The impact of wind power on APX day-ahead electricity prices in the Netherlands VVM-Intermittency project

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This report provides the outcomes of the *Vragen voor Morgen* Intermittency project (ECN project number 50556). Objective of the project is to assess the main issues related to the integration of large amounts of wind energy in the Dutch electricity sector. This report focuses primarily on quantifying the current level of flexibility of the Dutch electricity system by assessing the impacts of increasing amounts of wind power on day-ahead market prices in the past few years and model the future impacts in the near future.

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Abstract

A detailed analysis was conducted to assess to what extent availability of wind energy has influenced day-ahead electricity prices in the Netherlands over the period 2006-2009. With a meteorological model, time series of day-ahead wind forecasts were generated, and these were compared with APX-ENDEX day-ahead market prices. Wind energy contributes to only 4% of electricity generation in the Netherlands, but was found to depress average day-ahead market prices by about 5%.

With the help of the bid curves on the APX-ENDEX day-ahead market for 2009, a model was developed to assess the impact of increasing levels of wind generation on power prices in the Netherlands. One of the main findings is that the future impact on prices will be less than in the past. With an increase of installed wind capacity from 2200 MW to 6000 MW, average day-ahead prices are expected to be depressed by an additional 6% in case no additional conventional generation is assumed. Taking into account existing government policy on wind and ongoing investments in new conventional power plants, prices in 2016 will be only 3% lower.

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Summary

Het *Vragen Voor Morgen* Intermittency project heeft als doel de flexibiliteit van de Nederlandse elektriciteitsvoorziening in Noord-West Europese context in kaart te brengen. Met flexibiliteit wordt hier bedoeld de mate waarin het elektriciteitssysteem van opwekking, transport en consumptie in staat is om efficiënt te reageren op snel veranderende omstandigheden wat betreft vraag en aanbod. Het huidige systeem is in hoge mate robuust om het plotseling uitvallen van een enkele elektriciteitscentrale of een onderdeel van het hoogspanningsnet op te vangen.

Om uitspraken te kunnen doen over de mate van flexibiliteit van de huidige elektriciteitsvoorziening zijn de effecten van voorspelde windopbrengsten op de APX day-ahead marktprijzen geanalyseerd. Op deze 'dag-vooruit' of 'spot' markt kunnen marktpartijen reageren op informatie over recent veranderende omstandigheden, zoals meer up-to-date informatie over beschikbaarheid van centrales. Door de hogere betrouwbaarheid van weersvoorspellingen naarmate het tijdstip van uitvoering naderbij komt verbeteren ook de voorspellingen van de elektriciteitsvraag en het aanbod van windenergie.

Voor de planning van het bedrijf van hoogspanningsnetten en voor de inzet van centrales is het tijdstip van een dag vooruit een natuurlijk moment. De APX day-ahead markt is opgezet als een veiling in tegenstelling tot de termijnmarkt en de intra-day markt. Deze laatste twee kennen een continue stroom van bilaterale transacties. Op de dag-vooruit markt is er sprake van een hoge mate van liquiditeit, doordat een groot deel van de beschikbare productiecapaciteit wordt aangeboden. Deze hoge liquiditeit en het feit dat op dag-vooruit basis de windopbrengsten beter voorspelbaar zijn dan op de termijn markten, maken juist deze markt bij uitstek geschikt om het effect van een groeiend windaanbod op elektriciteitsprijzen te onderzoeken.

Effecten van wind op marktprijzen in het recente verleden
Een belangrijk aspect van markintegratie van windenergie bestaat uit het effect op elektriciteitsprijzen. Met een statistische analyse van alle dag-vooruit marktprijzen voor de periode 2006-2009 werd gevonden dat de marktprijs gemiddeld 5% hoger zou liggen als er geen windturbines zouden zijn die elektriciteit opwekken (no-wind situation). Op de korte termijn, waarin het niet mogelijk is te reageren met nieuwe investeringen in productievermogen, kan dit geïnterpreteerd worden als het effect van wind op het

gemiddelde prijsniveau. Het opgestelde windvermogen in 2010 dekt ongeveer 4% van de geleverde elektriciteit in Nederland en is tegelijkertijd verantwoordelijk voor een daling van het gemiddelde prijsniveau van 5%.

Naast het effect op het gemiddelde prijsniveau heeft het zin om vast stellen hoeveel de elektriciteitsprijzen worden beïnvloed gedurende die periodes dat het waait. Een 'windenergie prijs' kan gedefinieerd worden als de gemiddelde marktopbrengst voor een windturbine exploitant indien de geleverde windenergie vergoed zou worden op basis van APX prijzen. Deze 'windenergie prijs' blijkt over de periode 2006-2009, 3,64 €/MWh oftewel 6,9% lager te liggen dan de gemiddelde APX prijs. Deze prijseffecten komen in grote lijnen overeen met die van andere studies naar de effecten van wind op de markten van Spanje, Denemarken en Duitsland, waar meer windcapaciteit staat opgesteld en prijsdalingen gevonden zijn in de orde van 10% van de prijs op de dag-vooruit markt (zie sectie 2.3).

Gevolgen voor de overige elektriciteitsproducenten

Het prijsdrukkende effect van extra wind pakt verschillend uit voor de belangrijkste actoren in de elektriciteitssector. Indien de geproduceerde windenergie gewaardeerd wordt tegen APX prijzen, genereerde dit voor de windproducenten over 2006-2009 jaarlijks gemiddeld 248 M€ aan opbrengsten. De overige, niet-wind producenten misten hierdoor gemiddeld 281 M€/jaar aan opbrengsten vanwege de niet geleverde elektriciteit (het verschil in waarde met de windopbrengsten wordt veroorzaakt door het prijsdrukkende effect van de extra windenergie). De resterende productie van conventionele producenten op de dag-vooruit market levert door het prijsdrukkende effect op jaarbasis 40 M€/jaar minder op, terwijl de daling in de waarde van de geproduceerde elektriciteit voor de overige productie (niet voor de dag-vooruit markt) op 242 M€/jaar ingeschat is aannemende dat de overige marktprijzen gemiddeld hetzelfde zijn als op de dag-vooruit markt. In totaal bedroeg daardoor de totale daling in jaarlijkse opbrengsten van niet-wind producenten 563 M€. Daar tegen over staat dat consumenten en leveranciers van elektriciteit baat hebben bij de prijsdalingen op groothandelsmarkten. Voor beide actoren gecombineerd bedroegen deze baten op jaarbasis gemiddeld M€ 311.

Simpel model voor de day-ahead markt voor toekomstige prijseffecten van wind

APX-ENDEX BV heeft aan ECN de biedcurves van de day-ahead markt van 2009 beschikbaar gesteld. Met behulp van deze 'aankoop' en 'verkoop' krommes over 2009 is een eenvoudig model van de day-ahead markt opgesteld waarmee de effecten van een groeiend volume aan windvermogen op de toekomstige spotmarktprijzen kan worden gesimuleerd. Er is verondersteld dat de 'aankoop' krommes helemaal niet verschuiven bij toenemend windaanbod, en dat de 'verkoop' krommes in zijn geheel verschuiven door 30% van het extra windaanbod tegen een prijs van 0 €/MWh aan te bieden. Bij onveranderde marktomstandigheden (in het bijzonder geen verdere toename van het niet-wind vermogen) zou een groei van het huidige opgestelde wind vermogen, van 2200 MW eind 2009 tot 6000 MW leiden tot een daling van de gemiddelde APX prijzen vanaf het 2009 niveau met ongeveer 3 €/MWh. Wordt er wel een groei van het overige productievermogen en van de elektriciteitsvraag voorzien dan kan de prijsdaling tot 2016 beperkt blijven tot ongeveer 1.7 €/MWh oftewel ongeveer 3% van de elektriciteitsprijs.

Conclusies

Geconcludeerd kan worden dat de korte-termijn effecten van het groeiende windaanbod op de elektriciteitsprijzen duidelijk merkbaar zijn geworden. Analyse van deze recente marktdata suggereert een redelijke mate van flexibiliteit in de elektriciteitssector wat betreft de marktintegratie van groeiende volumina aan windvermogen. Recente ontwikkelingen, zoals de marktkoppeling met de Duitse markt in 2010 en de explosieve toename in nieuw op te stellen conventioneel, meer flexibel productievermogen in Nederland zullen beiden naar verwachting een positieve bijdrage leveren aan de marktintegratie van wind in Nederland in de komende jaren.

1

Introduction

1.1 Wind and electricity markets

Electricity markets can be divided into four types, depending on the time until delivery. Most electricity in the Netherlands is traded on the forward market ENDEX for days, weeks, months or years ahead of delivery. About one fifth of the consumed electricity is traded on the APX day-ahead market or spot market. A relatively illiquid intra-day market for adjustments after closure of the day-ahead market is also organized by the APX-ENDEX group (APX-ENDEX, 2010). The TSO TenneT operates the market for regulating and reserve power or the 'balancing market', which takes place over 15-minute periods close to real-time.

All these markets are to some extent affected by the increased share of wind generation. The short-term variation in wind power output over time provides an opportunity to assess the impact of different amounts of wind generation on electricity prices. Since in a forward market only the average level of wind generation can be taken into account, the impact of wind on forward markets cannot be assessed in this way. At the day-ahead time scale, the amount of wind power generation can be predicted with a higher level of reliability than at the time of the forward market.

Variations in predicted wind power output can be used to analyze the impact of wind generation on the electricity market. Because of the high volume of the day-ahead market and the ready availability of price data, the analysis conducted and presented here is limited to the impact of wind on the day-ahead market.

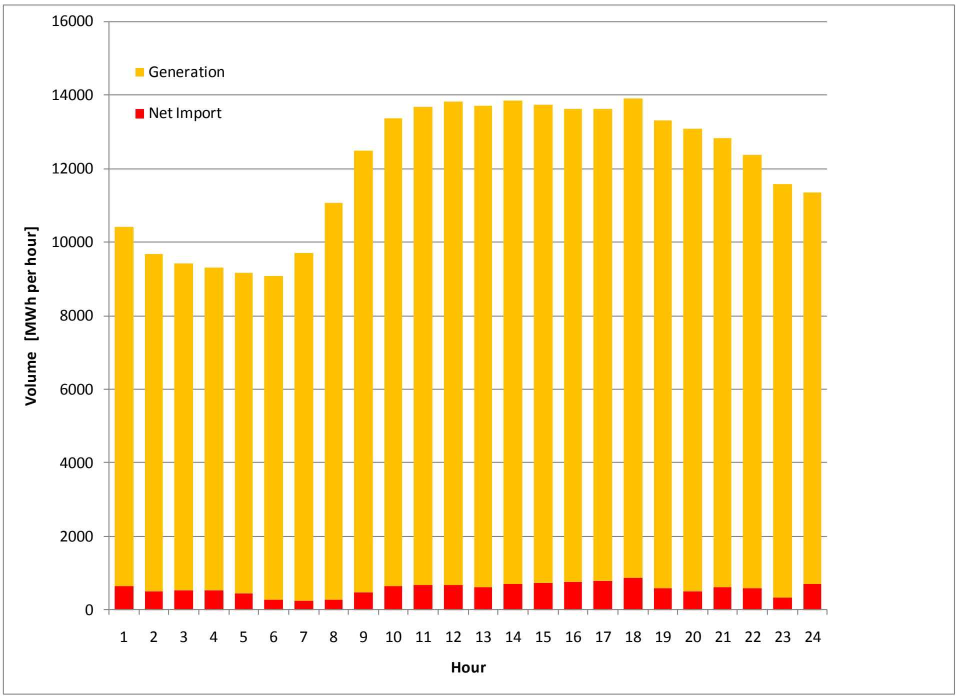
For the analysis, time series of wind power generation forecasts will be compared with time series of APX prices for the same period. Not the actual wind generation is relevant but the forecasted wind generation on a day-ahead basis.

1.2 The APX day-ahead market

From the point of view of wind forecasts it would be more optimal to postpone adjustments of production updates to a time closer to real-time. This does not fundamentally differ from the forecasts of demand which also improve closer to real-time. In the absence of wind, the day-ahead market primarily functions to balance updated demand forecasts with updates in availability of generators. An historic choice was made to have the day-ahead markets 12-36 hours before real-time, among others because it allows most decisions regarding production to be taken during office hours. Choosing a shorter time to real-time, a lower estimated error in the demand forecast would take place, but higher cost due to adjustments of generation closer to real time. It is therefore unclear if it would be beneficial to move the 12-36 hour period closer to real time. Most day-ahead markets therefore operate 12-36 hours before real time.

Figure 1 shows the hourly electricity supply as measured by TenneT. It consists of electricity generation fed into TenneT's high voltage grid (yellow top part of bar) plus the net imports from abroad (red, lower part of the bars). Not included in this graph is generation with CHP units of which the electricity is consumed on the site or is fed into distribution grids. This graph shows the availability of electricity on the market in the Netherlands. The pattern shows a peak demand during the day and early evening and lowest demand at the end of the night.

Figure 1: Hourly average electricity supply: Generation fed into TenneT's transmission grid by domestic generators plus net import (=import-export) in 2009.



Source: (TenneT, 2010).

Figure 2: Average hourly market clearing volume on APX day-ahead market in 2009

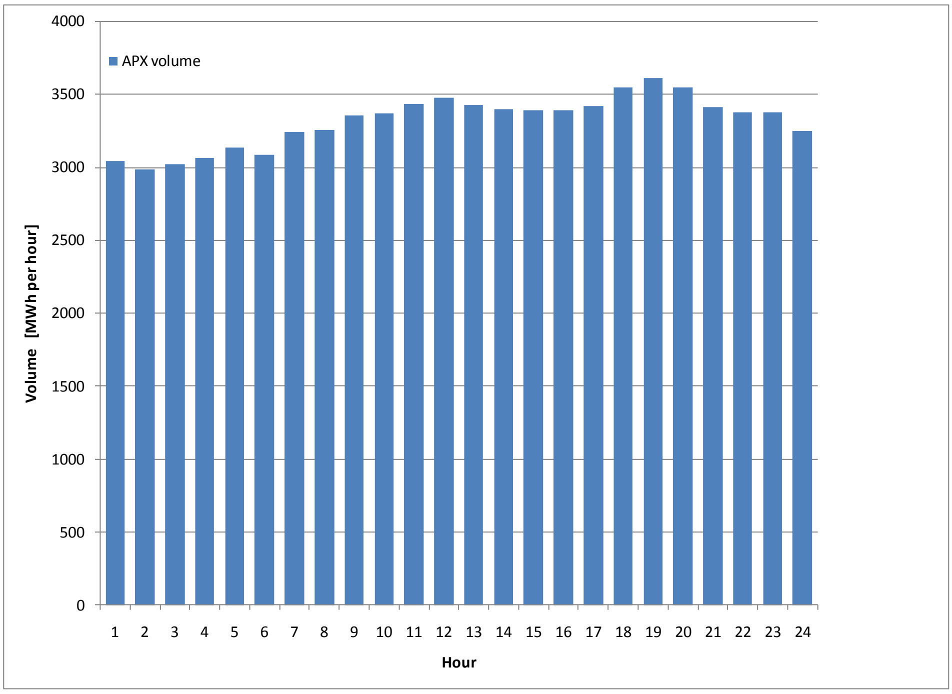


Figure 2 shows the hourly average volumes of electricity traded on the day-ahead market in 2009. Different than **Figure 1**, it does not show a daily pattern of strong variation in volume throughout the day. Since the volume of the intra-day market following the day-ahead market is very small (only about 1% of the electricity consumed) this implies that most of the daily variation of demand is taken care of in the forward markets before the day-ahead market. This is understandable given the relatively high regularity and predictability of hourly electricity demand over the day.

1.3 Relation with other work

Other studies focusing on the impact of wind on power prices also chose the spot market as the most relevant power market for wind (TradeWind, 2007; Obersteiner and Redl]. In the TradeWind study, the most detailed information is provided on the Danish market. To visualize the impact of wind on prices a division of the hours into different wind speed classes was made. This example was followed in our analysis. For the Danish study, actual wind power generation figures were used. For our analysis we prefer to use wind forecasts, because at the closure of the day-ahead market only the wind forecasts are known.

Obersteiner and Redl have analyzed the impact on the German and Austrian markets. They use forecasted wind generation, and modeled the impact of wind and other types of generation on the spot market price for base load power. Their analysis shows that both wind and CCGT technology influence base load prices on the spot market. Curiously the short run marginal cost of hard coal power did not substantially influence the variation in the base load spot price.

In our analysis we have limited ourselves on purpose to market information in the form of electricity prices only plus the use of wind forecasts. This allows the use of the findings as being complementary to the outcomes of market models using marginal cost of the different generation technologies.

2

The impact of wind power in the Netherlands on APX day-ahead market electricity prices

2.1 Determining the amount of wind generation

To obtain an hourly time series of day-ahead expected wind power generation, a time series of wind speed forecasts have been made. In the past decade the volume of wind turbines installed in the Netherlands increased rapidly as is shown in **Figure 3**, which is based on regular overviews of new wind farms as kept updated by Wind Service Holland (2010). Only in 2009 there was practically no growth in wind capacity compared to the previous year. With the HIRLAM weather model (HIRLAM, 2010), predictions of the wind speed at a height of 50 meters were made for the location Medemblik for periods between 12 and 36 hours in advance. These wind speeds have been multiplied with a standard power-wind speed curve to obtain the wind generation output per MW of installed capacity. In the next step this was multiplied with the installed wind capacity in the Netherlands to obtain a time series of day-ahead forecasts of the hourly output of all wind turbines in the Netherlands.

