generation remains constant** – Despite lower shares of conventional thermal generation, the cost-share remains more or less constant as short-run marginal costs of generation increase over time. In total, fixed and variable costs of generation amount to 31.6 bn. EUR (real, 2013) from 2015-2039 (~40% of total costs).

- **Changing variable costs of generation with limited effect on total costs –** Increasing or decreasing the variable costs of generation shows only a limited effect on total system costs as savings are compensated with higher imports.
  - Lower CO_2-prices reduce total costs by 1 bn. EUR (real, 2013) or 1.4%.
  - Higher CO_2-prices increase total costs by 1.1 bn. EUR (real, 2013) or 1.5%.
  - Higher fuel prices for coal and gas-fired generation increase total costs by 1.6 bn. EUR (real, 2013) or 2.3%.

- **Spill-over effects from foreign CRMs with limited effect on costs** – International spill-over effects from foreign capacity remuneration mechanisms increase total costs in the Netherlands by 0.3 bn. EUR (real, 2013) due to higher imports.

4.1.1 Costs of electricity generation

Cost of electricity generation is defined according to the cost elements incorporated in the objective function of the power market model:

[75] Cost figures are given as net present value from 2015 to 2039, 5% discount rate.

- **Variable costs of generation** include all cost directly incurred by the production of electricity in the short term, i.e. fuel costs, costs of carbon dioxide emissions and other variable costs of generation; both for generation capacities and demand side response;
- **Fixed costs of conventional**[76] power plants include the costs for investment[77], mothballing, reactivation and fixed operation and maintenance costs of conventional generation capacities and demand side response;
- **Costs of power exchange with neighbouring countries** include the costs of electricity imports valued at the power price in the respective country of import as well as the value of exports valued at the power price in the Netherlands.
- In addition to the cost elements captured by the simulation model, we also include the **cost of RES-E**, i.e. investment costs and fixed operation and maintenance costs of intermittent energy sources, i.e. wind-onshore/offshore and solar PV. The costs of these technologies are derived in **section 4.3.2**.

In total, costs of electricity generation amount to 60 bn. EUR (real, 2013), measured as net present value from 2015-2039.[78] With 38 bn. EUR (real, 2013), the highest share of cost is incurred by the expansion of renewable energy sources. Fixed costs of conventional power generation in the Netherlands amount to 10 bn. EUR (real, 2013), variable costs to 21.7 bn. EUR (real, 2013). Further information on the development of system costs is included in **section 4.1.3**.

It has to be noted that our analysis does not take the reinforcement or replacement investments into account that are not directly linked to the renewable expansion and therefore included in our approximation in **section 4.1.2.** Calculations from CE Delft suggest that the total investment requirements in the electricity grid from 2010 to 2050 could amount up to 66 bn. EUR.[79]

---

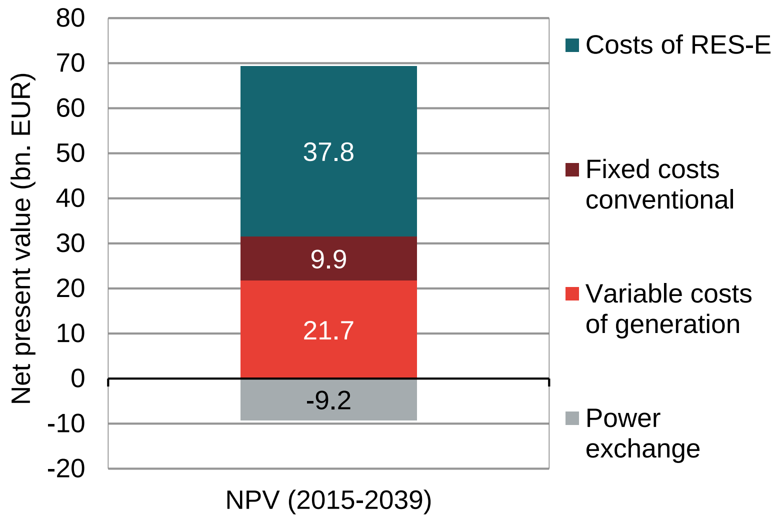
76 Capacity costs also include costs of back-up capacity for intermittent renewable energy sources.

77 It has to be noted that not all cost of the electricity system are included in our estimation: For instance, capital expenditure / investment costs of existing power plants are not included, as they are regarded as "sunk costs" in the model. Furthermore, investment costs for replacement investment in decentral CHP-generation are not included.

78 5% discount rate.

79 CE Delft (2010), p. 38.

Figure 56. Costs of electricity generation (Base Case)



Source: Frontier

4.1.2 Grid costs of RES-E expansion

In addition to direct investment costs of renewable energies (RES-E), the integration of RES-E induces costs in the distribution and transmission grids. In this section, we describe the indicative estimation of grid costs following RES-E expansion in the Netherlands up to 2039. We estimate costs arising in

- the distribution grid; as well as
- the transmission grid.

Regarding costs in the transmission grid we focus on the costs of connecting offshore wind parks to the main grid. The main Dutch transmission grid is already well developed, and we assume that additional investments requirements due to RES-E expansion are limited compared to the total system costs.

The effect of RES-E deployment on grid costs has not been quantified for the Netherlands yet. For this reason, we base our indicative estimation of the costs on the distribution grid level on a recent study that quantifies the effect of an increasing RES-E share on distribution grid costs in Germany (BMWi (2014)) and on a meta study that compares grid costs induced by RES-E in different countries (ECN (2014)).[80]

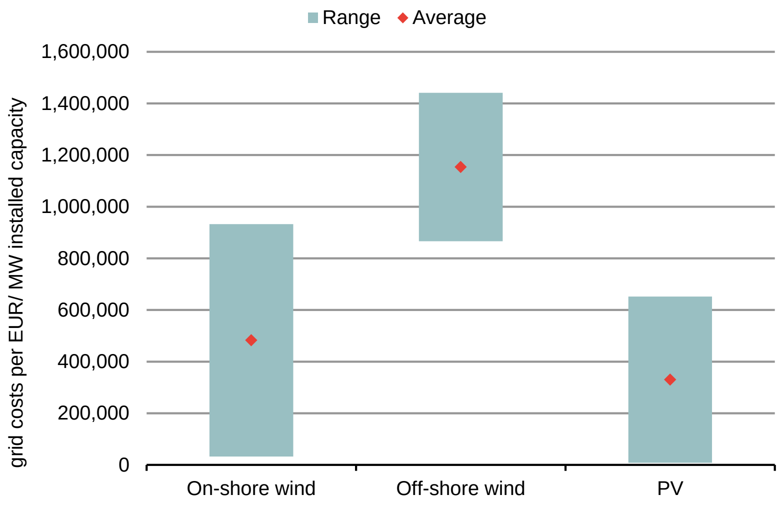
[80] The detailed methodology and the underlying assumptions of our estimation approach are described in the Annex 1

Grid costs to accommodate increasing RES-E in-feed

For the following calculations, we use the average of the cost range indicated in ECN (2014) (**Figure 57**). The publication provides cost figures for both

- the Distribution grid for wind-onshore and solar PV; as well as
- the transmission grid investment costs for wind-offshore.

Figure 57. Range of grid costs per MW installed RES-E capacity



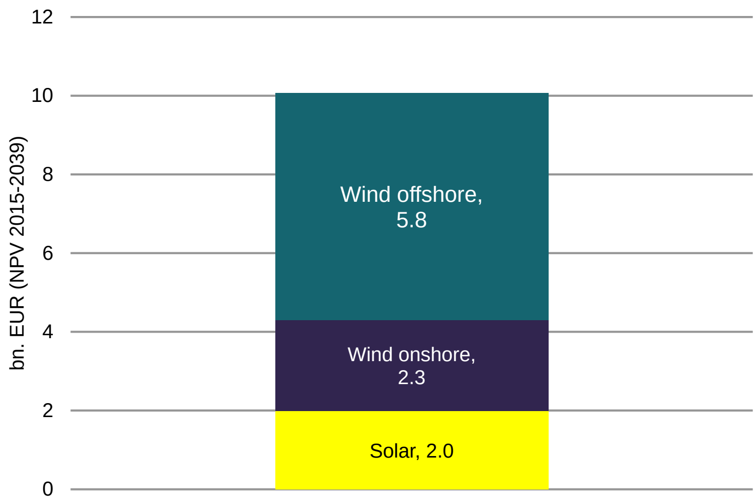
Source: Frontier based on ECN (2014a).

In order to approximate the total investment requirements, we apply this average cost estimator to the targeted expansion of renewable energy for wind-onshore, offshore and solar PV. The resulting indicative cost estimate is shown in **Figure 58** as the net-present value of aggregated grid costs from 2015 until 2039. Based on this rough approximation, the investment needs in the grids[81] amount to

- 6 bn. EUR for wind-offshore;
- 2.3 bn. EUR for wind-onshore; and
- 2 bn. EUR for solar PV.

81 These costs are for the distribution grid for solar PV and wind onshore and for connection to the transmission grid for wind offshore. They include costs for grid extension on the distributional level (mainly for wind on-shore and solar PV) and costs for the connection to the main onshore transmission grid (mainly for wind offshore).

Figure 58. Total grid costs (Base Case), NPV (2015-2039)



Source: Frontier

4.1.3 Costs of the electricity system

Based on the methodology described above, we identify the main cost-drivers in the electricity system and their impact on system costs in the Base Case and the sensitivities. It has to be noted that this model-based analysis does only include the costs elements as defined above. Additional costs will be incurred by required replacement and enforcement investments in the electricity grids. According to a study by CE Delft, these costs could range between 15 and 50 bn. EUR from 2010 until 2050. [82]

Costs of renewables main cost-driver in the future

The Base Case shows the following development of total system costs:

- **Costs of RES-E main cost driver in the future** – The costs for renewable energy sources represent the largest share of total system costs. Measured as net present value (NPV)[83] from 2015-2039, the RES-E amount to 38 bn. EUR (real, 2013), which corresponds to approximately 50% of total costs (**Figure 59**, right hand side). With increasing investment in renewable energy sources in the future, the share of RES-E costs increases over time (**Figure**

82 CE Delft (2010), p. 38; Scenario A (excl. connection costs for wind-onshore and wind-offshore installations).

83 5% discount rate.

59, left hand side) from 33% in the short run to more than 50% in the long-run.

It has to be noted that capital costs of existing power plants are not included in our calculation and regarded as sunk costs. In a calculation including capital expenditure of existing (conventional) power plants, the share of renewable costs in total system costs would be lower. The same is true for regular grid costs that are not related to the grid expansion.

- **Constant share of costs from conventional generation** – Variable costs of generation, i.e. short-run marginal costs, represent around 30% of total system costs (21.7 bn. EUR (real, 2013), fixed costs of generation, e.g. fixed operation and maintenance costs, investment/reactivation and mothballing costs, 12% (10 bn. EUR (real, 2013)).

  Despite a decreasing share of conventional power generation in the Dutch power sector, the costs of generation (fixed costs and variable costs) remain more or less constant (~40%) as specific fuel costs and CO_2-costs (in EUR/MWh) increase over time.

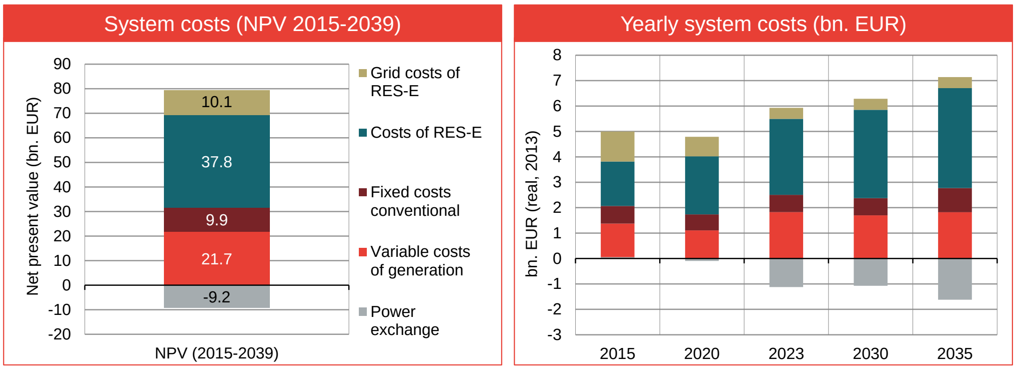
- **Highest RES-E related grid costs in the short-term** – Grid costs related to the expansion of renewable energy sources amount to 13% of total system costs (NPV 2015-2039).

  The Base Case includes the highest investment in renewable electricity sources in the first years. Therefore, incurred costs for grid investment related to this expansion are higher in the first years.

- **Total cost reduction due to net-exports** – As described in **section 3.3.2**, the Netherlands are becoming net-exporter of power in the medium- to long-term. Therefore, total system costs are reduced by the value of these net-exports (-7 bn. EUR (real, 2013)).

  Figure 59 shows positive costs in the first years with net-imports to the Netherlands. In the medium- to long-term, this term becomes negative with increasing net-exports.

Figure 59. System costs, Base Case



Source: Frontier

Impact of the sensitivities on system costs

Based on the methodology described above, we estimate the impact of the sensitivities on the system cost in the Netherlands compared to the Base Case.[84] We observe the following effects of the sensitivities on total system costs:

- **Low CO_2 prices decrease total costs in the NL** – We observe a small decline of system costs compared to the Base Case (- 1 bn. EUR (real, 2013)) especially due to lower variable power generation costs. Furthermore, fixed costs of power generation decrease compared to the Base Case as the nuclear power plant which is built in the Base Case in 2035 is replaced with by a coal-fired power plant, which incurs lower fixed costs but higher variable costs.

  Despite higher costs of power imports, the net-effect of lower CO_2-prices remains negative.

- **High CO_2 prices increase total costs in the NL** – Higher prices for carbon dioxide emissions increase system costs in the Netherlands. The increase is foremost caused by higher variable costs of power generation. Fixed costs of generation are not affected to a great extent.

  Compared to the Base Case electricity net-imports are lower in the sensitivity. This decreases costs associated with the power-exchange with foreign countries. However the cost increasing effect of higher CO_2 prices dominates the effect of lower costs for electricity imports.

84 Shown as net present value (NPV) from 2015-2039 (5% discount rate).

In sum, total system costs increase by 1.1 bn. EUR (real, 2013) in the sensitivity compared to the Base Case.

- **Higher gas and coal prices increase variable costs of power supply in the Netherland** – Higher CO_2 prices increase the costs of electricity supply in this sensitivity by 1.1 bn. EUR (real, 2013) as variable costs of power generation increase by 4 bn. EUR (real, 2013). Benefits from exporting power decrease by 3 bn. EUR (real, 2013).

- **Significant decrease of total system costs with less wind power capacities** – A slow-down of wind power expansion can reduce system costs significantly due to lower fixed costs for RES-E. As long as RES-E technologies have to be supported there is a value in slowing down RES-E expansions to later years. Costs can be reduced due to the fact that RES-E investments take place later which allows for the following cost savings from today's perspective:

  - We expect significant learning curve effects for wind-offshore that lower investment costs (2015 – 2030: - 26%)[85]; and

  - Higher time discounting of costs as investment takes place at a later point in time.

  According to our indicative calculation, costs incurred in the electricity distribution and transmission grid are also reduced as less renewable energy has to be integrated into the network. Therefore required grid expansions are lower.

  It has to be noted that this calculation does not include investment in other sectors or "green energy" imports from abroad that could be required to achieve the current political targets in 2023 or future renewable energy targets.

- **Small cost increase due to international spill-over effects –** Higher capacity requirements in neighbouring countries with capacity mechanisms reduce operational power plant capacity in the Netherlands (see **section 3.4.5**). Less electricity generation within the Netherlands reduces variable costs of generation and, to a small extent, the fixed costs through higher mothballing.

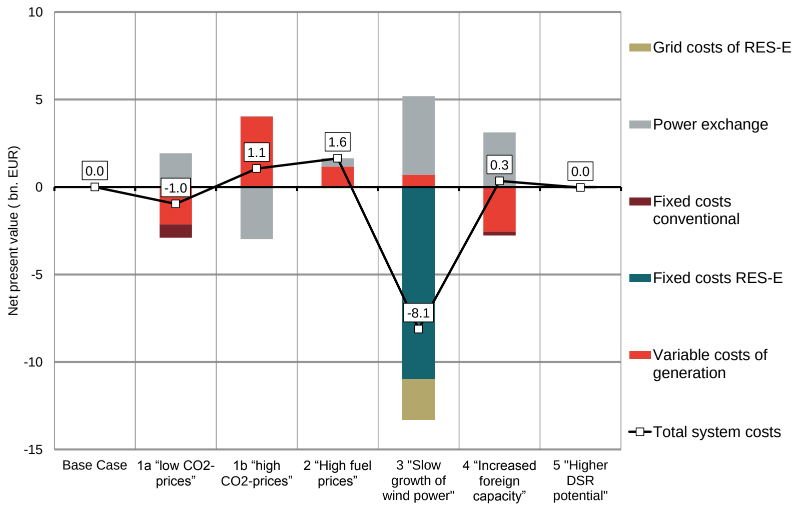
  The cost reduction is balanced with higher net-imports leading to a slightly positive net-effect of 0.3 bn. EUR (real, 2013).

85 The assumed development of investment costs is shown in **Table 3**.

- **Higher demand-side-response lowers total costs moderately** – Total costs of electricity supply decrease slightly by 0.1 bn. EUR (real, 2013), if more demand-side–response (load shifting) is assumed to participate in the market. The reduction arises from a small decrease of variable costs of power supply, as gas-fired generation is partly substituted by coal-fired power generation.

Figure 60 shows the difference in total system costs compared to the Base Case. Negative values indicate a decrease of costs, positive values increasing costs.

Figure 60. Sensitivity impact on total system costs in the Netherlands



Source: Frontier

4.2 Costs to final consumers

In this section, we analyse how consumer costs in the Base Case evolve over time and whether the consumption of electricity or the costs of renewables are the main cost driver. In addition, we assess how the different developments of the power market analysed in the sensitivities affect consumer payments.

The section is structured as follows:

- Estimation of costs to final consumers in the Base Case (**section 4.2.1**); and
- Impact of the sensitivities on consumer bills (**section 4.2.2**).

It has to be noted that the consumer costs of renewable supply are an outcome of the modelling and do not correspond to RES-E budgets under the SDE +

regime. For example, our model calculations do not take budgetary constraints, e.g. support caps, into account.[86]

Main results of the cost analysis

- **Increasing costs to final consumers** – Yearly costs to final consumers increase by 25% from 7.5 bn. EUR(real, 2013)/a in 2015 to 9.4 bn. EUR(real, 2013)/a in 2035. This increase is caused by the increase in wholesale electricity prices due to higher variable costs of generation.

- **RES-E with significant share of costs** – Our analysis shows that 25% (28 bn. EUR (real, 2013) of analysed costs to consumer are related to the growth of RES-E, either through RES support or through RES-E related grid costs. The costs incurred by RES-E decrease over time as profitability is improved and less financial support is needed.

  Assuming lower expansion of wind-energy (sensitivity 3 "Slow growth of wind-power") reduces costs to final consumers by 6%-point (7 bn. EUR (real, 2013)), despite higher power prices and higher costs for electricity supply.

- **Significant effect of variable costs of generation on consumer cost** – Total costs to final consumers are influenced by higher or lower short-run marginal costs of generation to the following extent:

  - Lower CO_2-prices reduce consumer costs by 4 bn. EUR (real, 2013) or 4%.

  - Higher CO_2-prices increase total costs by 6 bn. EUR (real, 2013) or 5%.

  - Higher fuel prices for coal and gas-fired generation increase total costs by 7 bn. EUR (real, 2013) or 6%.

- **International spill-over effects reduce costs of Dutch consumers** – Assuming higher capacity requirements in France and in Belgium leads to lower cost to final consumers in the Netherlands. Final costs to consumers decrease by 3 bn. EUR (real, 2013) compared to the Base Case. This cost reduction, however, is to the detriment of consumers in the regions with higher capacity requirements.

4.2.1 Estimation of costs to final consumers

This analysis aims at quantifying the cost burden on consumers, i.e.

---

86 Also, grid costs not incurred by the expansion of renewable-energy sources are not included, see **section 4.1.1**.

- How will consumer costs develop in the future; and
- What is the key-cost driver from a consumer perspective?

Methodology

The analysis focusses on the costs arising from the consumption of electricity and additional costs induced by the expansion of renewable electricity. Taxes and levies are not part of this calculation. Further, it has to be noted that our analysis does not include costs arising from enforcement or replacement investment in the power grid that are not directly linked to the RES-E growth. We include the following cost elements:

- **Costs for electricity** – The costs of electricity supply that have to be paid by consumers are calculated based on the hourly electricity consumption and hourly power prices. We assume that wholesale power prices are passed on without distortions or mark-ups through retail-services onto final consumers. In addition, we do not distinguish between different consumer groups, i.e. industry and households but estimate the cost burden for all consumer groups in aggregate.

