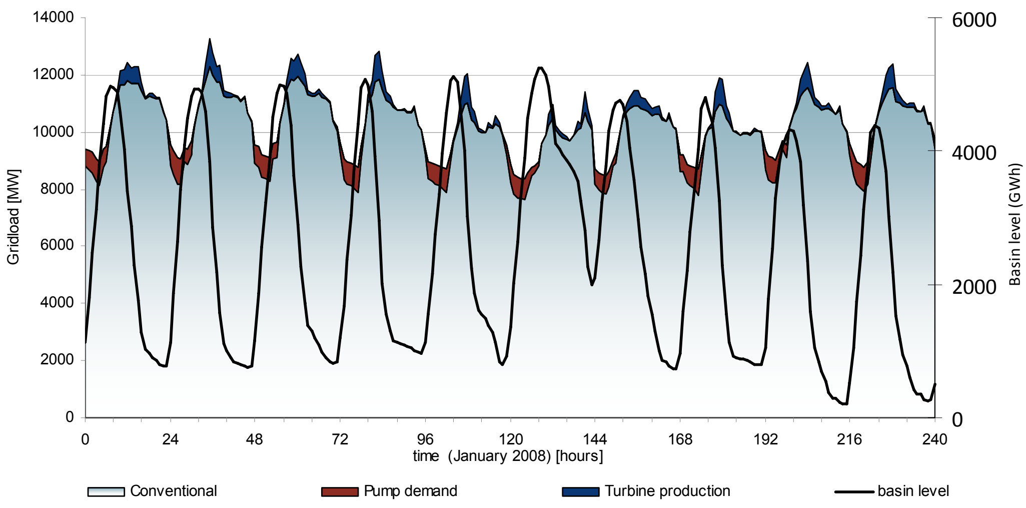
Universiteit Utrecht

Large Scale Electricity Storage in The Netherlands

A quantification of the costs and benefits for 2020 and 2030

Public Report



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Large Scale Electricity Storage in The Netherlands

A quantification of the costs and benefits for 2015, 2020 and 2030

Preliminary Public Report

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EXECUTIVE SUMMARY

Background and objective

Large scale electricity storage is proposed as a possible solution for the inclusion of large capacities of wind power in the Dutch electricity supply. It is also argued that these systems reduce the need for control and reserve capacity and can optimize electricity tariffs.

The objective of this study is to present a quantification of the costs and benefits of large scale electricity storage and to challenge an earlier study from 2008 under the super vision of SenterNovem that concluded that it is possible to include 4 – 10 GW of wind capacity in the electricity supply without additional measures, that the environmental consequences of the storage are negative and that their might be a potential business case for an electricity storage project.

Method

An electricity market model was developed with detailed demand and supply side information, based on public available data. The model optimizes the operational costs and price setting occurs on the principles of a power market with a market-clearing price, as is common in an electricity market such as the APX.

The model was validated with historic data and proved to produce results similar to historic data. It was validated based on the CO2-emissions (at the level of individual plants), consumption of coal and natural gas for electricity production and production of electricity generated from wind and PV.

Data and assumptions

Fuel prices were based on the Updated Global Economy energy scenario from the Energy Research Centre of the Netherlands (ECN). Electricity demand was based on the 2008 load profile and assumed to grow by 2% annually. The assumptions about the future installed capacity were based on the current installed capacity, announced projects and the renewable targets of the government. An overview of the main assumptions from this study is presented in Table 1.

		2015	2020	2030
Electricity demand	[TWh]	139	157	193
Export	[TWh]	30	25	20
Coal price	[EUR/GJ]	2.01	2.03	2.10
Natural gas price	[EUR/GJ]	6.07	6.42	6.74
CO2 price	[EUR/tonne]	20	35	50
Natural gas capacity	[GW]	19	20	26
Coal fired capacity	[GW]	7.8	7.8	5.8
Nuclear	[GW]	0.49	0.49	2.1
Wind	[GW]	4.8	10.0	14.0
PV	[GW]	0.15	0.80	5.0
Other	[GW]	1.6	1.6	1.2
Total installed	**[GW]**	**33**	**41**	**54**

Table 1: Overview of main assumptions.

For the electricity storage a system with a pump/turbine capacity of 2 GW and a storage capacity of 16 GWh was chosen, operated with a philosophy that aims to maximize the individual gross margin by the trading of electricity.

Results and conclusions

The performance of the electricity storage is depending on the installed capacity in the electricity supply.

The electricity production from the storage is in the range of 1 – 2 TWh annually. 100% Utilization would result in 5.8 TWh annually. The performance of the storage is correlated to the amount of renewable capacity in the electricity supply. This correlation is demonstrated in Figure 1, which shows a clear decline in utilization as the relative market share of renewable generators increases.