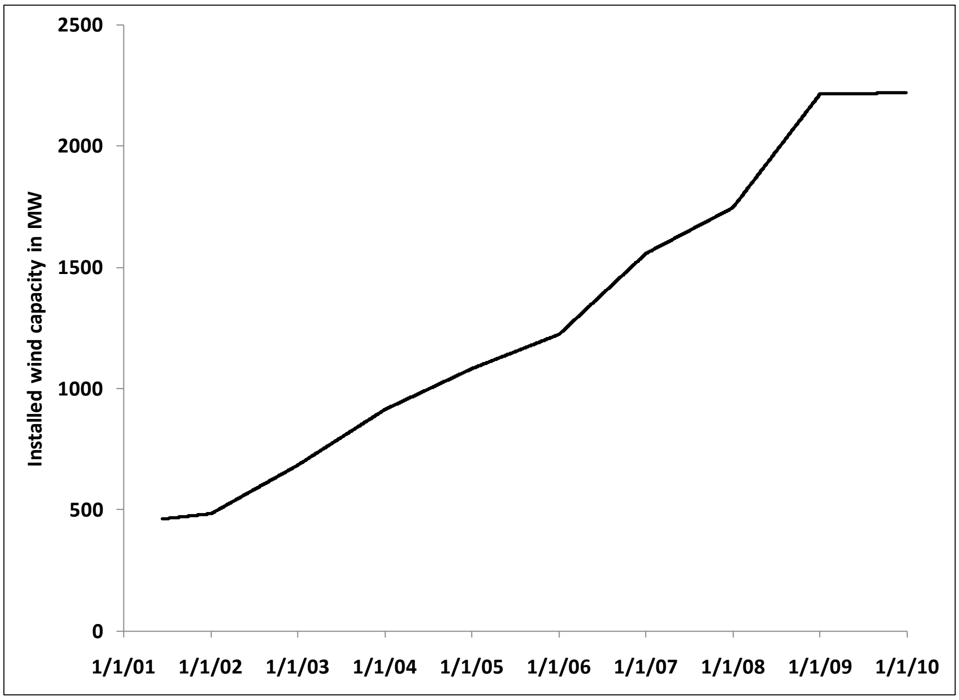
Over the period 2006-2009 the installed capacity of wind turbines in the Netherlands has increased with almost 50%. **Table 1** shows the annual averages of the installed wind capacity and the average forecasted wind power generation. For the sake of comparison, also the volume of the APX day-ahead market is given. Incidentally, both wind generation and the day-ahead market volume are increasing at about the same rate. The average volume of wind generation is about one-fifth of the volume of the day-ahead market. This substantial share suggests that one can expect to observe an impact on prices.

Table 1:. Annual averages of installed wind generation capacity, forecasted wind generation and APX volume (Market Clearing Volume) all in MW for the years 2006-2009

	2006	2007	2008	2009	Average
Installed wind capacity	1390	1651	1981	2218	1810 MW
Average forecasted wind generation	425	552	652	661	572 MW
Average APX volume	2196	2366	2826	3317	2676 MW

Sources: wind capacity: Wind Service Holland; wind generation forecasts: A. Brand, ECN; APX volume: APX-ENDEX.

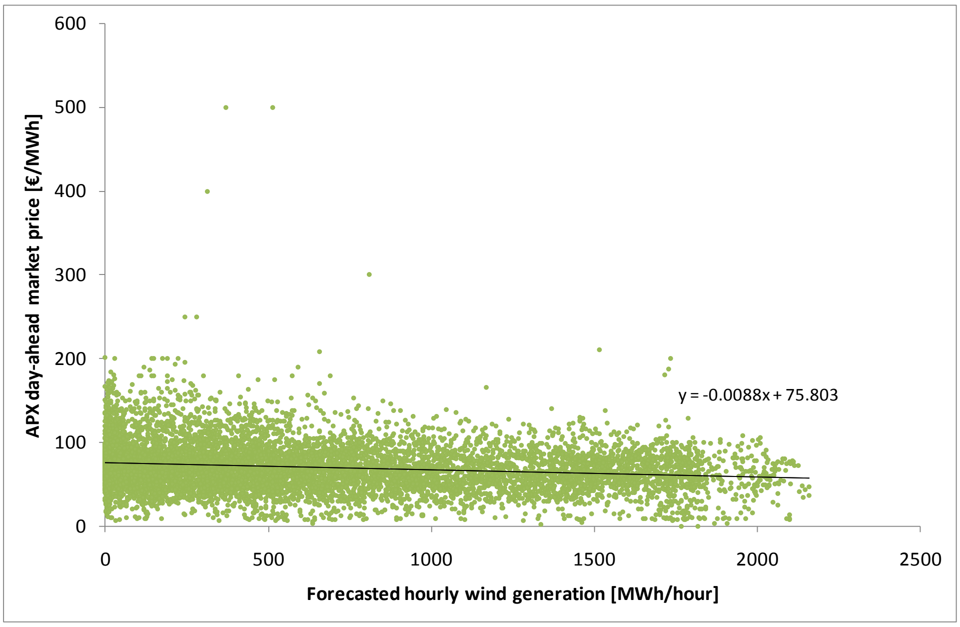
Figure 3: Installed wind power capacity in MW in the Netherlands over the period from June 2001 to December 2009. Source: Statistics from ([Wind Service Holland, 2010) interpolated by Arno Brand, ECN.



2.2 Impact of wind on APX day-ahead market prices

Figure 4 presents a scatter plot of all hourly APX prices with the forecasted hourly wind generation amounts for the year 2008. It shows a negative trend in which, on average, every 1000 MWh of hourly wind generation reduces the APX price by 8.8 €/MWh.

Figure 4: Hourly APX day-ahead prices versus day-ahead forecasted hourly wind generation for 2008. Source of wind power forecasts A. Brand, ECN (see Annex 2).



A substantial part of the scatter in **Figure 4** is caused by the hourly variations in APX prices due to variations in demand throughout the day. Wind is only a relatively minor parameter affecting electricity prices. The annual average daily demand pattern is shown in **Figure 5** for the year 2008. All hours of the year have been divided into four wind classes:

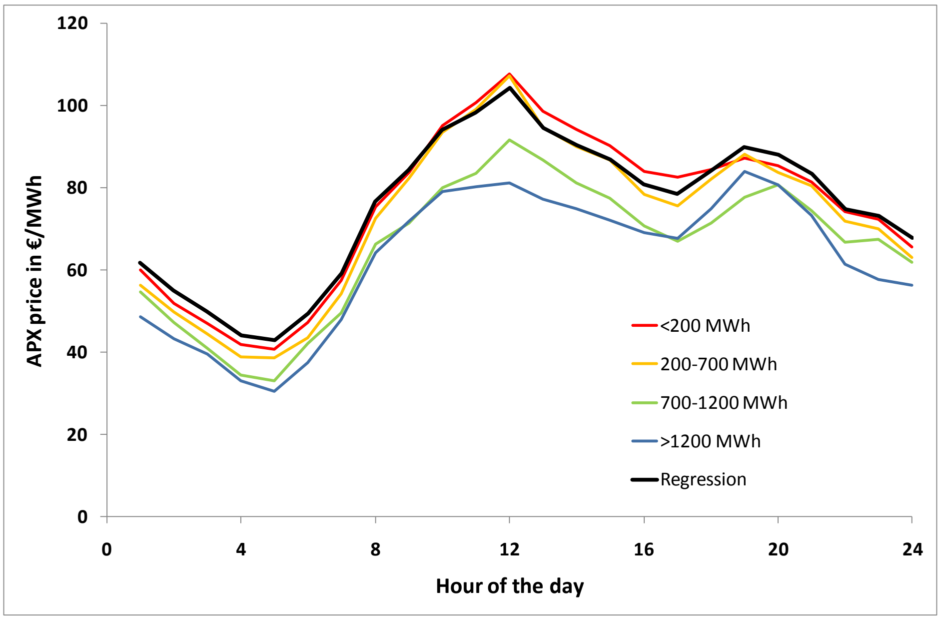
a) Forecasted wind generation below 200 MWh per hour.
b) Between 200-700 MWh per hour.
c) Between 700-1200 MWh per hour.
d) More than 1200 MWh per hour.

For each hour of the day, the average APX price is obtained for these four wind classes. As expected, higher wind output generally results in a lower average price. The largest impact (in absolute terms) is on the peak prices at around noon (see **Figure 5**). At night, the effect is most regular: higher forecasted wind generation always leads to lower prices. In the late afternoon/early evening there are clearly other effects overshadowing a simple relation between wind and APX prices. As of yet, no plausible explanation has been found of this anomalous behaviour in the early evening peak.

Starting point in quantifying the impact of wind on electricity prices is to determine price levels at times when there is no wind generation. This is done in two different ways: firstly, by dividing all hours into different wind generation classes, and secondly by using regression analysis. APX prices during the hours in the lowest wind generation class (below 200 MWh per hour) can be interpreted as approximating the situation without any wind generation. Maximum wind generation in this class is about 11% of the installed wind capacity. During these hours the average wind generation is 4% of the installed capacity. Only 3% of the annual electricity produced by wind is generated in hours in which production is below 200 MWh per hour. These figures all suggest that the chosen interval from 0 to 200 MWh per hour is a good approximation of the situation without wind. Choosing a lower upper bound in hourly generation (below 200 MWh per hour) would reduce the number of hours in this category too much.

There is a disadvantage in this first approach of using the lowest wind generation category to obtain an estimate of electricity prices at times when there is no wind generation. Electricity demand is known to be higher at higher ambient temperature levels [Hekkenberg et al, 2009] and high temperatures are correlated with low wind speeds (see Appendix A, **Figure 19**). Therefore an improved estimate of the hourly average APX prices in the absence of wind can be obtained from a regression analysis including temperature as one of the independent variables. Estimates for average hourly APX prices in the absence of wind power based on regression analysis are shown as a black curve in **Figure 5** for 2008 (for the other years see Annex 1). Tables with the regression coefficients and the resulting estimates of the APX prices in the absence of wind can be found in Appendix A, **Table 11** and **Table 12**. This latter estimate of the day-ahead price in the absence of wind has been used in the remainder of the analysis.

Figure 5: Hourly average APX day-ahead prices for 2008 for different levels of forecasted wind generation (coloured curves) and for regression estimates for a situation with no wind (black curve).



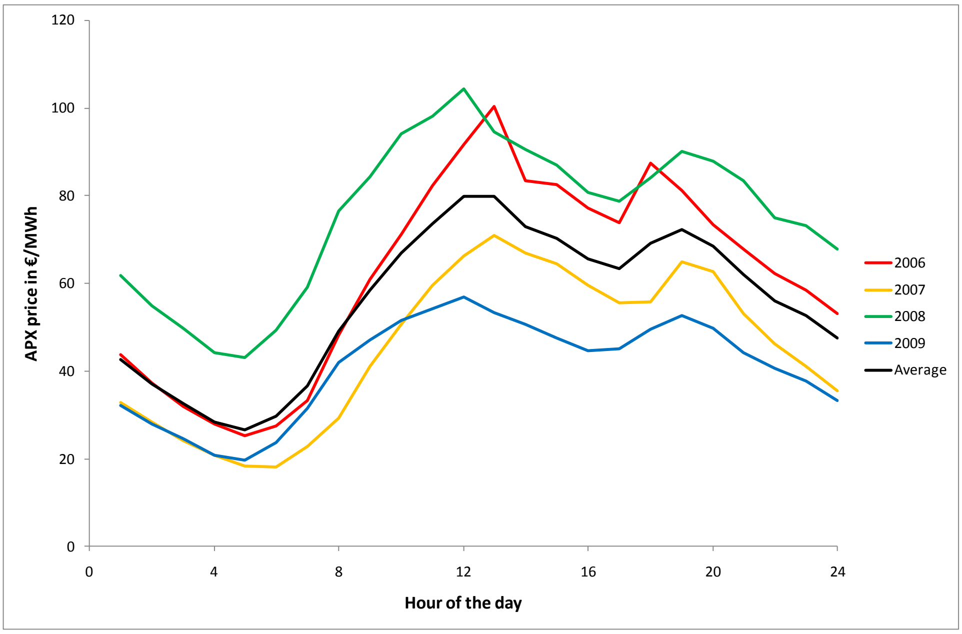
The boundaries of the four wind classes in which all the hours of the year were divided were chosen so that the class with the lowest wind speeds would approximate a situation with no wind and that each of the remaining classes would all have enough hours of wind. **Table 2** shows the average wind power generation in each wind generation class. One would expect to see in **Figure 5** distances between the different wind classes, which are somehow related to the differences in average wind generation per class as shown in **Table 2**. However, only in the period between 23:00 and 7:00 the price decrease seems to be more or less proportional to the amount of wind generated. In other periods of the day this relation is less obvious. The higher the APX prices the steeper the supply curve is. Therefore one would expect during the midday peak, that the difference between the two classes <200 MWh and 200-700 MWh would be larger than during the rest of the day. But the graph shows that on the contrary the differences are smallest during peak hours. However, when one would combine the wind classes <200 and between 200 and 700 MWh in a single class (<700 MWh) and the remaining hours in one other class (>700 MWh), then the impact of wind on the day ahead market prices would be highest during the peak at noon as expected. Also in the early evening peak there are some instances that a higher amount of wind generation is related to a higher instead of a lower price. However, apart from a few hours, the general trend is clear: higher wind generation leads to a price decrease on the APX day-ahead market.

Table 2: Average wind generation in 2008 in MWh per hour for each of the four wind generation classes (ranging from 0-200 MWh to 1200-2500 MWh per hour)

Class	From:	0	200	700	1200 MWh
	To:	200	700	1200	2500 MWh
Wind generation		77.0	422.9	928.5	1564.9 MWh

From year to year there are substantial differences in APX price levels, but the general patterns throughout the day remain more or less unchanged. **Figure 6** shows the estimated hourly average APX prices at times of no wind over the years 2006-2009, based on a regression analysis (for more details see **Table 12** of Appendix A). The effects of depressed electricity demand in 2009 due to the financial crisis is clearly visible. The differences between these four years are larger than the impact of wind as shown in **Figure 5**. This puts the impact of wind on spot market prices in perspective: the effect is noticeable, but year to year variations in average market prices, due to for example changes in demand or fuel prices, are still substantially higher.

Figure 6: Regression-based estimates of hourly APX day-ahead market prices in situation with no wind over the years 2006-2009



2.3 Summarizing historical price impacts

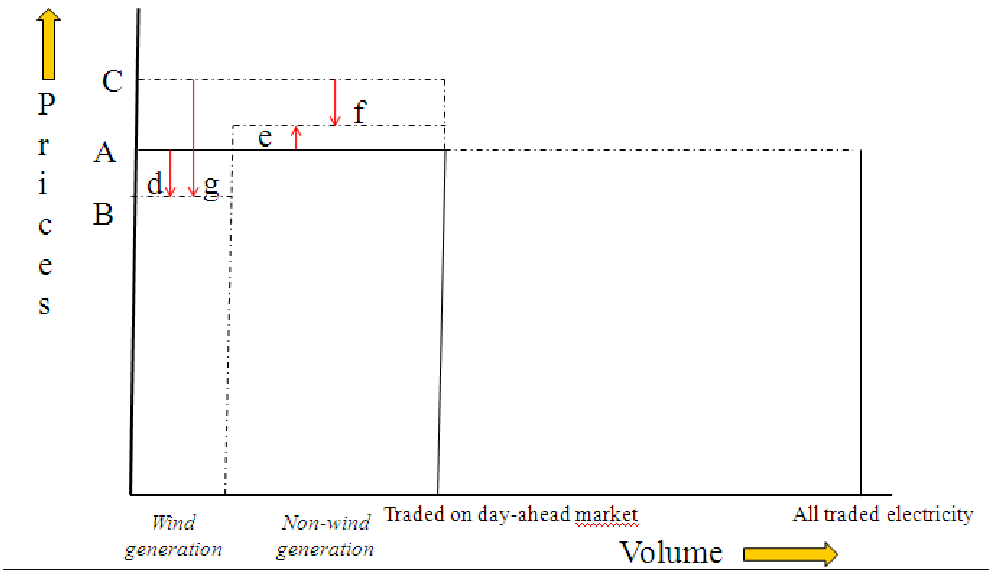
There are three day-ahead price levels which are interesting for the analysis (see also **Figure 7**):

a) *Average day-ahead price* calculated by weighing hourly day-ahead prices with hourly day-ahead volumes. This price is relevant for all producers (and consumers) of electricity. It contains the effects of wind generation as well as the impact of all other forms of generation.

b) *Wind energy price* calculated by weighing the hourly day-ahead prices with the volume of wind power generated. This price is primarily relevant for wind power developers because it provides the value of wind on the day-ahead market.

c) *Day-ahead price in case the installed wind capacity does not generate electricity* (*no-wind case*). This can be calculated in two alternative ways. First by weighing the hourly day-ahead prices with hourly day-ahead volumes, but only for those hours when the wind generation is below a certain limit (200 MWh per hour was chosen here). Another approach requires a regression analysis to find the day-ahead price at times the wind generation is exactly 0. These two methods provide price estimates for the annual averages which differ by about 1%. The regression approach is preferred in the rest of the analysis. This no-wind price level provides a starting point for quantifying the price depressing effect of wind power.

Figure 7: Prices and volumes of traded electricity. A= average day-ahead market price, B= wind as valued with day-ahead market prices, C= average day-ahead market price in situation with no wind (not to scale).



The straight lines in **Figure 7** denote well known or well-defined quantities, while the dashed lines require assumptions e.g. on the amount of forecasted wind generation. Another example resulting in a dotted line in **Figure 7** is the assumption that the average price of the traded electricity, apart from day-ahead market, is equal to the average day-ahead market price. Most of the electricity trade in the Netherlands is in the form of bilateral contracts for which no price information is made public. On theoretical grounds one can expect average day-ahead market prices not to diverge substantially from the rest of the traded electricity, otherwise arbitrage would take place between the different markets.

