Quantifying flexibility markets

Marit van Hout
Paul Koutstaal
Ozge Ozdemir
Ad Seebregts

December 2014
ECN-E--14-039

Acknowledgement

The authors would like to thank TenneT for its support of this project. Our study has benefitted substantially from the inputs and review of the members of the advisory committee, Oscar Tessensohn, Erik van der Hoofd and Eppie Pelgrum. In preparing this study, the authors have also profited significantly from support from Professor Benjamin Hobbs and Robin Broder Hytowitz from Johns Hopkins University. Any remaining errors are the sole responsibility of the authors.

This report is registered under ECN project number 5.2879. Contact Paul Koutstaal [koutstaal@ecn.nl]

Abstract

A model-based approach has been used to determine volumes and prices of flexibility on the future day-ahead and intraday market, given increasing levels of intermittent renewables in the electricity generation mix. While the focus is on market developments in the Netherlands, the analysis has been made with a detailed electricity market model for the whole of Europe. For this project, the model has been extended to include various flexibility constraints for different types of power plants such as, for example, ramping rates and start-up costs. In addition to the analysis of the day-ahead and intraday market, a number of business cases have been evaluated for different sources of flexibility such as gas-fired power plants and storage.

Contents

	Management summary	**4**
1	**Introduction**	**11**
2	**Increasing demand for flexibility**	**13**
2.1	Introduction	13
2.2	Scenario assumptions and results	14
2.3	Flexibility on the day-ahead market	17
2.4	Flexibility on the intraday market	21
3	**Business cases for flexibility supply in 2023**	**27**
3.1	Introduction	27
3.2	Flexibility from generation	27
3.3	Storage and demand response	32
4	**Discussion**	**39**
	Literature	**41**
	Glossary	**42**

Appendices

A.	Load duration curves and load factors	43
B.	COMPETES Unit Commitment model	46

Management summary

Main conclusions

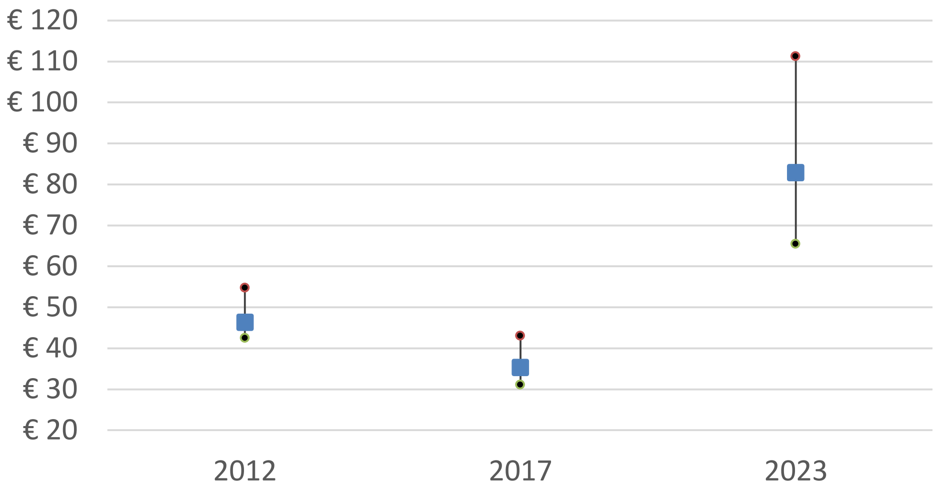
Gas-fired power plants in the Netherlands will provide significant amounts of flexibility in 2023

1. **Increase in renewables in North-West Europe requires flexible generation to accommodate variable production**

Power generation from intermittent renewable energy resources in North-West Europe is projected to increase significantly in the next ten years. One of the consequences of the growth in renewable electricity generation is more volatility in the production, with large changes in production from one hour to the other. This volatility will have to be accommodated by dispatchable conventional generation (or by other flexibility options). Not all conventional power plants will be able to accommodate those changes by ramping up or down their production fast enough because of flexibility constraints. These constraints include start-up costs, ramping up and ramping down rates and minimum operating levels. Increased flexibility requirements will significantly shift production towards more flexible gas fired power plants. In the Netherlands, gas-fired power plants will produce 3,2 TWh more in 2023 because of the constraints on other technologies. This production replaces not only coal and other less flexible capacity in the Netherlands, it is for a large part also used to provide flexibility to neighbouring countries.

The supply of flexibility from both incumbent and from new suppliers will not be forthcoming without adequate incentives. A well-functioning market will be crucial to provide the price signals needed to ensure that the flexible assets are available to accommodate variable production from renewables.

Figure 1: Volatility of annual average prices



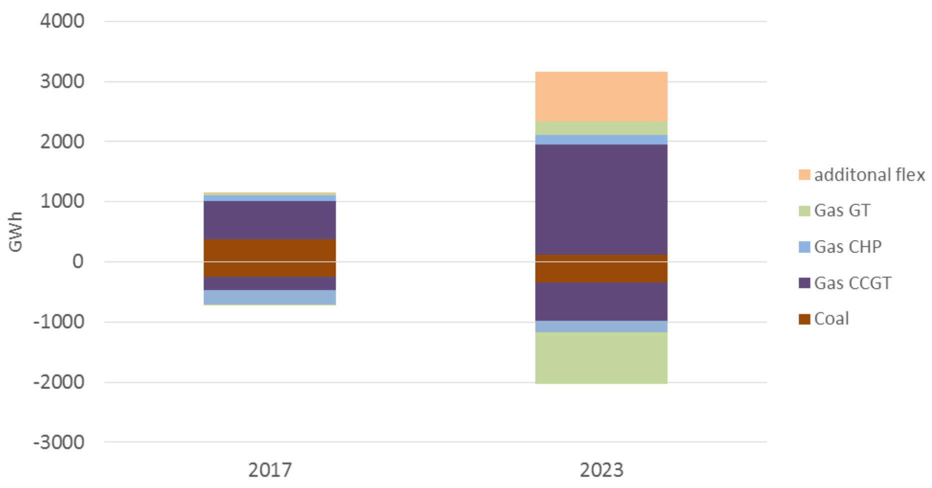
2. Price volatility rises with increasing shares of renewables in the production mix

With the rising electricity production from renewable energy sources, large variations in generation from renewables will be accompanied by increased price volatilities. This becomes apparent especially in 2023, see Figure 1. Price volatility will be an important driver for flexibility options such as storage and demand side response, options which can profit from the price differences caused by the variability of wind and solar power production.

3. The increase in wind generation in the Netherlands will significantly increase demand in the intraday and balancing market

Energy companies have to submit balanced portfolios day ahead to the system operator. Actual generation and consumption however will differ from these submitted programs. Energy companies can make adjustments within their own portfolio, trade on the intraday market to correct for these deviations or be exposed to the balancing mechanism of the system operator. Deviations will significantly increase with the increasing share of intermittent renewable energy sources because of the uncertainty with regard to forecasting production 24 hours ahead. This will drive an increased demand for flexibility on the intraday market, as is show in Figure 2 below.
Apart from the increase in demand for flexibility, Figure 2 also demonstrates which flexibility sources could cost-optimally provide in this demand for flexibility.

Figure 2: Demand for upward and downward flexibility on the intraday market



Demand, prices and revenues on the intraday market show a large increase

4. Increased demand on the intraday market will drive up prices, thereby providing additional value for conventional generation

The increasing need for balancing, either within portfolios or on the intraday market, will not only provide additional demand for ramping up of conventional production, it will also drive up the price on the intraday market for additional power to compensate a shortfall in production from renewables. Figure 3 below shows the monthly prices in 2023 for the spot market day-ahead and for the intraday market the price for additional generation and the bid price for ramping down. The monthly prices for ramping up are based on those hours in which there is a demand for additional generation, those for downward adjustment on the hours in which generation needs to be reduced.

Both ramping up and down will provide an additional source of revenue for conventional generation, as is shown in Table 1 below. The revenue shown is the revenue earned on the intraday market less the variable costs of electricity production when ramping up. It does not include the fixed costs of generation, therefore profits will be lower.

Table 1: Revenue on the intraday market

Mln €	2017	2023
Coal	2	5
Gas CCGT	1	16
Gas CHP	6	6
Gas GT	0	55

Demand on the intraday market will provide an incentive for new sources of flexibility. There are several sources for additional supply on the market, such as reduced exports or increasing imports, if there is spare capacity in neighbouring countries. In addition, there will be a shift from offering production on the day-ahead market to the intraday market, because profits on the intraday market will be higher. Finally, high prices on the intraday market will attract new generators and other sources such as demand side response and storage to enter the market. Without entrants, demand for flexibility will not be met because of a lack of sufficient supply of flexibility in the system.

Figure 3: Monthly day-ahead and intraday prices

5. Business cases

Taking investment costs into account, gas-fired power plants such as combined cycle gas turbines and open cycle gas turbines will be able to make a profit on the intraday market. While a gas turbine plant is only just profitable, profits for a CCGT plant are about €25 million in 2023. The positive profit for a CCGT plant indicates that there is room for additional sources of flexibility, especially in those hours in which CCGT provides flexibility.

The business case for flexibility supply on the intraday market from gas-fired power plants and storage is positive.

While new capacity will bid down prices on the intraday market, they will remain high enough to allow them to recoup their investment costs, otherwise additional entry would not occur. Figure 3 shows the monthly minimum upward adjustment prices including the scarcity rent needed for a CCGT plant in order to have a positive business case. This minimum price is below the day-ahead spot price, illustrating the profitability of a CCGT plant.

Another option to provide flexibility is storage. The storage technologies which can provide volumes useful on the intraday market are mainly pumped hydro storage and Compressed Air Electricity Storage (CAES). Given the focus on balancing in the Netherlands, a business case for a 300 MW adiabatic CAES has been analysed. Depending on the investment costs, for which current estimates provide a range of 600 - 1200 €/kW$_e$, the business case is positive, yielding a net profit in 2023 of € 17 - 36 mln. The increased price volatility is an important driver for the profitability of a CAES storage facility. The business case will be just positive, given prices equal to the minimum price for storage shown in Figure 3, assuming high investment costs of 1200 €/kW$_e$.

Balancing responsibility for all generators and imbalance prices which reflect full costs promote the development of intraday markets

6. An efficient and transparent intraday market will help accommodate increased levels of renewables in a cost-effective way

Our analysis has shown that efficient intraday markets will contribute to accommodating increasing levels of variable and uncertain renewables in the electricity market. These markets will give a price incentive for both flexible generation and other sources of flexibility such as storage and demand side response to provide the increased need for flexibility. On this market, the most cost-effective options will be selected to compensate higher or lower than forecast power production from renewable energy sources, thereby reducing overall costs of integrating renewables in the electricity system.

An important requirement for an efficient intraday market is balancing responsibility for all producers, including renewable energy power generators. Otherwise, renewable power generators will not have an incentive to trade on the intraday market. Without balancing responsibility for renewable generators, the intraday market will not develop and there will be no incentives to develop new sources of flexibility. Furthermore, there should be an incentive for balancing responsible parties to be active on the intraday market instead of leaving it to the TSO to balance the market. This requires that they bear the full costs of balancing incurred by the TSO. If this would not be the case, for example because part of these costs are socialized or because the price paid for imbalance is based on average costs instead of marginal costs, it would be less costly to leave balancing to the TSO and the intraday market would not develop. In essence both - the responsibility and the incentives - are part of the current balancing regime in the Netherlands.

Study approach and future issues

In this study, the market for flexibility in the Netherlands has been quantified, focussing on the intraday and balancing market. The analysis of flexibility on the day-ahead market also includes the effect of solar-pv electricity generation on the flexibility requirements, both in the Netherlands and in neighbouring countries. On the intraday market, we have restricted ourselves to the analysis of demand for flexibility driven by the wind forecast error, solar-pv has not been taken into account on this market. Future electricity market developments have been derived using the COMPETES European electricity market model, which has been adapted for this study to include flexibility constraints and unit commitment. The analysis is based on assumptions regarding future developments of fuel prices, interconnections, demand and capacity mix in the individual European countries and renewable energy generation profiles derived from various sources such as the IEA’s World Energy Outlook 2013, ENTSO-E scenario’s and network development plans and from detailed renewable energy data from TSO’s and other sources.

While developments and interactions with other European countries have been taken into account, the balancing market has only been analysed for the Netherlands, reflecting current practice in which system balancing takes place within countries. However, with further integration of electricity markets, balancing over a larger geographical area can be expected to reduce overall balancing costs by improving the exchange of flexibility. This is also illustrated by the important role imports and exports have in providing flexibility on the day-ahead market as shown in our analysis. It would therefore be valuable to look at the effects of integrating both intraday and balancing markets across country borders.

Furthermore, our analysis has been based on hourly data. However, volatility of renewable power generation is continuous. An analysis based on shorter time periods, such as 15 minutes, will probably show an increased demand and a higher value for flexibility.

Finally, while we have looked at large-scale storage at the level of the high voltage network, local battery storage by households have not been taken into account. However, the possibility that there will be a considerable deployment of such storage, especially if the current implicit tax subsidy for solar-pv would be diminished. Such a deployment would have an impact on the results from our study, diminishing the role of solar-pv generation on the demand for flexibility on the day-ahead market.