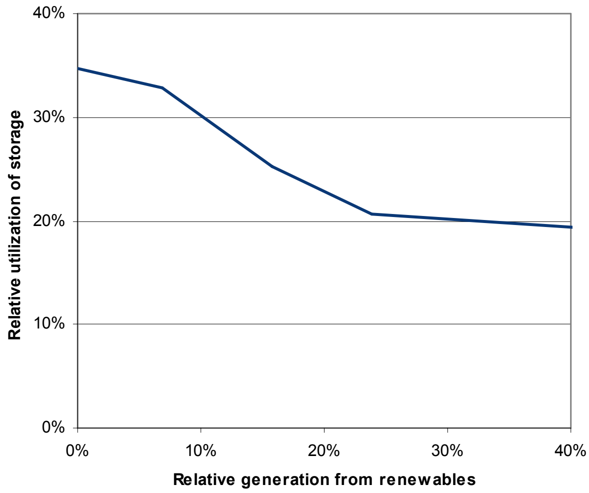


Figure 1: Utilization of the electricity storage as a function of the share of renewables in the electricity supply.

The gross margin made on trading electricity was observed in the range of 0 to 35 mln EUR/year and the avoided costs for reserve capacity where observed in the range of 0 – 300 mln EUR/year.

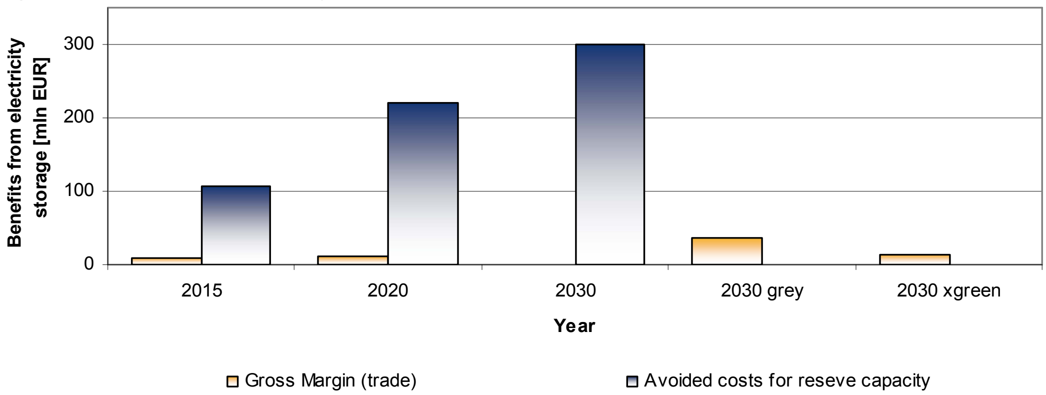


Figure 2: Gross margin and avoided costs for reserve capacity by storage.

In Figure 2 the results for the years 2015, 2020 and 2030 are displayed next to two sensitivity scenarios for the year 2030. A grey 2030 scenario, without any renewable capacity installed, and an extreme green scenario, with almost twice as much renewable capacity installed, combined with a very flexible conventional portfolio of plants.

A simple economical evaluation was made on the performance of the storage. In all analyzed situation the Simple Pay Back Time was 10 years or more. It is concluded that an electricity storage project is not a potential business case for a commercial investment.

Electricity storage can cause an emission reduction

The inclusion of a large scale electricity storage in an electricity supply with a large installed capacity of wind power can reduce the climate impact of the electricity supply in the range of 0 to 6 kg_{CO2}/MWh. This will results in a reduction 0 to 1.5 Mtonne annually by the electricity supply system, depending on the assumptions made about installed capacity and fuel prices. The reduction is achieved by limiting the part load operation of conventional power plants during times of planned electricity production from wind. The results of storage on the specific CO2-emissions for electricity generated in the Netherlands are displayed in Figure 3 and listed in Table 2.

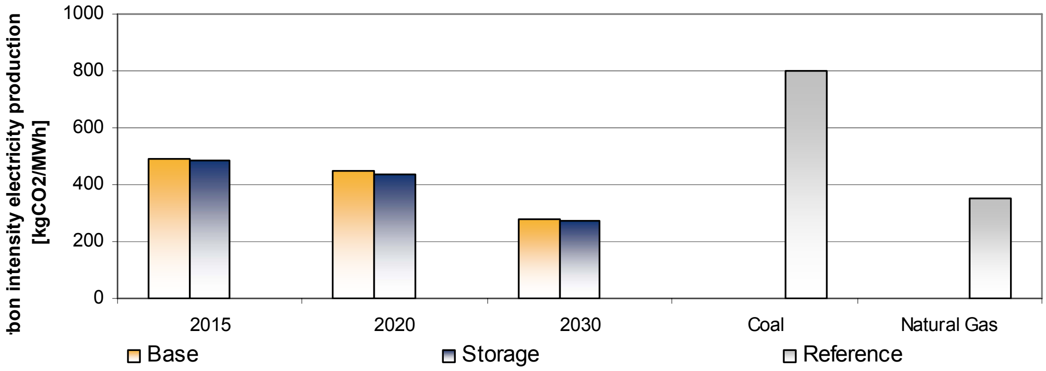


Figure 3: Estimated specific CO2-emissions from electricity generated in the Netherlands in 2015, 2020 and 2030.