Differences between the different price levels (A, B, C) on the day-ahead market can be translated into a number of relevant figures for the impact of wind on electricity prices:

a) Profile cost ('d' in **Figure 7**) is a concept derived from the current renewable support scheme (SDE). Wind energy is provided with a subsidy of which the level depends on the difference between investment and operating cost of wind turbines on the one hand and electricity prices on the other hand. Average day-ahead market prices are used as the benchmark prices for determining the level of subsidy. However, beforehand it is already known that at windy times electricity prices are lower. To account for this the profile cost as the difference between average day-ahead prices and wind energy prices (A-B) is determined first. It can be calculated based on a number of recent years and added as a cost component for determining the subsidy level.

b) The value of electricity traded on the day-ahead market apart from wind is valued somewhat higher than the average day-ahead price. This extra amount ('e' **Figure 7**) can be determined from the following relation: e * volume of non-wind generation = d * volume of wind generation.

c) The prices for non-wind generators are lower compared to the case of no-wind generation ('f' in **Figure 7**). For a short time horizon (up to installation of new generation plants, or about 5 years) this can be interpreted as the amount with which electricity prices for non-wind generation are depressed by the existence of wind generation.

d) The amount with which wind depresses the value of wind power on the day-ahead market compared to the no-wind case is shown as ‘g’ in **Figure 7**.

Table 3 summarizes the values of the different prices and price impact of wind as found in this study for the categories as outlined above. More detailed information on the year to year differences can be found in Annex 5.

Table 3: Average prices on APX day-ahead market over the period 2006-2009 and impact of wind in €/MWh (conventional is all power traded on APX except wind)

A	Average day-ahead price	53.04
B	Wind energy price	49.40
C	No-wind price	56.01
D	Profile cost	3.65
E	Price increase conventional compared to average	0.78
F	Price decrease conventional compared to no-wind	-2.19
G	Price decrease wind power compared to no-wind	-6.61

Summarizing the price impacts on four-year averages provides the following findings. Over the period 2006-2009 the average day-ahead electricity price in the Netherlands was found to be 53.04 €/MWh. Based on regression analysis findings, the average day-ahead price in the absence of wind generation was calculated to be 56.01 €/MWh. This implies that the wind has reduced average day-ahead prices by about 5%.

But this price depressing effect is even stronger when one focuses not on the general price level, but on the prices at times of wind generation. The value of electricity from wind on the day-ahead market was calculated by weighing the day-ahead market prices by the volume of hourly wind generation. These wind energy prices were about 7% below the average day-ahead prices (A-B)/B and 11.8% below the calculated price in the absence of wind (C-B)/C. This illustrates that even with a relatively modest contribution of wind generation (about 4% of total electricity generation in the Netherlands) the impact on electricity prices is already substantial.

Our findings regarding the impact of wind on average day-ahead prices are more or less in line with findings from other studies: TradeWind mentions an average of 6€/MWh reduction of spot prices in Spain in 2006. For Denmark, reduction percentages in day-ahead prices were observed of 14% in West Denmark and 5% in East Denmark in 2005 [Tradewind, 2007]. Obersteiner and Redl find for the German EEX a reduction in 2006 from 50.9 to 45.1 €/MWh [Obersteiner and Redl].

3

How does wind affect revenues of conventional generators

Wind power is expected to influence the operation of other types of electricity generation. Since the variable cost of wind power is practically zero, it replaces conventional generation. The foregone revenues of the non-wind generators amount to 281 M€ per year over the period 2006-2009 as is shown in the first row of **Table 4** (using the estimated prices in case of no wind generation as the basis for valuation). Besides lower production volumes, conventional generators are also affected by lower prices due to wind for their remaining production volume. This results in an estimated further revenue reduction of 40 M€ per year on the day-ahead market, and 242 M€/year for the rest of the traded electricity (valued at the difference between no-wind price and average day-ahead market price). This total loss of revenues for conventional generators of 563 M€/year.

Figure 8: Impact on annual income [M€/year] for non-wind electricity production over the years 2006-2009 for the three components I,II, III as mentioned in **Table 4**

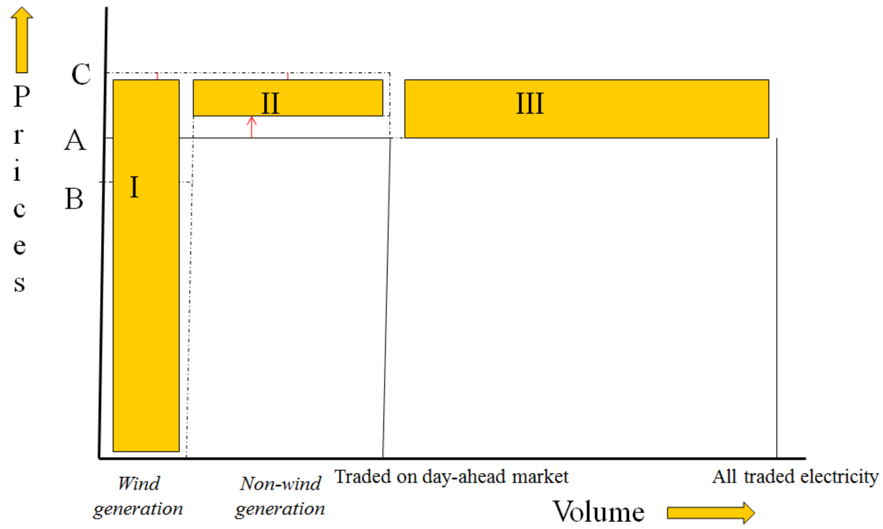


Table 4: Impact of wind on annual income [M€/year] for non-wind electricity producers over the years

Reduction in revenue of non-wind generators		[M€/yr]
Reduced sales on day-ahead market (valued a no-wind price	I	281
Reduced value electricity from non-wind generators on day-ahead market	II	40
Reduced value electricity from non-wind generators on rest of the market	III	242
Total = Reduction in revenues of non-wind generators		563

The lower wholesale prices on APX and forward markets will be reflected to some extent in lower retail prices. The combined benefits of lower prices for consumers and electricity suppliers amounts to 311 M€/year if the price reduction in all wholesale markets would be the same as in the day-ahead market (see **Table 5**).

Table 5: Impact of wind on annual revenues [in M€/year] for key stakeholders (consumers, wind producers, non-wind producers) averaged over 2006-2009 in M€/year.

	[M€/yr]
Consumer (and/or supplier) benefits due to lower prices	311
Value of generated wind (@ APX wind prices)	248
Reduction of revenues of non-wind generators	563

4

A simple electricity day-ahead market (EDAM) model to assess wind impact on future prices

4.1 Main model input: how do sales and purchase curves change

The analysis in the previous chapter was based on relating wind generation forecasts to the actual prices realised on the APX day-ahead market, the so called Market Clearing Prices. Additional insights can be obtained from the information in the underlying bid curves. For each hour there is a curve of aggregated sales offers and a curve of aggregated purchase bids. At the point of intersection of the two curves one finds the Market Clearing Price and Volume. Please note that the purchase bids have no direct relation to the concept of electricity demand at that hour. Purchase bids often originate from electricity generation companies that formulate bids to buy electricity when the prices are too low to generate themselves. Furthermore, the day-ahead market is only one of a series of different markets, and not all electricity generation is traded on markets. Electricity demand therefore cannot be inferred directly from volumes of power traded on markets.

From APX-ENDEX BV we obtained for all 8760 hours of 2009 the bid curves, both 'sales' and 'purchase' curves, and the resulting Market Clearing Prices and Market Clearing Volumes. Annex 4 describes the analysis of this large data set. Wind appears to affect both 'sales' as well as the 'purchase' curves. The impact is not a simple shift of the whole curve by adding (part of) the additional wind generation as zero marginal cost power in the 'sales' curve, but turns out to be strongly dependent on the price level. The 'sales' curve was found to be primarily affected at low price levels, and is almost unaffected at the maximum volume which take place at the highest price level of 3000 €/MWh (see **Figure 30**). The 'purchase' curve is practically unaffected at high price levels but shows most of the impact at low price levels at maximum volume (see **Figure 34**).

One can simplify the analysis and ignore the detailed dependency of the 'sales' and 'purchase' curves on the price levels by focusing only on the total volume of sales offers and purchase bids. **Figure 9** and **Figure 10** show for windy hours (forecasted>average wind generation) on working days a single month (October 2009) how the total volume in sales offers respectively purchase bids depend on the amount of forecasted wind generation. Because only those hours were selected in which the forecasted wind generation is higher than the annual average, one can expect an update of information in the form of an increase in expected volume of wind at the time of the day-ahead market. For every MWh of extra forecasted wind, the total volume of purchase bids was reduced by on average 0.225 MWh and the total volume in sales offers was increased by 0.038 MWh.

Figure 9: Total volume of sales offers in October 2009 for those hours in which the forecasted wind generation is higher than the annual wind generation.

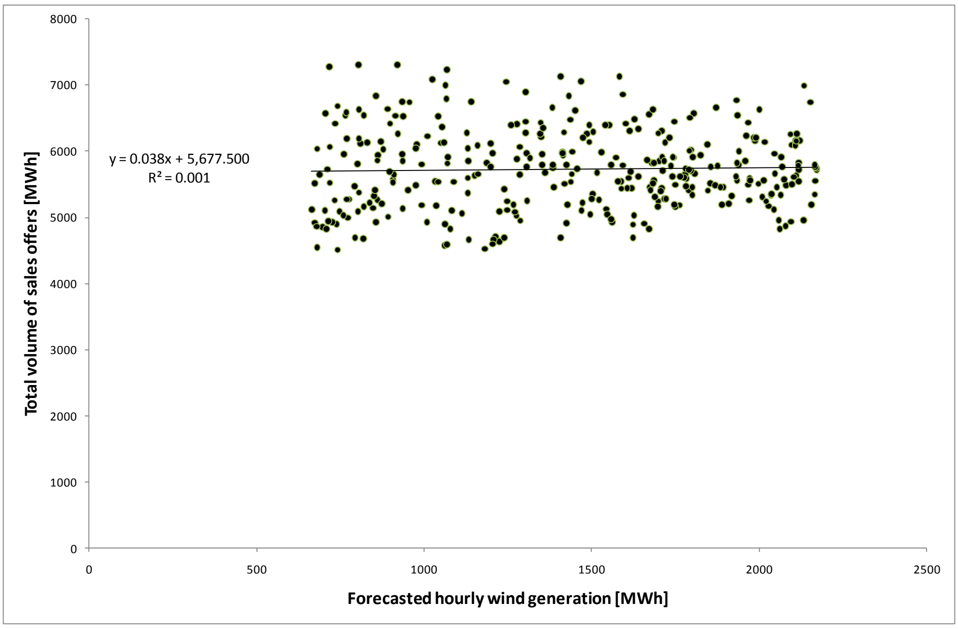
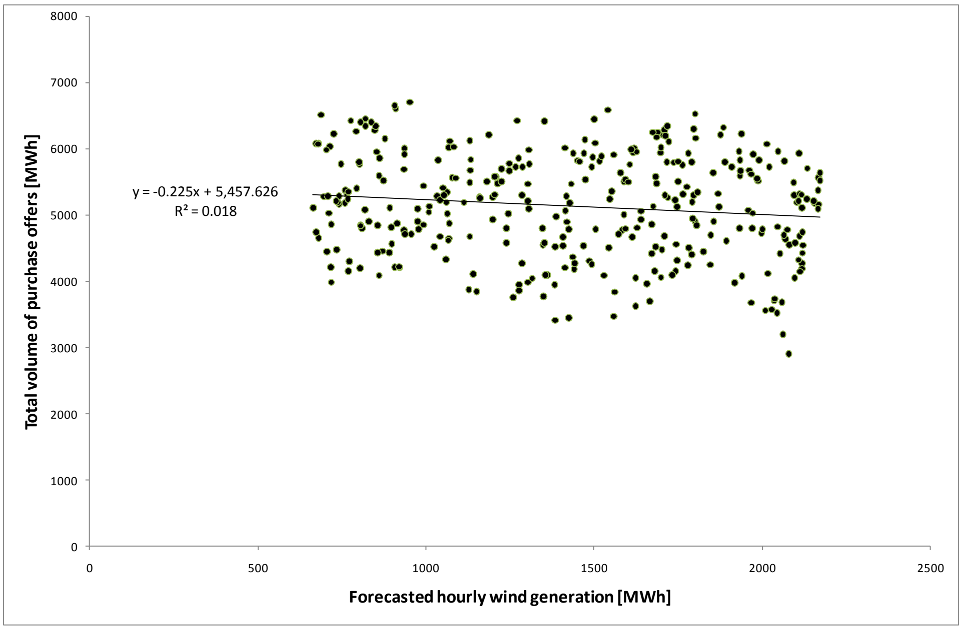


Figure 10: Total volume of purchase bids in October 2009 for those hours in which the forecasted wind generation is higher than the annual wind generation.



When an extra amount of forecasted wind is affecting the volume of offers to sell or bids to purchase, the effect on the resulting market clearing price is independent on the division on either sales or purchases. An increase in volume of sales offers has precisely the same effect as a similar decrease in the volume of purchase bids. It is the combined effect of wind on both sales and purchase curves which counts. For October 2009 the decrease in the purchase curve (22.5% of the increases in wind) plus the increase in the sales curve (3.8% of the increase in wind) totalled to a combined effect of 26.3% of the increase in wind on sales/purchase curves.

A simple model was built to assess the impact on day-ahead market prices of increasing volumes of wind generation. Additional wind is assumed to shift both ‘purchase’ and ‘sales’ curves separately with different percentages of the additional volume of wind generation. It is possible to scale-up ‘sales’ curves with additional conventional generation and ‘purchase’ curves with additional electricity demand growth. While it is acknowledged to be an oversimplification, it is expected to be an improvement compared to just extrapolating price impacts in previous years.

For the analysis described in Section 4.2 only the installed wind capacity increases over the years, while electricity demand and the installed capacity of conventional generation remained constant. This is expanded in Section 4.3, in which also a growing electricity demand and increases in conventional generation are taken into account.

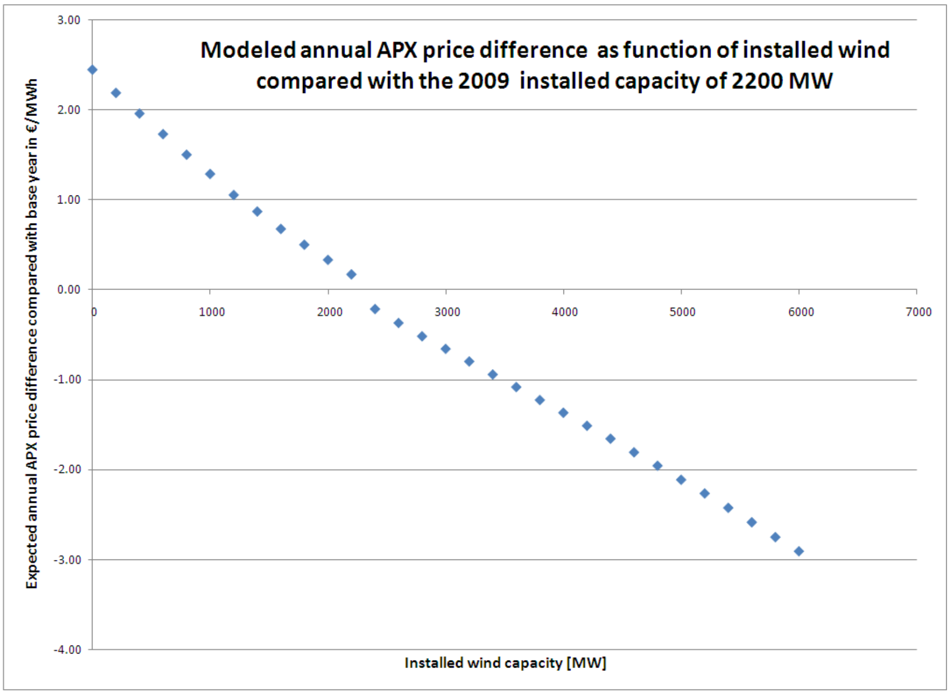
4.2 Constant demand and no additional conventional generation

A single model run was conducted with a constant electricity demand over the years, and a constant level of non-wind generation, but with increasing levels of installed wind capacity in steps of 200 MW up to a level of 6000 MW. Since the impact on the price level of a shift in the purchase curve is equivalent to the impact of a shift in the sales curve, only one curve was assumed to be shifted in relation with increasing quantities of wind generation. The ‘purchase’ curve was assumed to be un-affected, while the ‘sales’ curve is assumed to shift with 30% of the additional wind generation. The rounded value of 30% was used and not the more precise value of 26.3% which was found for October 2009 to illustrate the expectation that this value is very much dependent on market conditions. The results of the simulations are presented in **Figure 11**. It shows that the future impact of additional wind will be relatively smaller than in the past. An increase from the current level (end of 2009) of 2200 MW to 6000 MW will decrease the average APX price by almost 3 €/MWh equivalent to 6% of electricity prices. The future (2010-2016) impact is expected to be lower (0.8 €/MWh per 1000 MW wind) than the impact in the past (2006-2009: 1.1€/MWh per 1000 MW wind) This is due to the increased availability of wind in the future at times when few other power plants would still have spare capacity. In situations of scarcity, when prices are high, also the supply curve is steeper. With the additional wind, one ends up in a lower, less steeper part of the supply curve.