1 Introduction

Increasing shares of subsidised electricity generation from renewable energy sources will have a considerable impact on electricity systems. An important effect from increasing production of renewable energy sources is that the predictability of production decreases because non-dispatchable generation from wind and solar depends on inherent uncertain wind and solar predictions. This increases the need for balancing and therefore short-term flexible resources, including options such as flexible power plants, storage, demand response etc. In addition, a considerable amount of dispatchable capacity is needed for those periods in which renewables production is low. The hours at which this back up capacity will operate are expected to be limited, therefore prices need to be high enough to allow investors in such peak capacity to recoup their investments. The electricity market will also be affected. When wind and solar electricity production is high, production from conventional sources will be limited and electricity prices will decrease, thereby reducing the income for conventional power production.

Increasing shares of renewables therefore poses challenges for the performance of the current electricity market and for the business model of conventional generation. However, it will also raise new opportunities. Conventional production will be called upon to provide flexibility to accommodate the variability of wind. This includes, for example, increased ramping up and down to meet the variability of renewable production, both in the day-ahead market to meet the expected variability and on balancing markets to meet forecast errors, and to provide power at peak hours with low renewables. In order to be able to judge the potential of these new market opportunities, it is important to have quantitative information on the demand for these types of services and on the costs of the different options available to provide flexibility both for short run balancing and longer term back up capacity.

In this study, the main question which we address is *how markets for flexibility will develop with increasing levels of intermittent renewables*. Given this main question, specific questions which will be answered are:

1. What is the size of the market for flexibility in the Netherlands in 2017 and 2023 in terms of price volatility, volume and value, both in the day-ahead market and in the intraday balancing market?

2. What are the costs of different flexibility options such as, for example, flexible power plants, storage and demand response?
3. Given price volatility, demand for and costs of flexibility options, what are the business cases for different types of flexibility?
4. How might new or enhanced markets for flexibility perform in terms of liquidity, risks, number and type of participants etc. and what barriers and market failures might hamper the development of these markets?

So far, there is limited quantitative research on the effects of increasing levels of intermittent renewables on demand for flexibility, although there have been many studies which have looked at the power system impacts of intermittent renewables (e.g. Sijm 2014, IEA 2014, NREL 2010a and 2010b). In our approach, we will use the European electricity market model developed at ECN, COMPETES, to determine market effects of increasing renewable production such as increased demand for flexibility and prices. Subsequently, we will use these market data to analyse business cases for different types of flexibility options.

In the next chapter, we will describe our methodology and main assumptions and we will present the market effects of increasing intermittent renewables production. In chapter three, different flexibility options are discussed and the business cases for these options are analysed. It should be noted that no new equilibrium is calculated using the outcome of these business cases. Chapter 4 concludes with a discussion of the results and of the future of flexibility markets.

2

Increasing demand for flexibility

2.1 Introduction

The main question to be answered in this study is how increasing shares of renewable power production in the Netherlands will affect the need for flexibility within the electricity system and how markets for flexibility will develop. To address this question, we will analyse the expected future developments on the electricity market in the Netherlands and the rest of Europe for the years 2017 and 2023. According to the Energy Agreement concluded in 2013 in the Netherlands, renewable energy production in the Netherlands will have to reach a share of 14% in 2020, with a capacity of 6000 MW of wind on shore in 2020 and 4450 MW of wind off shore in 2023. Assuming that these shares will be realised, the year 2023 will provide a good example of an electricity market with a substantial share of intermittent renewable power production. The comparison with 2017, in which year renewable shares are considerably smaller, allows us to highlight the effects of increasing renewable shares.

In the analysis of flexibility, we will make a distinction between on the hand variability from wind energy based on the expectations of wind power production on the day ahead market and on the other hand the increasing demand for balancing in the intraday and balancing markets because of the forecast error of wind power generation. On the day ahead market, flexible generation will supply increased ramping up and down in order to accommodate increased variability of renewable production. Furthermore, peak generation will be needed to meet high demand levels at moments of low wind power production.

Because of the forecast error, realized wind production will differ from the forecast production on the day ahead. Balancing responsible parties will therefore look for flexibility in the intraday market to balance their programs, given differences in wind production compared to their submitted programs. In as far as these differences cannot be met on the intraday market, these will have to be addressed by the TSO, TenneT, who will contract regulating and reserve power in order to ensure system stability. In our approach, we will not distinguish between the intraday market and the single-buyer market for regulating and reserve power, instead we will consider the need for flexibility because of forecast errors as one (intraday) market. In this analysis of the intraday market, we focus on the forecast error of wind, which is the main intermittent renewable technology in 2023 in our scenario. However, in other scenarios, with a higher level of sun-pv, the forecast error from sun-pv would be more significant and contribute to demand on the intraday market.

2.2 Scenario assumptions and results

Assumptions
To provide a detailed quantitative analysis of future electricity market development, we have used ECN's European electricity market model, COMPETES. For this study, the model has been further developed. This includes a detailed modelling of the power production within the Netherlands, which now contains all large scale power plants as a distinct production unit. The model has been adapted in order to be able to model unit commitment. Furthermore, start-up costs have been added and constraints on ramp rates for different technologies. This allows us to analyse the impact of increased variability from I-RES generation on the dispatch of conventional units, given their flexibility characteristics. For a more detailed overview of the version of COMPETES used for this study, see the appendix titled 'The COMPETES Model'.

Future electricity market developments are driven by a number of different factors. The most important factors are:
- Fuel and CO_2 prices
- Electricity demand
- Generation capacity mix
- Interconnection capacity

Prices of fossil fuel input for electricity generation, coal and gas are important determinants of electricity prices. Choosing fossil fuel price scenarios however is difficult, given the many factors that influence fuel markets and the large uncertainties with regard to future developments. For the first couple of years, future markets give some indications about future prices, reflecting current market expectations with regard to future prices. Therefore for 2017, we use recent forward prices for coal and gas. For 2023, we use prices based on the World Energy Outlook current policies scenario. Table 1 gives the prices used in 2017 and 2023.

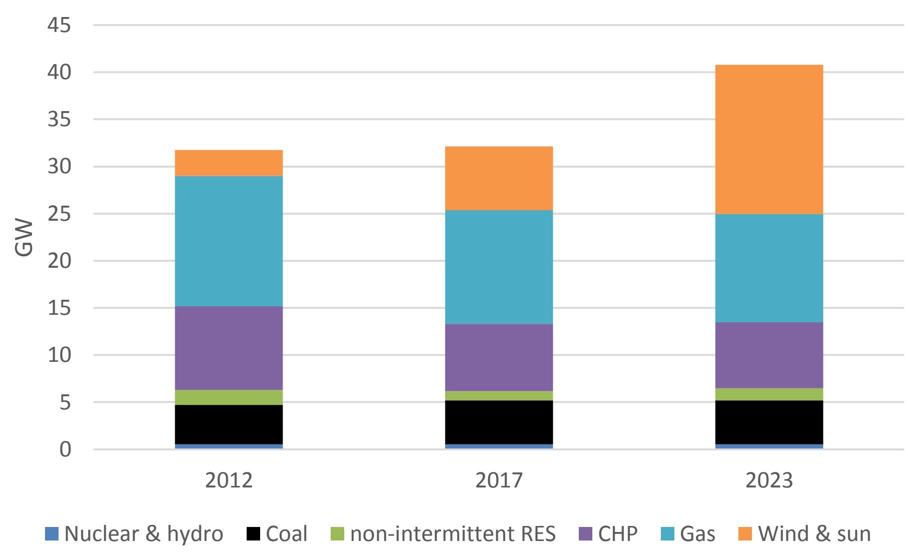
Table 1: fuel and energy prices

		2017	2023
Coal Price	[€ct/GJ]	3.3	3.5
Natural gas price	[€ct/m]	25.8	30.9
CO_2 price	[€/ton]	9.0	13.5

Electricity demand is driven by economic growth. Furthermore, electricity prices and government policies such as energy efficiency policy will influence demand. Demand is an input in the model, for the Netherlands expected demand is based on the 2012 reference projection for the Netherlands (PBL/ECN, 2012). For the other European countries, demand has been based on ENTSO-E SO&AF 2013 (ENTSO-E 2013). Scenario A is chosen to represent the generation and demand developments up to 2020 for all EU countries except for Germany and the Netherlands. Since only data for 2013, 2015, 2016 and 2020 are provided in SO&AF scenarios, data for 2017 is linearly interpolated between 2016 and 2020. In addition, also the end year of the Energy Agreement (2023) is of interest for the flexibility analysis. Figures for 2023 are derived by linearly interpolating data between 2020 (Scenario A) and 2030 (Vision 3). Vision 3 is referred to as the “Green transition” scenario.

This ENTSO-E scenario has also provided the input with regard to the development of the generation mix for those countries. For the Netherlands, the generation mix is similar to the Dutch Energy Agreement, which has been adjusted to take into account recent mothballing or selling of 7 new CCGT units[1] (equal to about 3145 MW). CHP is projected to decrease to about 23-24 TWh in the period 2017-2023, roughly 30% less than 2010 levels. Renewable energy capacity development is based on the Energy Agreement, see above. Figure 4 presents an overview of Dutch generation capacity over the years. In 2023, there 4.4 GW of sun-pv capacity according in our scenario. It should be noted that this figure is quite uncertain, depending on government policy regarding sun-pv, it might as well be considerably larger or, with a reduction of the tax credit, end up at a lower level.

Figure 4: Installed generation capacity Netherlands



For Germany, capacity has been derived from recent BNetzA figures (BNetzA, 2014). The same source has been used to estimate the amount of planned decommissioning in

1 4 units of RWE/Essent (Moerdijk-2 and 3 Maasbracht units), 2 units of the Nuon Magnum power plant and 1 unit of Eneco/Dong Enecogen power plant.

Germany (nuclear and other thermal power plants) and conventional new build for the coming years. The increase in renewable power has been based on a combination of SER EA and SO&AF scenario A. I-RES capacity (Wind+Sun) growth is 5.5 GW/year (7.6% /year) of which 2GW/year is the growth of wind power capacity and 3.5GW/year is the growth of solar-PV capacity.

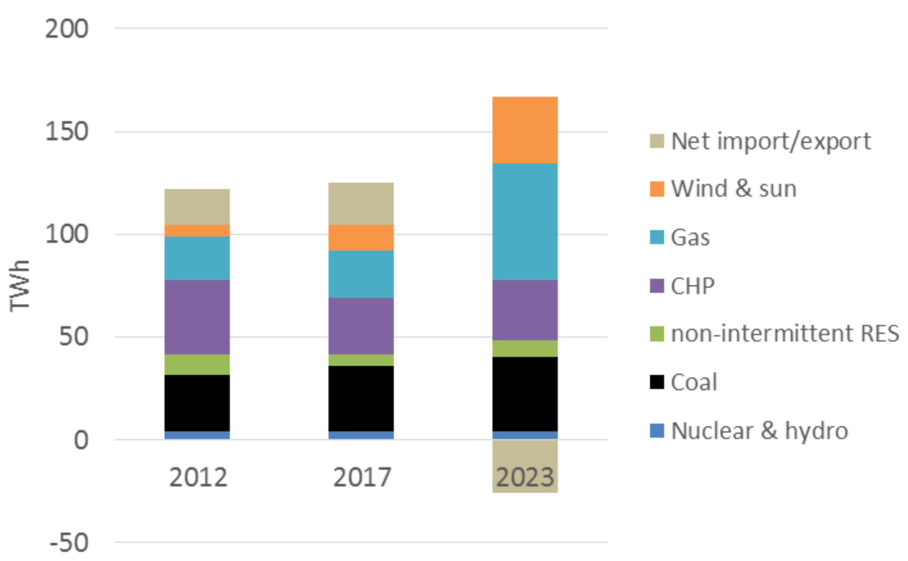
Interconnection capacity developments in Europe have been based on the ENTSO-E SO&AF as well, with some adjustments made to the 2013 data for interconnection in consultation with TenneT. For the Netherlands, connection capacity increases from 4550 MW in 2012 to 8050 in 2017 and 8750 in 2023.

Hourly renewables production profiles have been based on actual data for 2012, obtained from both TSO's and from data available at ECN.

Electricity market results

Based on the assumptions described above, annual generation, import and export flows and prices have been calculated. Figure 5 below shows the production and gross import in the Netherlands for 2012, 2017 and 2023. Given the increase in intermittent renewables capacity, especially wind, production increases significantly over the years. In 2012 and 2017, the Netherlands is a net importer (17 TWh in 2012 and 20 TWh in 2017), in 2023 it has become a net exporter (26 TWh), which is reflected by an increase in generation from 2017 to 2023 within the Netherlands.

Figure 5: Generation Netherlands



Average prices decline in 2017 compared to 2012, in 2023 they are significantly higher, see Table 2. These prices are the price on the wholesale market and do not include subsidies or transport tariffs. In 2023, there is a limited level of demand curtailment in the Netherlands (in 10 hours, for a total of 13,4 GWh). In these hours, prices reach the level of the given VOLL. Two different values have been assumed for the VOLL, a high value of 3000 €/MWh and a low value which is related to the marginal costs of an expensive peak unit such as a gas turbine, 200 €/MWh in 2012 and 2017 and 320

€/MWh in 2023. The average price will depend on these assumptions, therefore with a high VOLL the average price is higher. The higher prices in 2023 as compared with 2012 and 2017 can be explained by higher fossil fuel prices and relatively lower capacity, compared with demand, in 2023 as compared with prices and capacity in the earlier years. The high prices during the curtailment hours will provide a strong incentive for demand response. This has not been modelled because inelastic demand is assumed.