		2015	2020	2030	Coal	Natural Gas
Base	**[kg/MWh]**	492	446	280	800	350
Storage	**[kg/MWh]**	486	438	274	800	350

Table 2: Estimated specific CO2-emissions from electricity generated in the Netherlands in 2015, 2020 and 2030.

It is possible to include 10 GW wind capacity without measures or losses

From analyses of “extreme” situations, with maximal availability of electricity from wind in a time segment with minimal demand and export of electricity was observed that it is possible to include the target of 10 GW of installed wind turbine capacity in 2020 without loss of wind energy, even if no additional measures are taken.

Electricity storage can reduce the operational costs of wind energy.

The inclusion of large scale electricity storage in the electricity supply can reduce the operational costs of large capacities wind energy, resulting from contracting or planning reserve capacity, by 7 to 11 EUR/MWh produced from wind.

Electricity storage is a potential strong tool for price manipulation

A decrease in wholesale electricity base load market price in the range of 1 to 5 EUR/MWh was observed and for peak prices up to 10 EUR/MWh (Figure 4). The effects on the revenues from electricity production for the wholesale market (by price manipulation) can be several times than the gross margin of the storage itself. This makes the storage an inviting potential tool for price manipulation, downwards and possibly upwards as well.

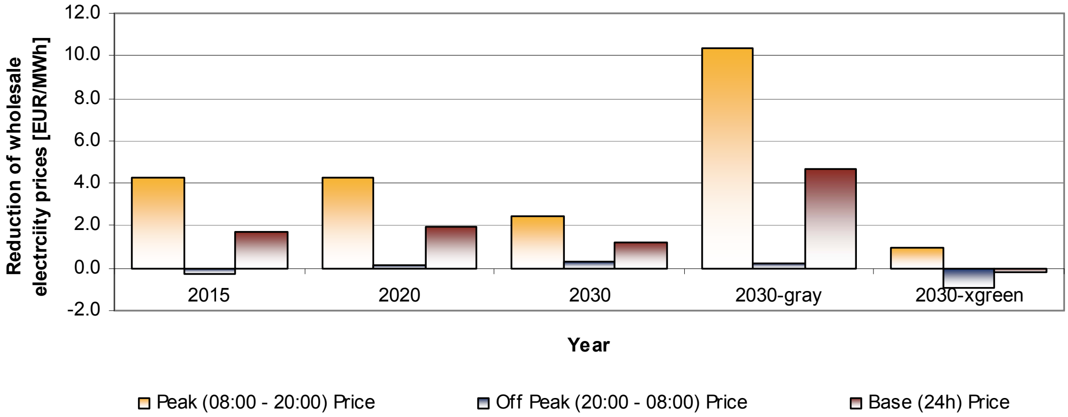


Figure 4: Reduction of wholesale electricity prices by the electricity storage

Results from other studies

The results found in this study are less extreme than found in an earlier study. This is caused by the lower utilization of the storage. The results for the environmental performance are the opposite to those found in an earlier study under the supervision SenterNovem. This difference is caused by the part load operation of conventional plants, to include wind energy in the system, while maintaining a reliable electricity supply. This effect was not explicitly taken into account by that study.

From the results of this study is concluded that the reduction of part load operation of conventional units (as a feedback effect of the inclusion of wind energy) is the major impact of large scale electricity storage and cannot be neglected in an electricity supply with a high penetration of intermittent, renewable capacity.

1. INTRODUCTION

1.1 PROBLEM DESCRIPTION

The Dutch government has the ambition to integrate 10 GW of wind power in the electricity supply by 2020 (Ministry of Economic Affairs [EA], 2008). 6 GW of this capacity is to be installed off-shore and 4 GW on shore. Wind power is an intermittent source of electricity and the possible integration of large scale wind capacity in the electricity supply is not unlimited: A reliable electricity supply has to be maintained, while the maximum potential of available wind capacity is to be used.

The demand and supply of electricity need to be in balance at all times to maintain grid stability. The absence of electricity production from intermittent sources needs to be covered by other generating capacity, for the case were supply from these sources is low or absent. And in the case of more supply from intermittent sources than actual demand, in this case the electricity feed in from these sources may have to be limited to maintain grid stability.

Several large scale electricity storage projects for the Netherlands have been proposed as a possible (better) solution (Boonekamp et al., 2008). And besides being a solution for the integration of large scale wind capacities it is argued that storage facilities have other advantages since they reduce the need for control and reserve capacity and can optimize electricity tariffs (KEMA, 2009). The proposed projects have storage capacities up to 16 GWh and pump / turbine capacities up to 2 GW.

These systems have their drawbacks as well. Load/Unload efficiencies typically range from 70-85% and their tariff optimizing benefits are typically accompanied by a more CO2-intensive fuel mix. There is approximately 40 GW of storage capacity installed in Western Europe.