First validation

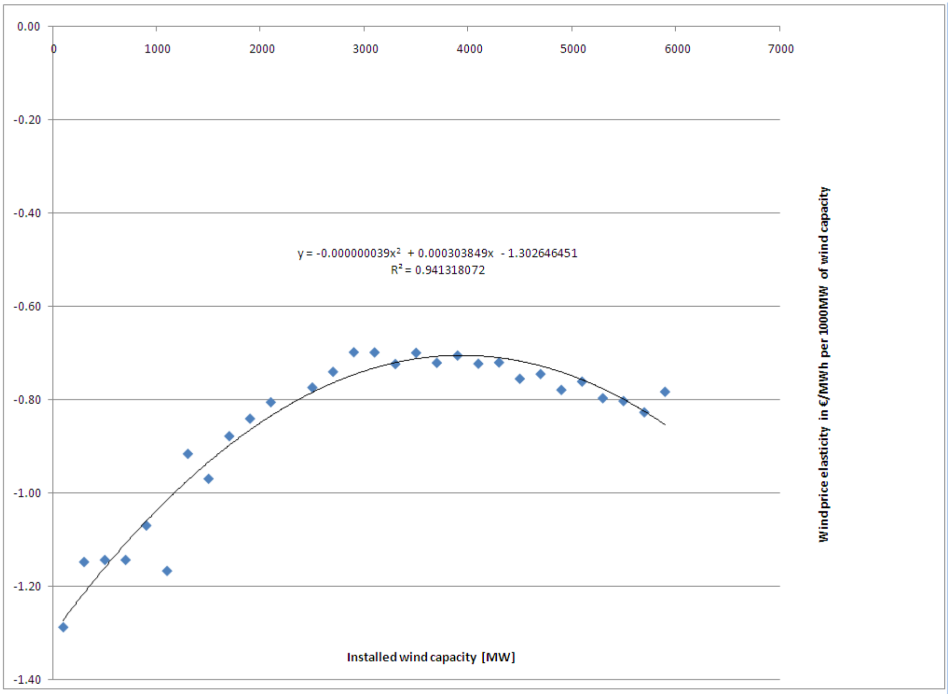
A simple validation of the model was performed by comparing the model-predicted increase in electricity prices at the level of 0 MW installed wind capacity (2.44 €/MWh, see **Figure 11**) with the price increase found in 2009 based on actual prices. From **Table 18** it can be seen that the regression-based estimate of the annual average APX price in 2009 in case of ‘no wind’ amounts to 41.40 €/MWh. The APX-volume weighted APX price was 39.63 €/MWh, resulting in price difference of 1.77 €/MWh, which is sufficiently close to the model prediction of 2.44 €/MWh. Off course this is not a completely independent validation, since the intersection of the ‘sales’ and ‘purchase’ curves from the model determine the market clearing price which was actually realised. But it shows internal consistency.

Figure 11: Change in average annual APX price in €/MWh with different amounts of installed wind capacity in MW, assuming no change in conventional generation capacity, and compared with the 2009 price levels.



With each pair of consecutive values in **Figure 11** a sort of price sensitivity can be calculated as the change in average APX price per unit change of wind capacity (see **Figure 12**). From this graph it can be concluded that for relatively small amounts of installed capacity, extra wind capacity leads to a relatively large decrease in prices. Beyond the currently installed capacity of 2200 MW, additional wind capacity leads to a APX price decrease which is more or less constant at a level of about 0.8 €/MWh per additional 1000 MW of installed wind capacity.

Figure 12: Price sensitivity due to wind: decrease in the average annual APX price due to an increase in installed wind capacity [in €/MWh per 1000 MW of additionally installed wind capacity] N.B. Legenda on vertical axis mentions 'wind price elasticity'. This has to be interpreted as: 'price elasticity of the APX price due to changes in installed wind capacity'.



4.3 Increasing demand and rising conventional generation

In the previous section the focus was on assessing the impact of growing wind generation on APX spot market prices, keeping every else fixed. In this section also electricity demand growth and the planned additions to conventional generation capacity are included. Electricity 'demand' as observed by TenneT is defined here as the amount of large-scale generation at the level of high voltage grids plus the available imports. It is assumed to increase from a level of 105 TWh in 2009, to 110 TWh in 2010 and growing with 4.5 TWh per year in the following years to account for the rapid growth in new generation power in the Netherlands. Purchase curves on the APX market are assumed to increase with the same growth percentage as the demand observed by TenneT.

Table 6: Scenario for installed wind capacity over the years 2009-2016 based on existing policy

	Onshore	Offshore	Total wind
2010	1993	228	2221
2011	1995	228	2223
2012	2727	228	2955
2013	3142	228	3370
2014	3943	1178	5121
2015	4000	1178	5178
2016	4000	1758	5758

Source: installed wind: Sander Lensink, ECN

Table 7 and **Figure 13** show the net cumulative generation capacity changes after 2009 based on the Reference Projections (PBL and ECN, 2010). It includes decommissioning of 638 MW gas in 2013 and 600 MW gas in 2014.

Table 7: Scenarios for cumulative installed generation capacity over the period 2009-2016 under existing policy

Year	Wind [MW]	Gas [MW]	Coal [MW]
2009	0	0	0
2010	4	420	0
2011	6	1895	0
2012	738	3595	1870
2013	1153	2957	3470
2014	2904	2357	3470
2015	2961	2357	3470
2016	3541	2357	3470

Source of conventional generation capacity: PBL en ECN, (2010)

Figure 13: Scenarios for cumulative newly installed generation capacity over the period 2009-2016 under existing policy

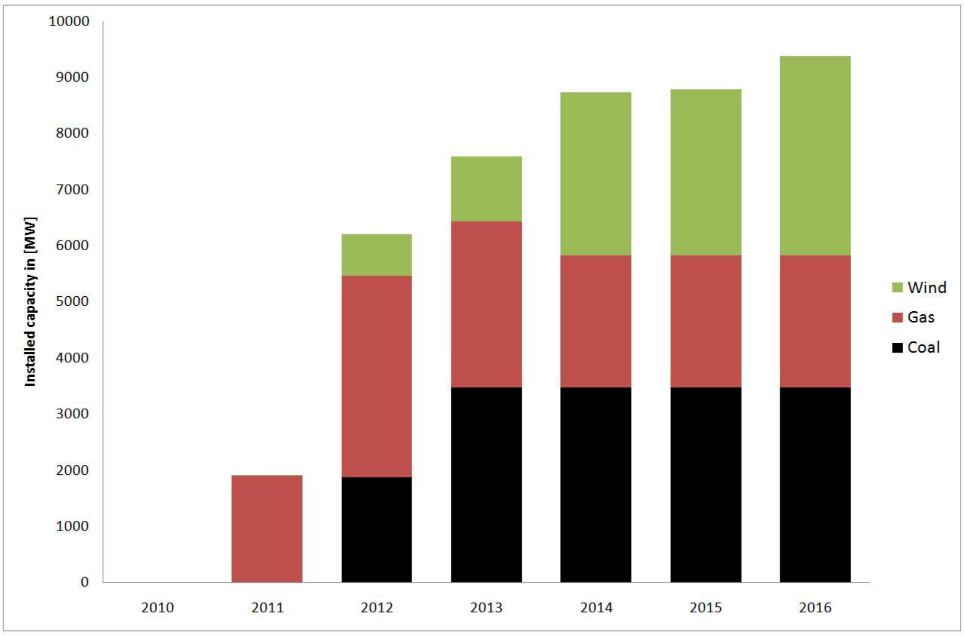


Table 8 provides the fuel prices assumed for calculating the marginal cost of the two conventional generation options considered. The marginal cost primarily consists of the fuel costs but also includes the cost of CO_2 allowances assumed at a price of 20 €/ton.

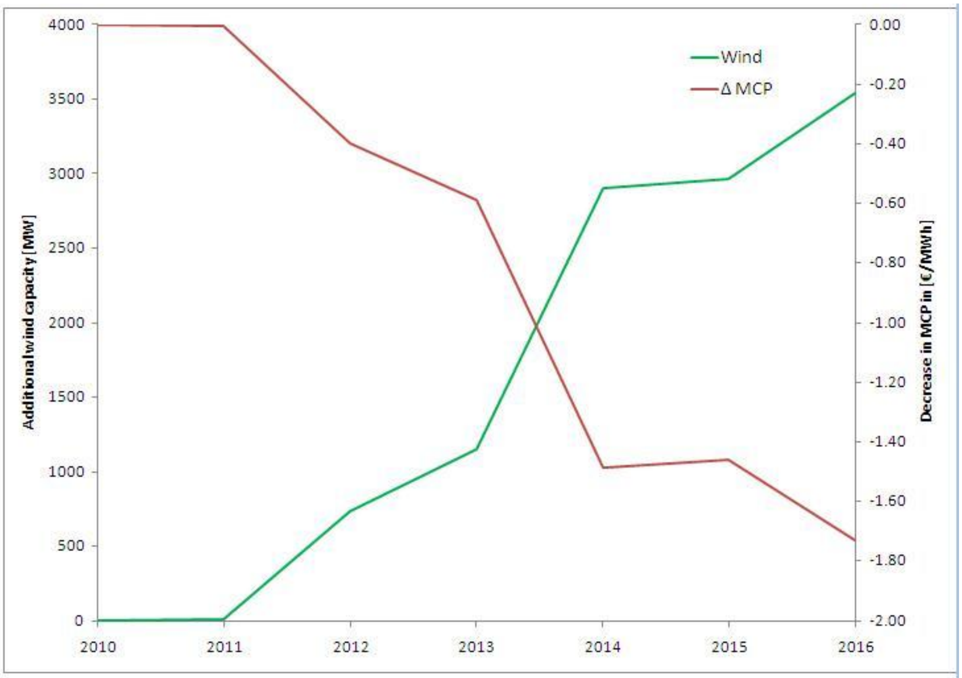
Table 8: Fuel prices and main characteristics of new gas and coal fired power plants

	Fuel price [€/GJ]	Efficiency [%]	CO_2 [kg/GJ]	Marginal cost [€/MWh]
Gas	6.5	58	56.7	47.38
Coal	2.2	46	94.7	32.04

Model outcomes with increasing electricity demand and changing conventional capacity

Figure 14 shows for each year in the period 2010-2016 the predicted effect on the day-ahead market prices of the increasing amounts of installed wind generation capacity and the changing amounts of conventional generation capacity as shown in **Table 7**. By taking into account demand increases and changes in conventional generation, the impact on prices is less than in the previous case in which demand and conventional generation were assumed to be constant. When the effects of a 30% electricity demand increase over the period 2009-2016 and an additional 5827 MW of conventional generation capacity are taken into account, prices in 2016 are predicted to decrease by 1.73 €/MWh due to the combination of effects, including the additional 3541 MW wind installed in the period 2009-2016 (see **Figure 14**). This is equivalent to a price depressing effect of only 3% of average day-ahead prices. As could be seen in **Figure 11** a similar increase in wind (up to a total capacity of 5758 MW) but without any changes in conventional generation and load would lead to a much larger predicted price decrease of 2.73 €/MWh in 2016.

Figure 14: Predicted decrease of APX spot market clearing prices (ΔMCP in red curve with scale on right hand side) with increasing installed wind capacity (green curve with scale on left hand side) compared to 2010 levels, including the effects of changes in conventional generation and increases in demand. Output of the above-described EDAM model.



5

Effect of wind on future SDE subsidies

Lower wind prices on the APX day-ahead market will result in higher future subsidy requirements in the SDE scheme. With the help of the model-calculated APX price decrease the extra amount of subsidy required can be calculated when this price depressing effect is taken into account. **Table 9** shows the impact on the required subsidy level for the installed wind capacity scenario as in 4.3. Assuming constant subsidy levels of 30 €/MWh for onshore and 86 €/MWh for offshore the fourth column in **Table 9** shows the increase in subsidies needed for the additionally installed wind capacity after 2009[1]. The next column shows the extra subsidy, needed to cover the cost due to lower wind energy prices. One of the findings shown in **Table 3** was that the wind energy prices were reduced by about twice the amount of the reduction in average APX prices. The additional subsidy shown in column 6 of **Table 10** is calculated based on the assumption that the wind energy price decrease with 2.22 times the rate in the decline of the average day-ahead price, as was the average rate over the period 2006-2009. (This rate over 2005-2009 can be calculated based on data in table **Table 18**).

[1] For onshore 2200 equivalent full load hours and for offshore 3650 hours was used.

Table 9: EDAM model predicted APX price decreases and consequences of additional subsidy required due to the price decreases

Year	Wind installed [MW]	EDAM APX price decrease [€/MWh]	Wind price decrease [€/MWh]	Subs. Before wind price decrease [€/MWh]	Extra subs. Due to wind price decrease [€/MWh]	Total subsidy [€/MWh]	Extra as % of total [%]
2009	2217	0.00	0.00	0	0.0	0.0	0.0
2010	2221	0.00	0.00	0	0.0	0.3	0.0
2011	2223	0.00	0.00	0	0.0	0.4	0.0
2012	2955	-0.40	-0.89	49	4.6	54	8.6
2013	3370	-0.59	-1.32	76	7.8	84	9.3
2014	5121	-1.49	-3.32	427	29.9	457	6.6
2015	5178	-1.46	-3.25	431	29.7	461	6.4
2016	5758	-1.73	-3.86	613	39.1	652	6.0

Since also the average APX prices decreases, the cost for electricity suppliers to obtain electricity for selling to consumers is reduced (or the consumer surplus is increased with the same amount). The one but last column in **Table 10** shows the total increase in consumer surplus for the whole electricity market[2] in the Netherlands assuming that the decrease in wholesale prices on the APX is similar to the decrease in prices in the remainder of the market. When comparing the last two columns, one can conclude that from the viewpoint of consumers, the increase in benefits of reduced overall electricity prices compensate about half of the cost of the total subsidies for wind.

Table 10: EDAM model predicted consumer surplus increase due to decreasing electricity prices as a consequence of additional wind capacity on top of 2009 capacity

Year	Wind installed [MW]	EDAM APX price decrease [€MWh]	Assumed total demand [TWh/year]	Increase consumer surplus [M€/year]	Extra subs. As % cons. surpl. [%]
2009	2217	0.00	105.0	0.0	
2010	2221	0.00	110.0	0.0	
2011	2223	0.00	114.0	0.0	
2012	2955	-0.40	119.0	47.6	10
2013	3370	-0.59	123.5	72.9	11
2014	5121	-1.49	128.0	190.7	16
2015	5178	-1.46	132.5	193.5	15
2016	5758	-1.73	137.0	237.0	16

From **Table 10** it can be concluded that the decrease in electricity prices due to wind results in about 6-9% higher level of subsidies to cover the higher cost of wind energy compared to conventional generation (*onrendabele top*).

2 TenneT figures for the total amount fed into their HV grid plus imports minus exports are used as a proxy for the size of the electricity market in the Netherlands. This 'TenneT' demand has been used in the analysis. It is close to domestic electricity demand, which require inclusion of embedded generation in distribution grids and correcting for losses in the HV grid. The size of the electricity market was 105 TWh in 2009 and is assumed to increase to 110 TWh in 2010 and grow with 4.5 TWh per year in the following years.

5.1 Discussion

The reliability of the estimated future impact on electricity prices of integration of wind energy in the electricity system, based only on market data of the past 4 years, is clearly limited. It is unlikely that the impact of wind in the recent past would be the same as in a decade from now, with the expected higher wind capacity, stronger interconnections with neighbouring countries, a more integrated European electricity market, possibly more demand response and a changing conventional generation capacity mix. Therefore the impact on future prices as shown for example in **Table 9** should be limited to at most 5 years in the future.

In the long run, there will be sufficient time for conventional generation capacity expansions plans to be adjusted to the new situation of higher wind generation and resulting lower prices. Operating hours and load factors of conventional power plants are likely to decrease due to fluctuating wind power availability. Higher power prices, at least part of the time, are needed to convince investors to invest in those power plants which are expected to operate less hours per year compared to previous operating circumstances without much wind. In the long run, when over-capacity is corrected by decommissioning old power plants, electricity prices are likely to rise. At times of low wind, future electricity prices will likely be higher than current prices at low wind. This implies that the increase in consumer surplus will eventually be smaller than the 311 M€/year as was shown in **Table 5** for the period 2006-2009. It is possible that in the long run there will be no (or only a very limited) average electricity price reduction due to additional wind generation capacity.

5.2 Conclusion

With a high share of relatively flexible gas-fired generation capacity, and strong interconnections with neighbouring countries, the Netherlands has a good starting position to integrate larger shares of wind generation in its electricity system. However, the potential benefits of further increasing the system flexibility are large, indicating the need for a careful assessment of the different flexibility options, their relative costs and potential in contributing to an improved integration of wind power.

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Appendix A. Wind and APX data 2006-2009

The following four graphs show the effect of wind on the annual average APX prices for each of the years 2006-2009 for four classes of wind generation:

a) Below 200 MWh per hour.
b) Between 200 and 700 MWh.
c) 700-1200 MWh.
d) More than 1200 MWh wind generation per hour.