Table 2: Electricity prices Netherlands

	Weighted Average Prices (€/MWh)	
	High VOLL	**Low VOLL**
2012	47.1	47.1
2017	35.9	35.9
2023	93.9	81.2

2.3 Flexibility on the day-ahead market

Demand for flexibility on the day-ahead market

The increasing share of I-RES, especially from wind in the generation over the years will increase the demand for flexible generation to accommodate the variability of I-RES production. A measure for flexibility is the change in dispatchable generation from one hour to the next hour. Total demand for flexibility can then be defined as the sum of the change in generation from one hour to the next over a year plus the total curtailment of demand in a year. The former can be considered as flexibility of demand that can be already accommodated given the assumed market conditions, while the latter can be considered as the demand for flexibility that cannot be fulfilled by generation. In table 3, total demand for flexibility is shown. The potential for new entrants is calculated based on level of curtailment (i.e. unfilled demand). The difference in the level of curtailment in consecutive hours gives an indication of the demand for flexibility for potential new (flexible) units. In 2012 and 2017 there is no curtailment of demand, and the total demand for flexibility only slightly increases (+6%). Between 2023 and 2012 there is an increase in total demand for flexibility of 46%.

Table 3: Total residual demand for flexibility in 2012, 2017 and 2023.

Total demand for flexibility (GWh)	2012	2017	2023
Total demand:	2332	2480	3397
of which potential for new entrants	0	0	4
Demand for flexibility ramp up:	2332	2480	3393
supplied by generation	2339	2313	2521
supplied by net imports	-6	167	872
Demand for flexibility ramp down:	-2332	-2480	-3395

supplied by generation	-2338	-2313	-2521
supplied by net imports	7	-167	-874

Source: COMPETES runs.

The increase in demand for flexibility has strongly been affected by the increase in wind power production. Table 4 below shows the absolute demand resulting from wind production and the percentage in total demand for flexibility in the respective years[2]. While in 2012 flexibility demand due to the increase in wind power generation was limited to only 1 percent, it increases to 20% in 2023.

Table 4: Demand for flexibility due to wind power generation

	2012	2017	2023
GWh (% of total flexibility demand)	25 (1%)	125 (5%)	674 (20%)

Supply of flexibility on the day-ahead market

When there is a domestic demand to ramp up, one would expect that imports increase and/or national production units are ramped up. Either or both of the two effects would be seen in case the Netherlands was linked with a single country with little or no variation in demand and production. Since the Dutch power market is already strongly linked with electricity markets abroad, it can be the case that when there is a domestic demand to ramp up, neighbouring countries will also show a demand to ramp up (or down). As we are interested in the supply of flexibility due to domestic demand, one needs to look at the net effect of imports and exports, and also the net effect of generation, because in a single hour with a domestic demand to ramp up, certain units might even be ramped down instead. Figure 6 shows that total *domestic* demand to ramp up and down in 2012 is fully supplied by generation. Net imports even seem to provide a small negative contribution to the supply of flexibility. In future years, interconnection capacity is becoming more important to provide flexibility since net imports are positively contributing to the supply of flexibility. Developments that are likely to increase the importance of interconnection capacity for flexibility are the increasing scarcity of generation capacity, stronger links between the Netherlands and surrounding countries, and the increasing volatility due to wind, not only in the Netherlands, but in the whole of Europe. Figure 7 shows the supply of domestic flexibility per technology. From this figure it becomes clear that especially Gas CCGT units are becoming important when providing domestic flexibility in the future in the day-ahead market. Furthermore, even though around 2.7 GW of gas GT capacity is decommissioned between 2012 and 2023, the remaining units in 2023 are utilized more to provide flexibility. On the contrary, base load units such as coal and biomass standalone that provide a certain share in the supply of flexibility in 2012 are contributing much less to the demand for flexibility in especially 2023. An important reason for the diminution of the role of coal fired power plants in providing flexibility is that they are used mainly to provide baseload in 2023 and therefore much less available to provide flexibility. Another reason is that the older coal-fired power plants are not flexible enough, see below.

[2] The share of flexibility demand due to wind power has been calculated by comparing a case in which it was assumed that wind power generation was flat on a monthly basis with a wind power production based on the hourly 2012 wind profile.

In order to better understand the drivers for the provision of flexibility and the role of different types of power plants in accommodating intermittent renewables, we have compared the model outcomes for 2023 with the results from an analysis in which there are no limits on the flexibility of any power plants. Table 5 below shows the differences per technology type, both absolute and as a percentage of the production levels for the case without flexibility constraints.

Table 5: Impact of flexibility constraints

Generation technology	Change in production [TWh]	Percentage change	Increase in turnover [mln €]
Coal	-0,3	-1%	
Biomass standalone	-0,04	-1%	
CHP	0,1	0%	
CCGT	2,5	6%	101
GT	0,6	21%	3,4

The increase in generation from flexible units such as CCGT and GT in the Netherlands is larger than the decrease in less flexible generation. This due to the fact that flexible generation in the Netherlands will also provide flexibility to neighbouring countries, where generation from coal fired power plants is also decreased. Turnover from this increased production is € 101 mln for Combined Cycle Gas Turbines in the Netherlands and € 3,4 mln for gas turbines.

Figure 6: Total supply of domestic flexibility

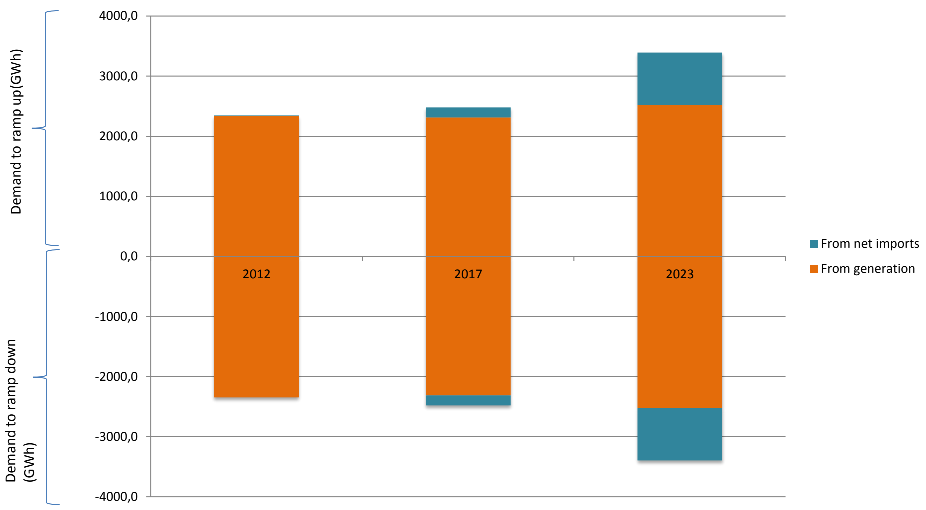
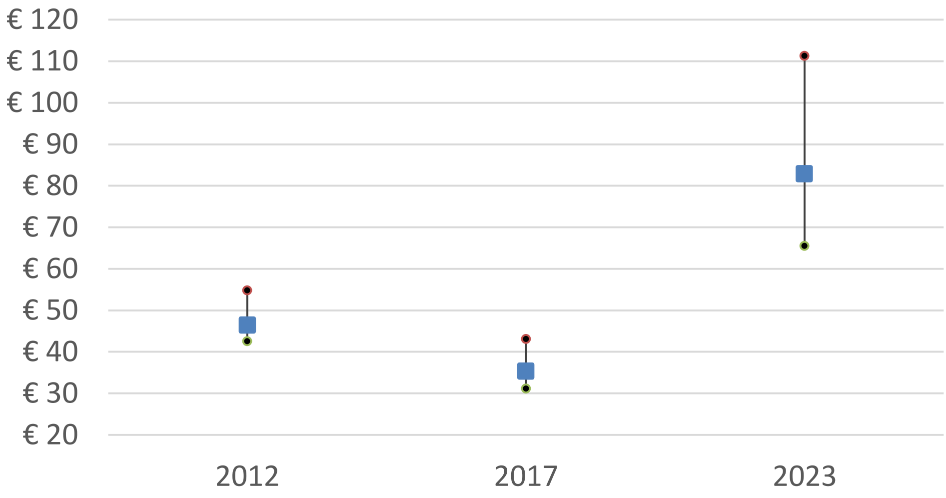


Figure 7: Supply of domestic flexibility per technology, day-ahead market

Price volatility on the day-ahead market

In addition to an increase in the volume of demand (and supply) for flexibility, there is also an increase in price volatility as the level of wind power generation differs from hour to hour. This is shown in Figure 8, which shows annual average prices and standard deviations for 2012, 2017 and 2023 for the Netherlands. The average price in 2023 is considerably higher compared with 2012 and 2017, given the higher coal and gas prices assumed for 2023. Furthermore, there is less capacity relative to demand in Northwest Europe. The increasing share of wind significantly raises price volatility in 2023. Price volatility will be an important driver for flexibility options such as storage and demand side response, options which can profit from the price differences caused by the variability of wind and solar power production.

Figure 8: Price volatility Netherlands



2.4 Flexibility on the intraday market

Demand for flexibility on the intraday market

Increased wind power generation will not only increase expected variability on the day-ahead market, it will also lead to an increased need for flexibility in order to accommodate forecast errors on the intraday market. Because of these forecast errors, wind producers or the balancing responsible party (BRP) which has assumed responsibility for wind production will need to compensate the errors. Or, alternatively, the TSO will have to contract reserve power to meet the imbalances. This will generate additional demand for flexibility on the intraday market[3]. Figure 9 presents the forecast errors for 2023, based on the forecasted and realised wind profiles[4] used in this study for the Netherlands, which are based on actual hourly data for 2012.

3 As explained above, section 2.1, we do not distinguish between the intraday market and the balancing market.

4 Hourly forecasted and actual realised wind data for the Netherlands were acquired from the Wind energy unit at ECN.

Figure 9: Wind forecast errors, 2023

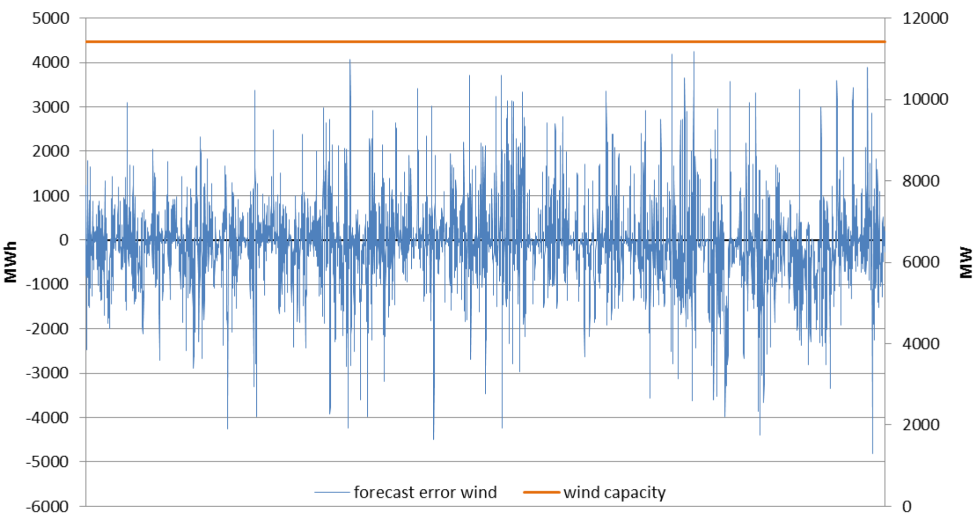


Table 6 shows the demand for flexibility in GWh on the intraday market due to wind forecast errors. Demand has been determined by taking the difference between two model runs, one with forecast and another with realised hourly wind production. It has been assumed that net import/exports remain fixed at the level based upon the day-ahead schedules (the forecast wind power generation), while generation within the Netherlands is allowed to adapt to the changed wind power generation. This gives an estimate of the increased demand within the Netherlands for flexibility to accommodate wind forecast errors.

Demand increases significantly with the increasing level of wind generation. Given our assumption of fixed net import/exports, not all demand for flexibility can be met in 2023 from incumbent sources not committed to exports. This will provide an incentive for other flexibility sources, such as a shift of capacity from the day-ahead market to the intraday market accompanied by reduced exports, new generators and other suppliers such as demand side response and storage to enter the market.

Table 6: Demand for flexibility on the intraday market

GWh		2012	2017	2023
Demand for flexibility ramp up	Non-committed incumbents	595	1143	2340
	Additional suppliers			824
Demand for flexibility ramp down		-368	-734	-2041

Supply of flexibility on the intraday market

The comparison between the two model runs mentioned above, the one with forecast and the other with realised hourly wind production, also provides information on the supply of flexibility on the intraday market. In the variant with realised wind production, the electricity system will adjust production in order to meet demand at the lowest possible costs, given the changed wind production as compared with the forecast. This adjustment provides an estimate of the most efficient accommodation on the intraday market of the forecast errors.

Flexibility on the intraday market is mainly supplied by gas units, which are the most flexible units available to supply flexibility. Some flexibility is supplied by coal fired power plants, especially by new units which are more flexible than the units in place in 2012. Figure 10 and Figure 11 show the supply of both upward and downward flexibility for different types of power plants. CCGT and gas turbines provide the major part of flexibility in 2023. Given the assumption of fixed net import/exports, not all demand for upward adjustments can be met by those generators which are available for the intraday market. This will provide an incentive for new sources of flexibility, see below in the section on the Value of flexibility in the intraday market at low VOLL for a discussion of these new sources.