- **Costs of renewable electricity –** The costs of renewable electricity (wind-onshore, wind-offshore and solar PV) are included as the difference between the LCOE estimate describes in **section 4.3.2**) and the market revenues, additional financial support needed to obtain the targeted capacity levels. We assume that all additional RES-E costs are passed onto final consumers, i.e. support caps are not included in the analysis. Furthermore, RES-E related grid costs are included as additional cost element.

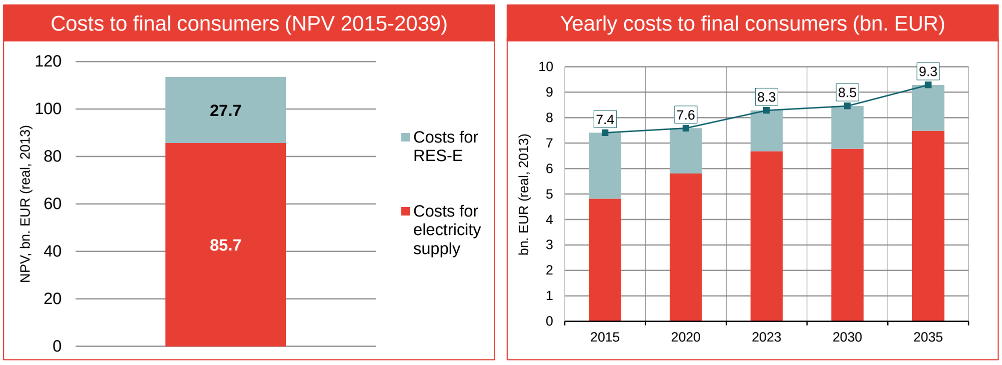
Increasing costs to final consumers in the Base Case

The Base Case shows increasing costs to final consumers:

- **Yearly costs increase by 25% from 2015-2035** – Yearly costs to final consumers are increasing over time by 25% from 7.4 bn. EUR (real, 2013)/a in 2015 to 9.3 bn. EUR(real, 2013)/a in 2035:
  - This increase is driven by higher electricity prices in the long-run. The cost of for electricity supply (energy) increase by 55%.
  - At the same time, costs for renewable support and RES-E related grid investments decrease by 31% as profitability of RES-E increases and less additional support is needed (see next section 4.3 for detailed information). Furthermore, the highest costs for grid investment are incurred in the first years.

- **RES-E costs represent 25% analysed cost elements** – Costs incurred by renewable energy sources in electricity supply (support costs and grid-related costs) amount to 28 bn. EUR (real, 2013) from 2015-2039.[87]

Figure 61. Costs to final consumers in the Netherlands, Base Case



Source: Frontier

4.2.2 Impact of the sensitivities on consumer bills

In this section, we summarise the results of the sensitivities on costs to final consumers:

- **Lower cost burden on final consumers due to lower CO_2-prices** – Lower costs for carbon dioxide emissions decrease the level of wholesale prices (see **section 3.4.1**). Consequently, consumers need to pay less for the supply of electricity. On the other hand, costs for renewable support increase as the price decrease also results in lower market revenues. In sum, costs are 3.7 bn. EUR (real, 2013) (3.2%) lower than in the Base Case.

- **Increasing consumer bills due to high CO_2-prices** – Higher costs for carbon dioxide emissions lead to the opposite effect: Power prices and costs for electricity supply increase. At the same time, revenues of intermittent renewables increase which leads to lower RES-E support costs. Nevertheless, consumers have to pay more in this sensitivity. Consumer bill increases by 6.1 bn. EUR (real, 2013) (5.4%).

- **High fuel prices reduce RES-E support costs but increase consumer bills** – Sensitivity 2 yields comparable results with higher power price due to higher short-run marginal costs of conventional power plants. The costs of RES-E decrease but the net-effect remains positive with an increase of costs

87 Net-present value, 5% discount rate.

to final consumers by 7.7 bn. EUR (real, 2013) (6.8%) compared to the Base Case.

- **Slow development of wind-energy reduces burden on final consumers –** Sensitivity 3 "slow growth of wind-energy" shows a moderate increase in power prices leading to higher costs for electricity supply to final consumers. At the same time, the growth of wind-installations is slowed down compared to the Base Case. This results in lower costs for renewables as higher learning rates are realised with postponed investments in renewables. In addition, less grid-enforcement is necessary and grid-related costs decrease. In sum, costs to final consumers decrease by 6.5 bn. EUR (real, 2013) (5.8%).

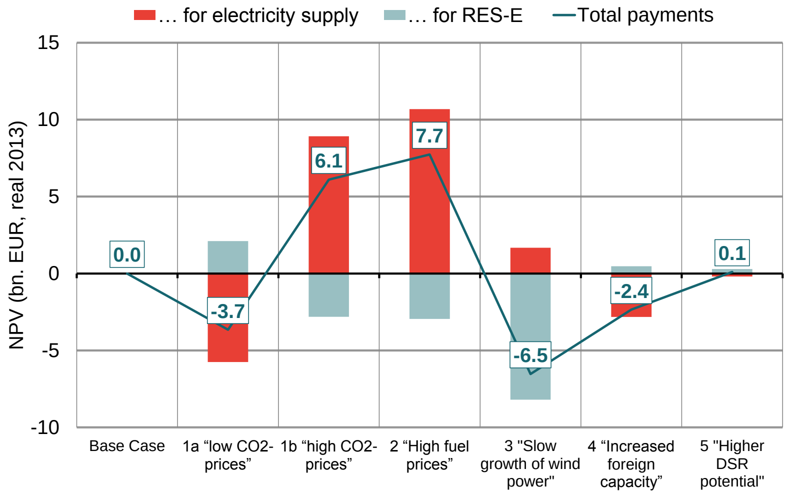
  It has to be noted that this calculation does not include investment in other sectors or for "green energy" imports that could be required to achieve the current or future political targets for renewable energies.

- **Decreasing costs for Dutch consumers due to increased foreign capacity** – The increase of generation capacity in France and Belgium in sensitivity 4 reduces power prices. This leads to lower costs to final consumers in the Netherlands as the cost incurred by the additional capacity do not pose an additional burden on Dutch consumers. They are borne by consumers in the regions with explicit capacity payments.

  Support costs for RES-E increase moderately without effect on the net-reduction of costs. In total, costs to final consumers decrease by 2.4 bn. EUR (real, 2013) (2.1%).

- **Higher demand side response without major effect on consumer costs** – Higher DSR has only limited effects on average power prices in the Netherlands. Therefore, there are no significant changes to the cost burden on final consumers.

Figure 62. Impact of the sensitivities on the costs to final consumers



Source: Frontier

4.3 Economics of RES-E

The Netherlands are aiming for a significant increase of renewable energy sources in electricity supply over the next decades (**see section 3.2.4**). In this section, we analyse whether these additional capacities will be able to finance themselves on the wholesale market, i.e. whether the market revenues will be sufficient to cover their levelised costs of electricity or whether additional financial support is required in the future.

We analyse the future profitability of intermittent renewable energy sources (wind-onshore, wind-offshore and PV). We describe

- The resulting market revenues of intermittent RES-E under the different market assumptions (**section 4.3.1**);
- The assumptions regarding costs of RES-E (**section 4.3.2**); and
- Our assessment of the future profitability of intermittent RES-E (**section 4.3.3**)

Main results regarding the economics of renewable electricity

- **Decreasing market values of renewables** – Despite increasing power prices, market values (as % of base price) of renewables can be expected to decrease with an assumed increase of in-feed: Increasing simultaneous in-feed from wind or solar PV leads to higher negative correlation of power prices and renewable in-feed. Revenues per MWh, however, will increase from 2015 until 2035.

- **Wind-onshore and offshore more profitable than solar PV** – Based on our cost estimate, we expect more promising future profitability for wind-onshore and offshore compared to solar PV. Nevertheless, there remains the need for additional funding for all examined RES-E technologies.

- **Importance of effective internalisation of carbon dioxide emissions –** The observed effects of higher/lower CO_2-price on the profitability of intermittent renewables illustrates the importance of an effective emission trading scheme in order to internalise climate externalities of carbon emission. With high CO_2-prices, the profitability of RES-E increases significantly whereas low CO_2-prices lead to a growing financing gap.

4.3.1 Market revenues of intermittent renewables

Market revenues of intermittent renewable energy sources are determined by

- the wholesale power price level; and

- the correlation between renewable in-feed and hourly power prices.

We observe an increase in electricity prices in the Base Case and the sensitivities compared to today's price levels. Ceteris paribus, this should lead to higher revenues per generated MWh of renewable electricity. With increasing simultaneous in-feed from renewable energy sources, the market value of the generated electricity is reduced and revenues per MWh decline over time for some energy sources:

- Wind power and solar PV capacities are not dispatched like other power plant, but depend on the availability of wind and solar radiation.
- With growing renewable capacity, in-feed in hours with high wind or solar radiation increases significantly, as all installations are exposed to the same wind pattern or radiation. This leads to increasing negative correlation between hourly in-feed from renewables and hourly wholesale price (see **Table 2**).

Table 2. Pairwise correlation of hourly in-feed and hourly electricity price*)

	2015	2035
Wind-onshore	-0.20	-0.23
Wind-offshore	-0.13	-0.22
Solar PV	0.10	-0.09

Source: Frontier
*) excluding negative prices

Decreasing market values in the Base Case

With increasing negative correlation between power prices and renewable in-feed, the average market value[88], which expresses the value of RES-E power compared to the yearly average base price of RES-E power production decreases:

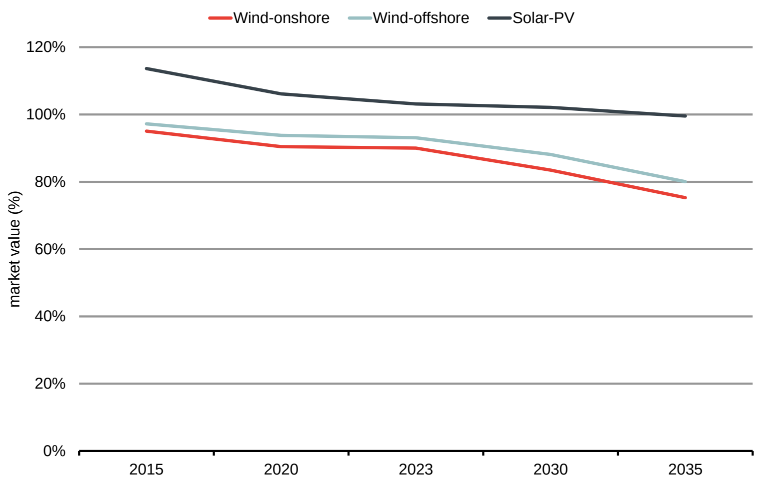
- **Solar PV** – Solar PV initially exhibits market values >1 and therefore a higher value than base-load power generation (and positive correlation between in-feed and power price), as the highest in-feed occurs around midday, a time period with high power demand compared to other hours. With increasing in-feed from PV installation, the formerly observed price

88 The market value of renewable is defined as relationship between hourly in-feed of renewables valued at the hourly price and the in-feed of renewables valued at the yearly average base price.

peaks around midday vanish and, in the long-run, market values decrease to slightly < 1.

- **Wind-onshore and -offshore** – Both, wind-onshore and offshore, exhibit market values <1 in 2015, as wind in-feed occurs in hours with lower load compared to solar PV, e.g. at night. With increasing simultaneous in-feed from wind-onshore and wind-offshore respectively, the average value of wind power generation decreases to around 80% of the yearly average base price.

Figure 63. Market values of intermittent RES-E



Source: Frontier

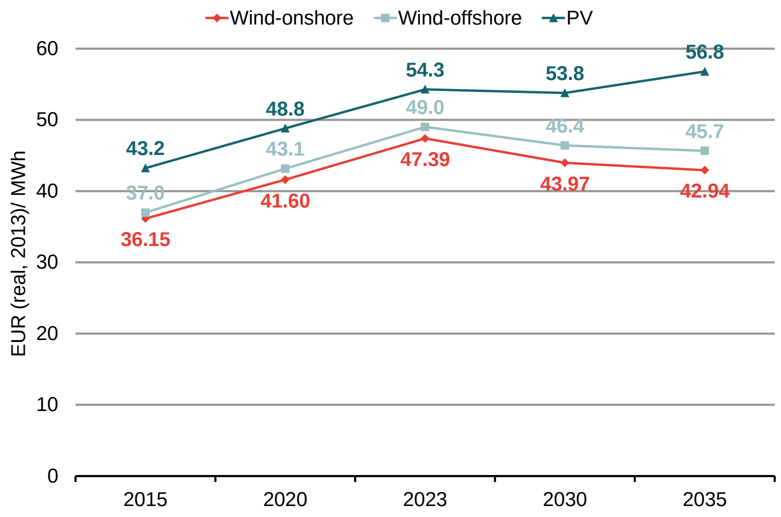
Increasing revenues for solar PV, long-term decrease of wind revenues

Both effects, increasing wholesale prices but at the same time decreasing market values, yield the following net effect on revenues.

- **Increasing revenues for wind power** – In the Base Case, revenues for wind onshore and offshore increase until 2023. Thereafter, revenues decrease slightly due to lower market values, but remain higher than in 2015:
  - Wind-onshore average revenues increase from 37 EUR (real, 2013)/MWh in 2015 to 47EUR (real, 2013)/MWh in 2023; thereafter, revenues decrease to 43 EUR (real, 2013)/MWh; and
  - Wind-offshore average revenues increase from 37 EUR (real, 2013)/MWh in 2015 to 49 EUR (real, 2013)/MWh in 2023; thereafter, revenues decrease to 46 EUR (real, 2013)/MWh.

- **Growing revenues for solar PV** – Solar PV on the other hand shows increasing revenues also in the long-run:
  - Steep increase from 43 EUR (real, 2013)/MWh in 2015 to 54 EUR (real, 2013) /MWh in 2023;
  - Moderate increase to 57 EUR (real, 2013)/MWh in 2035.

Figure 64. Revenues of intermittent RES-E (Base Case)



Source: Frontier

RES-E benefit from high fuel and CO_2-prices

The profitability of RES-E is determined by the development of power prices. Therefore, sensitivities with increasing short-run marginal costs of generation and consequently higher power prices exhibit in an increase in of RES-E.

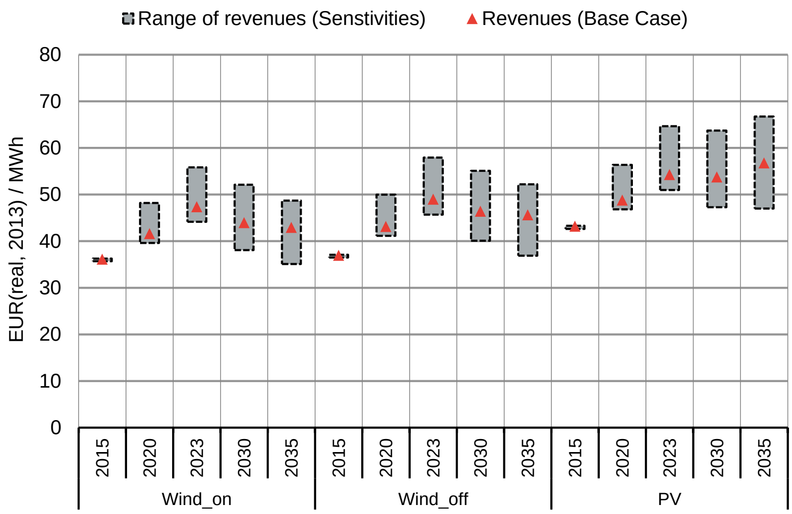
- **Benefits from high fuel costs** – Intermittent renewable energy sources benefit from high fuel and CO_2-prices as variable costs of conventional generation and therefore power prices increase. We observe a significant effect on RES-E revenues in the sensitivities with higher CO_2 (+ 12% in 2035) and fuel prices (+13% in 2035), which include an increase of short-run marginal costs of conventional power generation.

- **Reduced revenues with low CO_2-prices** – Compared to higher CO_2-prices, lower costs for carbon emission decrease the level of power prices and therefore lead to lower revenues of RES-E. In 2035, revenues are 18% lower than in the Base Case.

Figure 65 indicates the range of observed revenues for wind-onshore, wind-offshore and solar PV from 2015 until 2035 across the sensitivities:

- Solar PV shows the highest increase of revenues with up to 67 EUR(real, 2013)/MWh in 2035 in sensitivity 2 "high fuel prices";
- Wind-onshore and offshore exhibit increasing revenues until 2023 with up to 56 EUR (real, 2013)/MWh for wind-onshore and 58 EUR(real, 2013)/MWh for wind-offshore. After that, revenues decrease in all sensitivities.

Figure 65. Comparison of revenues (all cases)



Source: Frontier

4.3.2 Levelised cost of RES-E (LCOE)

The development of investment costs as well as operation and maintenance costs of intermittent RES-E is associated with high uncertainty. The cost development also depends on the specifics of the technology:

- **Wind-onshore** represents a quite mature technology with the highest learning rates already realised in the past;
- **Wind-offshore** instead is less mature in terms of technological experience. Therefore, more significant learning rates can be expected for the future.

- **Solar PV**[89] has shown substantial learning rates in the past, especially regarding the costs of solar modules. Further learning can be expected in the future.

In detail, the assumptions regarding the development of renewable costs are derived as follows:

- **Initial investment cost according to SDE (+)** – We derive our initial investment cost levels for 2015 from the analysis of support levels within the SDE (+) support scheme.[90] We use the following specific investment costs (2015) for our analysis:
  - Wind-onshore: 1,350 EUR(real, 2013)/kWe;
  - Wind-offshore: 2,600 EUR(real, 2013)/kWe; and
  - Solar PV: 1,030 EUR(real, 2013)/kWe.
- **Learning curve according to IEA World Energy Outlook** – The assumptions on the future development of investment costs are based on the learning curves indicated in the IEA World Energy Outlook (IEA, 2014). The IEA expects a reduction of capital costs from 2015 to 2035 of
  - 7 % for wind-onshore;
  - 30 % for wind-offshore; and
  - 34 % for solar PV.

  We also apply the fixed operation and maintenance costs for the RES-E installations as published in the WEO (2014).[91] This results in the following assumptions for the development of overnight-investment costs (**Table 3**):

89 The majority of Dutch solar PV installations are roof-top installations which exhibit higher specific investment costs per MW compared to open-space installation.

90 ECN (2014b).

91 Fixed operation and maintenance as % of investment costs: wind-onshore 2.5%; wind-offshore 3.5%, solar PV 1.3%.

Table 3. Assumed RES-E investment costs

EUR (2013)/MW	2015	2020	2023	2030	2035
Wind-onshore	1,350	1,300	1,295	1,270	1,250
Wind-offshore	2,600	2,195	2,120	1,940	1,820
Solar PV	1,030	830	800	730	675

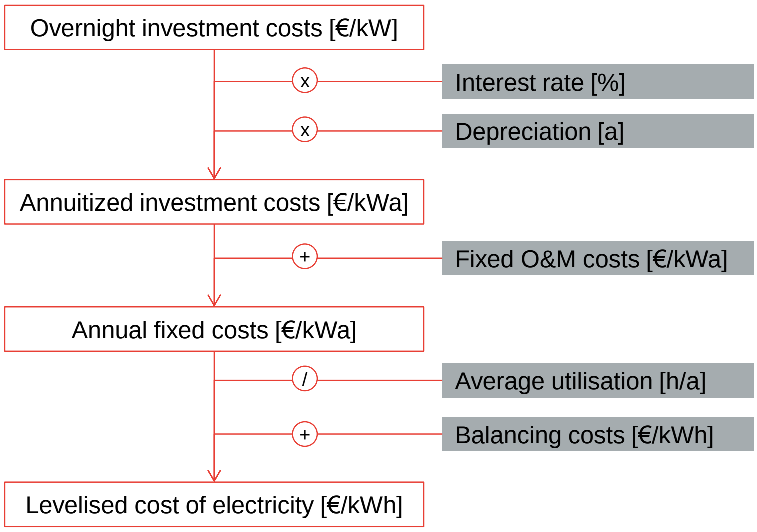
Source: Frontier based on ECN (2014b) and IEA (2014c)

Based on the assumptions described above, we derive the levelised costs of electricity in EUR (real, 2013)/MWh, i.e. the costs of generating one MWh of (**Figure 66**):

- Annual fixed costs per MW installed capacity include annuitized investment costs[92] and yearly operation and maintenance expenses;
- Annual fixed costs are translated into costs per MWh electricity by applying the yearly utilisation rates for each technology and add assumed balancing costs of 2.5 EUR (real, 2013)/MWh.

92 We assume a standard depreciation period of 20 years and an interest rate of 5%.

Figure 66. Calculation of levelised cost of electricity (LCOE)



Source: Frontier

Decreasing costs of electricity generation for all technologies

Based on the methodology described above, we estimate the following development of generation costs for intermittent renewables:

- **Moderate decrease of costs for wind-onshore** – Wind-onshore exhibits the lowest LCOE of the examined technologies in the short-term. As wind-onshore represents a more mature technology, future learning rates are limited and therefore LCOE decrease only moderately in the long-run
  - from 63.4 EUR(real, 2013)/MWh in 2015; to
  - 59 EUR(real, 2013)/MWh in 2035.
- **Significant cost reduction for wind-offshore**[93] – Compared to wind-onshore, we expect significant cost reductions for wind-offshore in the future. :
  - 82.8 EUR(real, 2013)/MWh in 2015; and
  - 58.6 EUR(real, 2013)/MWh in 2035.