Figure 15: Annual averages of hourly APX day-ahead market prices in 2006 [in €/MWh]

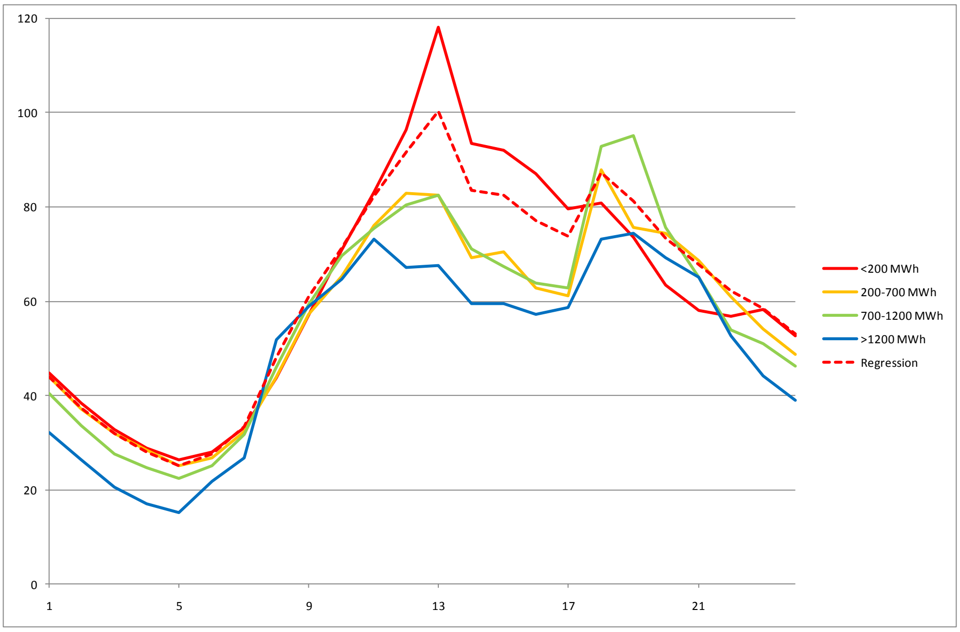


Figure 16: Annual averages of hourly APX day-ahead market prices in 2007 [in €/MWh]

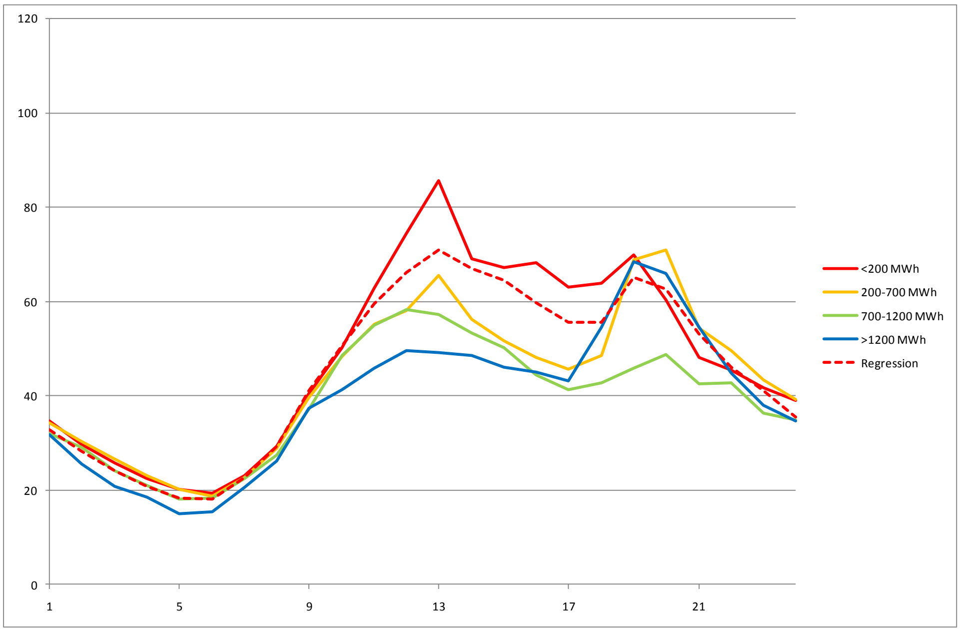


Figure 17: Annual averages of hourly APX day-ahead market prices in 2008 [in €/MWh].

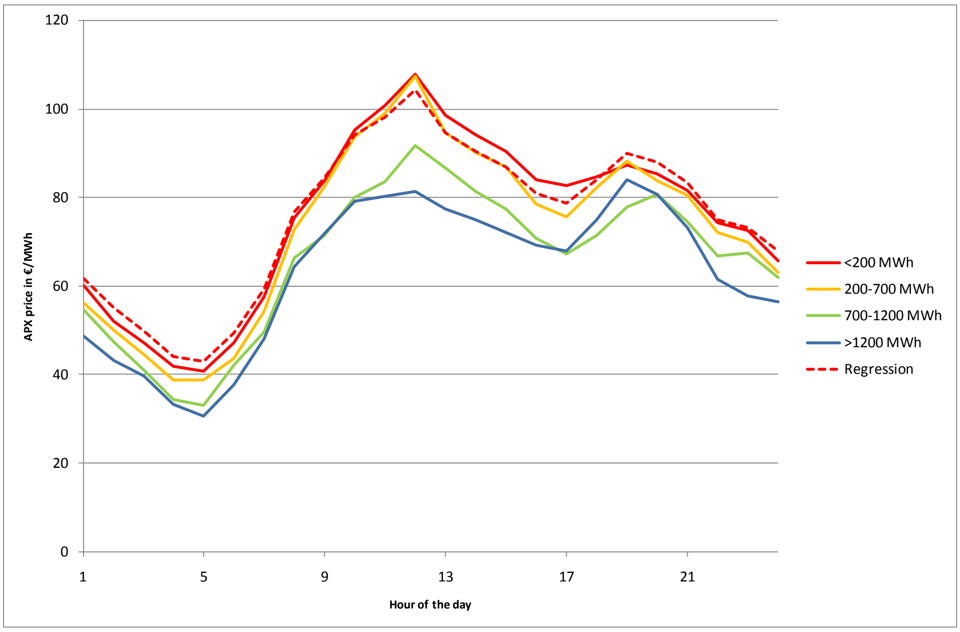
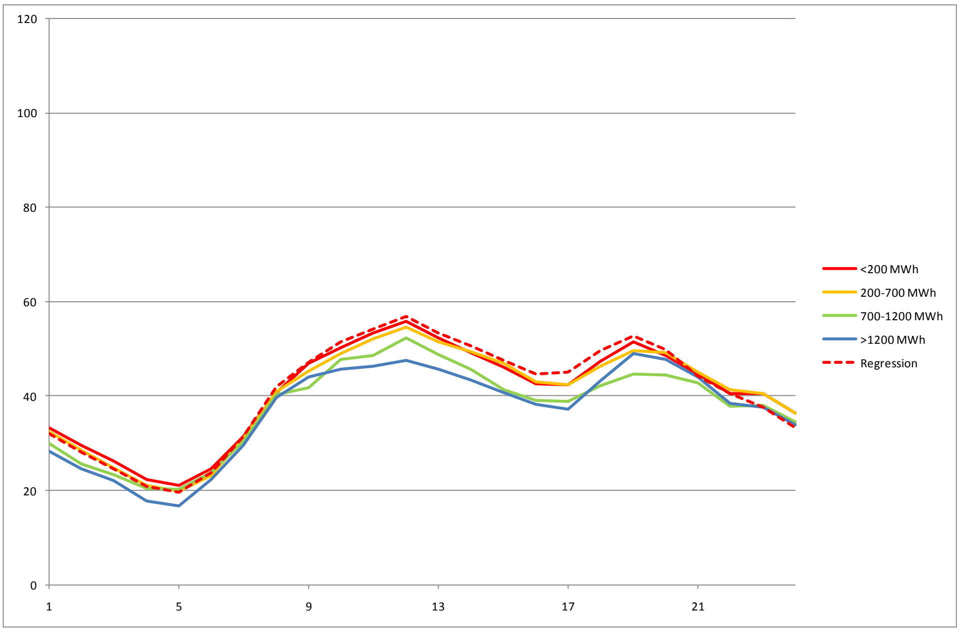


Figure 18: Annual averages of hourly APX day-ahead market prices in 2009 [in €/MWh].



Recalling that the volume of wind generation increased approximately in line with the increase in volume of the APX (both growing with about 50% over the period 2006-2009), it is surprising to observe that the impact of wind on APX prices, especially those during peak hours, appears to decline over the years. In 2009 total electricity demand declined substantially which can explain the limited impact of wind in that year, but for the remaining years, it might be due to some sort of learning effect.

Figure 19 shows the relation between wind energy forecasts and average temperature in the centre of the Netherlands, (i.e. De Bilt) in 2008. Higher than average temperatures appear to be correlated with lower than average forecasted wind generation. **Figure 20** shows that higher temperatures are correlated with higher APX prices. Combining these two findings one can conclude that using the wind generation class of <200 MWh wind generation per hour as the basis for estimating the impact of wind can possibly lead to an overestimation of prices at times of low wind. Therefore the statistical analysis is preferred in obtaining values for the prices at times of no wind generation.

Figure 19: Scatter plot of the relation between day ahead wind power forecasts and temperature in the centre of the Netherlands (de Bilt) in 2008. Higher than average temperatures are strongly correlated with lower levels of forecasted wind generation.

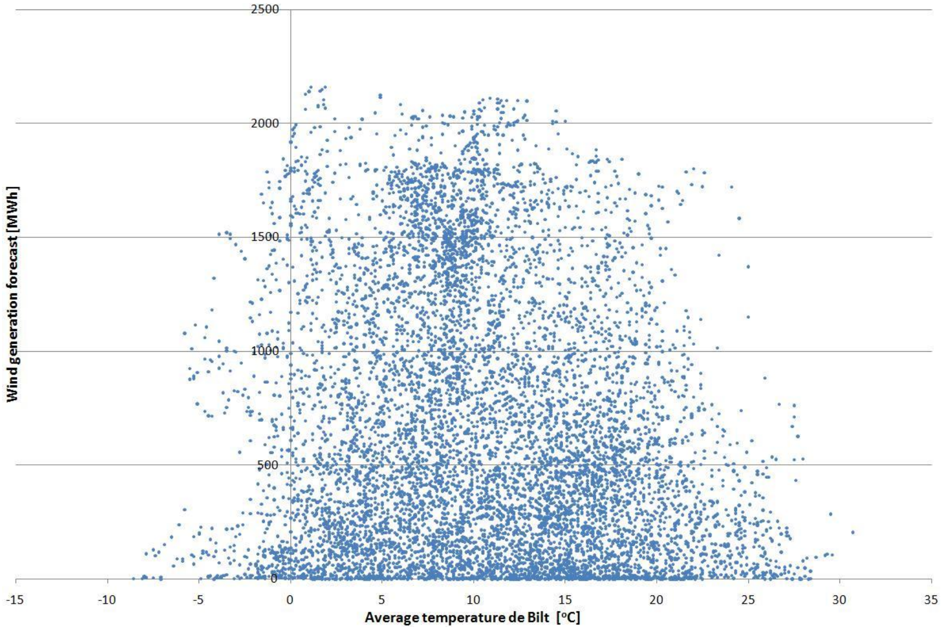
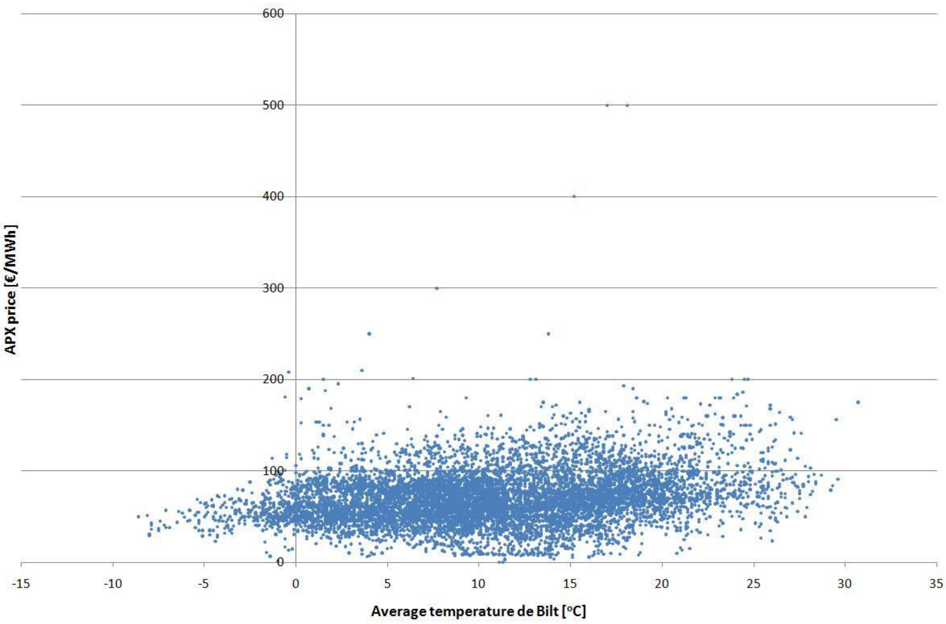


Figure 20: Scatter plot of temperature in the centre of the Netherlands (de Bilt) and the APX day ahead prices in 2008 [€/MWh]



To determine an estimate for the APX in the absence of wind generation, a regression analysis was conducted with hour of the day, wind generation, and temperature in De Bilt in the centre of the Netherlands as independent variables.

The following regression model was used:

$$APX_t \quad = \quad Const + a_n H_n + bW_t + cT_t + \varepsilon_t$$

With APXt a time series of the market clearing prices for all the hours t of a year. Const is a constant, and Hn are 24 dummy variables for each of the 24 hours n of the day[3]. Wt is the day-ahead forecast for the total hourly wind generation in the Netherlands, and Tt is a time series of the temperature in the centre of the Netherlands (de Bilt).

Based on the calculated regression coefficients, the following estimates of the annual hourly average APX prices in the absence of wind generation was calculated:

$$\left\langle APX \right\rangle_n = Const + a_n + c\left\langle T \right\rangle$$

The regression coefficients are shown in **Table 11**, and the resulting estimates for the hourly average APX price in absence of wind generation are presented in **Table 12**.

Table 11 Regression coefficients for the variables used: hours of the day, forecasted wind power generation and temperature in de Bilt.

N.B. The day had to be split into two halves because Excel does not allow a regression analysis with more than 17 variables); se = standard error;

Table 12 Estimates for average hourly APX prices [€/MWh] assuming no installed wind capacity. Based on regression coefficients presented in the previous table.

Table 11: Regression coefficients for the variables used: hours of the day, forecasted wind power generation and temperature in de Bilt

	2006 Coeffi cient	2006 se	2007 Coeffi cient	2007 se	2008 Coeffi cient	2008 se	2009 Coeffi cient	2009 se
1								
2	-6.59	1.78	-4.55	1.58	-6.75	1.71	-4.07	0.88
3	-11.98	1.79	-8.74	1.58	-11.89	1.71	-7.44	0.88
4	-15.91	1.78	-12.02	1.58	-17.65	1.71	-11.36	0.88
5	-18.66	1.79	-14.65	1.58	-18.71	1.71	-12.41	0.88
6	-16.26	1.78	-14.84	1.58	-12.38	1.71	-8.41	0.88
7	-10.49	1.78	-10.15	1.58	-2.52	1.71	0.65	0.88
8	4.33	1.79	-3.54	1.58	14.86	1.71	9.77	0.88
9	17.17	1.79	8.21	1.59	22.58	1.71	15.03	0.89
10	27.41	1.79	17.73	1.59	32.40	1.72	19.44	0.89
11	38.51	1.80	26.65	1.59	36.47	1.72	22.04	0.89
12	47.76	1.80	33.36	1.60	42.54	1.72	24.86	0.89
Wind	-0.0081	0.0009	-0.0057	0.0007	-0.0091	0.0006	-0.0033	0.0003
Temp	-1.02	0.05	-1.26	0.06	0.21	0.06	-0.78	0.03
Const	55.28	1.43	47.01	1.32	59.65	1.39	40.31	0.70
13								
14	-16.85	3.72	-3.86	3.06	-4.15	1.55	-2.60	0.82

3 In practice over determination is prevented by having one dummy variable less than the number of hours per period (11 for each half of the day).

15	-17.91	3.72	-6.45	3.06	-7.64	1.55	-5.84	0.82
16	-23.17	3.72	-11.24	3.06	-13.76	1.55	-8.68	0.82
17	-26.48	3.72	-15.27	3.06	-15.98	1.55	-8.34	0.82
18	-13.01	3.72	-15.20	3.07	-10.52	1.55	-3.80	0.82
19	-19.17	3.73	-5.86	3.07	-4.55	1.55	-0.60	0.82
20	-26.98	3.73	-8.19	3.08	-6.64	1.55	-3.60	0.83
21	-32.63	3.74	-17.71	3.09	-11.26	1.56	-9.17	0.83
22	-38.19	3.74	-24.72	3.10	-19.76	1.56	-12.77	0.83
23	-41.84	3.75	-29.90	3.10	-21.50	1.56	-15.66	0.83
24	-47.21	3.75	-35.34	3.11	-26.84	1.56	-20.06	0.83
Wind	-0.0114	0.0020	-0.0106	0.0013	-0.0078	0.0006	-0.0035	0.0003
Temp	-0.08	0.10	-1.87	0.11	0.33	0.05	-0.90	0.02
Const	101.30	3.19	91.81	2.83	91.11	1.37	62.80	0.71

N.B. the day had to be split in two halves because Excel does not allow a regression analysis with more than 17 variables); se = standard error.

Table 12: Estimates for average hourly APX prices [€/MWh] assuming no installed wind capacity. Based on regression coefficients presented in the previous table.

	2006	2007	2008	2009	Average
1	43.86	32.92	61.77	32.10	42.66
2	37.27	28.37	55.02	28.04	37.17
3	31.88	24.18	49.88	24.66	32.65
4	27.96	20.90	44.11	20.74	28.43
5	25.20	18.27	43.06	19.69	26.56
6	27.60	18.07	49.38	23.69	29.69
7	33.37	22.77	59.25	31.45	36.71
8	48.19	29.38	76.63	41.87	49.02
9	61.04	41.13	84.35	47.14	58.41
10	71.27	50.65	94.16	51.54	66.90
11	82.37	59.57	98.24	54.14	73.58
12	91.63	66.28	104.31	56.96	79.79
13	100.36	70.90	94.62	53.35	79.81
14	83.50	67.04	90.47	50.75	72.94
15	82.45	64.45	86.98	47.51	70.35
16	77.19	59.66	80.86	44.67	65.59
17	73.88	55.64	78.64	45.01	63.29
18	87.35	55.70	84.10	49.55	69.18
19	81.19	65.04	90.07	52.75	72.26
20	73.38	62.72	87.98	49.75	68.46
21	67.73	53.19	83.36	44.18	62.11
22	62.16	46.18	74.86	40.58	55.95
23	58.51	41.01	73.12	37.69	52.59
24	53.15	35.56	67.78	33.29	47.44

Appendix B. Day-ahead wind energy forecasts in the Netherlands 2001-2009

B.1. Research question

This appendix describes how historic day-ahead wind energy forecasts are made and wind energy production is estimated for the installed wind power in the Netherlands.

B.2. Day-ahead wind energy forecasts

Historic day-ahead forecasts of wind energy in the Netherlands are available on two time resolutions: 1 hour and 15 minutes. There are day-ahead forecasts for 99% of the days in the period between 9 June 2001 and 1 July 2008; **Table 13** lists the lacking data files.