Figure 10: Supply of upward flexibility on the intraday market

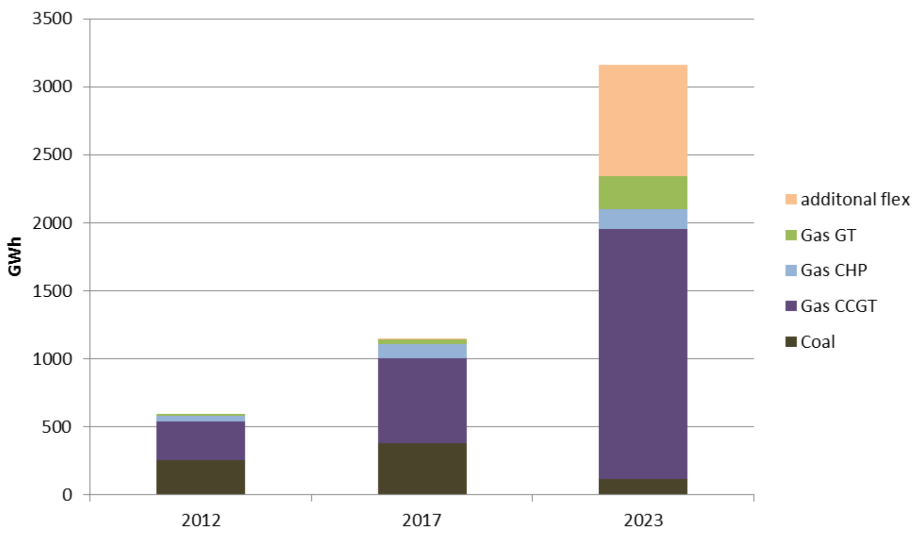
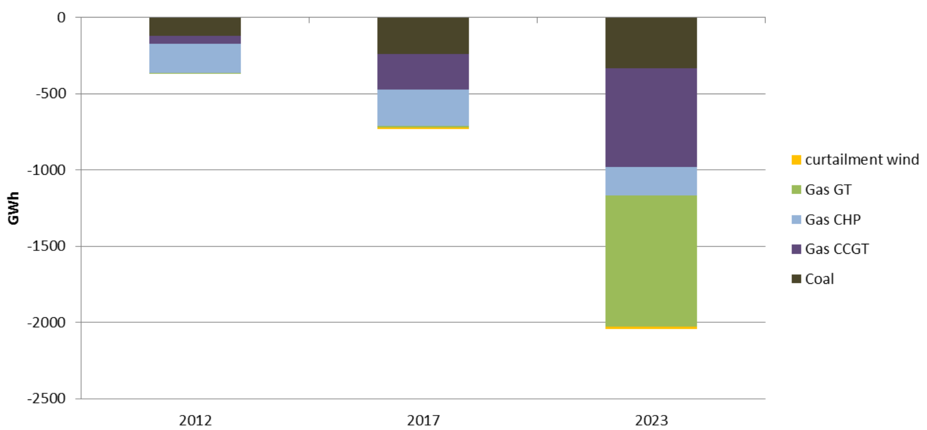


Figure 11 Supply of downward flexibility on the intraday market



Balancing prices in the intraday market at low VOLL

It is to be expected that in those hours where there is an upward demand for flexibility (generation increase) on the intraday market, prices will be higher price compared to the day-ahead market, while in those hours where there is a demand for downward flexibility (generation reduction) price will be lower. On the intraday market, for upward adjustments capacity will be offered that has not been sold on the day-ahead market and therefore prices will be higher than on the day-ahead market. For downward adjustments, suppliers will be prepared to pay the balancing party or the TSO, because they will already have sold their energy on the day-ahead market (see TenneT 2010 and Abassy et al. 2011).

Figure 12 and

Figure **13** show the monthly prices in 2017 and 2023 for both upward and downward adjustment on the intraday market to compensate for wind forecast errors. Note that the price for upward adjustment is based on those hours in which the realised wind power production is lower than forecast and therefore there is a demand for additional generation. Similarly, the price for downward adjustment is based on those hours in which generation has to be reduced because of higher than forecast wind power production.

Figure 12: Monthly spot and intraday prices 2017

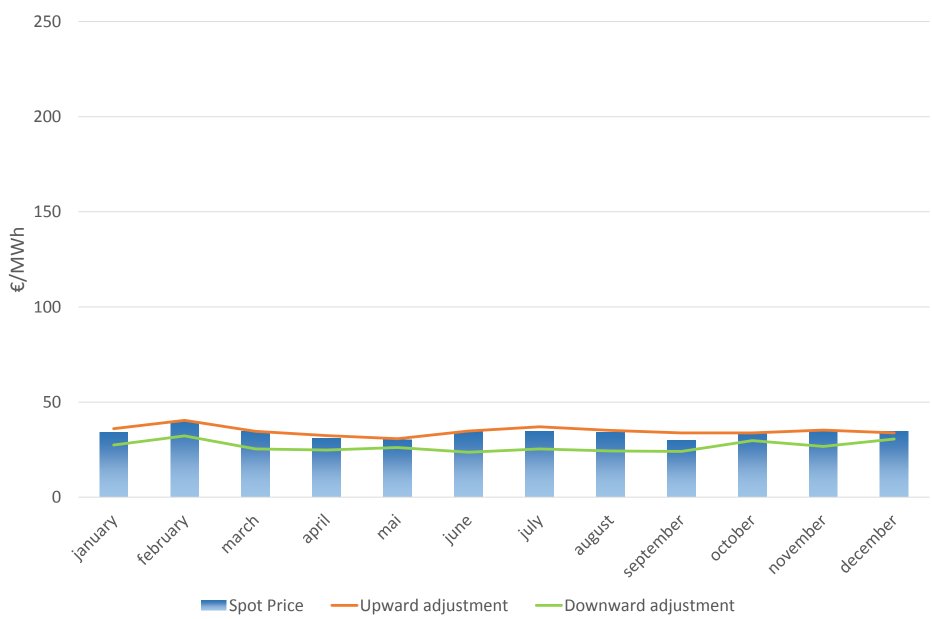


Figure 13: Monthly spot and intraday prices 2023

2017 and 2023 have the same scale, this clearly indicates the difference in the intraday market for flexibility between those years. In 2017, there is still more than sufficient capacity in the market, while 2023 presents a different picture. In 2023, in some months, e.g. February, March and October till December, prices for upward adjustment are high compared to the day-ahead price. This results both from the higher generating costs of the available capacity on the intraday market and from unmet demand, at which hours price equals VOLL. While this might have an upward effect on the average monthly price for upward adjustment, it also reflects the need for some additional capacity to balance wind forecast errors. It is a price signal which provides an incentive for new generation to enter the market. With entry, prices can be expected to fall, however there will remain a scarcity rent which reflects the costs of providing flexibility for balancing needs on the intraday market. We will get back to this in our analysis of business cases in Chapter 3.

Value of flexibility in the intraday market at low VOLL

Given the volumes and prices on the intraday market, we can determine the value of the flexibility provided on the intraday market. We have assumed that upward flexibility is recompensed at the actual market price as realised in the specific hour in which the flexibility is supplied (based on the assumed low VOLL of €320/MWh). This price is equal to the variable costs of the marginal production unit at that hour. For downward adjustment, the value equals the difference between the day-ahead price for the hour under consideration minus the price on the intraday market. Net revenue equals price times volume supplied minus the variable production costs in the case of upward flexibility. Based on these assumptions, Table 7 shows the net revenue realised by different types of technologies.

Table 7: Net revenue on the intraday market per technology

Mln €	2017	2023
Coal	2	5
Gas CCGT	1	16
Gas CHP	6	6
Gas GT	0	55

The large increase in wind power generation from 2017 to 2023 raises the net revenues on the intraday market, especially for Gas CCGT and gas turbines. In addition to the net revenues of the incumbent generators, additional upward flexibility could be provided by new generators or by an increase in net imports in the hours in which demand for flexibility cannot be met in 2023. Given the assumed low VOLL of €320/MWh, the gross revenue for unmet demand is € 264 mln.

The price on the intraday market is an important determinant of the value of providing flexibility on this market. As we have seen above, this price can be high in specific months because of unmet demand in which hours the price reaches the VOLL. In practice, such price levels will provide an incentive for new providers of flexibility to enter the market. There are several sources for additional supply on the market. If there is spare capacity in neighbouring countries, net exports can be reduced compared to the planned exports on the day-ahead market, which will allow incumbent producers to generate more for the national intraday market. In addition, there will be a shift of production from the day-ahead market to the intraday market, because profits on the intraday market will be higher. Arbitrage then will reduce the price differences between the two markets (although they will not disappear completely, for example because of different risk profiles for the two markets and because of a higher scarcity rent on the intraday market). Finally, high prices on the intraday (and through arbitrage also higher prices on the day-ahead market) can make it attractive for new generators and other sources such as demand side response and storage to enter the market (see the next chapter).

The effect of new sources of supply on the intraday market will be to reduce unmet demand and to decrease the price on the intraday market, especially in those hours in which originally not all demand for ramping up could be met. However, while new entrants on the intraday market will bid down prices, they will remain high enough to allow entrants to recoup their investment costs, otherwise additional entry would not occur.

3

Business cases for flexibility supply in 2023

3.1 Introduction

In the previous chapter, we have analysed the increased demand for flexibility given rising shares of intermittent renewables, both on the day ahead and on the intraday market. In this chapter, we will look at the business case for different types of power plants and for other flexibility options such as storage and demand response. We will focus on the intraday market, because this is the most significant market as regards demand for flexibility. Two different types of flexibility will be considered, flexibility which can be supplied by generation which either increases or decreases its production and flexibility from other options. Other options include storage, demand response and increased interconnection. In this study we focus on storage and demand response.

For downward adjustment, another option is to curtail wind power production. This will especially become an option when wind production is very high relative to demand. A business case analysis of wind curtailment in itself does not make much sense, because it will depend to a strong extent on the costs of other options for downward adjustment. However, in an analysis of the optimal mix of flexibility options, wind curtailment would definitely have a role to play.

3.2 Flexibility from generation

Conventional dispatchable generation can be used to provide the flexibility needed on the intraday market to meet unexpected changes in wind production compared to the forecasts in the day-ahead market. This requires sufficient flexibility in terms of ramp rates and minimum load levels, depending on the magnitude and the timing of the change in wind production as compared with predicted wind power production. The shorter the time period in which flexibility is needed and the larger the absolute volume change is, the more flexible the dispatchable generator has to be. The accuracy of the prediction in the last hours before gate closure is also important. The more in advance and the more accurate the prediction of wind power production is within the day, the more options there will be to acquire the needed decrease or increase in power production to compensate for the difference between forecasted and realised wind. Given demand and prices on the intraday market as established in the previous chapter, we will analyse the profitability of conventional generation in providing the flexibility demanded in this market. We will analyse the possible role CCGT and GT power plants, taking into account flexibility constraints for the different types of generation considered.

In our analysis, we concentrate on the intraday market. It should be realized that in practice, investments and generation decisions will take into account all markets on which these assets can be used, from longer term forward markets and day-ahead markets to intraday markets and the provision of ancillary services. Concentrating on the intraday market as defined in this study allows us to analyse the additional opportunities which demand for flexibility can provide using the results from the model presented in chapter 2 as an input. However, we will take into account that a plant will also produce on the day-ahead market and therefore investment costs do not have to be covered solely on the intraday market.

Costs and benefits

Whether an investment will be profitable or not depends on the costs and benefits of the project. Here, we will consider the profitability of investing in a conventional power plant to provide flexibility on the intraday market to accommodate wind power production. Table 8 gives an overview of the main costs and benefits which are incurred by an investor.

Table 8: Costs and benefits investments in conventional power plants

Costs	Benefits
Investment costs	Revenues
Fixed operation & maintenance costs	Residual value investments
Variable costs	

The major costs are the investment cost, which include capital costs for the capital expended during the construction time, and the variable costs. These consist of fuel costs and CO_2 emission allowances costs and the variable operation and maintenance costs associated with the operation of the power plant. In addition, there will be fixed 0&M costs which have to be made independent from the level of power production within the plant.

Revenues are realised by the sale of the produced power on the intraday market we have analysed in the former chapter. In addition, there can be a residual value which remains at the end of the operational lifetime of the investment.

In evaluating business cases, the costs and benefits over the whole lifetime should be taken into account. As we focus on a specific year, 2023, we will calculate the annuity of fixed and investment costs over the whole lifetime, allocate these costs to both the day-ahead and the intraday market based on production volumes and use the share of annual fixed costs attributed to the intraday market to evaluate the business case for the years under consideration.

Data input

Table 9 provides an overview of our main assumptions with regard to the fixed costs for the generation technologies considered here. These assumptions are based on a recent overview of the costs of power plants by Brouwer (2014), in which values have been derived for the different cost components based on a range of studies. Brouwer provides data for different future years, which include cost reductions based on average reduction in investment costs for different technologies. We have used the cost estimates for 2020. The investment costs include capital costs and has taken residual value into account.

Parameters such as lifetimes and discount rates are similar to those used in the 2010 edition of the IEA's *Projected costs of generating electricity* study (IEA 2010). Typical capacities of a single plant are based on those constructed recently and on data from the literature.