1.2 BACKGROUND

Upon request by members of parliament a study to the benefits for society of large scale electricity storage was undertaken. The results of this study were published in February 2008 in the report “Research to the added value of large scale electricity storage in the Netherlands” (Boonekamp et al., 2008)

The main conclusions of this research are:

1. It is possible to integrate 4 – 10 GW of wind power capacity in the Dutch electricity supply, without loss of wind energy, without additional measures (such as storage, increased interconnector capacity, etc).
2. The environmental consequences of electricity storage are negative.
3. There might be potential for a business case for a private party.

This study can be critiqued on the following points:

1. For the annual electricity demand, two scenario's for 2020 were taken, low electricity demand: 139 TWh and high electricity demand: 159 TWh in 2020. These correspond to respectively 1 to 2 % growth with respect to 2008 demand. These are based on energy scenarios made by ECN. The reports do not mention the spread (load curve) of this demand or the sensitivity of the results to this. For electricity market modeling the spread of this demand over the day and year is just as important as the total extra demand.

2. The study lacks the influences of other renewable targets/ambitions or developments for 2020 such as: 870 MWe of Micro CHP installed, possibly 600 MWp Solar PV.

3. The representative of some of the storage projects has made remarks about some of the starting points and assumptions made in the study. These include the uncertainties about assumptions of the future, the lack of results beyond 2020 and the benefits of storage systems in extreme situations.

4. The conclusion that 10 GW of wind capacity can be included in the Dutch electricity supply, without losses, raises some questions, like:

> In 2008 the lowest demand in the Netherlands was 7,9 GW (Tennet, 2009). This raises question about the conclusion that with 10 GW installed wind capacity can be fully absorbed by the system in 2020.
>
> At maximum generation, conventional capacity is switched to partload or off. This will lead to lower efficiencies (coal), extra start/stop losses and destruction of CHP potential, as bigger industrial installations will switch to produce steam with their back-up boilers, etc. The losses involved are not mentioned in the report.

1.3 STUDY OBJECTIVE

To quantify the costs and benefits of the integration of large scale electricity storage in the Dutch electricity supply in 2020 and 2030, taking into account the influence of load patterns and external effects.

1. To quantify the costs and benefits of a large scale electricity storage facility compared to an electricity supply without such a system in 2020 and 2030, for:
- The environment (emissions of CO2)
- The economy (price of electricity)
- A possible investor (Annual Revenues, Gross Margin)
- Electricity suppliers, both conventional as renewable (Gross Margin)
- Consumers (price of electricity)

2. To investigate the sensitivity to relevant assumptions such as:
    - Fuel and CO2 prices
    - Electricity demand and load patterns
    - Amount and type of installed generation capacity in 2020 and 2030

3. To analyze an electricity supply with and without storage in extreme situations.
    - Maximum electricity demand & minimal production.
    - Maximum wind power & minimal electricity demand.

2. METHODS AND APPROACH

A merit order electricity market model was created to quantify the costs and benefits of large scale electricity storage in the Dutch electricity supply and to investigate the sensitivity on assumptions. The functioning of this model, including the level of detail, simplifications and underlying assumption, is explained in this chapter.

2.1 OVERVIEW OF THE MODEL

A bottom-up (engineering) approach was used to simulate the power market: a least cost optimization model or merit order model. It includes a high level of detail of both electricity supply (a power plant database) and a high level of detail about electricity demand (load curves, with electricity demand for every hour in the year).

2.1.1 Dispatching of units

The electricity market is characterized by the requirement that demand and supply of electricity need to be in physical balance at all times. Physical supply of electricity is matched to the physical demand at the least cost in the model. The model ranks the power producing units in order of their least Short Term Marginal Generating Costs (STMGC). This ranking is referred to as the Merit Order. For every time segment the units are dispatched in the order of their dispatch ranking until the demand for electricity is fulfilled at the least cost.

The basic functioning of the model in the base case is visualized in Figure 5**Fout! Verwijzingsbron niet gevonden.**. A Clear distinction has been made between the electricity supply part (left) and the electricity demand part (right) of the model. The interaction between the two parts is a physical flow of electricity and a monetary flow in the opposite direction.

The demand part of the model contains detailed information about the demand for electricity on an hourly basis. The supply part of the model contains detailed information about all the electricity generators in the simulated market.