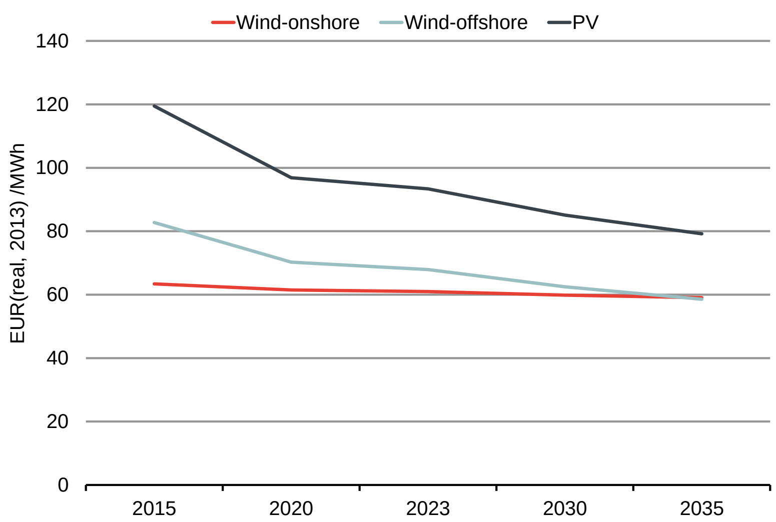
  In the long-run, LCOE of wind-offshore are more or less equal to costs of wind-onshore power generation. This can on the one-hand be explained with larger turbine sizes which in return lower the specific investment costs

93 Costs for grid-connection are not included in this calculation.

per MWe. On the other hand, wind-offshore exhibits higher utilisation rates which reduces the costs per generated MWh.

- **Solar PV most expensive from a system perspective –** Solar PV (roof-top) exhibits the highest costs of electricity generation in the short- and in the long-run. Despite the assumption of significant learning rates in the future, costs per MWh remain high compared to the other technologies. This is driven by a comparably low utilisation rate of around 10%. Estimated costs are
  - 119.5 EUR(real, 2013)/MWh in 2015; and
  - 79.2 EUR(real, 2013)/MWh in 2035.

Figure 67. Development of LCOE



Source: Frontier

Remaining uncertainty about future cost reductions

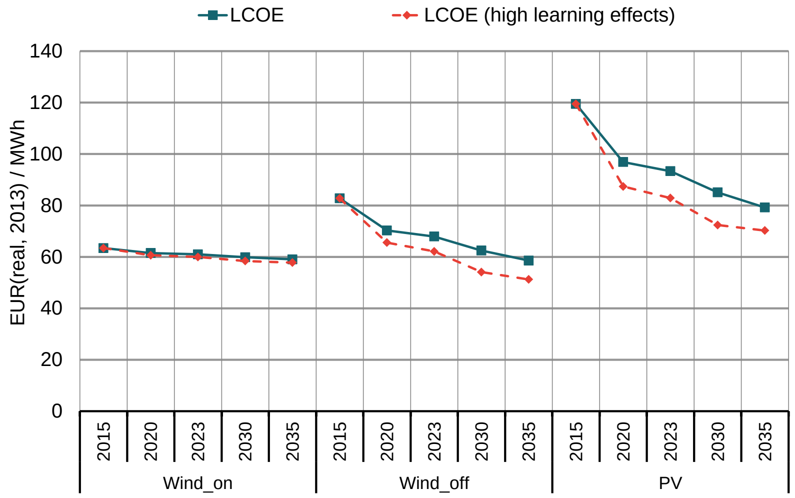
The baseline cost assumption for the following analysis is based on assumed learning curves from the World Energy Outlook (2014). This, of course, represents one of many possible sources for the development of investment costs for renewables. Other sources for example indicate lower future cost reductions[94] while other studies foresee higher learning effects in the future.[95]

94 E.g. CBP (2015)

95 E.g DLR/Fraunhofer IWES/IFNE (2012).

Beside uncertain development of market revenues, this causes additional uncertainty for the analysis of future profitability of RES-E. **Figure 68** illustrates an alternative development of LCOE based on DLR/Frauenhofer IWES/IFNE (2012).

Figure 68. Alternative development of LCOE



Source: Frontier

4.3.3 Future profitability of intermittent renewables

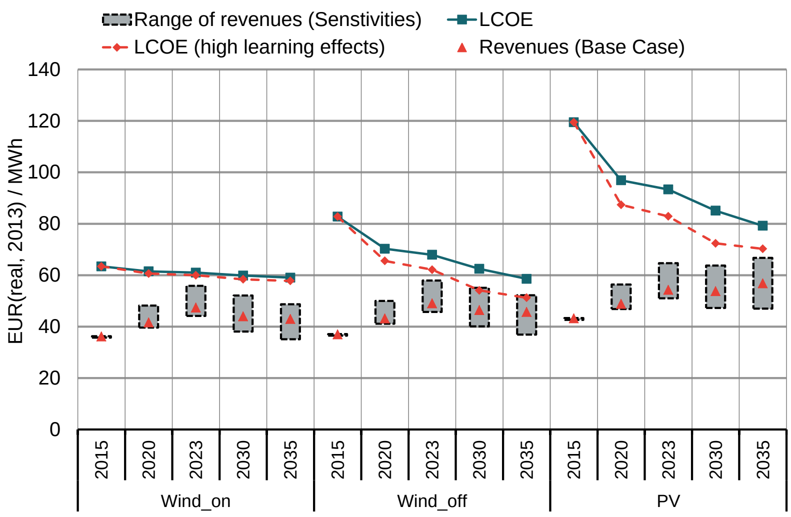
In the following, we compare the estimated costs of RES-E (baseline learning curve) with the expected market-revenues. Despite significant cost reductions in the long-run and increasing wholesale prices for electricity; our analysis shows that investments in wind-onshore, wind-offshore and solar PV will not be profitable by itself until 2035.

Our analysis takes an economic perspective on profitability of RES-E, i.e. includes costs and revenues from a system-wide perspective. The results can differ from a single investors' perspective that takes other benefits, e.g. from net-metering of consumption, into account. Furthermore, costs of grid-connection are not included in our profitability analysis.

Wind-onshore and offshore more profitable than solar PV

Based on our analysis, we conclude that the estimated LCOE of intermittent renewables are not covered by the market revenues. **Figure 69** shows the development of market revenues in the Base Case (red triangle) and in all sensitivities (grey area) compared to the LCOE estimate (blue bar). The dashed red line indicates the development of LCOE assuming higher learning rates and shows that RES-E investment could be profitable in the long-run if even higher learning effects are realised.

Figure 69. Profitability of intermittent RES-E



Source: Frontier

According to our calculations, LCOE of new investments are not covered by market revenues until 2035. The financing gap, however, decreases in the long-run with cost reduction and increasing revenues in the Base Case:

- **Wind-onshore close to profitability in the medium-term** – Wind-onshore shows the lowest financing gap in the short- and medium-term. Because of decreasing market revenues and more or less constant LCOE, the financing gap stays almost constant in the long-run:
  - 27 EUR (real, 2013)/MWh in 2015;
  - 14 EUR (real, 2013)/MWh in 2023; and
  - 16 EUR (real, 2013)/MWh.
- **Wind-offshore close to wind onshore in the long-term based on assumed future cost-reductions** – Wind-offshore require more financing support than wind-onshore in the short-term. In the long-run, however, LCOE for wind-offshore may decrease significantly. At the same time, market revenues increase. In sum, this leads to a reduction of the financing gap from
  - 46 EUR (real, 2013)/MWh in 2015
  - 13 EUR (real, 2013)/MWh in 2035.

- **Highest financing gap for solar PV** – The relative gap between LCOE per MWh electricity production and the respective market revenues amounts to 76 EUR (real, 2013)/MWh in 2015 for solar PV. With increasing revenues and decreasing costs in the long-run, the gap decreases to 22 EUR (real, 2013)/MWh in 2035.

CO_2-price and fuel prices drive profitability of RES-E

Depending on the sensitivity and the respective development of market revenues, the financing gap increases or decreases compared to the Base Case:

- **RES-E more profitable with high CO_2-prices** – As shown in **section 4.3.1**, we observe the highest market revenues in sensitivities 1b "high CO_2-prices"and 2 "high fuel prices". Consequently, these two sensitivities exhibit the lowest - but still positive - financing gap of
  - 11 EUR (real, 2013)/MWh in 2035 for wind-onshore;
  - 7 EUR (real, 2013)/MWh in 2035 for wind-offshore ; and
  - 16 EUR (real, 2013)/MWh[96] for solar PV.
- **Low CO_2-prices result in high additional needs for RES-E financing** – With lower prices for carbon emissions the need for additional financial support for renewable electricity increases. Assuming CO_2-prices of 12 instead of 30 EUR(real, 2013)/tCO_2 leads to long-term financing gap of
  - 24 EUR (real, 2013)/MWh in 2035 for wind-onshore;
  - 22 EUR (real, 2013)/MWh in 2035 for wind-offshore; and
  - 32 EUR (real, 2013)/MWh in 2035 for solar PV.

It has to be noted that our estimation does not represent an upper limit of possible revenues for intermittent renewables. If, for example, fuel prices increase even higher than anticipated in our sensitivity; or if CO_2-prices increase at the same time as fuel prices, revenues of RES-E could increase significantly, leading to higher profitability.

96 Solar PV financing gap of 12 EUR (real, 2013)/MWh in sensitivity 2 "high fuel prices"

Side note: Economics of small scale PV and benefits from net-metering

In this section, we have analysed the profitability of intermittent renewables from a system perspective, i.e. how expected market revenues compare to future costs of RES-E. According to the analysis, solar PV represents the technology that requires the highest financial support of the technologies analysed as of today, i.e. is currently the least efficient technology from a system perspective.

The decision of an individual investor to invest in RES-E, however, may deviate from the system perspective because of

- Existing renewable support payments; and
- Benefits from own-consumption of produced electricity; especially in combination with net-metering regarding the assessment of taxes and levies.

In the following, we assess the profitability of a small scale solar PV installation under different cases and assumptions[97]:

- **Case 1 – Renewable Support:** We assume that support levels are set to meet the levelised costs of electricity and that produced electricity that is fed into the power grid is remunerated accordingly.
- **Case 2 – Market based remuneration:** We assume that no renewable support mechanism is in place and that electricity production is remunerated according to market prices.[98]

In order to assess the profitability of the investment, we compare the total consumer bill under two different assumptions to the counterfactual of no investment, i.e. the case when 100% of consumption is served via the grid:

- PV installation with 30% own-consumption; taxes and levies[99] based on *net-metering*; i.e. total consumption less own-consumption
- PV installation with 30% own-consumption; taxes and levies based on *gross-metering*; i.e. total consumption, and

Significant incentives for investment in the case of net-metering and renewable support

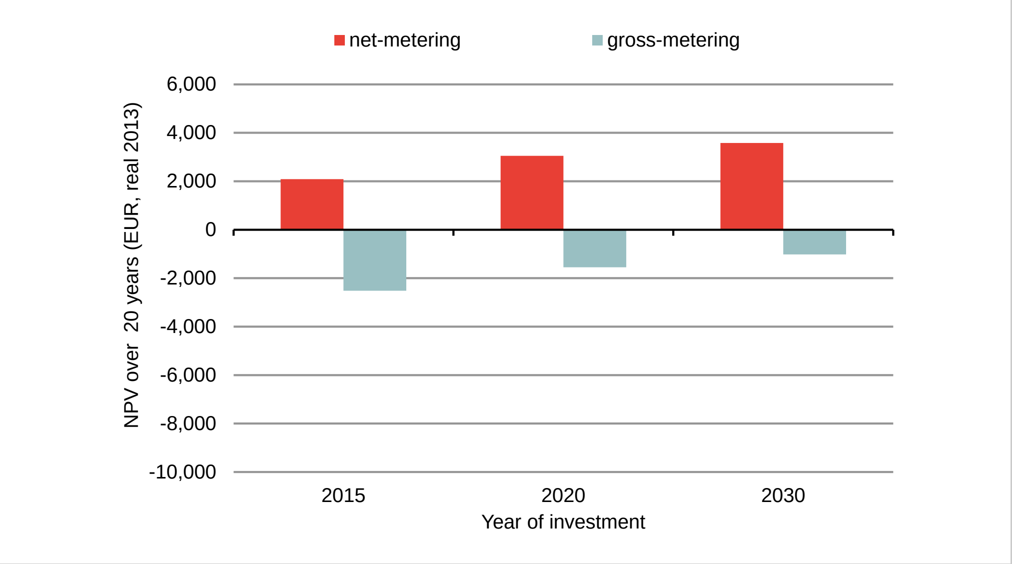
97 Net-present value over 20 years of lifetime;5% discount rate.

98 Power prices according to Base Case calculations.

99 Assumptions: installed capacity 10 kWp; utilisation rate of 10.3%; own-consumption of 30%; yearly electricity consumption 4.500 kWh; constant (real) levels of the electricity tax (0.1196 €/kWh) and the sustainable energy levy (0.0036 €/kWh), excl. 21 % VAT; tax threshold of 311.84 €/a.

Our analysis shows that significant incentives to invest in small scale PV installations arise from net-metering of consumption: The household's bill for electricity consumption in the case of net-metering is significantly lower than in the counterfactual of no investment. This incentives to invest in solar PV disappears in the case of gross-metering, as the amount of taxes and levies that have to be paid increase and the investment becomes unprofitable (negative benefits from investing in solar PV, **Figure 70**).

Figure 70. Benefits of net-metering (case 1 "Renewable support")

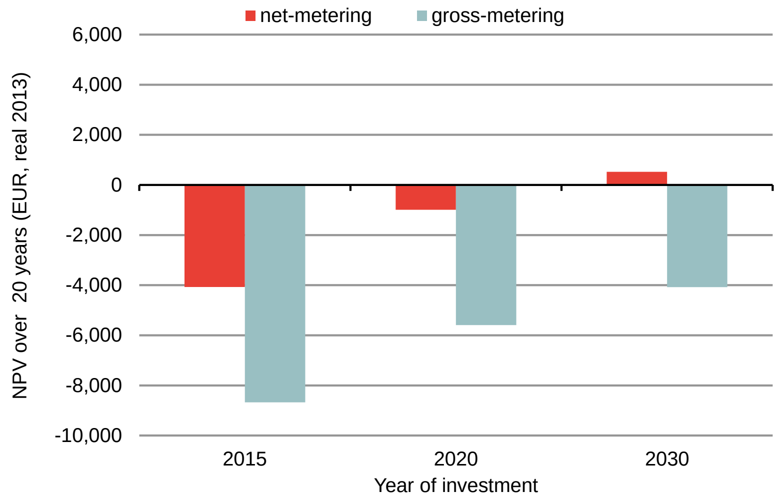


Source: Frontier

PV for households attractive without support only in the long-run and if net-metering is maintained

In the case without RES-E support, small scale solar PV installations are economical in the future (2030) only if net-metering is maintained. In the case of gross-metering, the total household bill exceeds the payments in the counterfactual of no investment in all years analysed, i.e. benefits are always negative (**Figure 71**).

Figure 71. Benefits of net-metering (case 2 "market based remuneration")



Source: Frontier

5 Reliability of the electricity system

In this section, we analyse whether and under which conditions the Dutch electricity system is able to provide for security of supply under the current market framework. In particular, we discuss if the current market design provides sufficient incentives to keep installed capacities, which are required to ensure security of supply, in operation and incentives to invest in new power generation capacities as well as in demand-side-response in the future

The electricity market design in the Netherlands and most other European countries is so far based on the principle of an "energy-only market" (EOM). In an EOM, investments for electricity production are primarily financed through energy-based prices (in €/MWh), which incorporate an implicit payment for available capacity. In this context, various market stakeholders wonder whether a market design based on the EOM principle generates sufficient incentives to ensure mid- and long-term security of electricity supply. Some stakeholders have suggested the introduction of a CRM. Through a policial intervention, a CRM would induce explicit capacity payments (e.g. in €/MW per year) that would incentivise additional capacity and thus security of supply. Some of the neighbouring countries of the Netherlands, for instance Belgium, France or Great Britain, are currently introducing CRMs.

The implementation of a CRM is a fundamental intervention into the electricity market. Generally, market interventions lead to distortions and can therefore, from the perspective of economic efficiency, only be justified in the presence of market imperfections that prevent an efficient market outcome. In the context of CRMs, the European Commission requires any Member State who plans to introduce a CRM to clearly demonstrate the reasons why the market cannot be expected to deliver adequate capacity.[100] Otherwise, the CRM will be treated as unjustified State Aid.

In the following, we thoroughly investigate the performance of the current Dutch electricity market design in the following steps:

- We describe how an idealised EOM provides reliability (**section 5.1**);
- We describe potential market imperfections in real-world EOM, assess their relevance for the Dutch electricity market and derive resulting policy implications (**section 5.2**); and
- We derive our conclusion (**section 5.3**).

100 European Commission (2014).

5.1 Performance of an ideal EOM

In this section we describe the performance of an ideal EOM, abstracting in a first step from market imperfections. The influence of potential market imperfections on the capability of an EOM to ensure security of supply will be discussed in **section 5.2**.

5.1.1 Demand and supply in an EOM

On the electricity market, demand (from consumers) meets supply (from power generators). Compared to other markets, the electricity market faces a number of specifics. The demand-side of an EOM is formed by electricity consumers (households, commerce and industry). Except for large consumers, electricity consumers normally buy electricity via suppliers. These procure the electricity on the wholesale electricity market, directly from an electricity producer or produce the electricity themselves. Large consumers (electricity-intensive industry) may buy electricity directly on the wholesale market, from producers through bilateral contracts or produce the electricity themselves. While some consumers, e.g. from the electricity-intensive industry, can react to (hourly) changes in wholesale electricity prices, e.g. by reducing their consumption during hours of high prices or by shifting consumption towards hours when prices are lower, other consumers (especially households and small industries) cannot (yet) react to hourly price changes on the wholesale market. Final electricity prices for small consumers usually don't reflect hourly wholesale prices. Instead, end-consumer prices are often constant in all hours of the year and reflect only an average wholesale energy price (the average procurement costs of the supplier) per year.

Suppliers in an EOM are producers that – under perfect competition and as long as there is no scarcity in the market – bid electricity at short-term marginal generation costs (especially costs of fuels and CO_2 certificates in the case of thermal power plants) into the market. Investment and fixed operation costs do not influence their bids, as these costs can be considered as "sunk costs" within the short trade horizon (day-ahead or intraday trade) and are therefore irrelevant for their production decision.

In addition, the wholesale electricity market allows suppliers and buyers to optimize their positions: For example, an industrial consumer with own power production will rather buy electricity from the wholesale market if electricity prices are lower than his own variable production costs.

In summary, in competitive wholesale electricity markets, producers bid electricity at variable (marginal) production costs and consumers (often via suppliers) signal their willingness to pay for electricity. Aggregated bids of producers form the supply curve ("merit order curve"), and the aggregated willingness to pay of consumers forms the market demand curve. The market clears at the intersection of supply and demand curve. These supply and demand curves are for example aggregated by organised power exchanges, in the Netherlands e.g. by APX. For power traded on the exchange, the corresponding market clearing price has to be paid for all units of electricity that have been bought during the auction ("uniform pricing"). This mechanism leads to an efficient (short-term) production and allocation of electricity in every period (e.g. hour). Clearing prices and quantities vary on an hourly basis, depending on specific supply and demand situations.

5.1.2 Recovering investment and fixed costs in an EOM

In a pure energy-only-market (EOM), electricity is in general financially and physically traded in energy units (kWh). For example, on forward, day-ahead and intraday markets of power exchanges, there is no explicit remuneration for holding capacity available. However, in this market design capacity is remunerated by margins in the energy market or indirectly by trading of back-up-capacity, as explained in the following.

In most periods, the wholesale electricity price corresponds to the marginal generation costs of the last unit that is still needed to clear the market. These marginal generation costs can either correspond to the variable costs of a power plant or to the (opportunity) costs of a flexible consumer for reducing or shifting his demand.

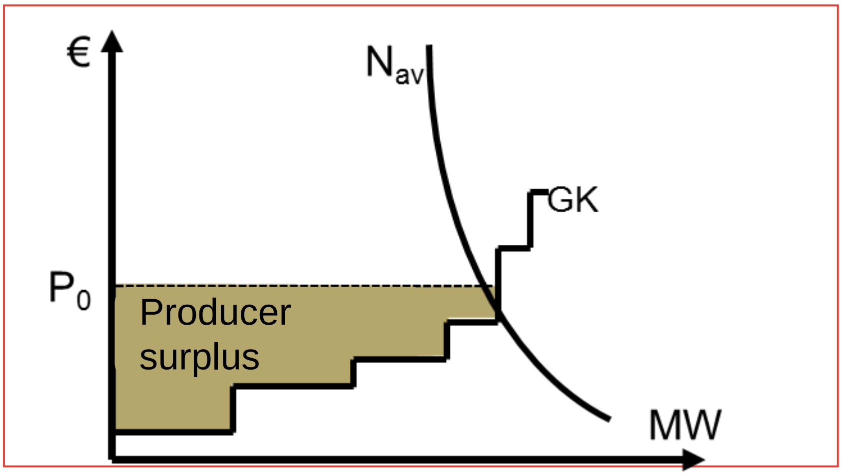
However, also in an EOM it is possible for power plants or demand flexibilities to achieve profit margins that exceed variable costs:

- **Infra-marginal plants** – In every period, all infra-marginal capacities[101] obtain profit margins as the power price exceeds their marginal costs (see **Figure 72**).