Table 9: Data input and parameters conventional power plants

	CCGT	GT
Investment costs	€661/kW$_e$	€355/kW$_e$
Lifetime	30 years	30 years
Capacity	435 MW$_e$	150 MW$_e$
Fixed O&M	€14/kW$_e$	€9/kW$_e$
Discount rate	10%	10%
Annual fixed costs	€37 mln	€7 mln

Gas turbines have lower investment costs and will in general have a smaller capacity than CCGT power plants. In contrast, the efficiency of GTs are lower than those of a CCGT plant (ca. 60% for a CCGT versus 38% for a GT) and therefore fuel costs will be substantially higher. Consequently, a CCGT plant will be preferable if it is to be expected that a sufficient number of operating hours can be made, given the flexibility constraints of a CCGT plant.

Results

Table 10 provides the results of the business case results for CCGT and GT plants, based on the input data and on demand and prices on the intraday market. The annual fixed costs have been adjusted to account for the fact that these plants will also operate on the day-ahead market. Based on the modelling results for the day-ahead and the intraday market, annual fixed costs have been allocated to either the day-ahead or intraday market based on the production volume in those markets.

Table 10: Business case gas-fired power plants

	CCGT [435 MW]	GT [150]
Ramp up (GWh)	880	342
Ramp up as % of max. annual output	23%	26%
Ramp down (GWh)	587	337
Net revenue (mln €)	34	1
Part of annual fixed costs intraday market (mln €)	8,9	1
Profit (mln €)	25,4	0
Internal rate of return (%)	47%	1%

The volumes provided on the intraday market are based on demand and supply on the intraday market analysed in the former chapter, taking into account flexibility constraints and marginal production costs of new CCGT and GT plants. Revenues for ramping down on the intraday market have been included as well, which would implicitly entail that the plant would operate on the day-ahead market as well. However, given our focus on the intraday market, although we adjusted the annual fixed costs, we did not include revenues from generation on the day-ahead market in our business case. Therefore, the only revenues included are those earned on the intraday market. If the day-ahead market would have been taken into account as well, total revenues would have been higher, however fixed annual costs would also be higher.

For the CCGT plant, the intraday market provides an opportunity to operate profitably, with a profit of €25,4 mln. For the gas turbine, profit is more or less zero. Assuming constant net revenues over the whole lifetime of a plant, the internal rate of return for the CCGT plant is high, 47% while for the GT it is 1%. This difference reflects the operating hours of both plants on the day-ahead market, where GT have a much lower load factor. Consequently, the annual fixed costs of the GT have to be covered to a larger extend on the intraday market than those of the CCGT plant.
The CCGT plant’s operations are constrained by its flexibility constraints; without those limits, it would have been able to ramp up for almost 200 GWh more. Flexibility constraints also limit the ramp down which can be delivered by the CCGT, by ca. 350 GWh.

Demand on the intraday market for ramping up is high, resulting in periods with high prices, which will incite additional flexibility providers to enter the market. This will bid down the price of flexibility up till the point where entrants will no longer be able to recoup their fixed costs. In equilibrium, prices on the intraday market will therefore include a scarcity rent in peak demand hours up and above the marginal costs of generation, otherwise new generators would not enter the market. As an indication of this scarcity rent, we have calculated the average monthly prices on the intraday market at which the business case for both types of plants is just positive, or, in other words, at which price both technologies can just recoup their investment costs. This is displayed in Figure 14, which shows the monthly average spot price, the price on the intraday market and the minimum prices required for CCGT and GT to break even.

Figure 14: Minimum monthly upward adjustment prices CCGT and GT

Prices for upward flexibility on the intraday market can be considerably lower while still allowing a CCGT-plant to break-even on the intraday market. For a CCGT plant, the minimum break-even price is below the spot price on the day-ahead market. For the gas turbine, the minimum price is more or less equal to the upward adjustment price, given its zero profit at that price.

Discussion and conclusions

Based on our analysis of the intraday market in 2023, there is a positive business case for both a CCGT power plant or in GT generation. The main driver for the business case is the increased demand for flexibility to balance the programmes submitted by balancing responsible parties. This demand is driven by the forecast error of wind production 24 hours in advance of real time. In addition, energy companies will want to reserve capacity for intraday not to be exposed to high and uncertain intraday prices. In equilibrium, the price on the intraday market will include a scarcity rent, in the hours of peak demand, which is needed for generators to recoup their fixed investment costs. This will also hold for the day ahead market. More generally, it is to be expected that prices on the day-ahead market and the intraday market will tend to converge up to a certain level because generators will have the choice at which market they want to bid in their production. While intraday markets can be expected to have a higher price, due to the higher scarcity of capacity intraday, a too large difference will incite generators to bid more on the intraday market and less on the day-ahead market, thereby driving down prices on the intraday market

Flexibility constraints on CCGT power plants to some extent limit their use to provide flexibility. It is to be expected that this will increase with larger levels of renewables and therefore larger production swings from hour to hour.

In our analysis, we have focussed on a single year based on a scenario for the future development of the electricity market. In actual investment decisions, the business case analysis will also include an analysis of uncertainty and potential risks, which will include different assumptions for fuel prices, demand and generation mix developments. In our analysis, we therefore have not only focussed on the specific results for the business cases examined but also looked at the minimum prices needed for a positive business case. These calculations provide a kind of sensitivity analysis, indicating the range of market conditions in terms of prices which allow profitable investments for the supply of flexibility on the intraday market.

3.3 Storage and demand response

Flexibility can not only be supplied by generation, it can also be provided by other options such as storage, demand side response or interconnections. In this section we will analyse the business case for storage and for demand side response on the intraday market. The next section is considering storage, subsequently we will look at demand side response.

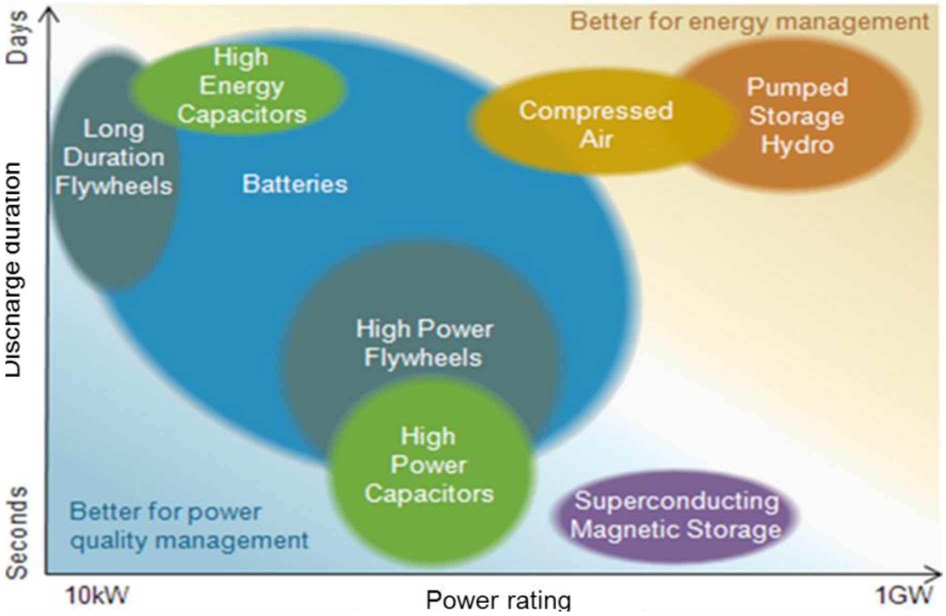
3.3.1 Storage

Introduction

There are a number of different technologies for storing the electricity or, more precisely, for storing the energy of electricity. The major categories are batteries, power to gas, compressed air energy storage (CAES), pumped hydro storage, flywheels, supercapacitors and superconducting magnetic energy storage (see DNV Kema, 2013, *Final Report, Systems Analyses Power to Gas, Deliverable 1: Technology Review*, for an extensive overview of different storage technologies). Of these technologies, pumped hydro storage is available at lowest costs and at large sizes. It is, however, not available within the Netherlands. While pumped storage in for example Norway could play a role in providing flexibility for North-West Europe, we will focus in this study on storage that can be realized within the Netherlands, given our focus on the intraday market within the Netherlands.

The focus here is on large-scale storage at the level of the high-voltage network, local battery storage by households is not analyzed in our study. However, there is a distinct possibility that there can be a considerable deployment of such storage, especially if the current implicit tax subsidy for solar-pv would be diminished. In that case, local battery storage in combination with already installed solar panels can become profitable, given the price of electricity paid by households. Such a deployment would only have a limited impact on the results from our study with regard to the intraday market, because solar-pv forecast errors have not been taken into account in the analysis of the intraday market. It might reduce the need for flexibility on the day-ahead market we have identified, because local storage will help accommodating the variability from solar-pv electricity production. Consequently, the variability on the day-ahead market will probably be less with local storage.

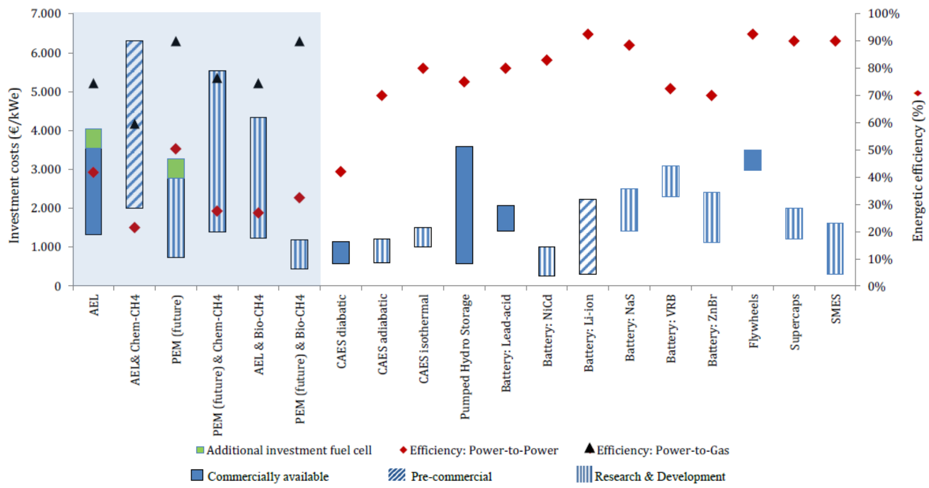
Figure 15: Overview of different types of storage



Source: EIA 2012.

Figure 15 provides an overview of different types of storage, showing the discharge duration and power ratings. For the purpose of providing flexibility on timescales of an hour and more in sufficient volumes, pumped hydro and CAES are the major available technologies (see also THINK Report Topic 8, Annex 1). The other options do not provide sufficient volumes to be able to provide flexibility on the intraday market, at least not at reasonable prices. Figure 16 shows the different technologies in more detail, providing information on investment costs, energy efficiency and the state of development of the different technologies.

Figure 16: Investment costs, stage of development and efficiencies



Source: DNV KMA 2013.

CAES technologies are currently the most promising, both in terms of volumes and of investment costs. We will therefore focus on CAES in our analysis. More specifically, we will consider the so-called adiabatic CAES. In contrast to diabatic CAES, this variant does not need natural gas to expand compressed air, because heat generated in compressing air is stored and used to provide the heat needed in decompressing. Although the investment costs will be higher, energy efficiency is higher compared with diabatic CAES.

CAES business case

Table 11 shows the characteristics and data with regard to this storage option (based on DNV KEMA 2013).

Table 11: Input data CAES

Investment costs	600 – 1200 €/kW$_e$
Lifetime	30 years
Capacity	300 MW
Maximum storage capacity	2700 MWh
Discount rate	10%
Efficiency	70%
Annual fixed costs	19 - 38 mln. €

We have assumed that storage can be used within a day, charging when electricity prices are low and discharging when demand and therefore prices are high. The optimal use and the revenues of storage have been calculated through modelling of the CAES unit in the intraday market analysed with the COMPETES model. Table 12 presents the results this simulation.

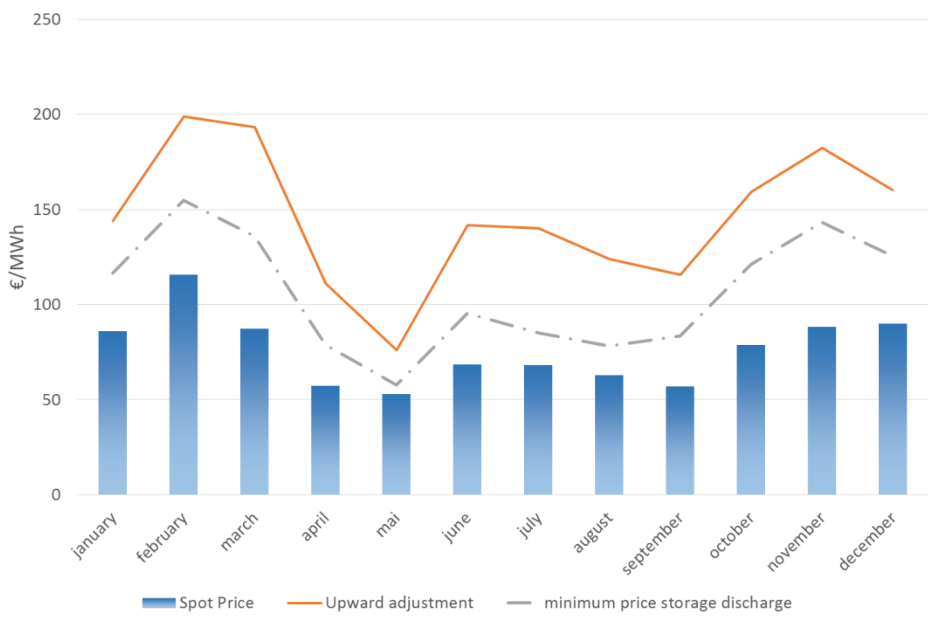
Table 12: Business case CAES

Yearly discharge	536 GWh
Yearly charge	788 GWh
Revenues	€ 117 mln
Charging costs	€ 45 mln
Yearly fixed costs	€ 19 - 38 mln
Profit	€ 17 - 36 mln

The analysed CAES storage will make a profit of € 17 to 36 mln, depending on the level of fixed investment costs. An important driver for the profitability of the CAES storage unit is the price volatility which increases significantly with the rise of variable renewables power production. Furthermore, unmet demand creates scarcity, driving up towards the low VOLL of €320 per MWh.