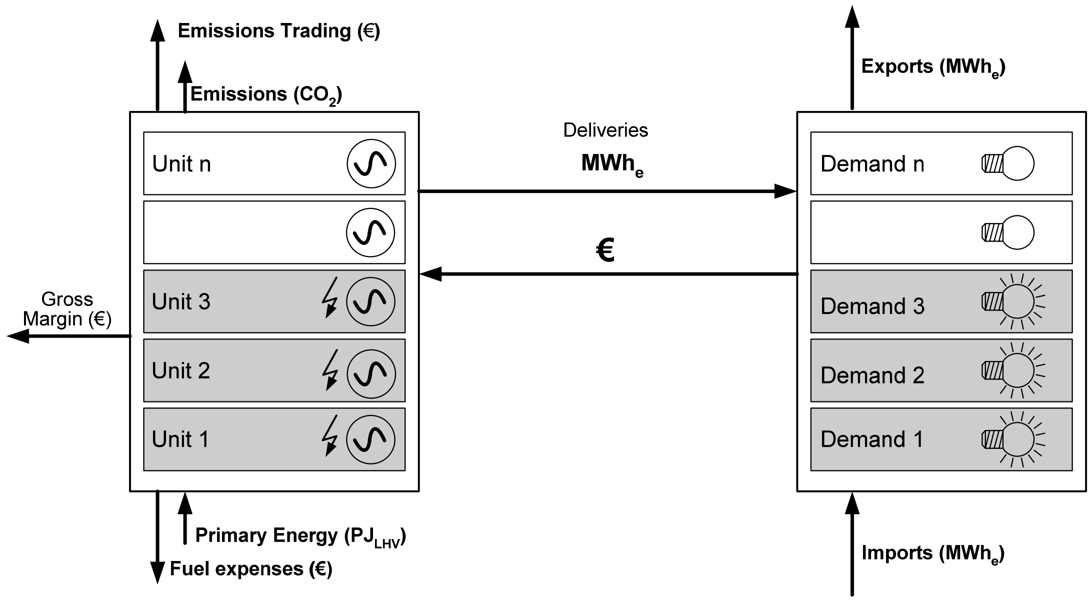


Figure 5: Simplified principle behind the model (base case).

2.1.2 Price setting in the model

It is assumed that the last (most expensive) unit necessary to be dispatched for a certain time segment will set the electricity price for that time segment. As a result, the latest unit will make no Margin (and no loss), all the other will make a margin that is equal to the electricity price (set by the STMGC of the latest unit) minus the STMGC of the own unit.

This type of price setting in the model approaches an auction with a single market-clearing price rule. All generators offer electricity at a price close to their STMGC and all receive the price for the highest accepted bid: a single price, named the market-clearing price.

For every hour of the year the electricity demand is fulfilled by dispatching just enough units. Since, electricity generation from wind and PV is characterized by having STMGC of zero, these technologies will be given the preference over conventional technologies (biomass, coal or gas fired).

Besides the base case there is a storage case as well. The storage case differs from the base, by having a storage system included. This is visualized in Figure 6**Fout! Verwijzingsbron niet gevonden.**.

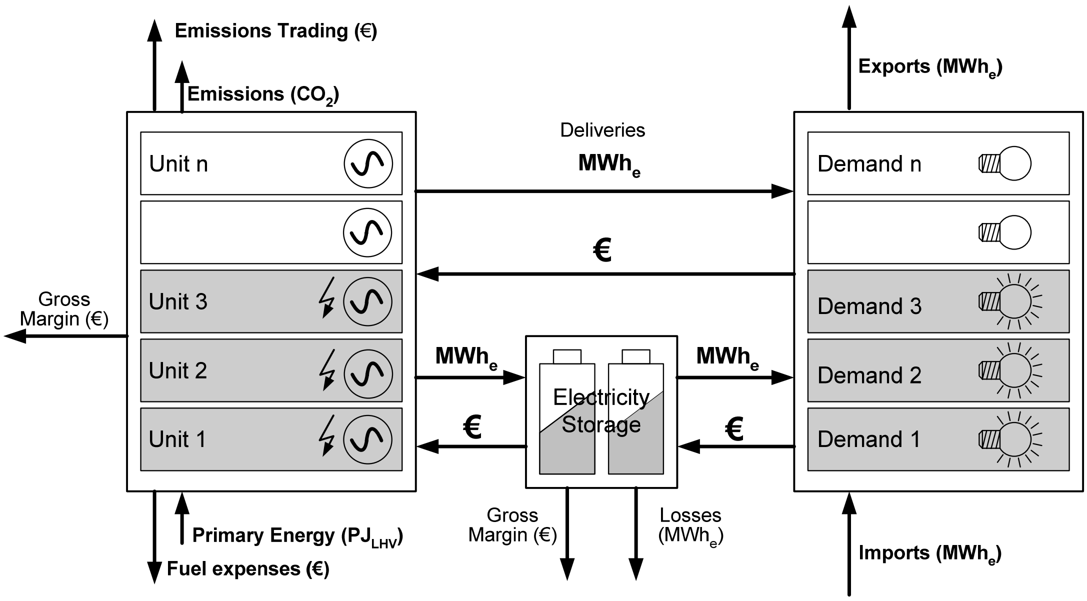


Figure 6: Model principle, storage case.

A simple representation of the electricity flows in the modelled electricity supply is made in Figure 7**Fout! Verwijzingsbron niet gevonden.**. The system is simplified to 7 main flows: Demand, renewable production, storage production, storage demand, production from conventional units, export of electricity and import of electricity. Several electricity meters (m1 – m7) are placed in the system to measure these main flows. They are described in Table 3**Fout! Verwijzingsbron niet gevonden.**.