- Plants can be infra-marginal because they are run with different fuel types or have different (technical) efficiencies than the marginal (price-setting) capacities. In addition, it is possible that plants that are marginal today (as they are less efficient than other, newer plants) have obtained enough profit margins needed to recover their fixed costs in the past, when they have been relatively more efficient than old plants at that point of time.

101 These are suppliers or flexible producers that have lower variable costs than the most-expensive plant or demand flexibility option that is still needed to clear the market - the marginal "supplier".

Figure 72. Infra-marginal rents

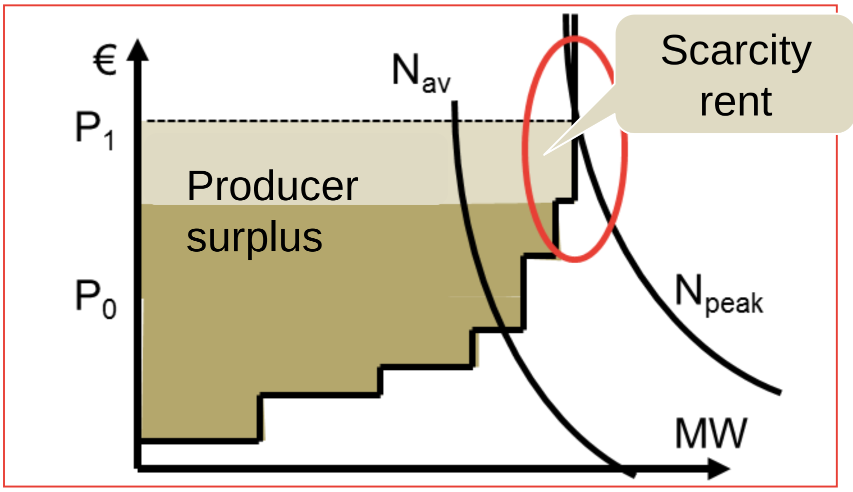


Source: Frontier economics

- **Marginal plants** - In most periods, the marginal supplier does not obtain profit margins as prices correspond to his short term marginal costs. However, two mechanisms permit that even the marginal plant can obtain profit margins during some periods:
  - **Scarcity rents because of demand flexibility** – If supply is scarce, the market can be cleared by consumers that reduce or shift demand (e.g. energy industry reducing good production) – often at high prices. If these consumers can reduce or shift demand without high investment or fixed operation costs to implement the demand flexibility, these units do not need to achieve any infra-marginal rents. All other power plants and demand flexibilities with investment costs can achieve "infra-marginal" rents during these periods.
  - **Scarcity rents via "Peak load pricing"** – If supply is scarce and not enough flexible demand is available, some suppliers get pivotal, i.e. demand cannot be met without their capacities. Therefore, within these situations, even in a perfectly competitive market these suppliers can include fixed costs when setting their price bids because – from a static perspective – these suppliers cannot be replaced by a less costly option.

Figure 73 illustrates how marginal suppliers achieve rents during scarcity periods.

Figure 73. Scarcity rents in an EOM



Source: Frontier economics.

In addition, EOMs also include implicit elements of capacity remuneration. The fundamental reason why capacity has a value – and therefore also a price – in EOMs is that electricity supply contracts between suppliers and end-consumers include an obligation to actually deliver the electricity in any occasion. If suppliers fail to supply electricity to their customers, they risk paying imbalance prices to the system operator (in the Netherlands to the transmission grid operator TenneT which has to balance the electricity system physically in any point in time). In order to hedge against paying imbalance prices, suppliers will hold available own capacities, engage in long-term contracts as part of their electricity procurement strategy, buy back-up capacities from other generators/suppliers or buy options to hedge against potential deviations between their supply obligation and their procured electricity. In general, these contracts include payments for capacities.

The fundamental prerequisite for effective incentives for power generators, suppliers and consumers to back up their electricity requirements with reliable capacity even in periods with substantial scarcity on the EOM is that the threat of paying very high prices for imbalances (i.e. shortage in covering the electricity) is substantial and that market participants take for granted that they have to pay imbalance prices in any event – the system of punishing imbalances (i.e. insufficient power supply/procurement in scarcity periods) has to be credible, the "penalty" of paying imbalance prices has to be sufficiently high.

Through these mechanisms, all capacities, including the marginal capacity cannot only recover their variable costs but also amortize their investment costs (via scarcity rents and/or income streams that remunerate capacity - e.g., as part of a long-term delivery contract or a buy option with a supplier). An ideal, perfectly competitive EOM therefore allows for full cost recovery (including investment and fixed operation costs) of all capacities required to clear the market. For this reason, in an ideal EOM sufficient investment incentives exist to build and maintain the efficient capacity and generation mix. As a result, the welfare-maximising level of security of supply is reached and financed.

5.2 Potential market imperfections

We outline above that an ideal EOM can lead to a welfare-maximising level of capacity and security of supply. However, the design of electricity markets in the real-world may be characterised by market imperfection that may undermine these mechanics:

- **Market risks** – Uncertain future revenues and variable costs impose risks to long-living and capital-intensive investments such as power plants. Some sources argue that these become prohibitively high in an EOM with increasing intermittent renewables and may result in insufficient investments and thus a threat to security of supply (**section 5.2.1**).

- **Political risks** – Further risks arise from uncertainty about future political actions. These include general energy politics, for instance any decisions with regards to nuclear energy or climate change. An additional particular risk may come from potential political interventions into price building mechanisms, for instance by implementing price caps. Some people argue that there is a high risk for such interventions when markets become scarce and prices peak, as state authorities can hardly distinguish between high prices due to (welfare-damaging) market power abuse and high prices due to (welfare-maximising) scarcity pricing. As a result, capacities that are needed to provide security of supply would not be able to generate sufficient revenues ("missing money") (**section 5.2.2**).

- **External effects** – Because price elasticity of electricity demand is low and because consumers are physically connected through the electricity grid, there may be situations where consumers are not served with electricity, although they are willing to pay a high price for it. In other words, signalling a high willingness to pay does not guarantee being served, because other consumers cannot be excluded from consumption. Furthermore, power plants which may be able to produce may be disconnected from the grid if brown-outs occur (disconnection of grid areas). In this case, generators are not remunerated for available power generation capacity since the disconnected plants are not able to realise the price peaks on the electricity market. Some people argue that this public good characteristic and external effects lead to reduced signalling of willingness to pay by consumers and reduced incentives to invest in power plants and demand flexibility, and results in insufficient capacity and security of supply (**section 5.2.3**).

- **International spill-over effects** – Some countries surrounding the Netherlands such as Belgium, France or the UK are currently implementing (different sorts of) capacity remuneration mechanisms (CRMs). As these tend to lead to lower wholesale prices in the whole region - via interconnections also the Netherlands would be affected - incentives to invest in the Netherlands might be reduced. Some market participants are concerned that this could lead to insufficient capacity and a threat to security of supply in the Netherlands (**section 5.2.4**).

An instrument to address welfare-damaging consequences of these market imperfections, if they are relevant, would be to implement a CRM. Through a CRM, operators of power generation, storage or demand flexibility capacities are granted support for the mere availability of their capacity (paid on top of the energy revenues that operators earn by selling electricity to the market). However, CRMs are very complex, and implementing a CRM does mean to overhaul the entire electricity market. Substantial parts of usually market-based decisions are transferred to central authorities, for instance how much investments are made at what time.

Therefore, a thorough analysis is needed whether the market is able to provide reliability without introducing a CRM. Accordingly, the European Commission requires any Member States who wishes to introduce a CRM to clearly demonstrate the reasons why the market cannot be expected to deliver adequate capacity.[102]

In the following, we analyse how relevant the above mentioned potential imperfections of an EOM are in the context of the Dutch electricity market. Whenever, we identify that there could be threats to security of supply, we discuss whether there are appropriate measures to mitigate these threats within an energy-only market design.

5.2.1 Market risks

There are basically two different sorts of market risks of possible relevance for security of supply in the electricity sector:

- **Short-term risks (volatility)** – To allow total cost remuneration for all required capacity, an EOM does rely on power price peaks in scarcity periods ('peak load pricing'). With increasing shares of intermittent RES-E with low variable costs, the overall price level is reduced. Therefore, price peaks need to occur more often and need to rise

102 European Commission (2014).

higher to allow cost remuneration of firm capacity required to back-up solar and wind plants. Thus, the short term fluctuation of electricity prices increase. Due to the stochastic availability of wind and solar power, electricity prices in specific hours also become less predictable. The resulting higher volatility increases uncertainty about short-term revenues.

- **Long-term risks (investment uncertainty)** – Power plants are durable investment goods, used for 20 or more years. At the time of deciding on investments, however, neither power prices nor fuel and CO_2 prices are known. For this reason, future revenues are uncertain which imposes risks on investments.

  In addition, a lack of coordination in investments between market participants might – in some periods - lead to overcapacities that would prevent price peaks needed to recover investment costs. Therefore, investment cycles might occur, increasing commercial risks of investors.

Market risks as a potential threat to security of supply – Assessment of relevance in the Netherlands

We assess for the Netherlands that short-term and long-term market risks don't threaten security of supply:

- **Short-term risks can be hedged by market-based instruments** – The increase in price volatility resulting from an increasing share of intermittent renewables may, ceteris paribus, be higher in the Netherlands than in other larger European countries due to the smaller size of the electricity market. However, markets are able to develop instruments to cope with risks resulting from volatile prices. For example, it can be empirically observed that participants in market with high wholesale price volatility increasingly develop and trade financial and physical products to cope with price risks such as for example buy options and contracts for differences. In addition, the Dutch power plant park is characterised by a large share of efficient and flexible gas-fired power plants that can react quickly to changing in-feed from wind and solar installations. Therefore, no public intervention is needed to cope with short-term risks.

- **Long-term risks are not new and not specific to electricity markets** –In many markets, investors bear long-term risks that they cannot insure. In many product markets, prices and quantities are determined on a short-term basis while production capacities have long lifetimes and are capital-intensive and thus have to be financed in light of future prices and quantities. For example, production sites for cars or shoes are capital-intensive and built for long production periods while consumers will not guarantee consumption quantities and their willingness-to-pay beforehand.[103] For this reason, many markets are characterized by cycles of relative scarcity, high prices and acceptable profits for suppliers, followed by excess supply, lower prices and consolidation on the supply side.

Furthermore, potential commercial long term market risks such as investment cycles or demand fluctuations are not linked to the massive expansion of renewable energies – these cycles can emerge also in markets solely based on thermal power generation. However, it can empirically be observed that substantial investments in power plants took place in electricity markets like the Netherlands in the past being aware that long term commercial risks already existed at that point in time.

Investors are remunerated for taking risks by risk-adjusted profits. The higher the risks investors have to bear in a market, the higher future expected profits have to be in order to make the market attractive for investors. If market risks in the power market are particularly high (as the timing and the level of scarcity prices needed to recover fixed costs cannot be exactly anticipated), capital costs and scarcity prices also have to be particularly high.

In summary, the market can cope both with short- and with long-term market risks. This holds true in light of an increasing share of intermittent renewables in the power market. The increasing share of renewables leads to increasing quantity-, price- and profit-risks for conventional power plants, storages and demand flexibility. However, these increasing risks do not change the fundamental market mechanism. The market will react to these increasing risks, e.g., by higher prices during scarcity periods and by a shift to investments into plants with lower capital costs (e.g., gas turbines or demand flexibility in the industrial sector).

Market risks as a potential threat to security of supply – Policy implications

As described above, markets are generally able to deal with market risks. The political and regulatory framework therefore should enable markets to develop the products and instruments needed to cope with these risks. Also, the political and regulatory framework should ensure that high prices, potentially emerging during scarcity periods, are not restricted (e.g., by setting price caps).

103 Like in power markets, a smoothening of profits is partly achieved via intermediate market stages (wholesale or retail traders).

5.2.2 Political risks

There are basically two different sorts of political risks of possible relevance for security of supply in the electricity sector:

- **Risks from general energy politics** – for instance any decisions with regards to nuclear energy or climate change.
- **Potential political interventions into price building** – for instance by implementing price caps. Some people argue that there is a high risk for such interventions when markets become scarce and prices peak, as state authorities can hardly distinguish between high prices due to (welfare-reducing) abuse of market power and high prices due to (welfare-maximising) scarcity pricing. As a result, capacities that are needed to provide security of supply would not be able to generate sufficient revenues ("missing money").

Political risks as a potential threat to security of supply – Assessment of relevance in the Netherlands

Political risks can substantially reduce investment incentives and therefore be critical to security of supply. This holds especially if market participants fear that investments undertaken in the past are devalued by political decisions in future. However, politicians can reduce political risks by themselves by refraining from strong political interventions into the energy markets and by limiting market distortions for investments undertaken in the past.

We assess the political risks for security of supply in the Netherlands as follows:

- **General political interventions are difficult to predict** – Investors in the Netherlands would be affected by political interventions on the national as well as on the European level (e.g., on the EU ETS). In addition, the Dutch power system is highly interconnected with its neighbouring countries. Therefore, political interventions in these countries (e.g. with regard to renewable energy promotion, the implementation of CRMs or nuclear policy) would also affect prices and revenues in the Netherlands.

  However, political risks are not automatically a threat to security of supply. Like market risks, political risks lead in first instance to higher risk premiums and therefore to higher required returns on investments, higher prices and higher costs for end-consumers, but not automatically to insufficient investments. However, since political interventions are difficult to predict, the calculation of risk premiums faces specific difficulties.

- **Risk of political intervention into price building seems to be low** in the Netherlands – Currently, in the Dutch electricity market no regulatory price caps exist. Price limits on the day-ahead and the intraday-market are only technical, but no regulatory price caps exist. If necessary, these price limits could theoretically be increased. However, even today price limits are comparatively high: On the intraday-markets prices up to 100,000 €/MWh can be realised and the price limit for imbalance prices is 100.000 €/MWh. In addition, technical price limits are not binding for bilateral trades.

- **General political framework can be assessed to be comparably stable –** In the Netherlands, the political framework for the energy market can be assessed to be rather stable and predictable compared to other countries. Massive disruptions in the energy policy which could be observed in other countries such as a short term shut down of nuclear power plants after the Fukushima nuclear power plant accident in Japan or massive political interventions against new technologies such as CCS can't be observed. Furthermore, policies to subsidise specific technologies such as RES –E exist but are less interventionist and more predictable (e.g. due to a budget cap) than in other countries. However, also in the Netherlands political interventions into the energy market exist (e.g. policies regarding the introduction of Smart Meters, the shut-down of old coal-fired power plants etc.). It is important to limit unpredictable interventions to a minimum and to implement policies in co-operation with the industry and other stakeholders rather than devaluing investments undertaken in the past without compensation in order to raise trust.

Political risks as a potential threat to security of supply – Policy implications

- **Risks from general energy politics should be minimised by** building (or maintaining) a stable political framework – To some extent, future political interventions are uncertain by nature because policy makers have to react to market developments and new insights from academia that cannot be foreseen. However, in some areas, uncertainty could be reduced:
  - **Reliable deployment paths of renewables** – While the Dutch promotion system for renewables prevents uncontrolled renewable deployment by setting constraints for the overall budget for promotion payments (see above), an uncontrolled deployment might be induced by incentives to install photovoltaic systems for auto-consumption (see **section 4.3.3**). Currently, auto-consumers of small scale renewable energy plants can make use of net-metering: They only pay energy taxes on their net electricity consumption (i.e., on the difference of the electricity they have taken from the grid and the electricity they have fed into the grid).[104] Net-metering makes the installation of small-scale RES-

[104] See res-legal.eu

E plants (in particular of photovoltaic systems) more attractive to electricity consumers and might lead to an uncontrolled deployment of renewable energy plants. This implicit subsidisation of small scale PV may lead to higher system costs since less costly power technologies don't get energy tax rebates. In order to enhance the predictability of market developments it would be advantageous if policy makers indicated whether or when regulatory rules may change – for example, it could be stated that the rules change as soon as a certain amount of photovoltaic capacity has been installed.

- **Reducing uncertainty about instrument for decarbonisation** – Currently, two instruments for decarbonisation are used in parallel: Renewable energies are promoted via the SDE+ premium tariff system and in parallel the EU-ETS penalises CO2-emissions. While the EU-ETS builds on EU-wide system in decarbonisation efforts, the SDE+ is a national promotion system that co-exists with several other national renewable promotion systems in other European countries. In the academic discussion, a broad consensus is that European cooperation in renewable support would lead to efficiency gains. A stronger co-ordination of RES-E support across Europe may also lead more stability of RES-E support systems since changing rules may at least to some extent have to be co-ordinate between member states. In this case, the predictability of energy policy would be improved.

- **Commitment to refrain from political interventions into price building mechanisms–** Price peaks are important for the functioning of the electricity and should therefore not be distorted by price caps. Price peaks indicate scarcity on the market to potential investors which are expected to invest based on these signals. Furthermore, price peaks indicate the need for generation and demand side short term flexibility in the market based on short term price fluctuations.

  Therefore, allowing high price peaks sets adequate investment signals for peak plants, and allows for the correct valuation of capacity and flexibility e.g. for the trading of back up capacity. For example, experience from Australia shows that in a market with high price peaks market participants will buy options to hedge against price peaks. In particular the South Australian price zone is characterized by high price volatility and high peak prices. In this market, options have become an important instrument of hedging and of ensuring security of supply. Carstairs and Pope (2011)[105] explain that in Australia the standard strike price of an option that is available in all hours corresponds approximately to the variable costs of an

105 Carstairs, J. and Pope, I. (2011).

OCGT plant. The buyer of a contract pays an (annual) fixed price for the auction and thereby hedges against prices above the variable costs of a peak plant. The seller of the option receives the fixed price and thereby can recover the investment costs of a peak plant even under uncertainty about whether and how often the peak plant will be used.

As market participants might always be concerned about potential future political interventions into price building mechanisms, policy may explicitly commit not to introduce caps for power prices. Such a commitment can be made, for two reasons:

- Price caps may be implemented due to the existence or the suspicion of market power (e.g. in the PJM -Pennsylvania, New Jersey, Maryland Power Pool - market in the USA). In this context, price caps can be used to prevent the exercise of market power. However, electricity markets are contestable markets; even if prices would be (or expected to be) above the competitive level, competitive pressure would arise from new market entrants or the activation of demand flexibility or emergency control systems.

- Furthermore, the market for power generation in the Netherlands is characterised by a diversity of suppliers compared to other countries, and interconnections to foreign power markets are strong, which reduces the probability of an abuse of market power further. For these reasons, we don't expect longer-lasting market power abuses in the Dutch power market that would require the introduction of price caps.

In addition to explicit price caps, implicit price caps might endanger security of supply and should be avoided. Implicit price caps can for example be set by poorly designed reserve mechanisms. If capacity that is contracted under a reserve scheme is bid into the market, it is likely that it will dampen price peaks and thereby reduces investment incentives.[106] The design of the Dutch "vangnet", a so far non-activated reserve mechanism, includes that capacities contracted by TenneT under the vangnet are kept out of the market in order to prevent implicit price caps.[107]

In order to reduce political risks, policy makers should therefore commit to accept price peaks in the future and confirm that they will not introduce regulatory price caps – neither explicitly nor implicitly.

---

106 Carstairs, J. and Pope, I. (2011).

107 The "vangnet" has not been activated so far. It can be activated by MinEZ based on advises of TenneT in its' yearly monitoring report and/or ACM . If it is activated, it gives TenneT the possibility to procure reserve capacities via long-term contracts that are kept out of the market and only used if the market (including the balancing market) is not able to provide enough supply to meet demand

5.2.3 External effects

In this section, we first describe external effects that might arise in EOMs and that potentially could jeopardize the achievement of security of supply in EOMs. Then, we discuss how relevant these effects are in the Netherlands.

External effects as a potential threat to security of supply – Description

A condition for achieving security of supply in an EOM is that demand can be met during (nearly) all periods and that demand and supply curve intersect during (nearly) all periods.