Just as for the business case of CCGT and GT gas fired power plants, we have calculated the monthly average price on the intraday market at which the business case for storage is just positive, or, in other words, at which price the CAES investment can just recoup its costs, see Figure 17. The minimum price shown is based on the upper limit of investment costs of €1200 per kW_e. Storage requires a higher monthly average price than a CCGT plant, but substantially lower than those of gas turbine.

Figure 17: Minimum monthly prices storage



CAES impact on the intraday market
Our analysis in this chapter is concerned with business cases for the investment in a single new plant or facility, investigating their profitability in the intraday market given expected future developments and minimum prices required for a positive business case. It is not the purpose of the analysis to derive the optimal capacity mix in the day ahead or intraday market. Therefore, we do not consider the impact of business case investments on market conditions, even though it is to be expected that new sources of flexibility entering the market will affect equilibrium volumes and prices.

However, including storage in our intraday market modelling provides interesting insights in the effects of storage on volumes traded, flexibility supply of incumbents, prices and upward flexibility supplied by non-incumbent sources. Figure 18 and Figure 19 show the effect of CAES on flexibility supply in 2023 supply. CAES ramping up is one of the non-incumbent sources for upward flexibility, it does not affect flexibility provided by conventional power plants. Ramping down from CCGT and coal fired power plants is replaced by CAES, furthermore wind curtailment is slightly reduced.

Figure 18: Upward flexibility supply intraday market in 2023 with and without CAES

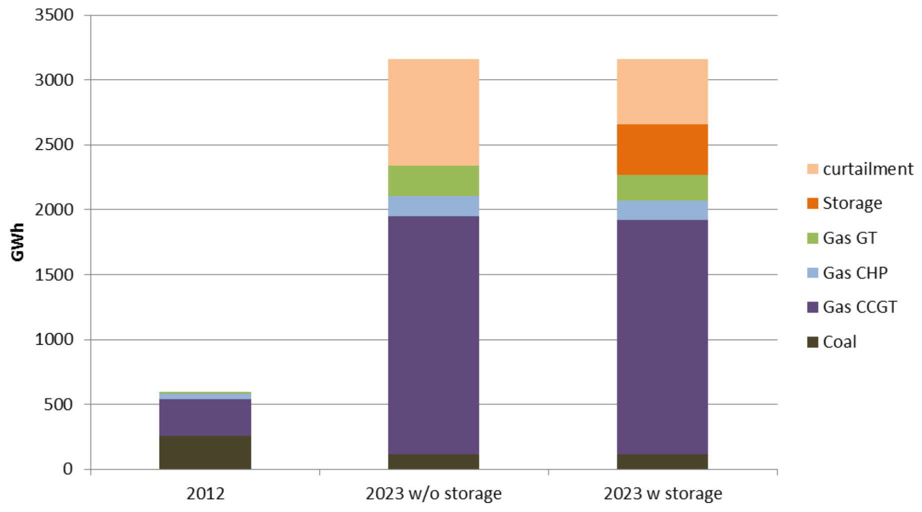
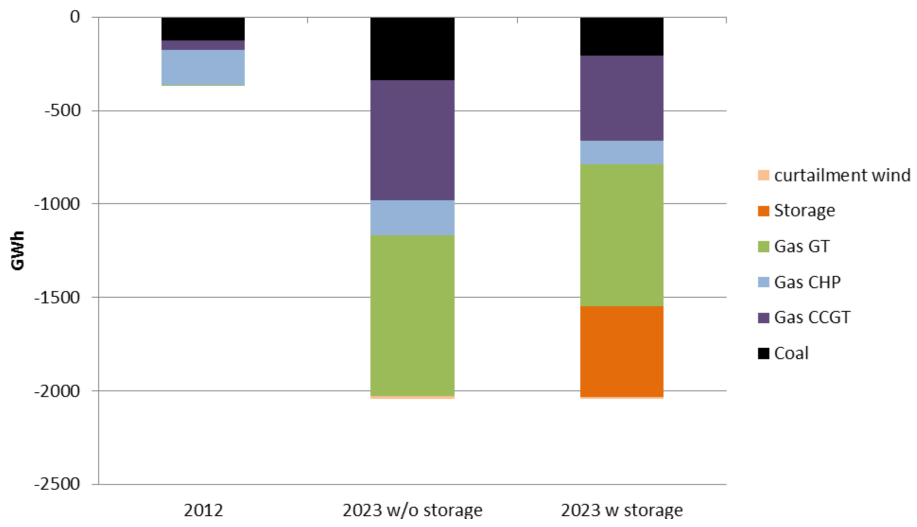


Figure 19: Downward flexibility supply intraday market 2023 with and without CAES

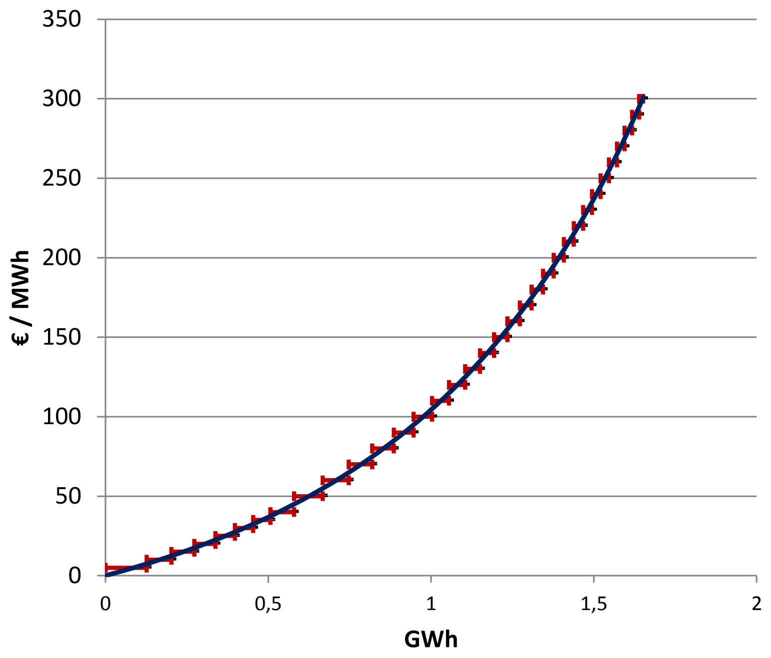


3.3.2 Demand side response

Demand side response (DSR) can potentially provide a cost-effective means to provide the flexibility needed to accommodate fluctuating power generation from renewables. DSR encompasses a wide range of different models and options, from switch-off contracts between large customers and TSOs to flexibility provided by household appliances within a smart grid environment. DSR can take several forms, such as on-site generation, heating and cooling buffering and deferred production. At present, DSR is mainly supplied by large scale customers (Andrew et al. 2011).
Given the limited use of DSR so far, information on the volumes, costs and operational details such as hourly volumes and time-scales for shifting has to be based on studies of

DSR potentials. While there is a considerable body of literature on DSR in different countries (see the IEA demand side management website, http://www.ieadsm.org), detailed information on potential and costs in the Netherlands is lacking. A study by Deloitte for the Ministry of Economic Affairs in the Netherlands (van der Linde et al. 2004) provides some cost and volume information for DSR in industry, horticulture and transport and cooling. Based on data on underutilisation and of the costs of production losses due to reduced power consumption, a total potential of about 1730 MW is mentioned, which would be available at costs of € 300 - 500 per kWh. In a cost-benefit analysis of smart grids (Blom et al. 2012), CE and KEMA provide some information on potential for DSR. Peak shifting has a potential of 3 - 25% of peak demand of participating commercial and industrial customers.

Figure 20: Stepwise approximation of DSR cost curve



Given the limitations with regard to information on potentials and costs of DSR in the Netherlands, we have modelled the potential volume DSR as a function of costs for the supplier of DSM, loosely based on the available data from the Deloitte and CE/KEMA studies. Figure 20 presents the assumed stepwise approximation of DSR. The horizontal axis shows the GWh demand reduction available, given the electricity price presented on the vertical axis. It has been assumed that DSR takes the form of demand shifting, moving electricity consumption from peak to other hours within one day. It should be noted that in practice, the possibilities and constraints for shifting or reducing demand will differ across industries and sectors. While in one case it might be possible to defer electricity consumption for a number of hours, in other cases a shift might be limited to one or two hours. Our approach takes a more general and possibly more flexible approach, therefore the results might present an overestimate of the possibilities for DSR in the Netherlands. On the other hand, given the lack of more precise data on volumes and costs of DSR, it could equally be an underestimation of the role of DSR, certainly if an increasing value for flexibility leads to increased attention for the role of DSR.

Including DSR as an option in the intraday market modelling provides the results as presented in Table 13 below. In contrast to the business cases described above, the analysis of DSR is not a business case of an individual option or firm, instead it is an evaluation of the whole potential of DSR as modelled here.

Table 13: Demand Side Response in the intraday market

Annual demand side response	489 GWh
Net gain lower electricity costs	€ 24 mln
Incurred costs peak shifting	€ 12 mln
Net gain from DSR	€ 11 mln

DSR will shift 489 GWh per year between hours, thereby reducing peak demand. This shift reduces expenditure on electricity by € 24 mln because of the lower prices in the hours to which consumption has been shifted. Taking the incurred costs into account yields a net profit of €11 mln.

In the consultation for the 2014 TYNDP from ENTSO-E, an estimate is provided of demand side response, as an input for market and network modelling studies. For the Netherlands, the estimate is 8,76 TWh, which is significantly higher than our results. This might suggest that our estimate of demand side response is on the low side.

Although it is difficult to draw clear conclusions about the quantitative contribution of DSR to accommodating intermittent renewables, given the lack of data, DSR will nevertheless have an important role to play in furnishing the flexibility required to adapt the electricity system to increasing levels of renewables. Meeting incidental large shortfalls of realized wind power production either on the day-ahead or intraday market without the option of voluntary demand shedding would be considerably more expensive. It would require considerable outlay on flexible generation plants which would only be needed for limited time periods. Within an optimal portfolio of flexibility options, DSR will have its place, next to options such as flexible generation and storage.

To acquire a better understanding of the future role of DSR in accommodating intermittent renewables, it would first of all be necessary to gather more information on the potential for DSR in the Netherlands. This information would include data on the potential, both MW and hours and the incurred costs, characteristics such as the number of hours in which DSR would be available, the number of times per year and the required warning time. Without this information, estimates such as presented above can only provide a very rough picture of the potential of DSR.

Furthermore, it would be necessary to look in more detail at regulation and market design in order to identify the barriers which hinder the use of DSR. Transparent markets, low thresholds for market entry, clear regulation with regard to the role of different stakeholders such as TSOs, DSOs and DSR suppliers (industry, aggregators) is imperative for the development of DSR.

4 Discussion

In this study, the market for flexibility due to increased variable generation from wind and sun in the Netherlands has been quantified, focussing on the day-ahead market and the intraday and balancing market. Future electricity market developments have been derived using the COMPETES European electricity market model, which has been adapted for this study to include flexibility constraints and unit commitment. The analysis is based on assumptions regarding future developments of fuel prices, interconnections, demand and capacity mix in the individual European countries and renewable energy generation profiles derived from various sources such as the IEA's World Energy Outlook 2013, ENTSO-E scenario's and network development plans and from detailed renewable energy data from TSO's and other sources.

While these assumptions will have some impact on the results of the analysis, they will robust be for a range of different assumptions because of the focus on demand for flexibility resulting from increased intermittent renewables generation. Probably the major factor which affects the results is the available capacity relative to demand on both the day-ahead and intraday market. Obviously, a situation of overcapacity will not allow all market participants to operate at a profit. However, in such a case it is to be expected that there will be a restructuring of the market, which reduces overcapacity and allows generators to cover all their costs.

Demand for flexibility on the intraday and balancing market due to increased wind generation in this study has been simulated by computing optimal dispatch for realized wind production, keeping import and export schedules from the intraday market fixed. Assuming full intraday flexibility for all available generation on the intraday market might be an overestimate of the possibilities for intraday adjustment, even though flexibility constraints have been taken into account. Then again, in practise there would be more capacity made available for the intraday market and less for export, given high demand and prices on the intraday market. Moreover, it is to be expected that entrants (such as flexible conventional generation, storage and demand side response) will provide additional capacity. While we have not calculated the final equilibrium on the intraday market, the minimum prices determined in the business cases provide some indication of equilibrium prices for individual technologies. A further step in the analysis of the impact of variable and uncertain renewables on day-ahead and intraday markets would be to model these markets explicitly in a dynamic setting in which not only generation but also investments be optimised. However, this is quite a challenge which would require substantial fundamental research and model development.