Meter	Description
m1	Electricity Demand
m2	Production of electricity from wind, PV and micro CHP
m3	Electricity demand from storage pumps
m4	Electricity production from storage turbines
m5	Electricity production from conventional units
m6	Export of electricity
m7	Import of electricity

Table 3: Descirption of electricity meters in figure 3.

For every time segment the model calculates the amount of electricity that has to be produced domestically (m1 + m6 –m7). The production measured at meter m2 is weather dependent. The production left for the electricity storage and conventional units: m5 + m4 – m3 = m1 + m6 – m7 – m2.

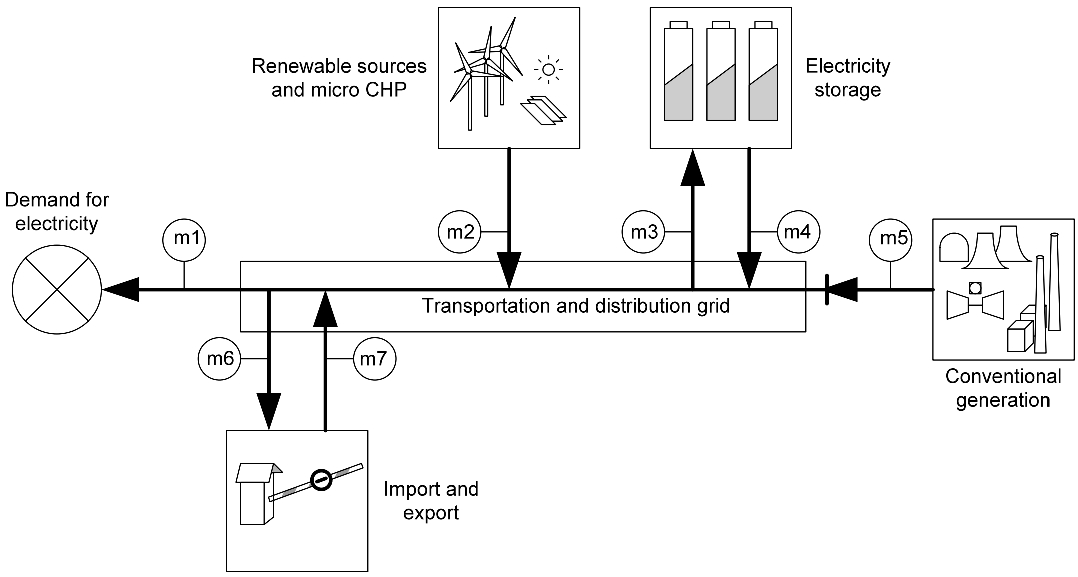


Figure 7: A simple diagram of the modelled electricity supply with storage.

2.2 PRODUCTION FROM RENEWABLE SOURCES AND MICRO CHP

2.2.1 Wind energy

The electricity production from the installed wind turbine capacity is modelled by five wind parks. The production for each park at every time segment is derived from the power - velocity curve (Pv-curve). This curve describes the relation between the wind speed at hub height and the power output. In Figure 8**Fout! Verwijzingsbron niet gevonden.** a Pv-curve is displayed, were the power output (P_{out}/P_{max}) is specified relative to the maximum power output.

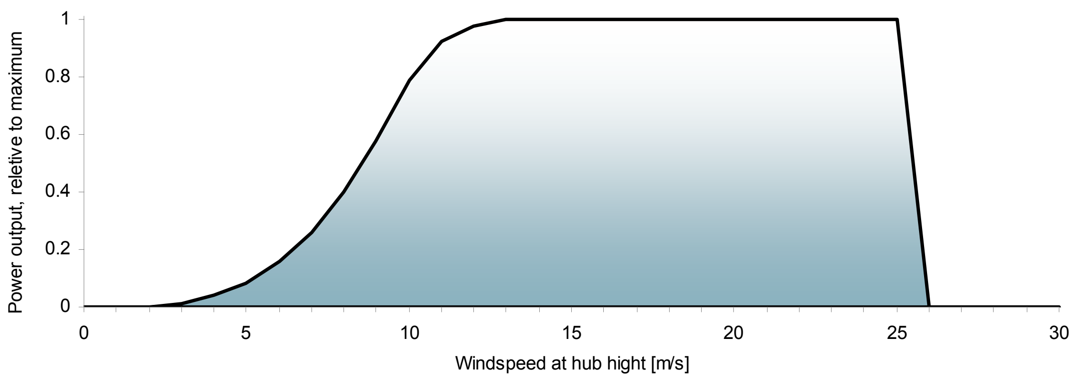


Figure 8: The relative Power-Velocity curve of the E82 Windturbine (Enercon, 2009).