However, electricity systems are characterized by the following specifics:

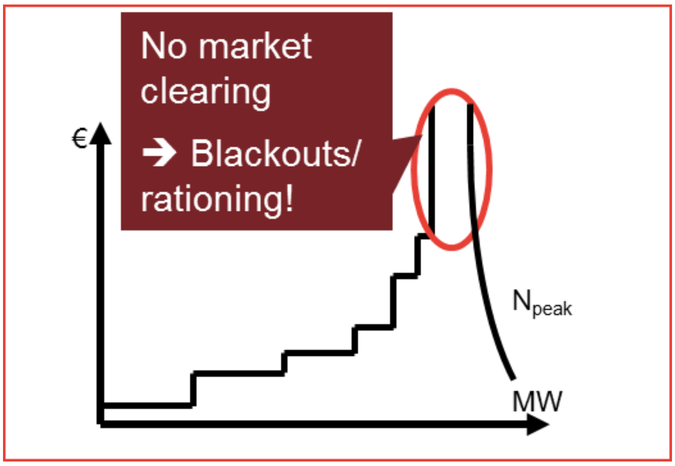
- **Low elasticity of demand (in the short term)** – Many consumers (especially households) do not yet have the necessary technical equipment that would allow them to reduce or shift demand during hours when wholesale prices are high. Therefore, a part of demand is price-inelastic. This can potentially lead to situations, in which demand and supply cannot be directly cleared by the price mechanism on the wholesale electricity market. However it is important to note that a clearing of demand and supply does not require that all consumers are price-elastic – it is just necessary, that an adequate amount of consumers is flexible.

- **Electricity trade is grid-bound** – An individual consumer normally does not have a direct grid connection to a producer (or supplier). Instead, he is connected to the general electricity grid. For this reason, activities of some market participants can also affect the level of security of supply of other consumers or the possibility of other producers to feed-in electricity to the grid (which is no longer possible for some producers if a brownout occurs). This leads to the following effects:
  - **Security of supply may have public good characteristics:** Many consumers (especially households, commerce and small industrial customers) cannot be individually switched off. Therefore, if security of supply is provided by some market participants, others cannot be excluded from benefitting from this security of supply. Therefore, security of supply has public good characteristics and market participants theoretically could have an incentive to not reveal their willingness to pay for security of supply.
  - **External effects on producers/consumers:** Individual consumers cannot (ex-ante) insure themselves against a partial load curtailment (during a situation of scarce supply and insufficient availability of price-elastic demand) by paying high prices. Consumers connected to distribution networks in which a brownout (unplanned shut-down of a

part of consumers or distribution networks) occurs are affected by the load curtailment regardless of how much electricity they have procured beforehand. This is especially harmful for consumers that have a high willingness to pay for security of supply. In addition, those consumers that have invested into demand flexibility cannot benefit from their investment during a brownout.[108]

Also producers who theoretically could fulfil their delivery obligations because their power plants would be available, cannot feed-in to the grid when the grid they are connected to, has been shut-down. If compensation mechanisms for such situations are missing, these external effects can lead to missing profits that reduce investment incentives for power plants, demand flexibility or decentralised power systems.

Figure 74. External effects in EOMs



Source: Frontier economics.

External effects as a potential threat to security of supply – Assessment of relevance in the Netherlands

Market participants will in their decision making process take external effects only into account if they expect with a sufficiently high probability to be affected by curtailments in the case of an imbalance in supply and demand.

Therefore, the relevance of external effects in the Dutch power market depends on the probability and the extent to which market participants might be affected by a supply disruption. This can be assessed by analysing which measures would be taken under the current Dutch market rules in the case of a supply scarcity. In

108 Except for decentralised emergency power systems (such as emergency generators or batteries).

this case, the following (short-term) markets options would successively be called:

- Day-Ahead-Market (APX):
  - All possible transactions would be cleared at the technical price cap of 3000 €/MWh;
  - In the case that demand and supply do not clear (i.e., for the Dutch bidding zone demand and supply curves would not intersect) demand bids would be curtailed.;
- Intra-Day-Market (APX)
  - All balance responsible parties that have not procured (or cannot generate) sufficient electricity to fulfil their contract obligations (with suppliers or end-consumers) will try to purchase additional electricity, e.g., on the Intra-Day-Market;
  - Up to a technical price cap of +100,000 €/MWh, additional supply can be activated on the APX Intra-Day-Market; prices paid in bilateral contracts can also be higher;
  - Some electricity suppliers might still not have procured sufficient electricity to meet their supply obligations;
- Balancing markets and imbalance settlement:
  - TenneT would activate all available reserve energy;
  - Imbalances would be settled at 100,000 €/MWh – the price limit for imbalance payments in the Netherlands.

If demand cannot be met by available electricity supply even after closure of the short-term markets, including available Dutch and cross-border reserve capacity, TenneT would activate emergency capacity. If the system is still unbalanced and the system stability in TenneT's control area is physically under threat TenneT can (as the responsible system operator) curtail exports that have already been confirmed.[109]

Only if these measures are still insufficient to balance the system, a partial (involuntary) curtailment of individual consumers or specific distribution networks would occur.[110] It is important to emphasize that an extensive blackout is very unlikely – due to the missing market clearing on the short-term markets,

109 See https://www.acm.nl/download/documenten/acm-energie/systeemcode-elektriciteit-2015-01-01.pdf

110 In addition, if the shortage in capacity was foreseeable a long time ahead, the "vangnet" could have been activated such that capacities contracted under the "vangnet" would contribute to meet demand and to prevent a curtailment.

the TSO is aware of the upcoming imbalance in supply and demand. Therefore, TenneT can plan a partial curtailment ("Brownout"), in order to guarantee a secure operation of the remaining grid. In addition, the Netherlands are currently in a very comfortable capacity situation, such that the likelihood of involuntary load curtailments (due to the lack of generation capacity) is quite low in the near and medium term future. Furthermore, although the existence of external effects in the event of supply disruptions cannot be completely excluded, market participants will expect with a high probability that most commercial transactions would still take place (because most producers/consumers would still be connected to the grid).

Therefore, in summary, it is unlikely (and it doesn't correspond with our market experience) that market participants take potential external effects from brownouts into account in their investment decisions.

The Dutch electricity market currently is already designed in a way that avoids external effects and favours security of supply. In many respects, the Netherlands are in this regard ahead of other European countries:

- **High price limit for imbalance prices** – The price limit of 100,000 €/MWh for the imbalance settlement is quite high compared to other countries (e.g. Belgium: 3000 €/MWh, Germany: 15.000 €/MWh). High price limits for imbalance payments help to mitigate external effects; market participants will have a high incentive to avoid imbalances if they expect high imbalance prices (especially during situations of scarce supply and demand flexibility). The incentives for market participants to strategically provide/purchase less capacity than required in scarcity events and to game against low probability of the occurrence of scarcity events (strategic behaviour) is very low – the potential "punishment" of miss-behaviour is substantial.

- **Imbalance prices are set with regard to the marginal costs of regulating power** – Imbalance prices are based on the marginal costs (bids) of reserve energy and thereby send strong price signals during situations of scarce supply. Therefore, the pricing mechanism provides adequate cost-based signals to avoid imbalances in economic terms, especially since the bids for the provision of reserve power can incorporate a scarcity rent in tight supply situations. In addition, the use of marginal pricing in the imbalance settlement system ensures that imbalance prices and prices on the intraday market are consistent.

- **Imbalance settlement system provides high incentive for self-balancing** – TenneT publishes imbalance prices and imbalance positions close to real time. In addition, trade on intraday-markets is possible up to five minutes before delivery. Thereby, market participants get a high incentive for self-balancing measures (e.g., by procuring electricity on the intraday market instead of paying imbalance prices).

- **Renewable energies bear balancing responsibility** – In the Netherlands, generally all market parties bear balancing responsibility. This includes renewable energies. Therefore, producers of renewable energy have an incentive to avoid imbalances.

- **Grid tariffs are to a large extent capacity-based** – In the Netherlands, grid-tariffs are mainly capacity- based; households pay a pure capacity-based grid tariff and consumers connected to high-voltage grid pay grid tariffs that are based approximately by 2/3 on capacity and by 1/3 on energy. Capacity-based grid-tariffs can incentivize consumers to reduce peak demand.

Furthermore, the Netherlands provides already provisions for a strategic reserve (Vangnet) which can be activated if the supply-demand balance (generation adequacy) turns out to be tight at some in time in the Dutch electricity market. This instrument enhances the credibility of the EOM and the imbalance mechanisms to penalise miss behaviour of market participants (i.e. gaming with imbalances) since the probability of (physical) external effects in the context of brownouts is further reduced and the financial settlement of imbalances is further ensured. Furthermore, the "Vangnet" can serve as a measure to ensure the provision of security of supply also for very rare events which market participants might not take into account in their calculations of back-up capacity.

External effects as a potential threat to security of supply – Policy implications

Although the Dutch electricity system is already well designed to avoid external effects, following measures could further mitigate them:

- Defining commercial rules for hypothetical brownouts
- Fostering demand flexibility and market-entry of unconventional generation capacities;
- Provide incentives to adapt supply and (actual) demand of small consumers.

In the following we discuss which challenges have to be overcome in order to achieve these three measures. In addition, we describe how rules for the case, a partial load curtailment would be necessary, should be designed.

Defining commercial rules for potential (hypothetical) brownouts

In the potential (hypothetical) case, that power markets were not be able to clear (and thus to balance supply and demand), some consumers may need to be curtailed involuntarily ('brownout'). If partial load curtailment would be necessary, it is important

- to curtail as least load as possible;
- to curtail first customers with a low willingness to pay for security of supply (if possible); and
- to curtail load on a rolling basis (such that not the same customers are curtailed for a long time, if curtailments occur during longer periods).

Furthermore, rules could be established to compensate market stakeholders for external effects and to account for financial imbalances. Commercial rules to compensate for external effects in hypothetical brownout situations and related to the settlement of imbalances would increase the credibility of market signals. Therefore, such rules could contribute to avoiding the situation for which the rules are made for.

Finally, at APX, current (technical) price limits have been set at 3,000/MWh (Day-Ahead). Since this price serves as a benchmark in many power contracts it should reflect the value of electricity in any event. In the cases of a supply shortage this might not be the case. Therefore, it should be assessed if the technical price limit at the power exchange has to be changed in the medium to long term when price peaks might occur in the market. Alternatively, a "brownout" price could be defined which steps in if no market clearing even on the intra-day market is possible and serves for the settlement of trades which still take place in the market (rather than the day-ahead price at the price limit). Ideally, this should be based on a VoLL estimate but could also be the 99.000 €/MWh which is the current price maximum on the intra-day market. The fictional price could also be used to compensate market stakeholders for external effects and to account for financial imbalances.

Demand flexibility and unconventional generation capacities Increasing flexibility of demand is only possible if consumers

- receive (adequate) price signals and can react to these signals; and
- if the change in demand can me metered and settled.

If consumers have time-variable electricity tariffs, price signals can be offset by grid costs that are paid on top of the market price. For example, if during a period of scarce supply demand is shifted to a period of lower (wholesale) electricity prices, higher grid tariffs may be charged to the customer if - due to the additional consumption in one hour - the maximal grid capacity used by the customer has been increased. In this case, a behaviour that is efficient with regard to the price spreads is actually punished by higher grid costs.[111] Unconventional generation capacities are capacities that originally have been built as decentralised capacities and not in order to bid into wholesale power markets, e.g., emergency power systems (such as battery storages or small scale generators). It is important that all available capacities in the electricity system can participate in the market and thereby contribute to provide flexibility. Therefore, if any obstacles with regard to the market participation of unconventional generation capacities exist, such obstacles should be removed.

Incentives to avoid imbalances of consumers with standard load profiles

The consumption of households, commercial customers and small industrial customers is not metered on an hourly (or quarter-hourly) basis. Suppliers that provide these customers with electricity procure electricity according to standard load profiles and also bear balancing responsibility with regard to these standard load profiles. This induces the following challenges:

- **On supplier-level:** Suppliers don't have an incentive to procure the electricity that their customers actually consume but only the electricity that is needed according to the standard load profiles.
- **On customer-level:** Customers neither have an incentive nor the technical possibility to adjust their consumption to the standard load profiles.

Companies, settling the imbalances of load profile customers should have an incentive to manage these imbalances actively e.g. by procuring back up capacity. Another option could be to solve these missing incentives would be to provide more customers with the technical metering equipment needed to include them into balancing groups.

5.2.4 International spill over effects

The Netherlands are highly interconnected with Belgium – where a strategic reserve has been introduced -, with Germany - where the introduction of a CRM is still under consideration - and with the UK, where a capacity market has been introduced. In this section we discuss how the existence or introduction of CRMs in neighbouring countries might affect security of supply in the Netherlands.

[111] One solution would be not to take into account load resulting from load shifting in the calculation of the customer's maximal grid capacity. This solution is applicable as long as the increase in the customers' individual peak load does not induce additional costs in the grid.

International spill over effects as a potential threat to security of supply - Description

CRMs increase the amount of available generation capacity and thereby, in general, reduce price peaks that would occur during hours of scarcity. Through network interconnection, this price dampening effect of CRMs does not only occur in the country where the CRM is in place but is (partly – depending on the extent of interconnection) "exported" to its neighboring countries. The higher the capacity requireements under the foreign CRM are the higher the probability of spill-over effects to other countries.

International spill over effects as a potential threat to security of supply – Assessment of relevance in the Netherlands

The quantitative power market analysis (sensitivity 4 "Increased foreign capacity") has shown that the introduction of capacity reserve requirements in connected or neighbouring countries affects investment decisions within the Netherlands.[112] Sensitivity 4 represents a situation, in which foreign capacity mechanisms don't take the contribution of interconnected capacity fully into account, i.e. excessive capacity requirements are defined. This leads to lower capacity provision in the Netherlands (see **section 3.4.5**).

Nevertheless, even with excessive capacity requirements, we do not observe involuntary load-reduction in the Netherlands, and the Netherlands remain net-exporter of power in the long-run. Both factors indicate that security of supply can still be safeguarded:

1. The additional generation capacity in neighbouring countries, induced by the foreign CRMs, also contributes to maintaining security of supply in the Netherlands: As long as scarcity events don't occur in both countries and interconnector capacity is available, demand in the Netherlands can also be met by imports.

2. High price peaks will still occur during situations in which foreign capacity is not or only to a limited extent available for exports to the Netherlands. This can for example be the case when demand peaks occur at the same time in both countries or because of limited interconnector capacity. Thus, investments into new generation capacity can still be profitable.

Despite all of the above, there remains the challenge that price peaks occur less often[113]. Therefore, price- and quantity risks for investors in the Netherlands

112 We have analysed possible spill-over effects for countries that have decided to introduce some form of CRM, France and Belgium.

113 We observe that the number of prices above 200 €/MWh in 2030 reduces significantly from 28 in the Base Case to 4 hours per years in sensitivity 4.

increase compared to a situation in which all neighbouring countries would only have an EOM. This holds especially if foreign CRMs induce over capacities in the respective markets. These risks need to be financed via higher prices and profits in the market which increases total costs of electricity supply. In addition, high price peaks increase the political risk of market intervention (see **section 5.2.2**).

Moreover, interactions between energy-only-markets and markets that have a CRM (via electricity import and exports) lead to distributional effects. In the Netherlands, the price dampening wholesale electricity price effect that results from foreign CRMs is

- beneficial to Dutch consumers (see **section 3.4.5**); but
- it can lead to lower profits for Dutch electricity producers if they are not able to explicitly participate in the foreign CRMs and therefore don't receive capacity payments.[114]

Distributional effects occurring in countries that have a CRM but are interconnected to countries with an EOM, are opposite to those described above:

- the financial burden for foreign consumers increases as they pay the capacity payments, but do not fully benefit from lower wholesale electricity prices (as a part of the price decrease is "exported" to the Netherlands);
- foreign producers are better off compared to a situation in which all countries would introduce a CRM because they receive capacity payments but do not bear the total price dampening effect.

From an economic point of view, these distributional effects are neither beneficial nor problematic. However, from a political point of view, distributional effects can play a role when making decisions on market intervention.

International spill-over effects as a potential threat to security of supply – Policy implications

The introduction of CRMs in neighbouring countries is no threat to security of supply in the Netherlands. However, risks for Dutch investors increase because scarcity prices occur less often (but are higher if they occur). For this reason, the measures in order to reduce political risks, described in Section 5.2.2 are especially important in the light of (potential) international spill over effects. In

114 EU state aid guidelines require that CRMs need to explicitly allow for cross-border participation. However, there are different ways to meet this requirement. For example in the UK CRM, cross-border participation will be introduced within this year but includes capacity payments for the interconnector only and not for power plans in neighbouring countries.

particular it is important that policy makers commit to accept price peaks in the future and that they will not introduce regulatory price caps.

In addition, the co-existence of fundamentally different market designs in the European power system that is strongly physically interconnected, can lead to various distortions, especially if interconnected capacity is not taken into account appropriately when capacity requirements are defined. EU member states should clearly co-ordinate especially in the case of the implementation of CRMs which reliability measure is used for calculating the capacity requirements and how international portfolio effects (e.g. non full correlation of residual demand across EU countries) are taken into account. Otherwise, there is the risk of over capacities increasing the spoil-over effects between countries substantially.

Furthermore, in CRMs x-border trading of capacity (generation and/or transmission capacity) should explicitly be allowed and made possible in order to comply with the European energy market. The current debate about CRMs indicates that x-border capacity participation in CRMs is complex. For example the availability of capacity across the borders has to be assured in scarcity events, it has to be assured that capacities are available for those customers paying for the capacity (that means in this case for customers abroad), and availability of generation and transmission capacity has to be assured "as a package".

In this context, also the coordination and harmonization of market rules for scarcity events should be enhanced across in Europe. For example, grid operators disconnecting x-border interconnections in scarcity events are not compatible with cross-border trading of capacities in CRMs. Furthermore, differing (maximum) imbalance prices across countries can distort price signals and cross-border power trading in scarcity events not only on the balancing market, but also on the day-ahead and intra-day markets; electricity will be traded to the market area with the presumably highest imbalance prices since market participants which face imbalances will try to minimise penalties from paying imbalance prices by moving their short position to the country with the lowest prices.

5.3 Overall assessment of the future EOM design

As described in **Section 5.1**, we assess that an ideal EOM can guarantee security of supply without "explicit" capacity payments. Due to scarcity rents that can be achieved during hours of peak demand and scarce supply and due to implicit capacity payments (e.g., on balancing markets or via long-term contracts), even marginal plants can recover investment and fixed costs in an EOM.

Possible market distortions could arise from market and political risks, external effects and international spill over effects. As described in **Section 5.2**, we assess that these potential market (design) failures are either not relevant in the Netherlands or can be mitigated by reforms:

Reliability of the electricity system

- **Market risks can be borne by investors; no action needed** – We expect that the market participants can cope both with short- and with long-term commercial market risks. This also holds in the light of an increasing share of intermittent renewables in the power market that will entail higher quantity-, price- and profit-risks for conventional power plants, storages and demand flexibility. However, these increasing risks do not change the fundamental market mechanism. The market will react to these increasing risks, e.g. by higher prices during scarcity periods and by a shift to investments into plants with lower capital costs (e.g. gas turbines or demand flexibility in the industrial sector).

  The political and regulatory framework therefore should enable markets to develop the products or instruments needed to cope with these risks. Also, the political and regulatory framework should ensure that high prices, emerging during scarcity periods, are not restricted (e.g., by setting price caps).

- **Political risks seem to be rather low in the Netherlands compared to other countries but could be reduced further** – Generally, political interventions are difficult to predict but not automatically a threat to security of supply. Risks from general energy policies can be reduced by setting or maintaining a stable political framework. In the Netherlands, political risks could be reduced e.g. by clarifying whether policy will accept a further substantial deployment of small-scale photovoltaic or whether net-metering rules might be abolished once a certain threshold of installations has been reached.

  The risk of political interventions into price building seems to be low in the Netherlands: Currently no price cap exists, and even the technical price limits are comparatively high compared to other European countries (especially intra-day and in the balancing market). In order to maintain a stable political framework, Dutch policy makers may commit not to introduce price caps in the future.

- **The Dutch electricity system is already well designed to avoid external effects, however, a few improvements could still be made** – Due to the specific characteristics of electricity markets, signalling a high willingness to pay does not guarantee being served, because other consumers cannot be excluded from consumption. Therefore, investments into security of supply might be insufficient. However, external effects can be avoided if market participants expect with a high probability to be affected by curtailments in case an imbalance between supply and demand occurs. The current Dutch electricity market is already well designed to prevent external effects as market participants will expect with a high probability that most commercial transactions would still take place (because most producers/consumers would still be connected to the grid) and imbalances will be settled with high probability. Furthermore, a number of market design elements are designed to avoid or mitigate externalities, for example:

- price limits for imbalance prices are comparatively high;
- imbalance prices are set with regard to the marginal costs of regulating power;
- the imbalance settlement system provides high incentive for self-balancing;
- renewable energies bear balancing responsibility; and
- grid tariffs are to a large extent capacity-based (which incentivises to reduce peak load).