While developments and interactions with other European countries have been taking into account, the balancing market has only been analysed for the Netherlands, reflecting current practice in which system balancing takes place within countries. However, with further integration of electricity markets, balancing over a larger geographical area can be expected to reduce overall balancing costs. This is also illustrated by the important role imports and exports have in providing flexibility on the day-ahead market as shown in our analysis. It would therefore be valuable to study the implications for our results from integrating intraday and balancing markets over a wider geographical area. Furthermore, our analysis has been based on hourly data. However, volatility of renewable power generation also occurs in shorter time periods, such as 15 minutes. An analysis based on shorter time periods (given that data would be available) can be expected to show an increased demand and a higher value for flexibility.

Our analysis has shown that efficient intraday markets will contribute to accommodating increasing levels of variable and uncertain renewables in the electricity market. These markets will give a price incentive for both flexible generation and other sources of flexibility such as storage and demand side response to provide the increased need for flexibility. On this market, the most cost-effective options will be selected to compensate higher or lower than forecast power production from renewable energy sources, thereby reducing overall costs of integrating renewables in the electricity system.

However, such a market will not evolve by itself. There are several requirements which have to be met so that an efficient intraday market can develop with sufficient liquidity. An important requirement for an efficient intraday market is balancing responsibility for all producers, including renewable energy power generators. Otherwise, renewable power generators will not have an incentive to trade on the intraday market. Without balancing responsibility for renewable generators, the intraday market will not develop and there will be no incentives to develop new sources of flexibility. Furthermore, there should be an incentive for balancing responsible parties to be active on the intraday market instead of leaving it to the TSO to balance the market. This requires that they bear the full costs of balancing incurred by the TSO. If this would not be the case, for example because part of these costs are socialized or because the price paid for imbalance is based on average costs instead of marginal costs, it would be less costly to leave balancing to the TSO and the intraday market would not develop.

Literature

Blom, M.J., M. Bles, C. Leguit, F.J. Rooijers, R. van Gerwen, D. van Hameren, F. Verheij, 2012, *Cost and benefits of smart grids (in Dutch)*, CE en KEMA.

ENTSO-E, 2013, Scenario outlook and adequacy forecasts 2013 -2030.

Grond, L., P. Schulze and J. Holstein, 2013, *Final Report Systems Analyses Power to gas, Deliverable 1, technology Review*.

Hirst, E., 2001, Real-*time balancing operations and markets: key to competitive wholesale markets*.

Keane, A., A. Tuohy, P. Meibom, E. Denny, D. Flynn, A. Mullane, M. O'Malley, 2011, Demand side resource operation on the Irish power system with high wind power penetration, *Energy Policy*, **39**, p. 2925-2934.

Linde, R. van der, R. Mazier, W. Obermann and P. Smidt, 2004, *Utilising demand side response in the liberalised electricity market (in Dutch),* Deloitte.

Loisel, R., A. Mercier, C. Gatzen, N. Elms, H. Petric, 2010, Valuation framework for large scale electricity storage in a case with wind curtailment, Energy Policy **38**, p. 7323-7337.
Scheepers, M. en J. de Joode, 2007, *Project Energie opslag, Rapportage WP3: Kosten/baten energieopslag*, ECN.

Glossary

CAES	Compressed Air Energy Storage
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
DSR	Demand Side Response
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatthour
IEA	International Energy Agency
MW	Megawatt
MWh	Megawatthour
TSO	Transmisson System Operator
TWh	Terawatthour
VOLL	Value of Lost Load

Appendix A. Load duration curves and load factors

Figure 21, Figure 22 and Figure 23 show the residual load duration curves for the years 2012, 2017 and 2023, including gross imports, based on forecast wind power production. These graphs show hourly non-intermittent generation, both conventional and renewables, plus gross imports, over the year, arranged from highest to lowest levels. Over the years, there is an increased utilisation of coal and gas plants. Furthermore, there is an increased volatility in the production form especially gas-fired power plants, reflecting increased variability in electricity generation from wind and sun.

Figure 24 gives the load factors for different technologies in the three years considered. In 2023, load factors have improved considerably, reflecting market developments in the background scenario for Europe in which capacity is more in line with demand.

Figure 21: Residual load duration curve 2012

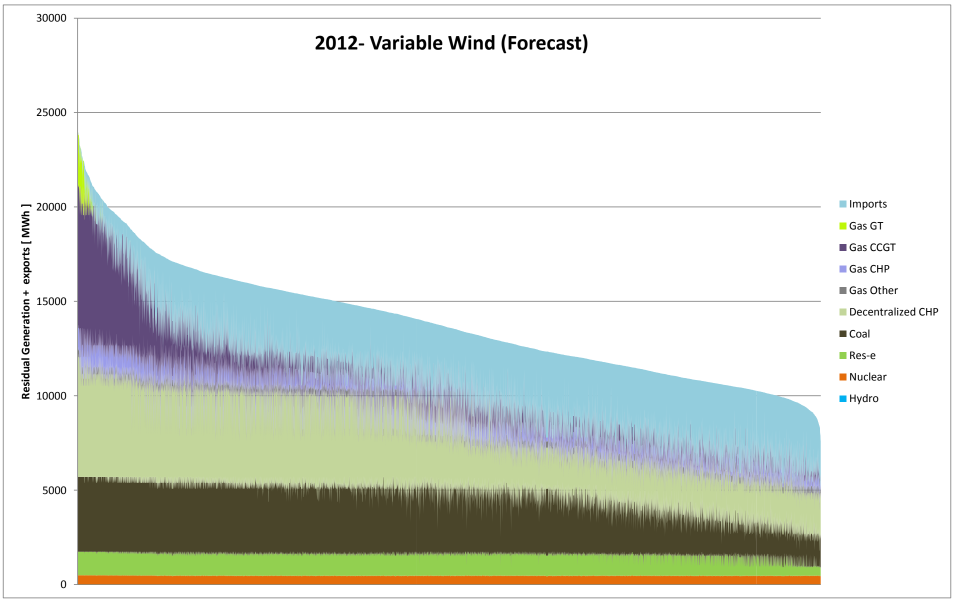


Figure 22: Residual load duration curve 2017

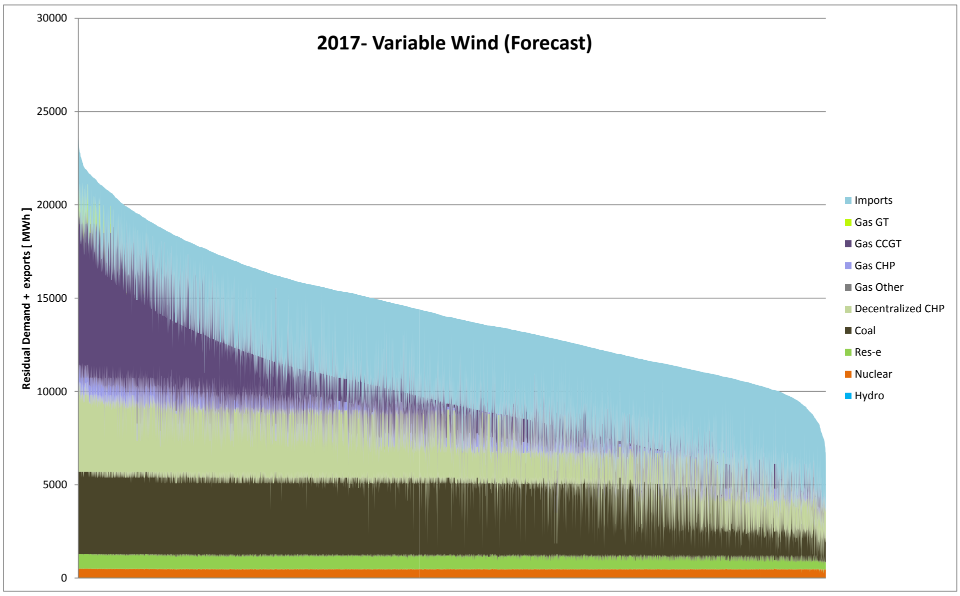


Figure 23: Residual load duration curve 2023

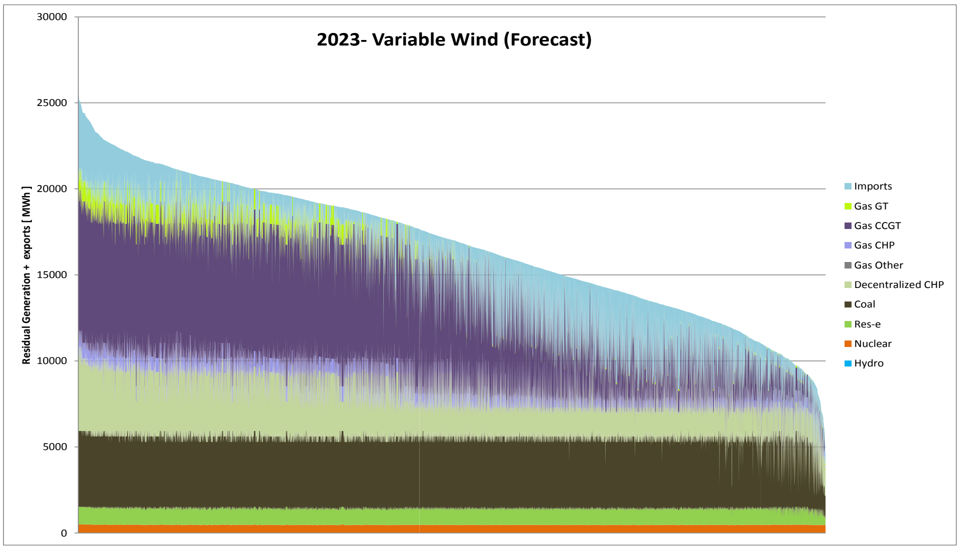
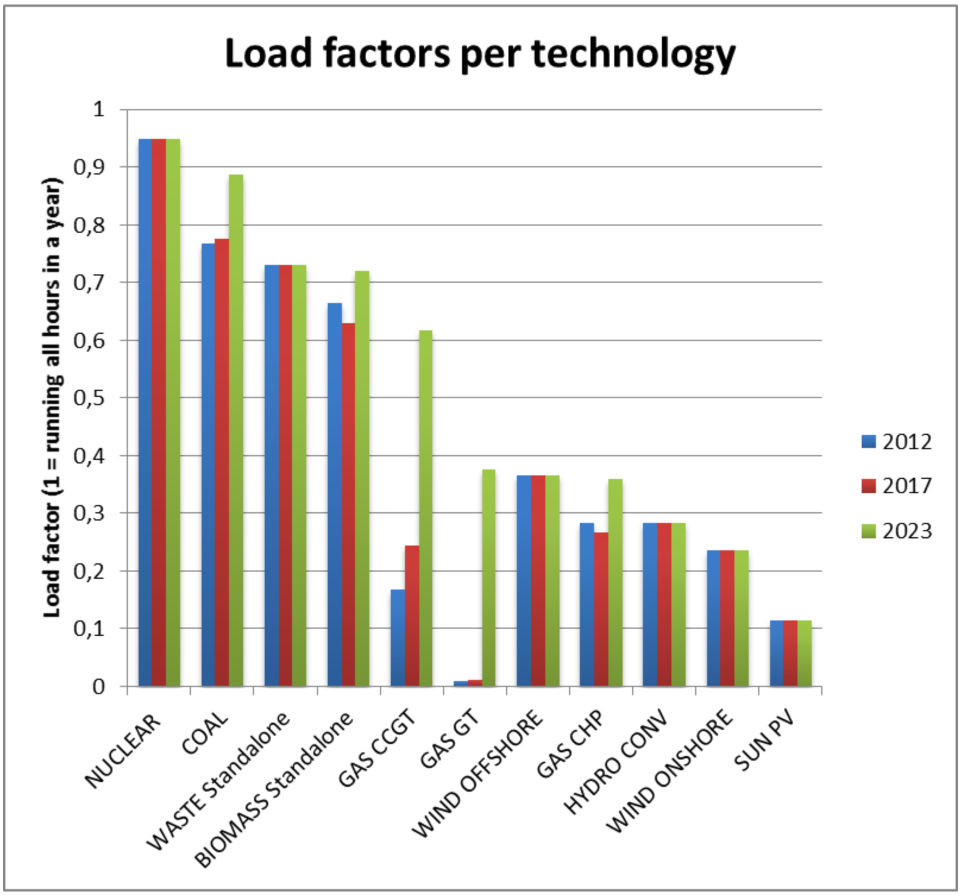


Figure 24: Yearly load factors per technology (1 = running all hours in a year)



Appendix B. COMPETES Unit Commitment model

Model overview

COMPETES[5] UC is a unit-commitment model of the transmission-constrained European power market. The model covers 27 EU member states and some non-EU countries (i.e., Norway, Switzerland, and the Balkan countries) including a representation of the cross-border transmission limitations interconnecting these European countries.
Every country is represented by one node, except Luxembourg which is aggregated to Germany, Balkan and Baltic countries are aggregated in one node, and Denmark is split in two nodes due to its participation in two non-synchronous networks (See Figure 1).
The model assumes an integrated EU market where the trade flows between countries are constrained by "Net Transfer Capacities (NTC)" reflecting the ten year network development plans (10YNDP) of ENTSO-E.