The use of the Pv-curve to estimate the power output requires the wind speed at hub height. Wind speeds are higher at larger heights. There are relatively limited historic measurements at hub height (typically 60-100m) Wind speeds are measured by the Royal Netherlands Meteorological Institute at height h_{ref} = 10 m. The wind speed at hub height is approached with Equation 1**Fout! Verwijzingsbron niet gevonden.**.

$$\frac{v_h}{v_{ref}} = \frac{\log\left(\frac{h}{z_O}\right)}{\log\left(\frac{h_{ref}}{z_O}\right)}$$

Equation 1

v_h	Wind speed at hub height	[m/s]
v_{ref}	Reference wind speed at height h_{ref}	[m/s]
h_{ref}	Height of reference wind speed measurement	[m]
h	Hub height	[m]
z_O	Surface roughness	[m]

Equation 2**Fout! Verwijzingsbron niet gevonden.** is used to produce a matrix which specifies the electric power output for every wind park y (y=1 – 5), for every one hour time segment t (t = 0 – 8760 hours).

$$P_{e,t,y} = P_{inst,y} \cdot a_y \cdot P_{rel,t,y}$$

Equation 2

$P_{rel,t,y}$	Relative power output (P_{out}/P_{max}) at time t for wind park y	[-/-]
$v_{hub,t,y}$	Wind speed at hub height at time t for wind park y	[m/s]
$a_{,y}$	Availability factor of wind park y	[-/-]
$P_{inst,\ y}$	Installed capacity of wind park y	[MW]
$P_{e,t,y}$	Electric power output at time t of park y	[MW]

For each wind park the technology, hub height, wind regime (at 10 m altitude), surface roughness and availability factor is specified.

2.2.2 Solar PV

The estimations of production from solar PV are made with Equation 3**Fout! Verwijzingsbron niet gevonden.**.

$$P_{PV,t} = A_{PV} \cdot R_{sol,t} \cdot \overline{\eta}_{PV}$$

Equation 3

$P_{PV,t}$	Power production from PV at time t.	[MW]
A_{PV}	Installed surface of PV	[m^2]
$R_{sol,t}$	Solar radiation at time t	[W/m^2]
η_{PV}	Average electrical efficiency of A_{PV}	[-/-]

As input for the PV-production calculations the model requires the installed surface of PV, average efficiency and hourly data for solar radiation. Solar radiation is measured by the meteorological station “De Bilt”. The data is specified for every hour of the year in [J/cm2/h]. This is converted to [W/m2]. Figure 9 is included as illustration: It shows the measured solar radiation in 2008.

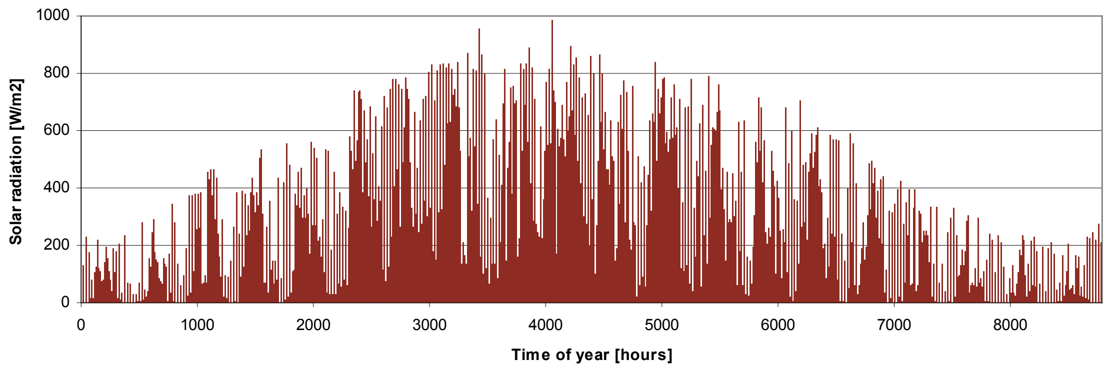


Figure 9: Solar radiation measured at station "De Bilt" for 2008. (source KNMI).

2.2.3 Micro CHP

All micro CHP installations together are modelled as one virtual power plant, driven by heat demand. It is assumed that at -20 °C and below all micro CHP installations are producing at full load to keep the living space at room temperature, while at 15 °C and above it is assumed that no heating is required. In between the power factor is linear interpolated. This results in the curve as displayed in Figure 10.