Although the Dutch electricity system is already well designed to avoid external effects, following measures could further mitigate them:

- Beside technical rules, define commercial rules for potential situations with brownouts including provisions for the compensation of external effects;
- Increase flexibility of demand, e.g. by ensuring that the calculation of grid costs does not prevent load shifting (a potential obstacle to load shifting could be that a customer has to pay higher grid tariffs if due to his load shifting his maximal grid capacity used has increased);
- Avoid barriers for unconventional generation capacities to participate in the market; For example, the current regulatory framework doesn't recognize storage as such and therefore need to consider it both as load and production making it difficult for storage providers to compete with conventional generation.
- Incentivise companies, settling the imbalances of load profile customers, to manage these imbalances actively e.g. by procuring back up capacity. Currently, imbalances of load profile customers are balanced by the distribution grid operators. Costs for balancing these customers are passed on into the grid tariffs and are therefore socialised. With the smart meter roll-out in the Netherlands it can be expected that a least a substantial share of load profile customers are transferred to the balancing of metered customers. Costs for balancing these customers are then transferred to the Programme-Responsible-Parties, who then have an incentive to minimise balancing costs by a mix of measures such as short-term trading and long-term procurement of back-up capacity. It may be an option to implement an obligation to transfer the

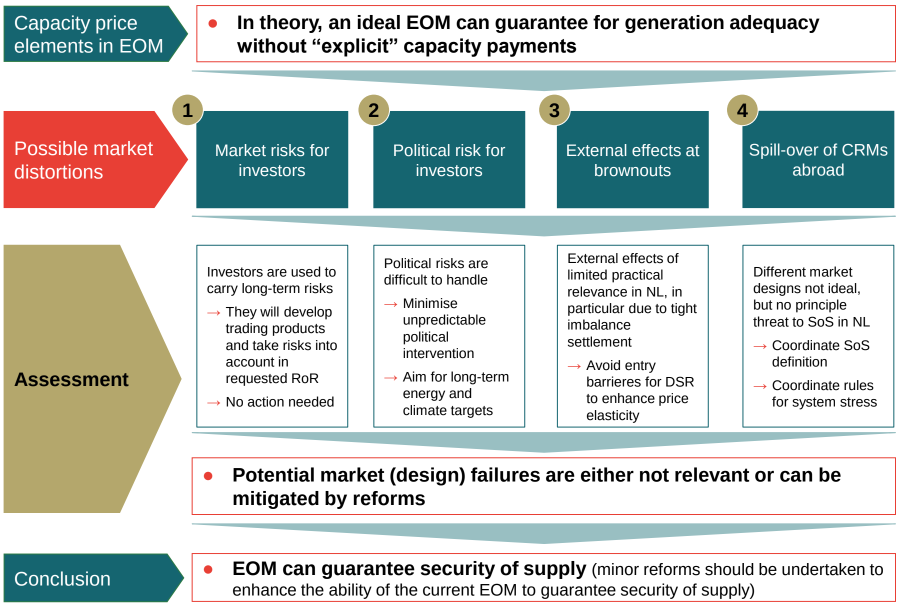
balancing of all smart metered customers to Programme-Responsible-Parties.

- **International spill-over effects are not necessarily a threat to security of supply** – The Dutch electricity market is interconnected with countries that have introduced a CRM. For this reason, wholesale power prices and the number of price peaks might also be reduced in the Netherlands. High price peaks will still occur during hours in which foreign capacity is not or only to a limited amount available for exports to the Netherlands. However, especially if substantial additional generation capacity is induced by the foreign CRM these price peaks occur less often so that price- and quantity risks for investors in the Netherlands increase compared to a situation in which all neighbouring countries would only have an EOM. These risks need to be financed via higher prices and profits in the market. For this reason, it is important that policy makers commit not to introduce price caps - especially in light of potential international spill-over effects. Furthermore, capacity requirements in foreign capacity mechanisms should not lead to substantial overcapacities.

Furthermore, the Netherlands already provides provisions for a strategic reserve (Vangnet) which can be activated if the supply-demand balance (generation adequacy) turns out to be tight at some point in time in the Dutch electricity market. This instrument enhances the credibility of the EOM and the imbalance mechanisms to penalise misbehaviour of market participants (i.e. gaming with imbalances) since the probability of (physical) external effects in the context of brownouts is further reduced and the financial settlement of imbalances is further ensured. Furthermore, the "Vangnet" can serve as a measure to ensure the provision of security of supply also for very rare events which market participants might not take into account in their calculations of back-up capacity. We recommend maintaining the "Vangnet" as an instrument to provide back-up to the Dutch power market if developments deviate from the expectations.

Figure 75 summarizes our assessment of the Dutch electricity market with respect to its ability to guarantee security of supply. Based on our analysis, we conclude that the Dutch electricity market currently is already well designed to guarantee security of supply. However, some reforms may be implemented in order to enhance the ability of the current market design to ensure reliability. In particular, political uncertainty should be minimised, i.e., policy makers may commit not to interfere into electricity price building mechanisms in the future.

Figure 75. Conclusion on reliability of the Dutch electricity system



Source: Frontier

6 Policy implications

This section summarises the policy implication derived from the analyses on the reliability and affordability of the electricity system in the Netherlands regarding

- The electricity market design (**section 6.1**); and
- The design of renewable support and market integration of renewables (**section 6.2**).

6.1 Policy implications related to the Market Design

The Dutch electricity market is already well designed in order to achieve security of supply and reliability. Elements of the Dutch electricity market design that encourage the provision of security of supply in an "energy-only-market" include the following:

- No regulatory price caps exist and technical price limits at the power exchange are comparatively high (especially in the intra-day market);
- The price limit for imbalance prices is comparatively high generating strong incentives for market participants to balance power generation, procurement and supply;
- Imbalance prices are set with regard to the marginal costs of regulating power providing an adequate signal for the value/costs of imbalances;
- The imbalance settlement system provides high incentive for self-balancing;
- Renewable energies bear balancing responsibility; and
- Grid tariffs are to a large-extent capacity-based (which provides incentives to reduce peak demand).

Furthermore, market rules in the Netherlands already incorporate provisions for a strategic reserve (Vangnet) which can be activated if the supply-demand balance (generation adequacy) turns out to be tight at some point in time in the Dutch electricity market. This instrument enhances the credibility of the EOM and the imbalance mechanism to penalise misbehaviour of market participants (i.e. gaming with imbalances) since the probability of (physical) external effects in the context of brownouts is further reduced and the financial settlement of imbalances is further ensured. Furthermore, the "Vangnet" can serve as a measure to ensure the provision of security of supply also for very rare events which market participants might not take into account in their calculations of back-up capacity. We recommend maintaining the "Vangnet" as an instrument to provide back-up to the Dutch power market if developments deviate from the expectations.

Some additional reforms could however enhance the ability of the Dutch electricity system to provide security of supply further:

- In order to maintain a stable political framework, Dutch policy makers should commit **not to introduce price caps** in the future even when electricity prices become more volatile (at least no price caps below the Value-of-Lost-Load);

- In order to minimise potential (rather hypothetical) external effects **commercial rules for potential (hypothetical) brownouts** may be defined. This may include commercial rules for the involuntary supply curtailment as well as rules to compensate market stakeholders for (potential) external effects and to account for financial imbalances in the case of brownouts. These commercial rules could especially increase the credibility of market signals and therefore contribute to avoid the situation for which the rules are made for.

- Incentives should be improved to manage **imbalances of load profile customers** actively e.g. by procuring back up capacity. Alternatively, an increasing share of consumers, which are subject to standard load profiles today, may be equipped with technical metering equipment. In this case, the consumption of these customers can be settled by metered data instead of load profiles. However, costs for the meter equipment and the required IT have to be taken into account.

- **Spill-over effects from foreign CRM's** may occur especially if additional capacity induced by the CRM is substantial and overcapacities arise in the market. On the other hand, these spill-over effects are limited if the design of the CRM is adequate and capacity requirements defined in the CRM are moderate (e.g. by taking international portfolio effects into account). Therefore, it is important that the Netherlands takes actively part in the European debate on CRMs such that

  - the definition of security of supply is coordinated at the European level;

  - excessive capacity requirements in CRMs in neighbouring is avoided;

  - the designs of CRMs get harmonized across Europe; and

  - Dutch power plants are allowed to explicitly participate in CRMs of neighbouring countries (as envisaged by the European Commission).

Furthermore, the general policy framework should be assessed as stable by market participants. For example, climate policy in the power sector should be embedded in the EU ETS. This means, for instance, that unforeseeable *ad hoc* intervention in the power market as a national instrument of CO2 policy deviating from the long term plan should be avoided. Otherwise, trust of participants in the policy framework might be undermined leading to negative impacts on investments in the longer term.

6.2 Renewable energies and other technologies

The Energy Agreement defines technology specific targets, i.e. increasing capacities for wind-onshore and wind-offshore in the medium-term, and other measure of climate change, i.e. short-term retirement of old coal-fired power plants. These targets and measures are designed to support the medium-term goal of a share of renewable energy sources in the energy mix of 16% in 2023.

Currently, financial support to increase the deployment of RES-E is granted in the form of a market premium under the SDE(+) scheme:

- The current RES support mechanism in the Netherlands (sliding market premium) represents a relatively cost-efficient way to deploy renewable energy sources in the electricity sector. It incorprates competition between techologies (even though it is not completely technology neutral) while keeping track of support costs. In addition, the cap on support payment limits the total cost burden to final consumers. In addition, the current mechanism is reviewed on an annual basis.

- Furthermore, all market participant (incl. renewables) bear balance repsonsibility. This enhances the market integration of renewables.

Based on our analysis of the future profitability of intermittent RES-E, we derive the following conclusions:

- Further cost reductions are required to achieve grid-parity of intermittent renewable electricity sources until 2035 if the market environment doesn't change substantially (e.g. due to substantially higher CO_2-prices in combination with substantially higher primary energy prices);

- From a economic perspective, wind-onshore and offshore are more efficient than solar PV as less additional support is required to finance the deployment;

- Individual incentives to invest, however, can deviate from the efficient technology choice as implicit subsidies in the form of net-metering of consumption are granted e.g. for solar PV and distort the individual investment incentives.

Policy implications

Based on our modelling analysis, we expect that financial support is required in order to achieve the targeted levels of renewable energy in the Netherlands. We derive the following implications for future renewable policies in the Netherlands:

- The Netherlands should aim for a consistent framework of renewable policy for the period after 2020 in order to create long-term incentives and thereby certainty for investors in both renewable and conventional energy sources;
- Our modelling analysis shows that the growth of renewable energy sources in electricity supply represents a significant leverage on costs to final consumers. Therefore, the definition of targets and instruments should take the affordability and costs to final consumers into account;
- In order to increase effciciency, more co-ordination regarding RES-E support in the European Union should be achieved; and
- The framework should explicitly adress implicit subsidies for certain technologies that could distort investment incentives and lead to uncontrolled and unforeseeen growth of decentral generation. This is true especially for solar PV which is currently not economical from a system perspective but from an individual's perspective due to implicit subsidies arising from net-metering of consumption.
- In order to enhance the predictability of market developments it would be advantageous if policy makers indicated in a timely manner whether or when regulatory rules may change – for example, it could be stated that the rules change as soon as a certain amount of e.g. photovoltaic capacity has been installed

Due to the increasing share of intermittent RES-E in the electricity system, the flexibility of the electricity system is an important element of the energy transition. However, as of today, there is substantial flexibility available in the Dutch power market Based on our power market simulations, we don't expect a massive need to invest in unconventional flexibility technologies since sufficient flexibility can be provided e.g. from gas-fired power stations, CHP plants, and cross-border interconnections:

- The low level of power prices in the short-term (39€(real, 2013)/MWh in 2015) on the one hand and the high amount of final or temporary retirement of power plants on the other hand indicate the existance of overcapacities in the power sector. These overcapacities arise from the high growth of renewable energy sources in the past decade (in the Netherlands and in Europe) as well as decreasing power demand after the financial crisis and higher energy efficiency (in the Netherlands and in Europe).

- After a period of consolidation, previously mothballed generation capacities re-enter the market when the supply-demand balance in the electricity market becomes tighter (in the Netherlands and in Europe) and power prices rise to above 50 €(real, 2013)/MWh. Based on these flexible power plants and taking into account new and existing interconnection and storage capacities across Europe, substantial amounts of RES-E can be integrated into the system without major investments in new storage technologies in the next 20 years.

In the long term, additional flexibility options such as demand-side-response (DSR) can be further developed. Due to the envisaged smart meter roll-out programme in the Netherlands, there will be substantial potential for developing DSR. Clear mechanisms and rules are required to coordinate the use of these decentralised flexibility options for alleviating grid constraints (in particular in the distribution grid) on the one hand side, and for balancing the power system (e.g. to balance fluctuating wind and PV on the system level) on the other hand side. Furthermore, taxes and levies could be designed in a way that electricity is especially used in periods with substantial power generation from renewable sources (high wind, high sun periods). This could include reducing taxes and levies in periods of low wholesale power market prices. However, on the other hand side, the modification of taxes and levies should not lead to inefficient high incentives to invest in decentralised flexibility such as small scale batteries.

We do not observe a specific need to support the implementation of new technologies (including flexibility technologies) on large scale. Instead, the larger scale implementation of those technologies can be left to the market mechanisms. However, technology options should not be ruled out and politically sorted out in an early stage. The Netherlands should keep the options for deploying other technologies such as compressed air energy storage (CAES) as well. Developing these technologies in the context of Research and Development (R&D) can offer further flexibility options in the more distant future when even higher shares of power supply may be generated by RES-E

References

- Bundesministerium für Wirtschaft und Energie (BMWi) (2014a): *"Ein Strommarkt für die Energiewende – Diskussionspapier des Bundesministeriums für Wirtschaft und Energie (Grünbuch)"*, Berlin.

- Bundesministerium für Wirtschaft und Energie (BMWi) (2014b), *"Moderne Verteilernetze für Deutschland (Verteilernetzstudie)"*, Berlin.

- Carstairs, J. / Pope, I. (2011): "*The case of a new capacity mechanism in the UK electricity market – Lessons from Australia and New Zealand*" Energy Policy, Vol.39, pp.5096-5098

- CE Delft / DNV GL (2014): "*Toekomst WKK en warmtevoorziening industrie*", Delft.

- CE Delft (2010): *"Net voor de Toekomst"*, Delft.

- CPB Netherlands Bureau for Economic Policy Analysis (2015): *"Technological Uncertainty in Meetings Europe's Decarbonisation Goals"*, CPB Discussion Paper 301.

- CBS (2015), *"Prognose intervallen van de bevolking, 2015-2060"*, Centraal Bureau voor de Statistiek (CBS), The Hague.

- Clingendael / PBL (2014), *"Reflections on coordination mechanisms: for accommodating increasing amounts of wind and solar in the power market"*, by Clingendael International Energy Programme and Planbureau voor de leefomgeving, Netherlands.

- Deloitte (2004): *"Benutting vraagrespons in de geliberaliseerde elektriciteitsmarkt"*, Onderzoek voor het Ministerie van Economische Zaken Directoraat-Generaal voor Marktordening en Energie, Amstelveen.

- DLR/ Frauenhofer IWES/ IfnE (2012): *"Langfristszenarien und Strategien für den Ausbau der erneuerbaren Energien in Deutschland bei Berücksichtigung der Entwicklung in Europe und global – BMU Leitstudie 2011"*, BMU-FKZ 03MAP146.

- ECF (2010), *"Roadmap to 2050; a practical guide to a prosperous, low-carbon Europe, technical analysis"*, European Climate Foundation (ECF).

- ECN/PBL (2014): *"Nationale Energieverkenning"*, Petten.

- ECN (2014a): *"Cost and revenue related impacts of integrating electricity from variable renewable energy into the power system – a review of recent literature",* Energy Research Centre of the Netherlands, Netherlands.

- ECN (2014b): Berekening basisbedragen SDE (+) 2015.

- European Network of Transmission System Operators for Electricity (ENTSO-E) (2013): "Guideline for Cost Benefit Analysis of Grid Development Projects", Brussels.

- European Network of Transmission System Operators for Electricity (ENTSO-E) (2014): *"Scenario Outlook & Adequacy Forecast 2014-2030"*, Brussels.

- European Commission (2014): *"Guidelines on State aid for environmental protection and energy 2014-2020"*, 2014/C200/01.

- European Commission (2012): *"The state of the European carbon market in 2012"*, COM (212, 652), Brussels.

- Frontier Economics / Formaet Services (2014): "Strommarkt in Deutschland – Gewährleistet das derzeitige Marktdesign Versorgungssicherheit?"; Bericht für das Bundesministerium für Wirtschaft und Energie (BMWi).

- IEA (2014a): *"Energy Policies of IEA Countries – The Netherlands, 2014 Review"*, International Energy Agency (IEA/OECD), Paris.

- IEA (2014b): *"The Power of Transformation – Wind, Sun and the Economics of Flexible Power Systems"*, International Energy Agency (IEA/OECD), Paris.

- IEA (2014c): *"World Energy Outlook",* International Energy Agency (IEA/OECD), Paris.

- NEA (2012): *"Nuclear Energy and Renewables: System Effects in Low-Carbon electricity systems*", Nuclear Energy Agency (NEA/OECD), Paris.

- PV Parity project (2013), *"Grid Integration Cost of PhotoVoltaic Power Generation – Direct Cost Analysis related to Grid Impacts of PhotoVoltaics"*, Imperial College London, London.

- Réseau de transport d'électricité (RTE) (2014): *"French Capacity Market – Report accompanying the draft rules"*, Paris.

- Rijksdienst voor Ondernemend Nederland (RVO) (2011): „*Elektrisch Rijden in de versnelling*“, Plan van Aanpak 2011-2015.

- Rijkswaterstaat Ministerie van Infrastructuur en Milieu (2010): BS-10-002, ECN Beleidsstrudies „*Potentieel en rijpheid van hernieuwbare energieopties*“, Petten.

- Sociaal-Economische Raad (SER) (2013): *"Energieakkoord voor duurzame groei"*, Rapport, Den Haag.

- TenneT TSO B.V. (2014): *"Rapport Monitoring Leveringszekerheid 2013-2029"*, Arnhem.

- U.S. Energy Information Administration (EIA) (2014): "Annual Energy Outlook 2014 with projections to 2040", DOE/EIA-0383(2014), Washington.

- VVD (People's Party for Freedom and Democracy) / PvdA (Labour Party) (2012): *Coalition agreement cabinet Rutte-Asscher – "Building Bridges"*, AVT12/AZ106835, Den Haag.

Annexe 1: Methodology of estimating grid cost

In **Section 4.1.2**, we presented our estimation of grid investment costs induced by the planned RES-E deployment in the Netherlands up to 2030. In the following, we describe the methodology used for our estimation in more detail. We describe how we derived grid investment costs per MW of additional RES-E deployed in the system from the BMWi and the ECN Study, respectively. Then, we show the results of the grid investment costs per unit of RES-E and the RES-E deployment numbers that we multiplied with the unit grid investment costs.

Methodology for deriving grid investment costs induced by RES-E deployment

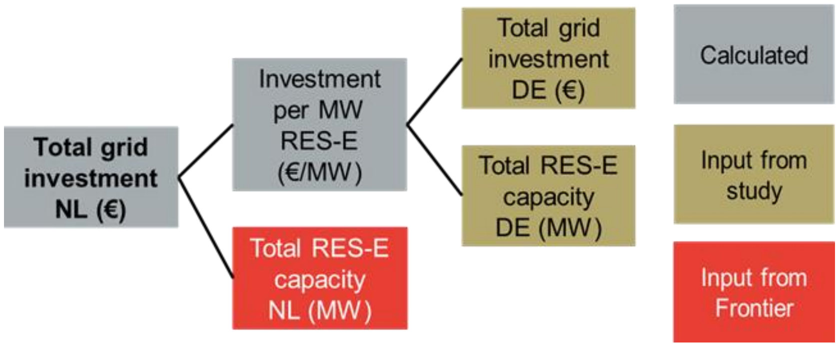
We estimated grid investment costs induced by RES-E deployment based on two studies. In the following we describe which data was provided in the two studies and which assumptions we had to make.

BMWi-Study

At the end of 2014, the German Ministry of Economic Affairs (Bundesministeriums für Wirtschaft und Energie (BMWi)) commissioned a study to understand what the increased share of energy from renewable sources meant for distribution grid investment.

We take the resulting investment numbers and translate them into an amount per additional MW of renewable energy as described in 3.2.4. We use the investment scenario "Netzenentwicklungsplan" as the upper bound for our calculations and the scenario "Bundesländer" as lower bound. In the German study it is assumed that all of these costs will have materialized by 2032, whereas we have used different time scales for different scenarios.

Figure 76. Methodology to obtain estimates of total required grid investment in the Netherlands from BMWi study



Source: Frontier Economics

By taking this approach we have assumed that the costs of integrating a higher share of renewables into the electricity distribution grid will be comparable for the Netherlands and Germany.