Table 13: Lacking forecasts because of missing or defect HiRLAM data files; format mmdd

2001	0703, 0709, 0710, 0715, 1026
2002	0102, 0319, 0322, 0718
2003	0109
2004	-
2005	0706
2006	-
2007	0106, 0805, 0806, 0823, 0827, 0830, 0901, 0918, 1018, 1019, 1020, 1026, 1029
2008	0129, 0204

As an example **Table 14** shows an excerpt from the excel file with 1 hour resolution forecasts. Indicated are: date, time period, and forecasted wind energy. Local time is used so that a shift to or from daylight saving time occurs twice per year, resulting in one day with 23 hours and one day with 25 hours. Also indicated are installed power and forecasted wind direction, wind speed and air density.

Table 14: Example of day-ahead wind energy forecasts with a resolution of 1 hour

#Date	Period	EneNO	PowInst	WsExp	Wd	Rho
#[yr/mn/dy]	[hr:mn]	[MWh]	[MW]	[m/s]	[deg]	[kg/m3]
2001/06/09	00:00-01:00	33.8	461.9	4.7	313.8	1.233
2001/06/09	01:00-02:00	25.2	461.9	4.3	312.8	1.234
2001/06/09	02:00-03:00	17.3	461.9	4.0	309.8	1.236
2001/06/09	03:00-04:00	12.5	461.9	3.8	304.5	1.237
2001/06/09	04:00-05:00	10.0	461.9	3.6	296.8	1.238
2001/06/09	05:00-06:00	9.2	461.9	3.6	287.5	1.238
2001/06/09	06:00-07:00	9.7	461.9	3.6	278.1	1.237
2001/06/09	07:00-08:00	11.5	461.9	3.9	270.3	1.237
Etc.						

N.B.: EneNO is the forecasted wind generation; PowInst the installed wind power capacity, WsExp the wind speed, Wd the wind direction and Rho the density of air

Because of the amount of data the forecasts with a resolution of 15 minutes are distributed over several work sheets. As an example **Table 15** shows an excerpt from the work sheet with 15 minute resolution for the year 2001.

Table 15: Example of day-ahead wind energy forecasts with a resolution of 15 minutes

#Date	Period	EneNO	PowInst	WsExp	Wd	Rho
#[yr/mn/dy]	[hr:mn]	[MWh]	[MW]	[m/s]	[deg]	[kg/m3]
2001/06/09	00:00-00:15	9.2	461.9	4.9	313.5	1.231
2001/06/09	00:15-00:30	8.8	461.9	4.9	313.7	1.232
2001/06/09	00:30-00:45	8.2	461.9	4.8	313.8	1.232
2001/06/09	00:45-01:00	7.6	461.9	4.7	313.8	1.233
2001/06/09	01:00-01:15	7.0	461.9	4.6	313.7	1.233
2001/06/09	01:15-01:30	6.6	461.9	4.5	313.6	1.234
2001/06/09	01:30-01:45	6.0	461.9	4.4	313.2	1.234
2001/06/09	01:45-02:00	5.5	461.9	4.3	312.8	1.234
2001/06/09	02:00-02:15	5.1	461.9	4.3	312.2	1.235
Etc.						

B.3. Methodology

The historic day-ahead forecasts of wind energy in the Netherlands were made with ECN's wind power forecasting method AVDE and data from ECN's archive with HiRLAM files which spans the period from June 2001 up to now. The employed site is typical for the Dutch wind climate, and the employed wind turbine and hub height are typical for the period that is considered. Such a day-ahead forecast is based on run00 of the underlying HiRLAM weather forecast because this run is available well before noon on the day before delivery.

The already existing site Medemblik (MDB) was selected as the typical site because according to the wind map of the Netherlands its average wind speed is characteristic for the regions in the Netherlands where wind turbines are located (p. 86, Heijboer and Nellestijn, 2002).

A hub height of 52 m is employed because this value is characteristic for the turbine hub heights which are between 30 and 70 m in the period 2001 - 2010. A nominal power of 660 kW is employed as it is characteristic for the turbines in the period, and accordingly the Vestas V47 is selected as the baseline wind turbine.

The estimates of wind energy in the Netherlands were made by using measured wind speeds which span the period from 1 May 2001 to 31 May 2010. The site Cabauw was selected because of availability of a long time record of measured wind speed at the relevant heights of 40 m and 80 m4. (Note that according to the wind map of the Netherlands the average wind speed in Cabauw is not characteristic for the regions in the Netherlands where wind turbines are located (p. 86, Heijboer and Nellestijn, 2002)).

Estimates of 15-minute averaged wind speed at a height of 52 meter were obtained in two steps:

1. Measured 10 minute average wind speeds at 40 m and 80 m were linearly interpolated to yield the wind speed at 52 m.
2. Consecutive pairs of 10-minute averaged measured wind speed were combined into a 15-minute average, each triplet of 10-minute values giving a doublet of 15-minute values.

The time period of 15 minutes was selected because it is the standard time period in the Dutch electricity system (Programme Time Unit).

In order to account for the distribution of the sites over the Netherlands, in the forecasts as well as in the estimates a regionally averaged power curve was employed (Gibescu et al., 2008), to which end the distance scale is determined from the average number of wind turbines in the period 2001 - 2008 and the surface area of the Netherlands (up to 2005) increased with 18% of the area of the NEEZ (beyond 2005). Also, in order to account for the growth of the installed capacity over the years a normalized[5] wind power curve is used, whose normalized power is multiplied with the daily value of the installed power in order to get the forecasted power.

The general data on wind energy in the Netherlands, like the already mentioned characteristic nominal turbine power, the average number of turbines and the daily value of the installed power, originate form Wind Service Holland (WSH). For comparison also the data from Statistics Netherlands (CBS) is presented. The difference between installed power and number of turbines from WSH and CBS is small, and for this reason does not affect the characteristic nominal turbine power, the distance scale, or the daily growth rate.

4 Measured data originates from the Cabauw Experimental Site for Atmospheric Research (CESAR)

5 Normalized to make the maximum or nominal output of the windturbines equal to 1.

Figure 21: Characteristic single-turbine and regionally averaged normalized power curve.

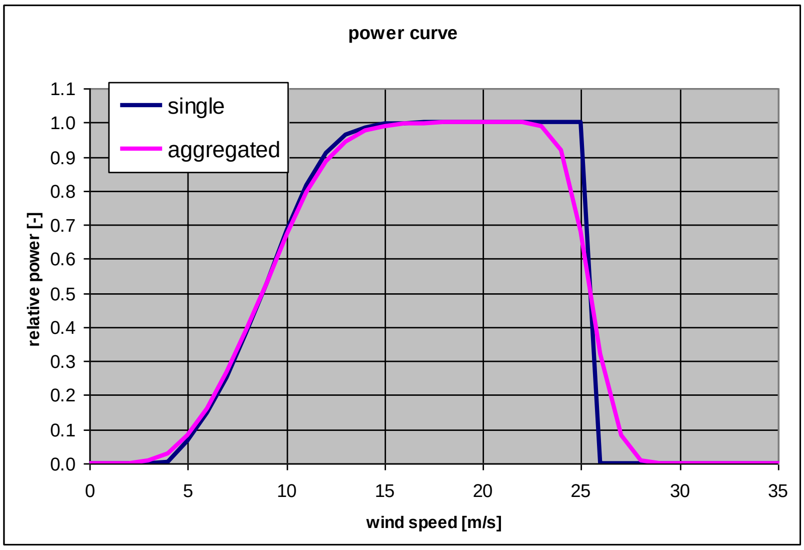


Table 16: General data on wind energy in the Netherlands between 2000 and 2008 from two sources: WSH= Wind Service Holland and CBS= Central Bureau of Statistics

Date	Installed nominal power		Number of turbines	
	[MW]	[MW]	[-]	[-]
	WSH	CBS	WSH	CBS
31 Dec 2000	445	447	1276	1291
31 Dec 2001	484	485	1326	1342
31 Dec 2002	685	670	1451	1450
31 Dec 2003	914	906	1593	1595
31 Dec 2004	1083	1073	1667	1651
31 Dec 2005	1224	1224	1714	1709
31 Dec 2006	1558	1558	1832	1826
31 Dec 2007	1747	1748	1888	1889
31 Dec 2008	2216	2121	2048	2029
31 Dec 2009	2221		1975	
31 May 2010	2227		1976	

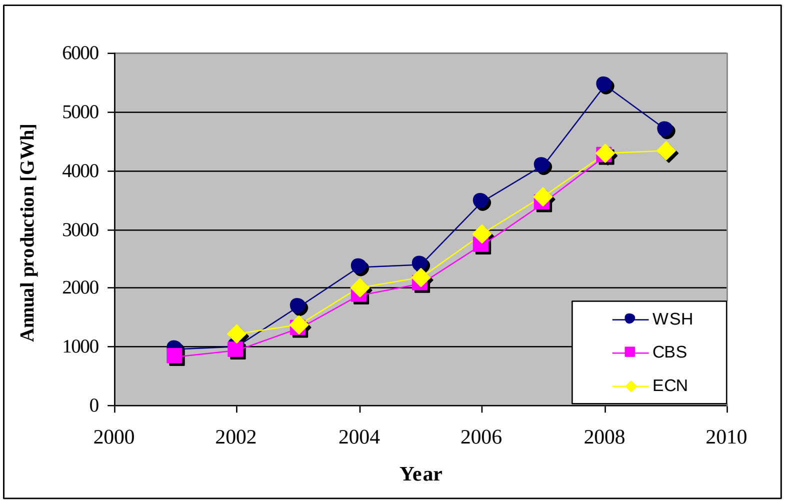
B.4. Validation - Rough and rapid

In the context of this study the estimated wind energy is validated on basis of published productions. To this end the estimated wind energy is accumulated per year, where wind energy is assumed to be zero when wind speed measurements lack. As to the published annual productions two estimates are given: one originating from WSH and the other from CBS. The values of WSH come from their reference production ("productie in een gemiddeld windjaar") and their Windex (an estimate of the annual wind climate as normalized to a long-term wind climate). The values of CBS, on the other hand, are based on the electricity that was fed into the grid.

Table 17: Forecasted and published wind energy production per year. Values between brackets are for an incomplete year.

Year	WSH			CBS	ECN
	Reference production [GWh]	Windex [%]	Estimated production [GWh]	Estimated production [GWh]	Estimated production [GWh]
2001	1.0 10^3	95	950	825	(723)
2002	1.0 10^3	101	1010	946	1217
2003	2.0 10^3	84	1680	1318	1379
2004	2.4 10^3	98	2350	1867	2013
2005	2.6 10^3	92	2390	2067	2190
2006	3530	98	3459	2733	2932
2007	3884	105	4078	3438	3564
2008	5242	104	5452	4256	4300
2009	5209	90	4688	-	4341
2010	-	-	-	-	(1750)

Figure 22: Forecasted and published wind energy production per year.



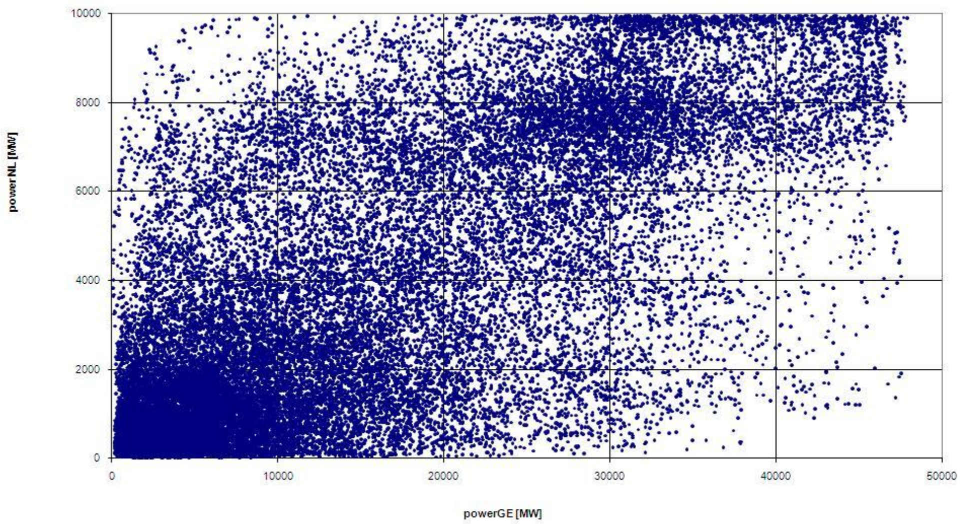
Production estimates from ECN agree well with those from CBS. This supports the employed method, in particular the choice of site and height, but also the use of a manufacturer's power curve and not taking availability into account. Note that the production estimates from WSH are higher than the ones from CBS[6], and that the WSH estimate for the year 2008 seems to be erroneous.

6 See CBS, 2008, p. 36 for an explanation

Appendix C. Impact of wind in Germany on the market in the Netherlands

At the end of 2009 the installed wind capacity in Germany was reported to be 25777 MW, which is more than 10 times higher than in the Netherlands (2229 MW)[7]. It is likely that there will be some impact of German wind on the market in the Netherlands. The reason is that there is a substantial correlation between wind power generation in the Germany and in the Netherlands. **Figure 23** shows simulated wind forecasts for a period of 8000 hours for both the Netherlands and Germany.

Figure 23: Simulated wind power generation in the Netherlands (10,000 MW installed capacity) versus simulated wind power generation in Germany (48,000 MW). Source Arno Brand ECN

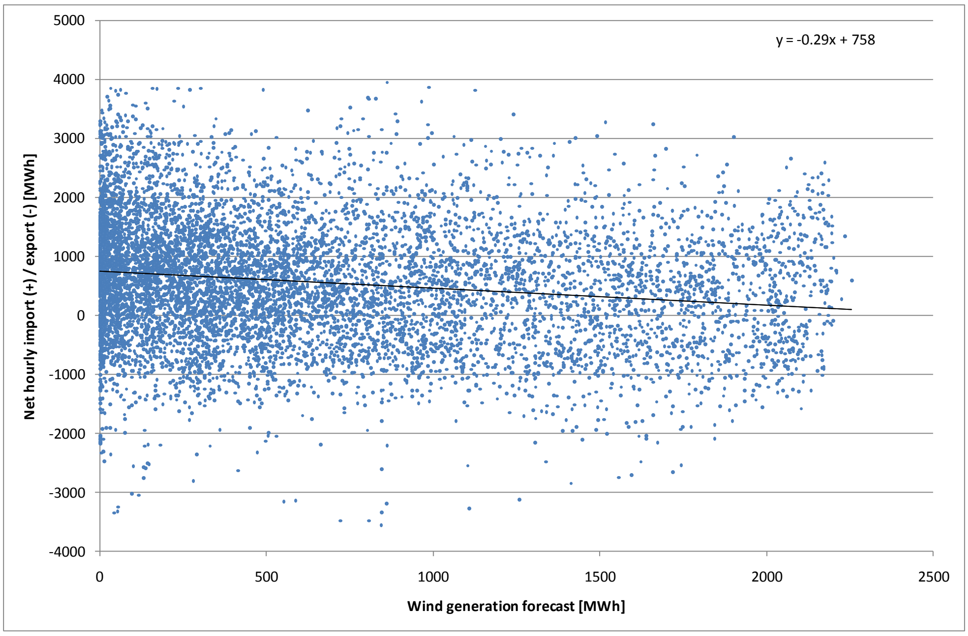


With high wind generation in Germany, prices in Germany are expected to be depressed, possibly leading to more export to the Netherlands. Because of the correlation between the wind generation in both countries, one would expect high wind generation in the Netherlands to be correlated with higher imports. **Figure 24** shows forecasted wind generation and net imports to the Netherlands in 2009. It shows a different picture: the higher the local wind generation the lower the imports. From

[7] Global Wind Energy Council http://www.wind-energie.de/fileadmin/dokumente/statistiken/WE%20Welt/Welt_2009_GWEC.pdf

every MWh of wind generation on average about 70% is used domestically (and leads to a reduction in conventional generation) and the remaining 30% is exported.

Figure 24: Import (+) and export (-) in MWh per hour as a function of the forecasted wind generation in MWh/h in 2009. Source of import/export data: TenneT meetdata invoeding 2009.



Wind generation in the Netherlands is clearly more important for APX price levels than wind generation in Germany. However it is still likely that there is some impact of German wind on Dutch price levels. Quantifying these would need a more substantial effort. This conclusion is likely to change now the Dutch and German spot markets are integrated with the spot markets in Belgium, Luxemburg and France as part of the Penta Lateral market Coupling (PLC) which happened at the end of 2010. It can be concluded that the impact of German wind on the Dutch market can be omitted in a first analysis as is presented here.

Appendix D. Impact of wind on detailed APX bid curves

Expected impacts
Over a year the average output of all wind farms in the Netherlands is about 30% of the installed capacity (wind capacity factor). It is likely that a manager of a portfolio of wind and conventional generation and electricity loads will include to a certain extent the long-term average expected wind generation in making decisions regarding positions in electricity forward markets. For an illustration of the mechanisms we assume that the portfolio manager sells the full amount of expected average generation on forward markets. On a day-ahead basis relatively reliable estimates of wind generation in different hours of the coming day will be available. Market positions in a portfolio can be adjusted to reflect the updated wind generation estimates, either by offers to sell additional electricity in the day-ahead market in case a more than average amount of wind is expected, or by reducing bids to buy electricity with a similar amount, or a combination of both. Averaged for the whole country, a mix of both types of transactions can be expected. An increase in expected wind generation will then lead to both a higher volume of offers to sell electricity and a lower volume of bids to purchase electricity. Two further assumptions can be made. The first is that the gradually improving quality of wind generation estimates in the days before real time is being neglected and only on the day-ahead market the first reaction on the wind generation is made. When we also assume that the transactions on the day-ahead market fully compensate for the updated wind generation forecast then one can expect that the shift in the 'sales' curve, minus the shift in the 'purchase' curve in the opposite direction, equals the additionally expected wind generation. When the size of the shift of the 'sales' curve would have the same magnitude as the shift of the 'purchase' curve, then the Market Clearing Volume would remain approximately constant and the only effect would be a decrease in the Market Clearing Price.