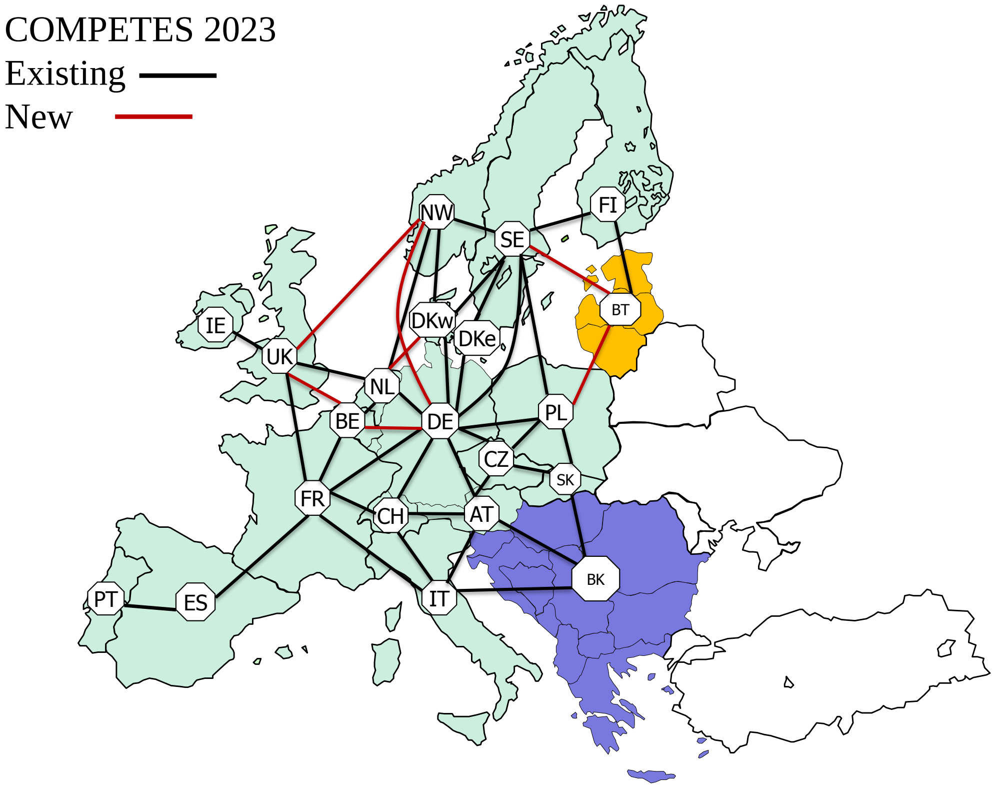


Figure 25 *Geographical coverage in COMPETES UC and the representation of the cross-border transmission links in 2023 according to Ten-Year Network Development Plans of ENTSO-E*

[5] COMPETES UC is an extension of COMETES Model (Hobbs and Reijkers (2004a)) which has been developed in cooperation with Benjamin F. Hobbs, Professor in the Whiting School of Engineering of The Johns Hopkins University, as a scientific advisor of ECN.

COMPETES UC model is used to find an optimal generation schedule for the problem of deciding which power generating units must be committed/uncommitted over a planning horizon at minimum cost, satisfying the forecasted system load as well as a set of technological constraints. These constraints include the flexibility capabilities of different generation technologies as well as the lumpiness in generator start-up decisions, a feature not considered in most continent-wide electricity market models. The model also includes hourly profiles of wind and solar generation that are intermittent in nature.

Unit Commitment Problems are considered to be difficult to solve for systems of practical size due to their complexity of finding integer solutions. To overcome this, while the exact formulation of MILP is used for the units in the Netherlands, an approximation of MILP is formulated for the other countries/regions. The corresponding approximating problem proposed by Kasina et. al (2013) aims to solve large scale systems within a reasonable time while capturing the most of the characteristics of a unit commitment problem.

To summarize, the unit commitment formulation of COMPETES minimizes total variable, minimum-load and start-up costs of generation and the costs of load-shedding in all countries subject to the following electricity market constraints

- *Power balance constraints:* These constraints ensure demand and supply is balanced at each node at any time.

- *Generation capacity constraints:* These constraints limit the maximum available capacity of a generating unit. These also include derating factors to mainly capture the effect of planned and forced outages to the utilization of this plant.

- *Cross-border transmission constraints:* These limit the power flows between the countries for given NTC values.

- *Ramping up and Down constraints:* These limit the maximum increase/decrease in generation of a unit between two consecutive hours

- *Minimum Load Constraints:* These constraints set the minimum generation level of a unit when it is committed. For the Netherlands, every unit is modelled with minimum generation levels and the corresponding costs. For other countries, this constraint is approximated by a relaxed formulation since the generation capacities and the minimum generation levels represent the aggregated levels of the units having the same characteristics (e.g., technology, age, efficiency etc.).

- *Minimum up and down times (Only for the units in the Netherlands):* These constraints set the minimum number of hours that a unit should be up or down after being started-up or shut-down.

The incorporation of start-up costs, ramping rates, minimum load levels allows a better representation of the system flexibility to accommodate the variability and forecast errors of wind. In addition, the model also includes the flexibility decisions related to the operation of storage and demand response in the Netherlands. The long-term planning decisions in the form of adequate generation capacity and cross-border import capacity is part of the scenario and thus exogenous to the model.

Model Inputs and Assumptions:

Electricity supply characteristics

The input data of COMPETES UC involves a wide-range of generation technologies (see Table 1). The generation type, capacity, and the location of existing generation technologies are regularly updated based on WEPPS database UDI (2012). COMPETES database is in particular detailed out with unit by unit generation in the Netherlands. For the other countries, the units using same technology and having similar characteristics (i.e., age, efficiency, technical constraints) are aggregated.

Table 14 The categorization of electricity generation technologies in COMPETES

FUEL	TECHNOLOGY	DESCRIPTION
CONVENTIONAL TECHNOLOGIES		
Gas	GT	Gas Turbine
Gas	CCGT	Combined cycle
Gas	CHP	Cogeneration
Gas	CCS	
Derived Gas	IC	
Derived Gas	CHP	
Coal	PC	
Coal	IGCC	
Coal	CCS	
Lignite	PC	
Oil	-	
Nuclear	-	
RENEWABLES		
Biomass	Cofiring	
Biomass	Standalone	
Waste	Standalone	
Geo	-	
Sun	PV	Photovoltaic
Sun	CSP	
Wind	Onshore	
Wind	Offshore	
Hydro	CONV	Conventional
Hydro	PS	Pump Storage
RES	Other	

The main inputs for electricity supply can be summarized as:

- Operational and flexibility characteristics per technology per country
  - Efficiencies
  - Installed power capacities
  - Availabilities (seasonal/hourly)
  - Minimum load of generation and min-load costs
  - Start-up/shutdown costs
  - Maximum ramp-up and down rates

- Minimum up and down times (only for the units in the Netherlands)

– Emission factors per fuel/technology
– Fuel prices per country, CO_2 ETS, (national CO_2tax)
– Hourly time series of intermittent RES (wind, solar etc.)
– RoR (run of river) shares of hydro in each country
– (Optional) external imports from Africa

The flexibility assumptions for conventional units are assumed to differ with the type and the age of the technology as summarized in Table 14. The part-load efficiencies for min-load levels given in Figure 26 are taken into account for calculation of the min-load costs incurred when units with these technologies are committed.

Table 15 Flexibility Assumptions for conventional technologies in COMPETES

Technology	Time of being commissioned	Minimum load (% of max capacity)	Ramp rate (% of max capacity/hour)	Start-up cost[a] (€/MW installed per start)	Min up time	Min down time
Nuclear	<2010	50	20	46 ±14	8	4
	2010	50	20	46 ±14	8	4
	>2010	50	20	46 ±14	8	4
Lignite and PC	<2010	40	40	46 ±14	8	4
	2010	35	50	46 ±14	8	4
	>2010	30	50	46 ±14	8	4
IGCC	<2010	45	30	46 ±14	8	4
	2010	40	40	46 ±14	8	4
	>2010	35	40	46 ±14	8	4
NGCC	<2010	40	50	39 ±20	1	3
	2010	30	60	39 ±20	1	3
	>2010	30	80	39 ±20	1	3
OCGT	<2010	10	100	16 ±8	1	1
	2010	10	100	16 ±8	1	1
	>2010	10	100	16 ±8	1	1
CHP	<2010	10	90	16 ±8	1	1
	2010	10	90	16 ±8	1	1
	>2010	10	90	16 ±8	1	1
Sources[b]		[1-9]	[1-8, 10]	[11]	[11]	[11]

a) Warm start-up costs are assumed for all technologies but OCGT. For OCGT, a cold start is assumed.
b) [1] (Jeschke et al., 2012); [2] (Dijkema et al., 2009); [3] (OECD/IEA, 2012b); [4] (IEAGHG, 2012a); [5] (Klobasa et al., 2009); [6] (Balling, 2010); [7] (Hundt et al., 2010); [8] (Isles, 2012); [9] (Stevens et al., 2011); [10] (NETL, 2012b); [11] (Lew et al., 2012).

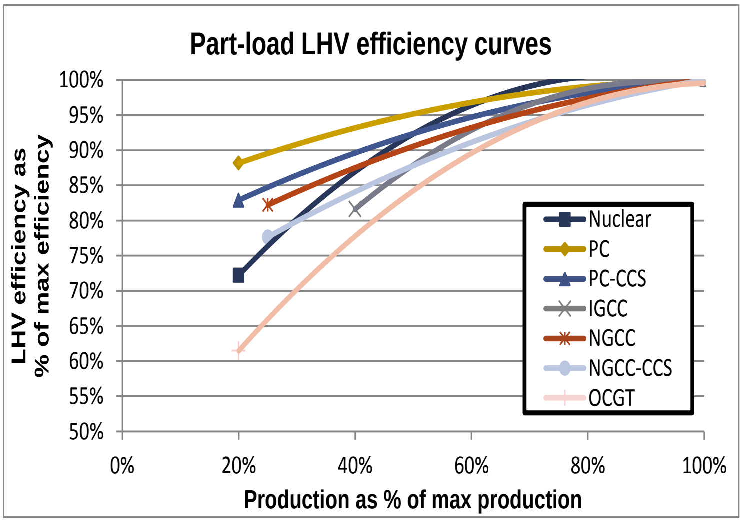


Figure 26 Part-load efficiency curves for different technologies. Source: ECN (Brouwer et al. (2013))

Intermittent RES generation

The hourly generation of solar and wind power depend on the hourly load factors and the installed capacities of these technologies that are exogenous to the model. The hourly load factors representing the variability of wind and solar are calculated based on the 2012 hourly generation data provided by the TSOs of different countries. For the countries for which the hourly data is not available via TSOs, other sources such as Tradewind (2009) for wind power and SODA[6] (2011) for solar power are used, taking into account the correlation between countries.

Hydro generation

Hydro production can be divided over conventional hydro (run-of-river (ROR) and reservoir storage) and hydro Pump Storage and hourly hydro generation is calculated a prior as an input to the model. Hourly ROR generation is determined by using data on annual hydro generation, the share of ROR per country, and monthly data on the ROR production. In order to calculate hourly hydro storage production, ROR is assumed to be a must run technology, and the dispatch of hydro storage is assumed to depend on the residual demand hours (demand minus intermittent generation). Since the highest prices are expected in the high residual demand hours, hydro storage is assumed to produce in the highest residual demand hours in a certain year. Hydro storage is dispatched in a way that the sum of the generation of the 8760 hours in a year is equal to the annual hydro production calculated based on the "Green Transition" scenario of ENTSO-E[7].

Storage

For the purpose of providing flexibility on timescales of an hour and more in sufficient volumes, we mainly focus on the bulk electricity storage technologies such as hydro pumped storage and compressed air energy storage (CAES). These electricity storage

[6] Solar hourly load factors were calculated on the basis of the sunsets time, sunrise time, their evolution throughout the year and solar irradiation values in 118 nodes distributed in Europe (SODA, 2011).

[7] Values of annual hydro production are gathered from Beurskens et al. (2011) for EU27 (excl. Malta and Cyprus). Values for Norway, Switzerland and the Balkan countries are gathered from the ENTSO-E data portal (www.entsoe.eu). These values are used to determine annual hydro production for future years based on the assumed total installed hydro capacity in "Green Transition Scenario" of ENTSO-E.

technologies are modelled to operate such that they maximize their revenues by charging and discharging electrical energy within a day. By doing so, they are able to increase or decrease system demand for electricity and contribute to the flexibility for generation-demand balancing. The amount of the power consumed and produced in the charge and discharge processes and the duration of these processes depend on the characteristics of the storage technology such as efficiency losses and power/energy ratings which are input to the model. Given the focus of this study, we analyse the flexibility contribution from CAES that could be realized within the Netherlands.

Electricity Demand

The demand represents the final electricity demand in each country. The demand can be chosen to be inflexible or flexible. The inflexible demand is an input to the model driven by the economic growth and government policies in a scenario. The hourly load profiles of inflexible demand are based on the 2012 hourly data given by ENTSO-E. The flexibility of the demand depends on the price elasticity of demand, the maximum potential for demand response, and the unit cost of shifting within a day which are user-specified parameters in the model.

ECN

Westerduinweg 3	P.O. Box 1
1755 LE Petten	1755 LG Petten
The Netherlands	The Netherlands

T +31 88 515 4949
F +31 88 515 8338
info@ ecn.nl
www.ecn.nl