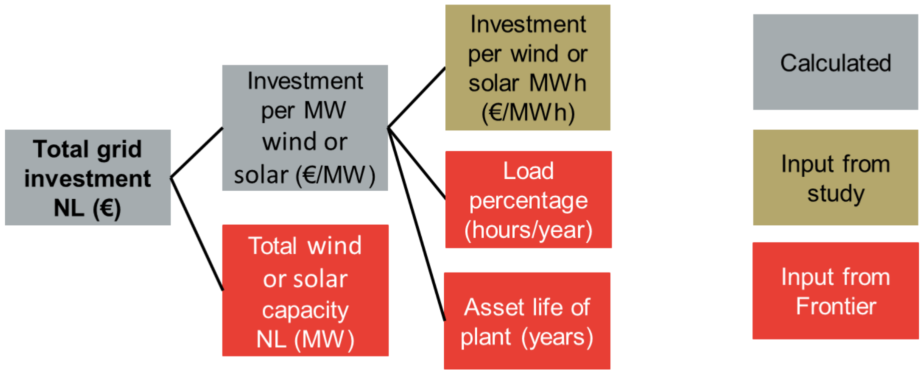
ECN-Study

In May 2014, Jos Sijm published the meta-study "Cost and revenue related impacts of integrating electricity from variable renewable energy into the power system – a review of recent literature", for the Energy Research Centre of the Netherlands (ECN). This study compares a set of recent publications on the cost and revenue related impacts of integrating higher shares of electricity from renewable sources in the electricity system.

As our analysis is focused on the impact of higher shares of renewable energy on the grid investment costs, we have only considered the grid-related costs in this paper and have ignored additional balancing and adequacy costs.

Estimates in the ECN study are given in €/MWh, which we have used to obtain an estimate of total grid investment required in the Netherlands using the methodology described above.

Figure 77. Methodology to obtain estimates from ECN meta-study



Source: Frontier Economics

Estimated investment costs per additional MW

We have derived the following investment costs per MW of renewable electricity for both the BMWi and ECN studies (**Table 4**).

Table 4. Required grid capital expenditure in per €/MW of electricity from a renewable source

Investment costs per MW of	BMWi		ECN	
	Lower bound	Upper bound	Lower bound	Upper bound
RES-E	€337,241	€360,256	-	-
Solar PV	-	-	€8,190	€651,924
Wind on-shore	-	-	€32,648	€932,800
Wind off-shore (Transmission grid)	-	-	€866,056	€1,440,938

Source: BMWi, ECN, Frontier Economics

We derive the total grid costs by multiplying the average of indicated ranges in the ECN study with the yearly capacity additions of intermittent renewable energy sources. Therefore, we assume constant costs of renewable expansion on grid level. This represents a rather conservative assumption as it does not take into account possible economies of scale.

Annexe 2: Power market modelling

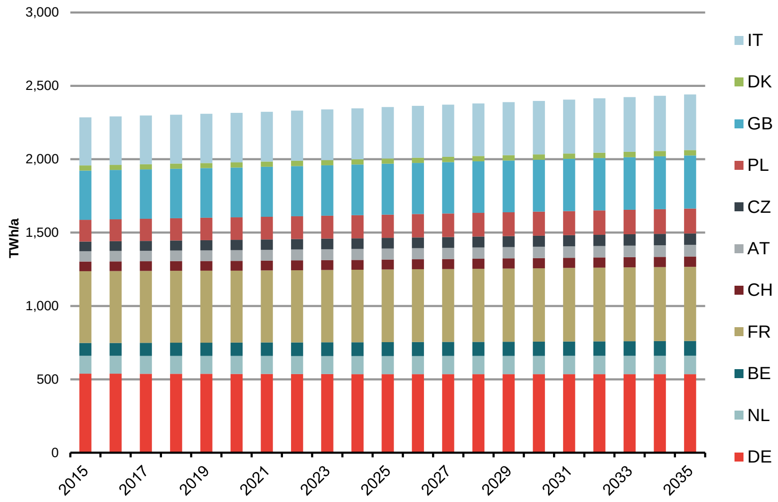
In this Annexe we present additional information on quantitative analysis and the power market modelling:

- Assumptions regarding the development of power demand in all modelled regions;
- Development of interconnection capacity in all modelled regions;
- Development of generation capacities and power generation (Base Case);
- Impact of the sensitivities on power generation in all regions;
- Development of imports and exports of power to and from the Netherlands; and
- The modelling of capacity mechanisms.

Assumptions regarding power demand in all regions

We assume that electricity consumption increases moderately by 7% from 2015 to 2035 in all modelled regions (**Figure 78**). The assumptions are derived from multiple sources, e.g. the network development in the case of Germany and TSO forecasts for France.

Figure 78. Electricity demand (model-region)

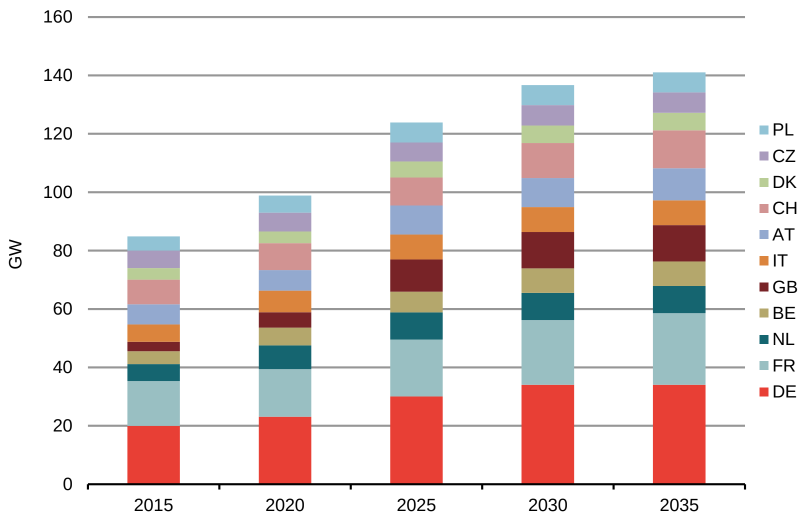


Source: Frontier

Development of interconnection capacity in Europe

We expect that interconnection capacity will continue to increase in order to achieve an integrated internal electricity market in Europe. As described in **section 3.2.6**, we base our assumptions regarding the future development of IC-capacity on the ENTSO-E TYNDP (2014). **Figure 79** shows the assumed development of interconnection capacity (average of import/export capacity) in all modelled regions until 2035.

Figure 79. Average of import/export capacity (Europe)



Source: Frontier

Cost assumptions for thermal power generation plants

Table 5. Assumed overnight investment costs

EUR(real, 2013)/kW	2015	2020	2023	2030	2035
Hard coal	1,750	1,750	1,750	1,750	1,750
Natural Gas (OCGT)	450	450	450	450	450
Natural Gas (CCGT)	750	750	750	750	750
Hard coal (IGCC) with CCS	2,750	2,750	2,750	2,750	2,750
Natural Gas (CCGT) with CCS	1,200	1,200	1,200	1,200	1,200
CAES	806	806	806	806	806
AACAES	1,300	1,300	1,300	1,300	1,300
Power-to-Gas (to-Power)	1,950	1,860	1,710	1,650	1,600
Pumped-Hydro-Storage	1,300	1,300	1,300	1,300	1,300
Nuclear	4,600	4,600	4,600	4,600	4,600

Source: Frontier

Table 6. Other costs elements

Technology/Fuel	Fixed O&M costs (EUR/MW)	Other variable costs (EUR/MWh_el)	CO2 Transport & Storage Costs (EUR/t CO_2)
Hard coal	26,250	5	-
Lignite	36,000	4	-
Natural Gas (OCGT)	6,750	15	-
Natural Gas (CCGT)	11,250	10	-
Hard coal (IGCC) with CCS	54,950	5	15
Natural Gas (CCGT) with CCS	18,000	10	15
CAES	16,120	1.2	-
AACAES	26,000	1.2	-
Power-to-Gas (to-Power)	45,000	1.2	-
Pumped-Hydro Storage	26,000	0	-
Nuclear	69,000	2	-

Source: Frontier

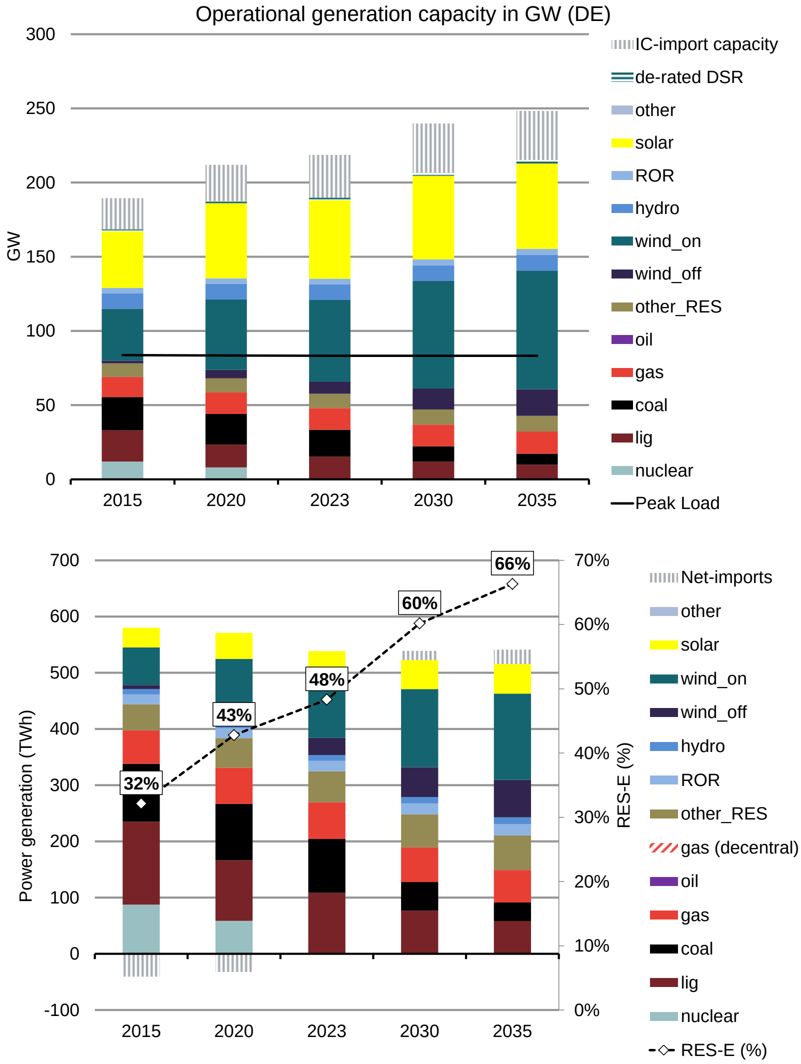
Development of generation capacities in the core-region (Base Case)

The power market model includes endogenous development of conventional generation capacities in France, Germany, Belgium and Austria (core-region) which takes into account known entries and retirements of power plants. The development of renewable energy sources is included as exogenous assumption based on:

- Our assumptions for RES-E in **Germany** are based on the current legal targets (EEG 2014) which aim at achieving a renewable electricity share (% of net-consumption) of at least 80% in 2050.

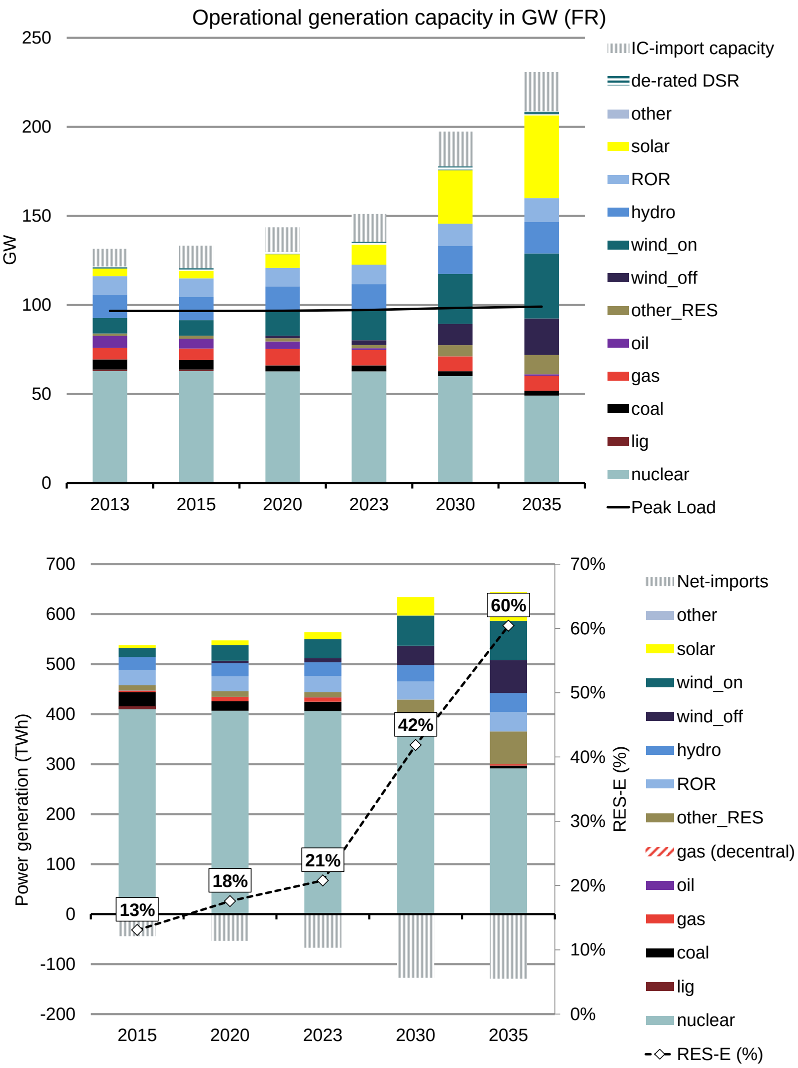
- Our assumptions regarding the development of RES-E for **France, Belgium** and **Austria** are based on the ENTSO-E SO&AF Scenario B until 2025 and Vision 3 for 2030 (linear extrapolation afterwards).

Figure 80. Generation capacity and power generation in Germany (Base Case)



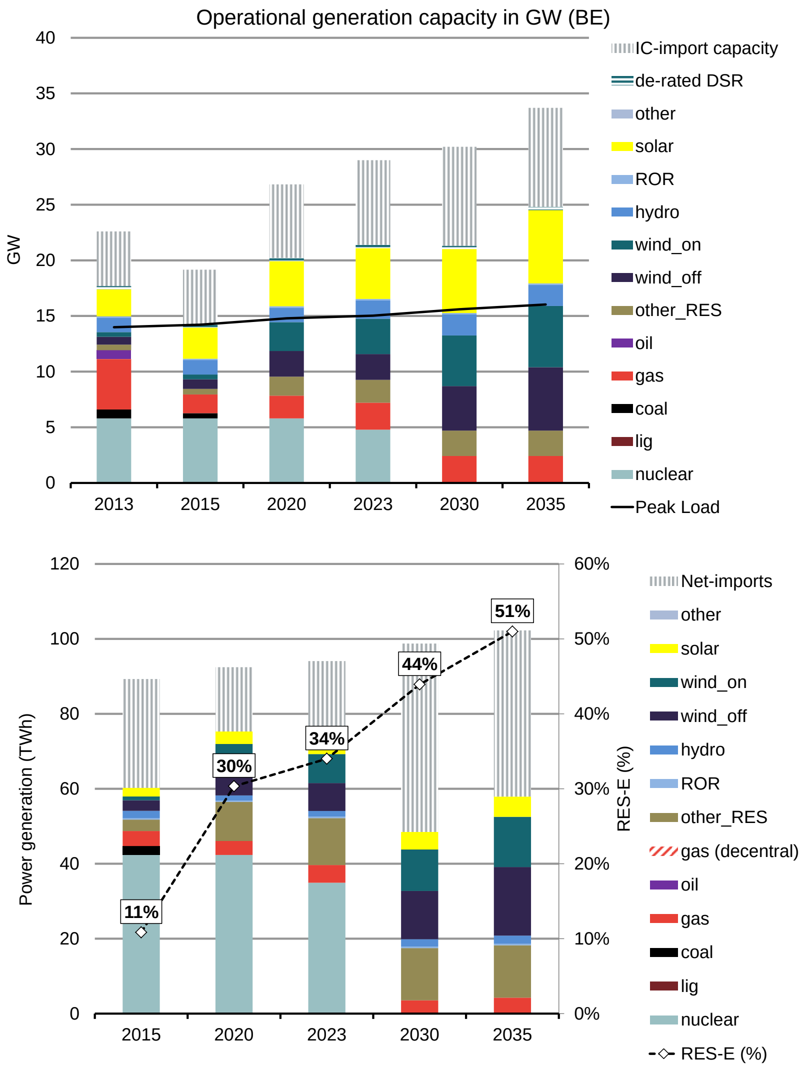
Source. Frontier

Figure 81. Generation capacity and power generation in France (Base Case)



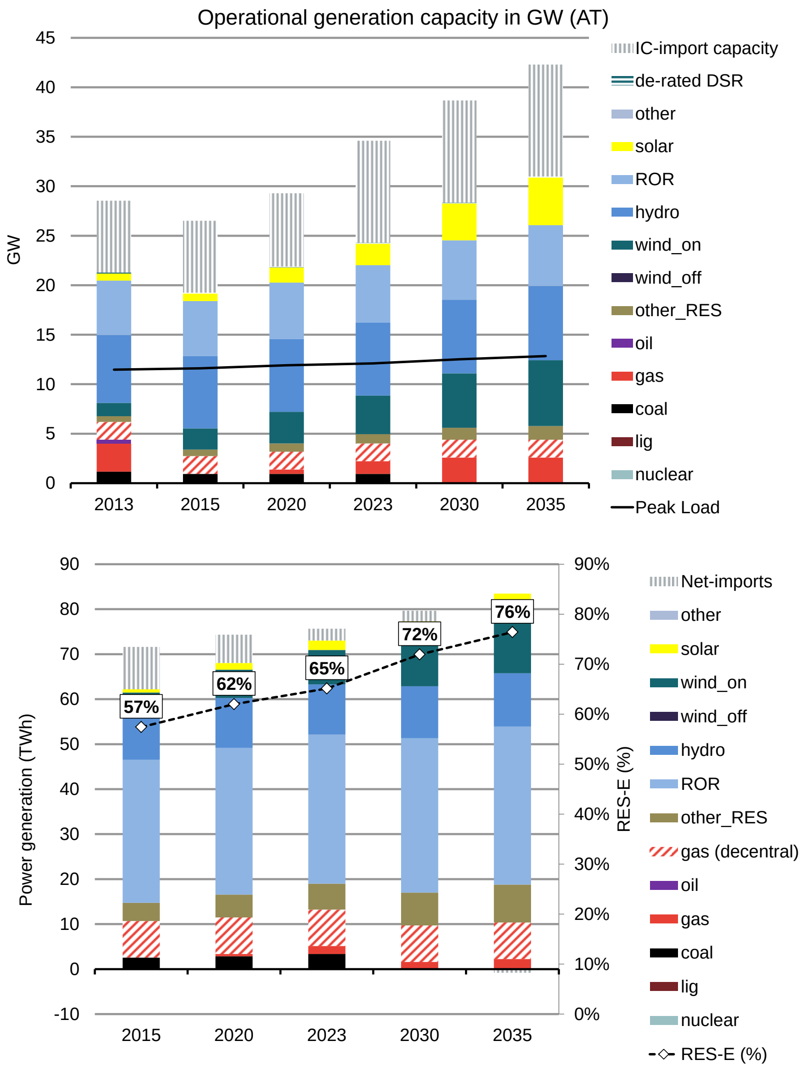
Source. Frontier

Figure 82. Generation capacity and power generation in Belgium (Base Case)



Source. Frontier

Figure 83. Generation capacity and power generation in Austria (Base Case)



Source. Frontier

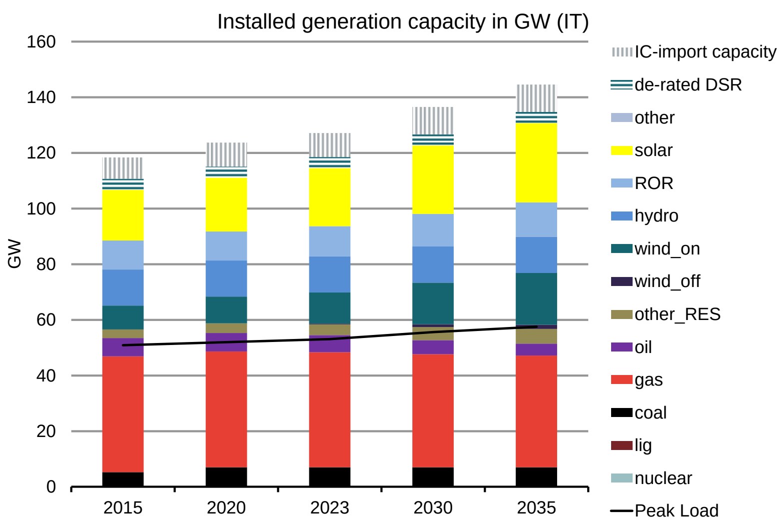
Assumed development of capacities and power generation in other modelled regions

Besides the core-region of the Netherlands, Germany, France and Belgium, the power market model includes other regions in which the power generation is modelled based exogenous development of generation capacity. The development of generation capacities has been derived from ENTSO SO&AF (2014):

- Scenario B until 2025; and
- Vision 3 for 2030 and linear extrapolation afterwards.