Effect on the Market Clearing Volume
The volume of realised transactions (Market Clearing Volume) on the APX day-ahead market in 2009 was found to be almost independent of the level of forecasted wind generation as can be seen from **Figure 25**. It is assumed that on forward markets the average expected wind generation has been sold already. At the time of the day-ahead market more reliable estimates of next day's wind generation will be available. We focus now on adjustments to take into account the increase in expected wind generation at the time of the day-ahead market compared to the long-term average wind generation. A regression analysis on those wind forecasts values higher than the annual average (see **Figure 26**) provides information that the volume on the APX market increases on average with about 5% of the amount of additional forecasted wind generation.

Figure 25: Realized volume on the APX day ahead market (Market Clearing Volume) as a function of forecasted wind generation for 2009 (The outliers higher than 6000 MW are 16 consequitive hours on November 19th)

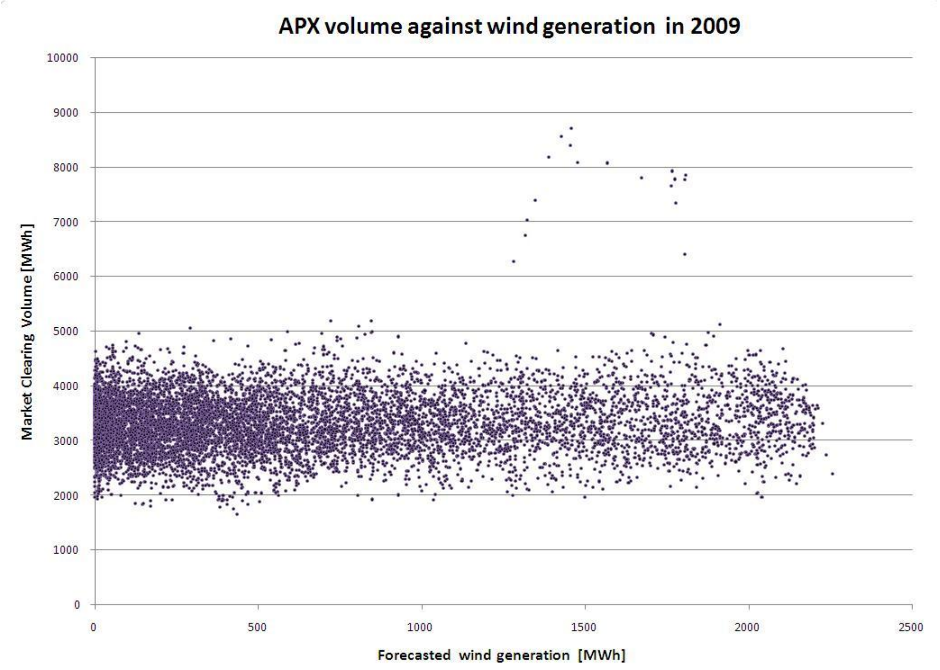
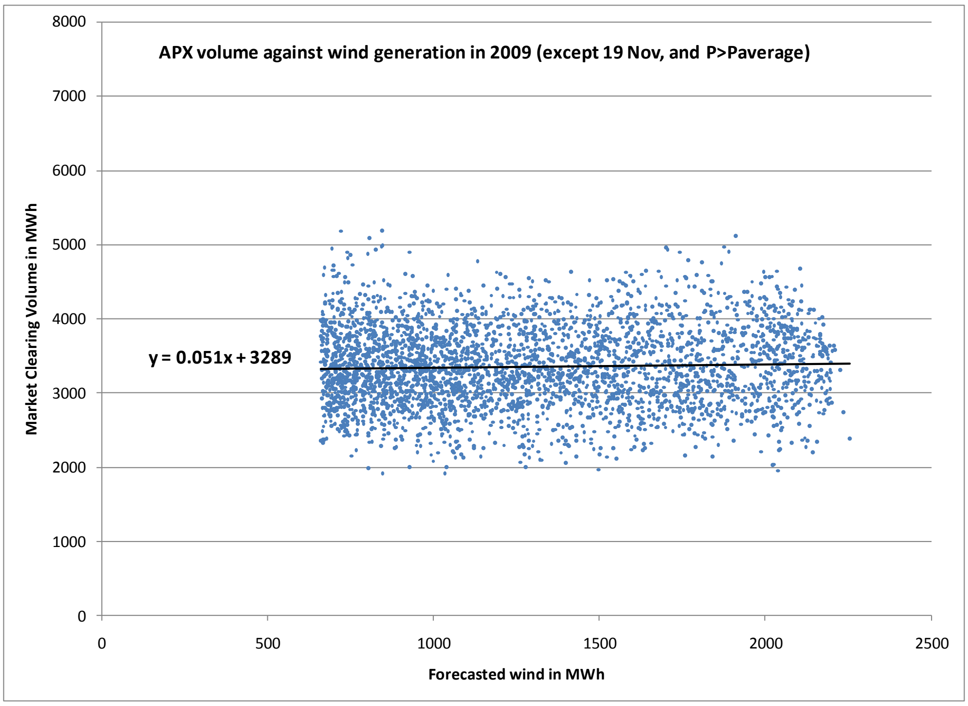


Figure 26: Realized volume on the APX day ahead market (Market Clearing Volume) as a function of forecasted wind generation for 2009 for levels of wind higher than average (except for 16 hours on November 19th).



Impact on 'sales' curves

Figure 27 and **Figure 28** show the curves with the cumulative offers to sell electricity for a number of hours at widely different levels of hourly wind energy forecasts ranging from 2 to 2095 MWh. To make the other circumstances similar as much as possible, the same hour of the day has been chosen (hour 13, i.e. from 12:00 to 13:00) only for working days, and limited to only one month (October 2009). Therefore the main difference between these curves lies in the amount of forecasted wind generation. The first graph zooms in on the upper part of the sales curves. The curves for the different hours appear to be shifted with respect to each other in horizontal direction (most curves are parallel to each other). The lower part of the sales curves shows more diversity, implying that differences from day to day affect mainly the lower part of the sales curve. In both the lower and upper parts, the curves at times of high wind are on average more or the right hand side of the graph.

Figure 27: Upper part of the sales curves on working days in October 2009, hour 13. Different colours show the forecasted amounts of wind generation, ranging from 2 MWh (blue) to 2095 MWh (red).

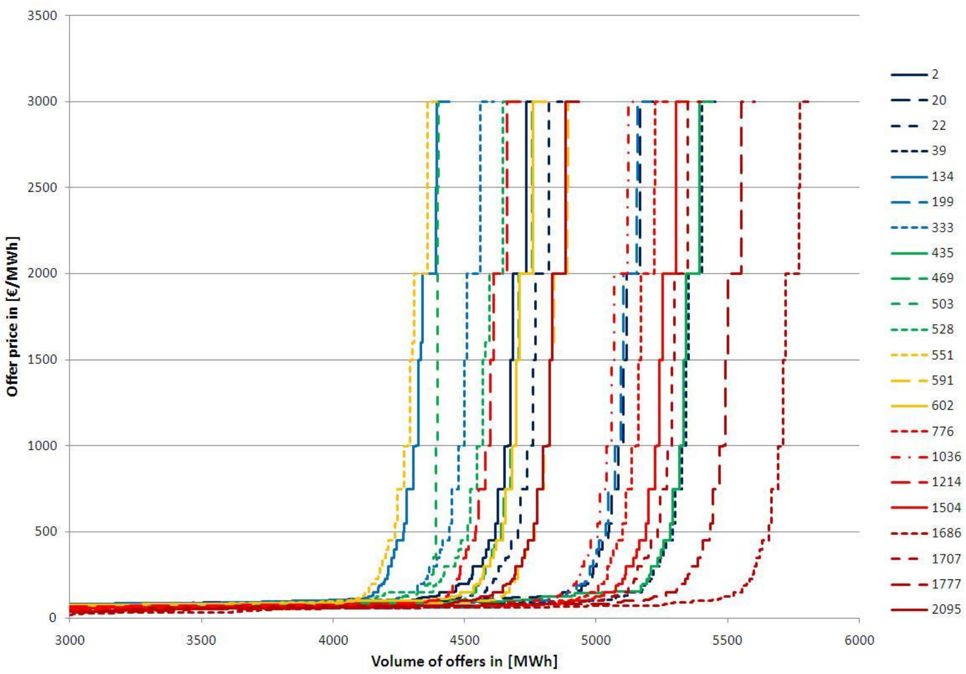
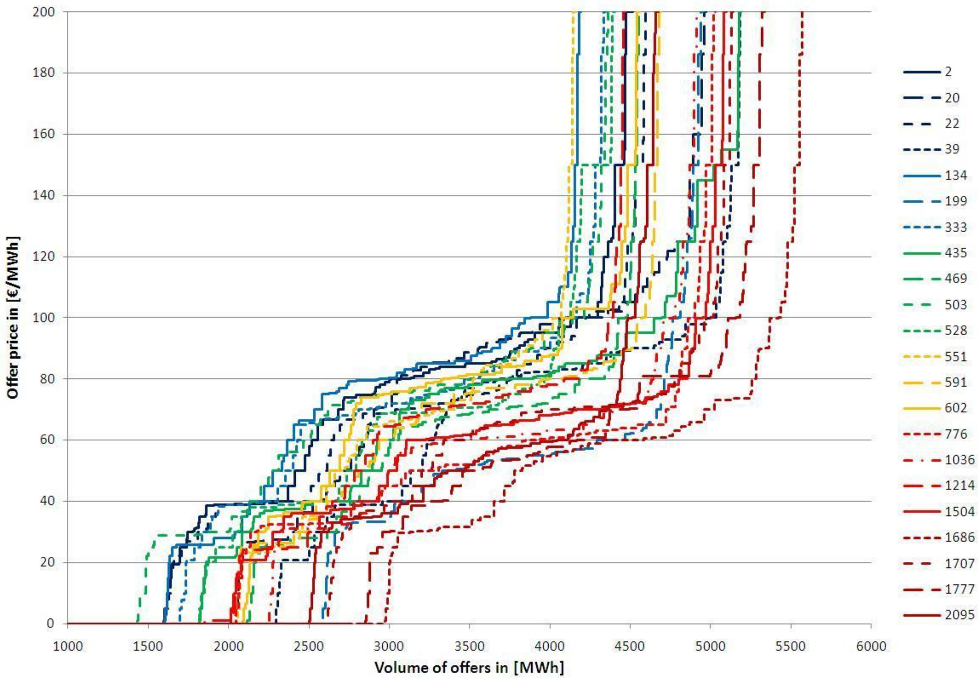


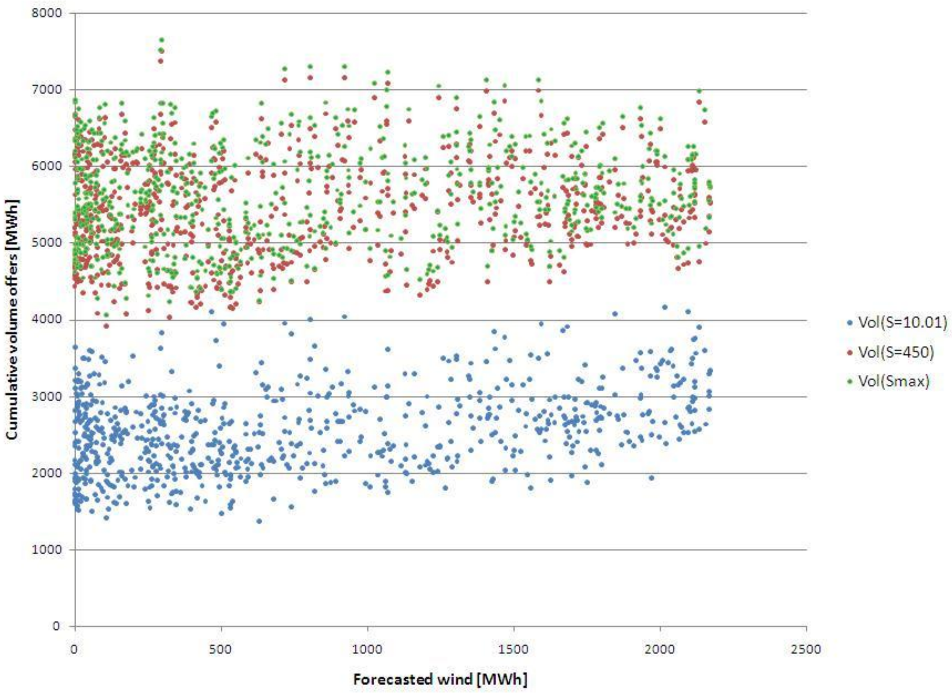
Figure 28: Lower part of the sales curves (<200 €/MWh) for working days in October 2009, hour 13. Different colours show the forecasted amounts of wind generation, ranging from 2 MWh (blue) to 2095 MWh (red).



The curve with the cumulative offers to sell electricity is expected to be affected differently by increasing levels of forecasted wind generation at different price levels. To quantify the impact of wind on the volume of sales offers, one has to choose first an offer price[8]. Since wind energy has almost zero marginal cost**,** at a very low price level, e.g. 10 €/MWh, one can observe how much is actually additionally offered at zero, or close to zero price levels. To assess how the full sales curve is affected, two price levels were chosen: a high level of 450 €/MWh and the maximum of 3000 €/MWh. As can be seen in the upper half of **Figure 29**, the volume of sales offers at these two price levels are very close to each other.

8 The APX day ahead price as referred to in previous sections is determined by the intersection of 'sales' and 'offer' curves, which is at the level where the market clears (Market Clearing Price). "Offer' price and 'purchase' price are used here to distinguish from this MCP.

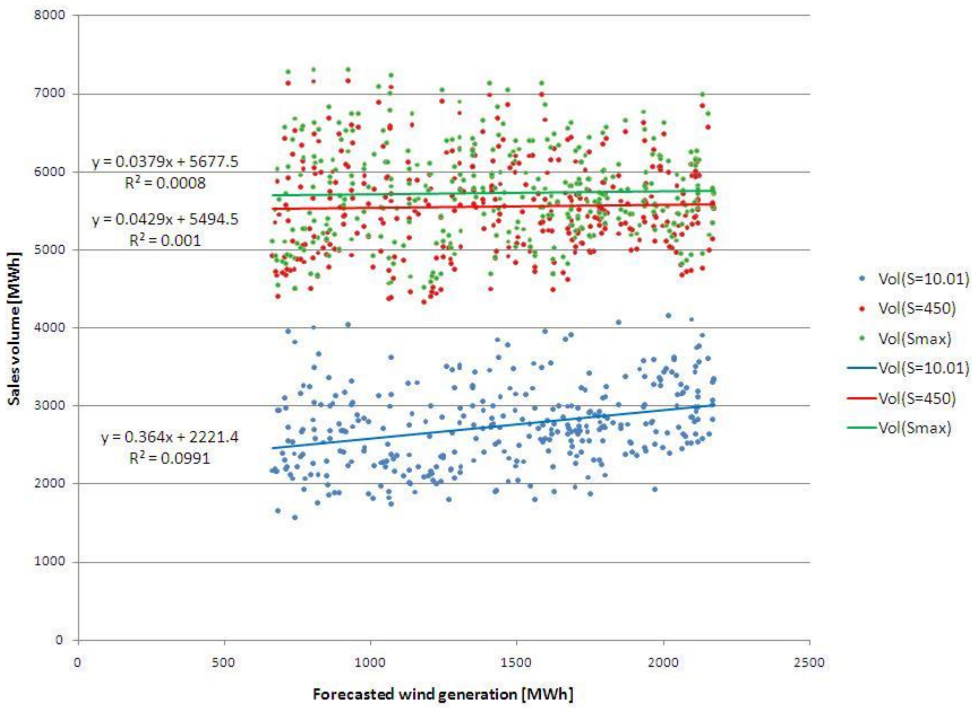
Figure 29: Cumulative volume of sales offers in October 2009 for different price levels (10.01, 450 and 3000 €/MWh) as function of forecasted wind generation[9].



A regression analysis was conducted, which was limited to values of forecasted wind higher than the annual average. Results are shown in **Figure 30**. Volume of sales offers with prices close to zero, increases with about 36% of the additional forecasted wind generation. But the total volume of sales offers increases only with about 4% of the additional wind generation. These findings suggests that more wind leads to a reduction in prices at low price levels, but very little impact at higher price levels. Total volume offered to the market is likely to be more determined by estimates of market players of the expected level of the Market Clearing Volume than by the availability of generation capacity.

[9] At the price level of exactly 10.00€/MWh the value of the volume is ill defined, but at a one cent higher price level there is only one volume offered.

Figure 30: Cumulative volume of sales offers at different price levels (10.01, 450 and 3000 €/MWh) for higher than average wind forecasts in October 2009.



Impact on 'purchase' curves

The 'purchase' curves for working days in October 2009 for hour 13 are shown in **Figure 31** and **Figure 32**. There is more variations from day to day in the upper parts of the purchase curves than in the upper part of the 'sales' curves. The reasons are unknown.

Figure 33 and **Figure 34** show the cumulative volume of 'purchase' bids at different price levels (450, 10.01 and 0 €/MWh). From the last graph it can be concluded that for the hours with higher than average levels of forecasted wind generation, the volume of the 'purchase' curve at high prices is practically unaffected by wind forecasts (showing an insignificant 3% increase per additional unit of wind generation). The total volume (at 0 price level) decreases with 23% for each unit of additional wind generation.

Figure 31: Full purchase curves on working days in October 2009, hour 13. Different colours show the forecasted amounts of wind generation, ranging from 2 MWh (blue) to 2095 MWh (dark red).