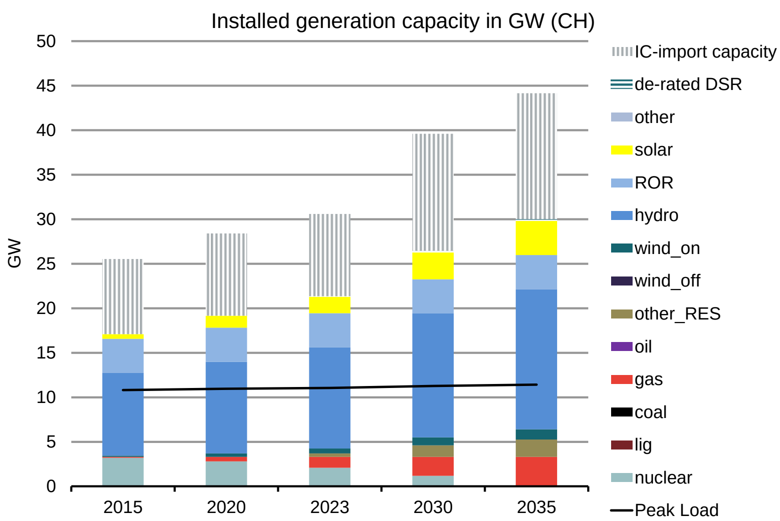
Based on the capacity development indicated in ENSTOE SO&AF, derived our assumption taking into account more recent market expectation. The figures below show the resulting development of generation capacity (not affected by sensitivity calculations) and the modelled power generation in the Base Case.

Figure 84. Assumed development of generation capacity (IT)



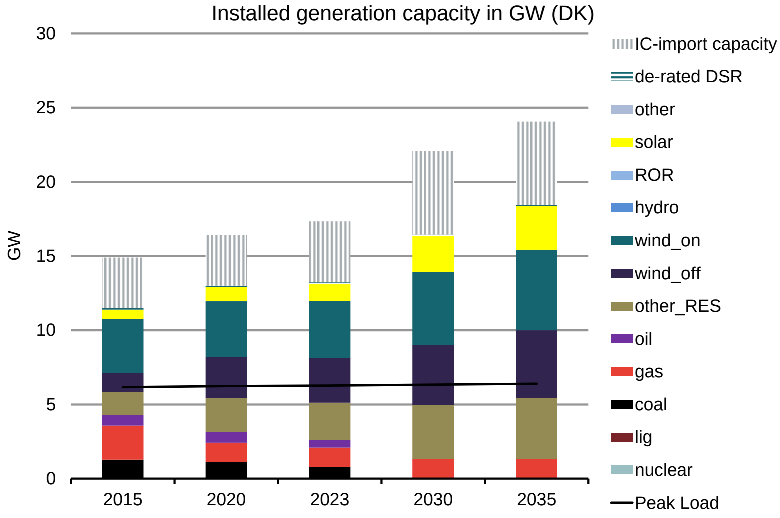
Source: Frontier

Figure 85. Assumed development of generation capacity (CH)



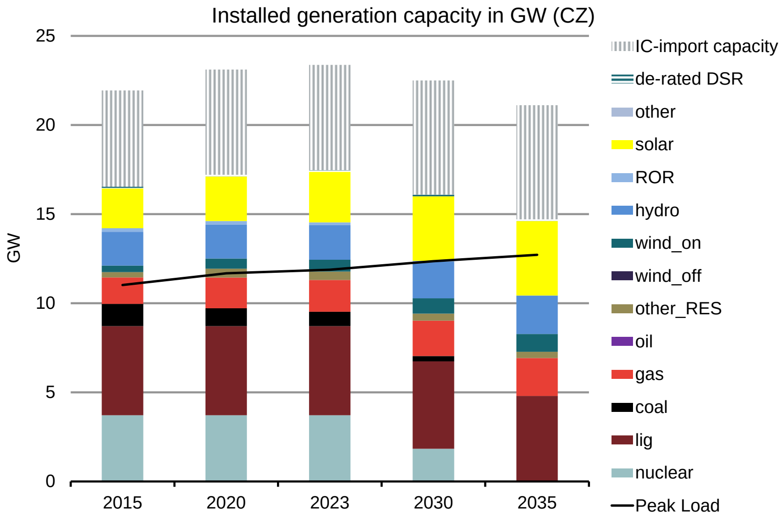
Source: Frontier

Figure 86. Assumed development of generation capacity (DK)



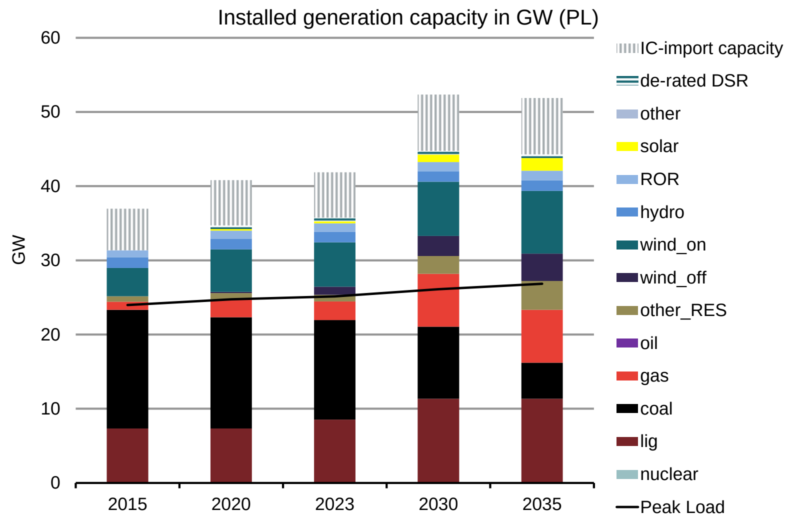
Source: Frontier

Figure 87. Assumed development of generation capacity (CZ)



Source: Frontier

Figure 88. Assumed development of generation capacity (PL)

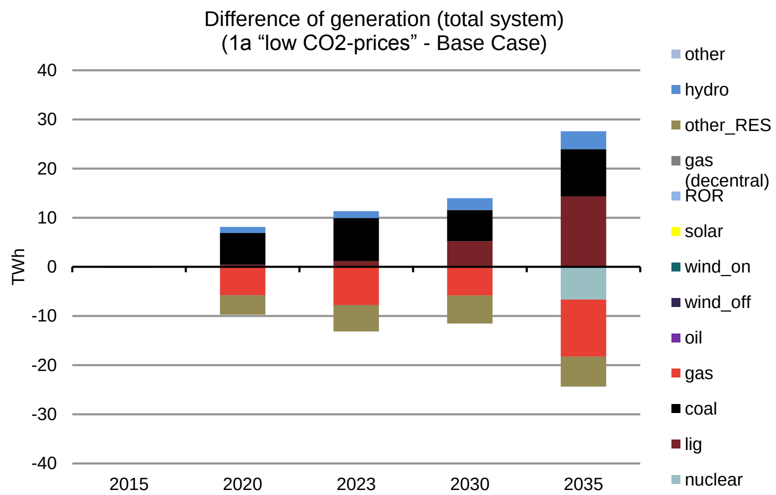


Source: Frontier

Impact of the sensitivities on power generation in all regions

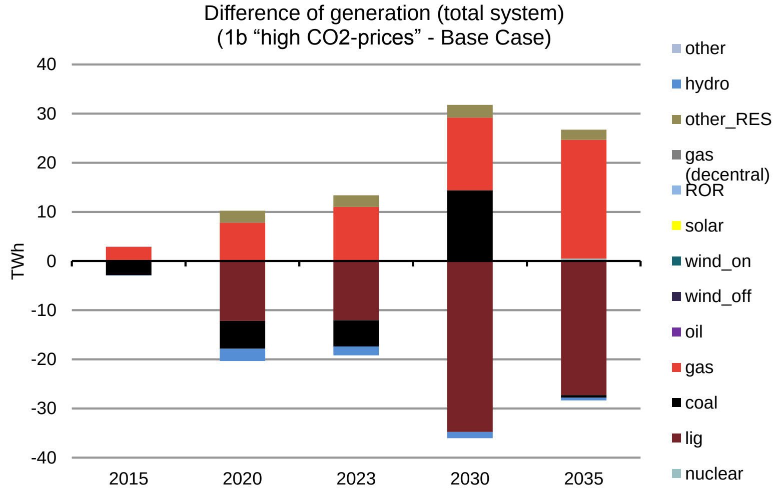
The following figures show the impact of the sensitivities on power generation in all modelled regions compared to the Base Case.

Figure 89. Impact on power generation, all regions (1a "low CO2-prices")



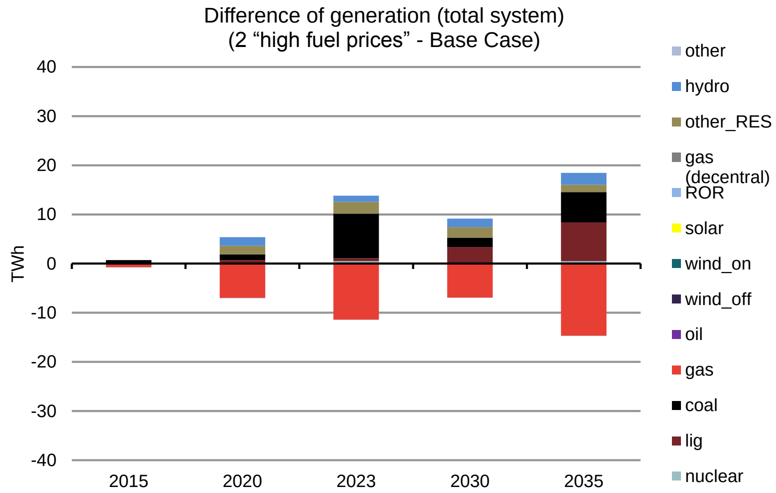
Source: Frontier

Figure 90. Impact on power generation, all regions (1b “high CO2-prices”)



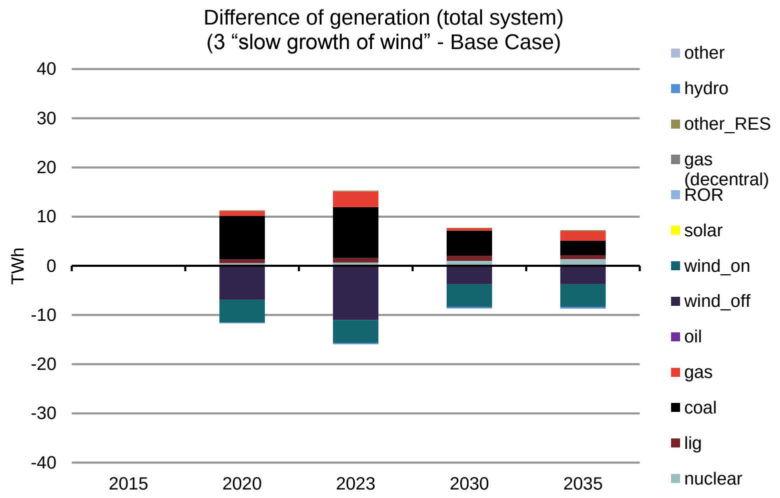
Source: Frontier

Figure 91. Impact on power generation, all regions (2 “High fuel prices”)



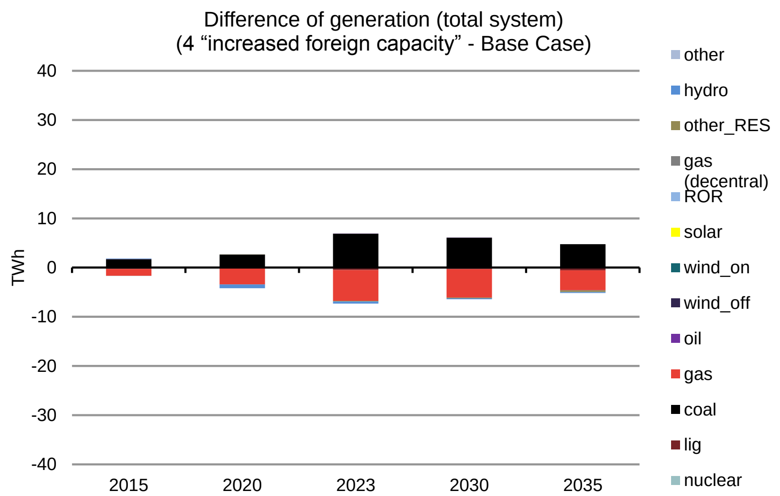
Source: Frontier

Figure 92. Impact on power generation, all regions (3 “Slow growth of wind power”)



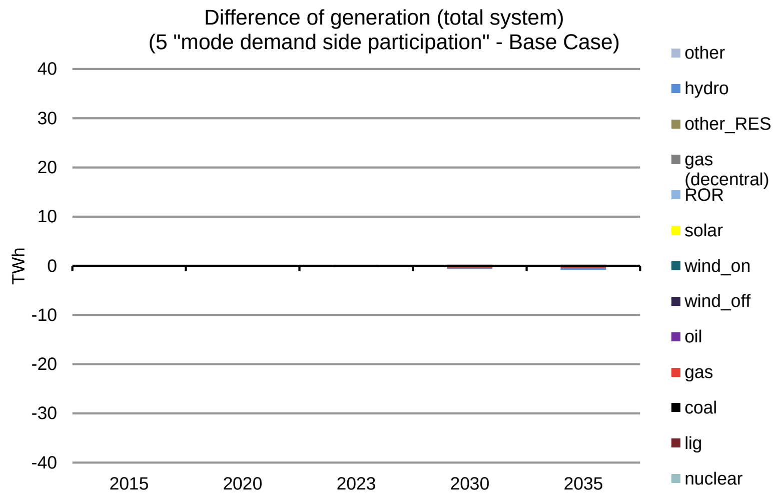
Source: Frontier

Figure 93. Impact on power generation, all regions (4 “increased foreign capacity”)



Source: Frontier

Figure 94. Impact on power generation, all regions (5 “Higher DSR potential”)

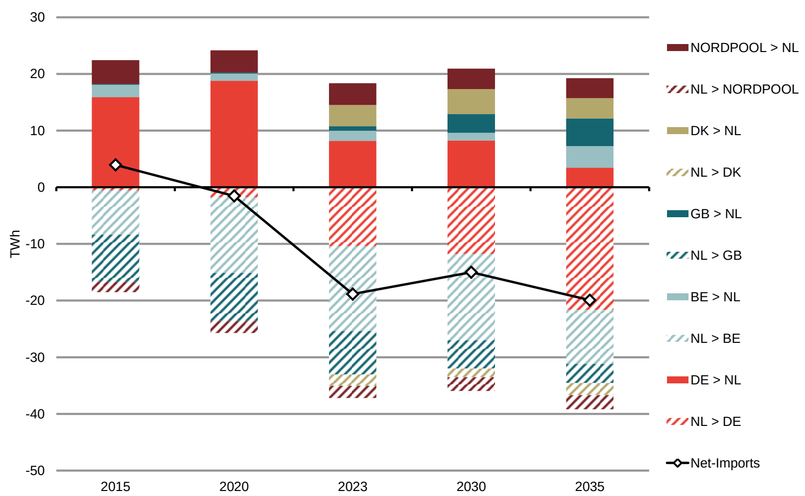


Source: Frontier

Development of power imports/exports of the Netherlands (sensitivities)

The following figures show the development of power exchange (imports/exports) of the Netherlands in the modelled sensitivities.

Figure 95. Power Exchange NL – Sensitivity 1a “low CO_2-prices”

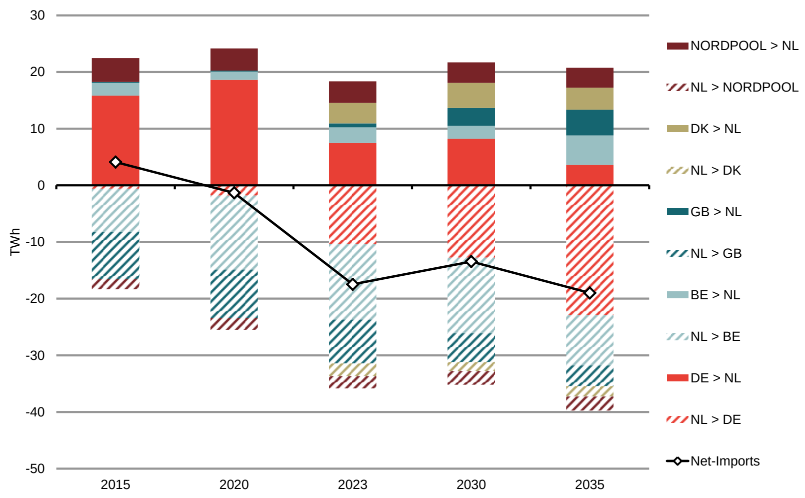


Source: Frontier

Figure 96. Power Exchange NL – Sensitivity 1b “high CO_2-prices”

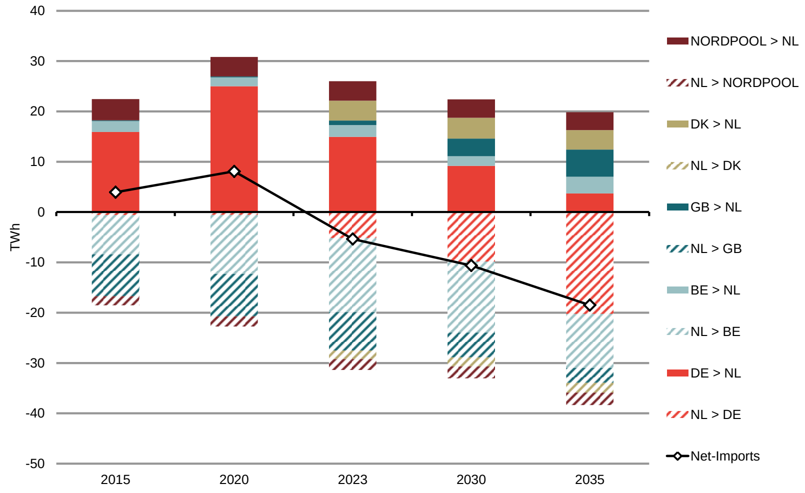
Source: Frontier

Figure 97. Power Exchange NL – Sensitivity 2 “high fuel prices”



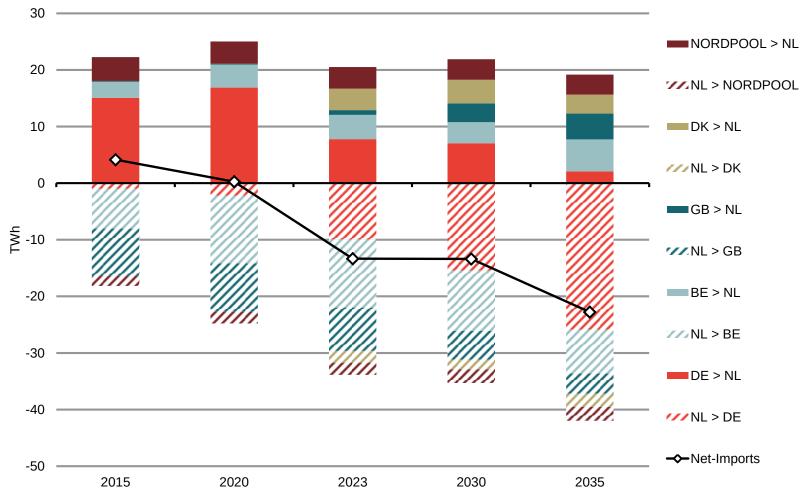
Source: Frontier

Figure 98. Power Exchange NL – Sensitivity 3 "Slow growth of wind power"



Source: Frontier

Figure 99. Power Exchange NL – Sensitivity 4 "Increased foreign capacity"



Source: Frontier

Figure 100. Power Exchange NL – Sensitivity 5 "Higher DSR potential"

Source: Frontier

De-rating factors and modelling of capacity remuneration mechanisms (CRM)

The power market model includes additional constraints on the development of installed capacity for France in the Base Case and for Belgium and France in sensitivity 4 "Increased foreign capacity". These constraints are included to mimic the effect of capacity remuneration mechanisms on installed capacity and plant dispatch and power prices. **Section 3.4.5** includes a description of the sensitivity. In this section, we provide additional information on the chosen capacity credits and capacity demand.

Capacity supply is de-rated according to the maximum availability in peak-hours. **Table 7** shows the capacity credits that are used to de-rate capacity supply in the model.

Table 7. Capacity credits for CRM supply

Power plant type	Capacity credit for CRM
Nuclear	93.1%
Lignite	89.6%
Hard Coal (with/without CCS)	89.6%
Gas (CCGT)	88.8%
Gas (OCGT)	82.1%
Oil	87.3%
Wind-offshore	11%
Wind-onshore	8%
Solar PV	2%
Biomass	65%
Run-of-river	48%
Pumped-Hydro-Storage	90%
Reservoir-Storage	85%
Power-to-Gas	85%
AACAES	85%
CAES	85%
DSR (load reduction)	90%

Source: Frontier

FRONTIER ECONOMICS EUROPE
BRUSSELS | COLOGNE | LONDON | MADRID

Frontier Economics Ltd 71 High Holborn London WC1V 6DA
Tel. +44 (0)20 7031 7000 Fax. +44 (0)20 7031 7001 www.frontier-economics.com