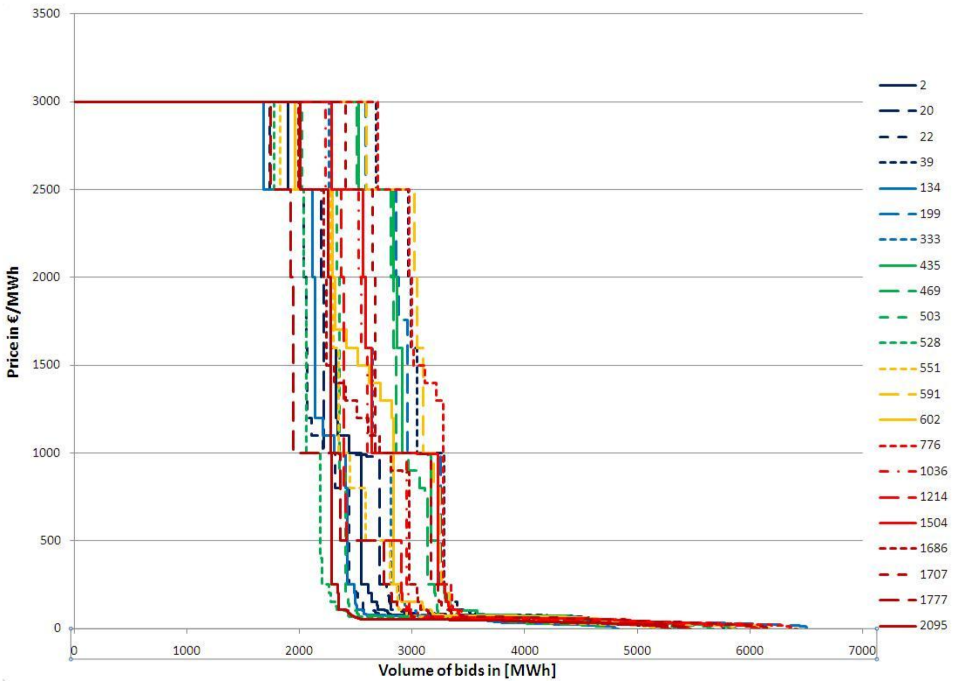


Figure 32: Lower part of the purchase curves (<200 €/MWh) for working days in October 2009, hour 13. Different colours show the forecasted amounts of wind generation, ranging from 2 MWh (blue) to 2095 MWh (red).

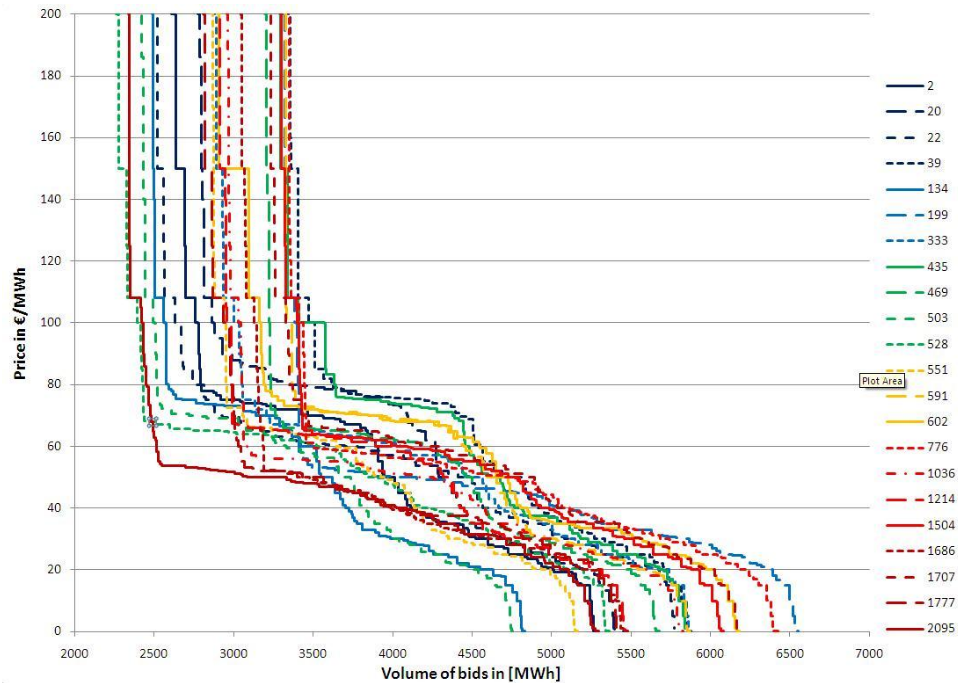


Figure 33: Cumulative volume of purchase bids in October 2009 for different price levels (450, 10.01 and 0 €/MWh) as function of forecasted wind generation.

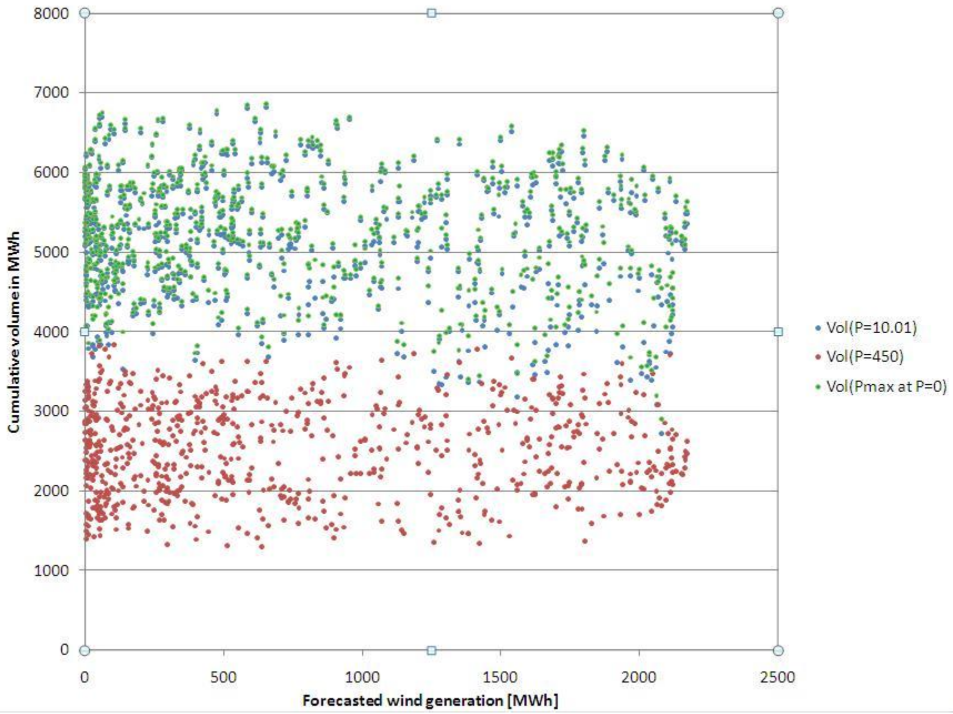
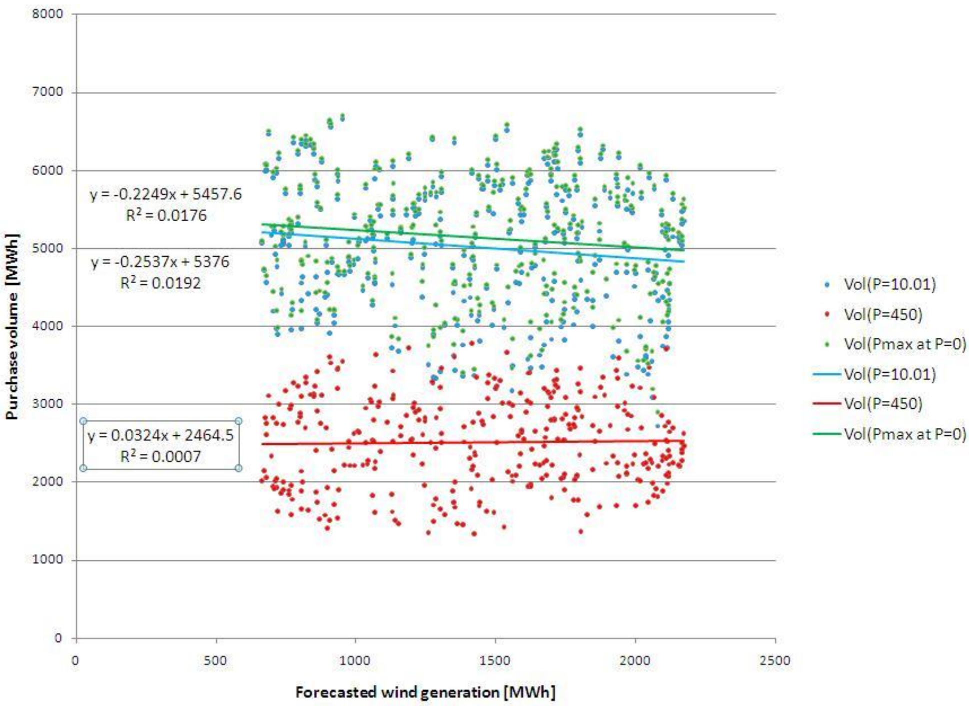


Figure 34: Cumulative purchase bids at different price levels (450, 10.01 and 0 €/MWh) for higher than average wind forecasts in October 2009.



Appendix E. Impact of wind on annual APX prices

Table 18 summarizes the main findings regarding the impact of wind on the APX day-ahead market clearing prices in recent years. There are two different ways to determine the annual average APX price:

a) The first is to divide the total turnover in a year in € by the total volume in MWh. APX-ENDEX supplies time series with hourly values of market clearing price and hourly market clearing volume. These volumes have been used as weights to calculate a volume-weighted average price. This is similar to the common use of the phrase 'average price' of a commodity.
b) APX-ENDEX also provides a daily or monthly index of the day-ahead market prices which is calculated as a simple (non-weighted) average of the hourly values. In **Table 18** and **Table 19** this average is shown in the second row and is called the APX_{base} index.

Differences between these two alternatives for calculating an average annual price are only about 1%. For the sake of completeness the alternative based on the APX_{base} index are shown in **Table 18** and **Table 19**, but they are not used in the rest of the analysis.

The next two rows in **Table 18** and **Table 19** show two different estimates of the APX prices in case there would be no wind power output. The first is based on APX values when the wind generation is below 200 MWh per hour. And the second is based on a regression analysis using wind generation, the temperature in the centre of the Netherlands (De Bilt) and the day of the week as independent variables (see 35). For the differences in hourly values between these two alternative methods, one can compare the black and red lines in **Figure 5**. It shows that both estimates are close to each other. Annual averages based on these two methods differ by only 1-2%.

For the wind energy subsidy in the SDE scheme it is relevant to know the value of the generated wind electricity at (APX day-ahead) market prices. The '*profile cost'* of wind energy is defined as the difference between the annual average APX price and the APX at the times of wind generation (also called here the *wind energy price*). It combines two effects which cannot easily be separated from each other: a) on average, more wind power is generated in the middle of the day when APX prices are higher than average[10]. And b) The amount with which wind generation depresses APX prices during times of wind generation. The profile cost is calculated by averaging the APX day-ahead price by using the volume of wind generation as weights, and comparing this with the average APX price. As discussed before, the annual average APX can be determined in two alternative ways, providing two alternative estimates of the expected profile cost (a weighted average and an index). Note that since wind forecasts are used instead of

10 On shore wind speeds are on average relatively higher during the day, when also the APX prices are higher. Therefore only this first effect would result in a net benefit (wind prices would be higher than the average APX price).

actual wind measurements, the resulting outcomes are 'expected values' for the profile costs. The above mentioned two effects work in opposite directions, the first leading to an expected increase in wind energy prices, while the second causes a decrease. Since the net effect obtained, turned out to be always a decrease in prices, this implies that the second effect of wind generation reducing market prices is the dominant one.

In the last two rows of **Table 18** and **Table 19**, the reduction in the value of the wind is provided based on the two alternative ways of determining the APX prices in the absence of wind generation. From these figures it can be concluded that for wind turbine owners, wind power has reduced wind energy prices, i.e, the value of electricity at times that wind power is generated, by about 6.6 €/MWh, which is a reduction of approximately 12% of the APX price[11] in case there would be no wind[12]. In **Table 19**, the same figures of **Table 18** are presented but in the form of ratios compared to the estimated APX price based on the regression analysis assuming no wind generation.

Table 18: Impact of wind on annual average APX day-ahead market prices over the years 2006-2009 in €/MWh.

Impact on prices (annual averages in €/MWh)	2006	2007	2008	2009	Average
1) APX-volume –weighted average APX price	58.27	43.60	70.68	39.63	53.04 €/MWh
2) Hourly average APX (APXbase index)	58.09	41.76	70.68	39.17	52.28 €/MWh
3) No wind APX (based on wind class <200 MWh)	61.85	48.01	75.94	41.19	56.75 €/MWh
4) No wind APX (based on regression analysis)	61.27	45.31	76.05	14.40	56.01 €/MWh
5) Wind-weighted average APX price	54.64	39.24	65.77	37.94	49.40 €/MWh
6) Average APX weighted non-wind production	59.14	44.93	72.95	39.73	54.19 €/MWh
7) Expected profile cost based on average APX (=1-5)	3.63	4.36	4.90	1.69	3.65 €/MWh
8) Expected profile cost based on APXbase index (=2-5)	3.45	2.52	4.31	1.23	2.88 €/MWh
9) Reduced value of wind (based on wind clas <200 MWh): (=3-5)	7.21	8.77	10.17	3.25	7.35 €/MWh
10) Reduced value of wind (based on regression analysis): (=4-5)	6.63	6.07	10.28	3.46	6.61 €/MWh

[11] This is in line with findings from other studies: TradeWind mentions a 6€/MWh reduction of spot prices in Spain in 2006, equivalent to 5% per 1000 MWh-wind. For Denmark these reduction percentages were 14% in West Denmark and 5% in East Denmark in 2005 (http://www.trade-wind.eu/fileadmin/documents/publications/D4.1_Summary_report_of_market_rules.pdf)

Oberstein finds for the German EEX a reduction in 2006 from 50.9 to 45.1 €/MWh http://www.univie.ac.at/crm/simopt/Obersteiner_Redl_ENERDAY_long.pdf

[12] Note the difference with the impact on the average APX, which is about 3.65€ or 6.3%. The impact of wind on APX prices for wind generators is about twice as high as the impact of wind on the average APX price.

Table 19: Impact of wind on annual average APX day-ahead market prices over the years 2006-2009 (same as previous table but expressed as % of the estimated prices assuming no wind generation).

	Impact on prices (annual averages in €/MWh)	2006	2007	2008	2009	Average
1)	APX-volume –weighted average APX price	59.10	96.23	92.93	95.72	94.99%
2)	Hourly average APX (APXbase index)	94.81	92.16	92.15	94.62	93.43%
3)	No wind APX (based on wind class <200 MWh)	100.95	105.96	99.85	99.49	101.56%
4)	No wind APX (based on regression analysis)	100.00	100.00	100.00	100.00	100.00%
5)	Wind-weighted average APX price	89.18	86.60	86.49	91.64	88.48%
6)	Average APX weighted non-wind production	96.52	99.16	95.93	95.97	96.89%
7)	Expected profile cost based on average APX (=1-5)	5.92	9.63	6.44	4.08	6.52%
8)	Expected profile cost based on APXbase index (=2-5)	5.63	5.56	5.66	2.98	4.96%
9)	Reduced value of wind (based on wind clas <200 MWh): (=3-5)	11.77	19.36	13.37	7.85	13.09%
10)	Reduced value of wind (based on regression analysis): (=4-5)	10.82	13.40	13.51	8.36	11.52%

By summarizing the impact of wind on electricity prices per unit of wind generation one can use these specific[13] figures to estimate future price impact developments. In two tables this is presented for both the *average APX* prices (**Table 20**) as well as for the *wind energy* prices[14] (**Table 21**). Table **Table 20** shows that for every 1000 MWh of additional wind generation in an hour, the APX price is depressed by almost 10%. With the wind capacity factor (annual average generation/installed capacity) as shown in the one but last row of Table **Table 20**, the figures per unit of energy can be transformed into per unit of capacity. Expressed in relation to the installed wind capacity: Every 1000 MW of installed wind capacity leads to a day-ahead price reduction of 3%.

Table 20: Summary of impact of wind on *average APX* day-ahead market prices over the years 2006-2009.

	2006	2007	2008	2009	Average
Average APX price	58.27	43.60	70.68	39.63	53.04 €/MWh
Average APX with no installed wind	61.27	45.31	76.05	41.40	56.01 €/MWh
Average forecasted wind generation	425	552	652	661	572 MWh-wind/hour
Average ΔAPX/MWh-wind	-0.0071	-0.0031	-0.0083	-0.0027	-0.0053 €/MWh/MWh-wind
Δ%APX/1000 MWh-wind*)	-12.1	-7.1	-11.7	-6.8	-9.4 %/1000MWh-wind
Wind capacity factor	30.6	33.4	32.9	29.8	31.7 %
Δ%APX/1000 MWh installed wind*)	-3.7	-2.4	-3.8	-2.0	-3.0 %/1000MW-wind

*) as percentage of average APX day-ahead price

13 Specific in this context means per unit of power or per unit of energy.

14 This the annual average APX price weighted by the volume of hourly wind generation.

The impact on wind energy prices is even larger than on the average day-ahead prices. **Table 21** shows the impact on wind prices per unit of wind generation and per unit of installed capacity. Over the years 2006-2009 an average wind price reduction of 6.6% per 1000 MW of installed wind capacity was found.

Table 21: Summary of impact of wind on *wind energy* prices on the day-ahead market over the years 2006-2009

	2006	2007	2008	2009	Average
Average APX price	54.64	39.24	65.77	37.94	49.40 €/MWh
Average APX with no installed wind	61.27	45.31	76.05	41.40	56.01 €/MWh
Average forecasted wind generation	425	552	652	661	572 MWh-wind/hour
Average ΔAPX/MWh-wind	-0.0156	-0.0110	-0.0158	-0.0052	-0.0119 €/MWh/MWh-wind
Δ%APX/1000 MWh-wind*)	-25.5	-24.3	-20.7	-12.7	-20.8 %/1000MWh-wind
Wind capacity factor	30.6	33.4	32.9	29.8	31.7 %
Δ%APX/1000 MWh installed wind*)	-7.8	-8.1	-6.8	-3.8	-6.6 %/1000MW-wind

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