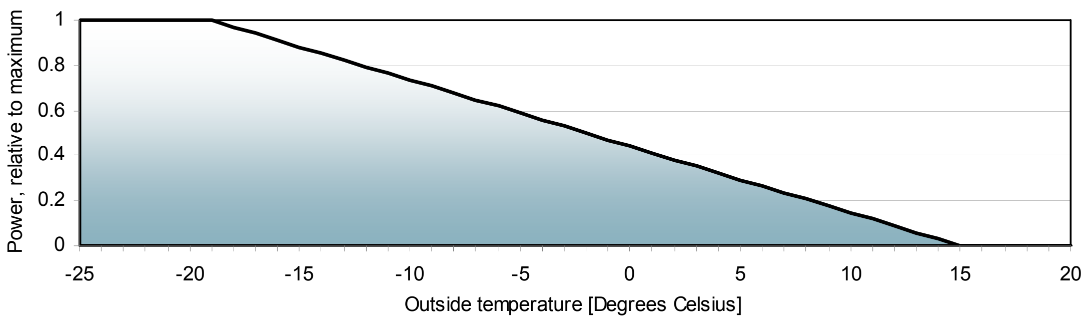


Figure 10: Assumed production as a function of temperature from micro-CHP virtual power plant.

Equation 4**Fout! Verwijzingsbron niet gevonden.** is used to estimate the electricity production from Micro CHP.

$$P_{MCHP,t} = P_{MCHP,inst} \cdot a_{MCHP} \cdot P_{MCHP,rel,t}$$

Equation 4

$P_{MCHP,t}$	Power production from micro CHP at time t	[MW]
$P_{MCHP,rel,t}$	Relative power output at time t	[MW]
a_{MCHP}	Availability of electric capacity from Micro CHP	[-/-]
$P_{MCHP,inst}$	Installed electric capacity Micro CHP	[MW]

2.3 ELECTRICITY STORAGE (STORAGE CASES ONLY)

The storage will be described as if being a pumped storage. In reality the technology could be based on pumped storage, batteries or a virtual storage by import/export with a country with large hydroelectricity capacity. The exact technology is not considered relevant for this study.

The decision making of the storage is based on a strategy to eliminate utilization of the most expensive capacity and to increase the utilization of the least expensive capacity in the specified control time span. The effects on the load profile of a singe day are visualized in Figure 11**Fout! Verwijzingsbron niet gevonden.**.

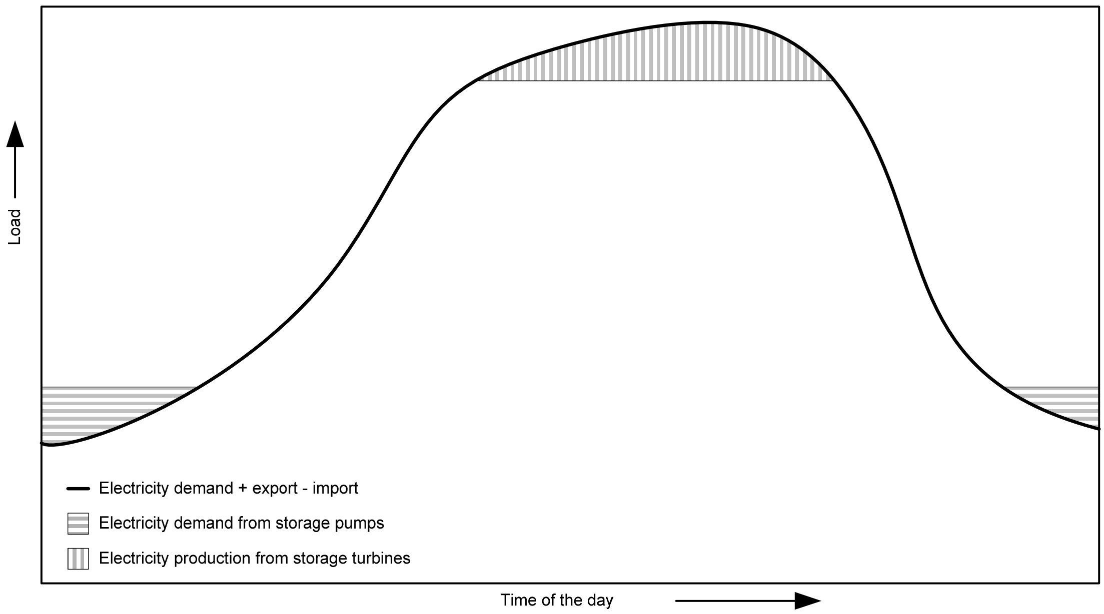


Figure 11: Impact of the operating philosophy of the electricity storage on the load profile of a single day.

2.3.1 Basic control philosophy of the storage facility

Pump operation
Every hour the storage facility will make a decision to produce electricity (turbine operation), to store electricity (pump operation) or to do nothing at all.

A decision to store is made when the following criteria are met:

1. The demand for electricity + export - import at the moment is lower than the lowest required production from conventional units during the control time span + pump capacity.
2. There is enough storage capacity left.

The deployed pump capacity is determined as follows:

Deployed pump capacity = lowest required production from conventional units during control time span + pump capacity – actual demand for conventional electricity.

Turbine operation
A decision to produce is made when the following criteria are met:

1. The demand for electricity at the moment is higher than the highest demand for conventional electricity – turbine capacity.
2. There is enough stored electricity left.

The deployed turbine capacity is determined as follows:

Deployed turbine capacity = actual demand - highest conventional demand over control time span + turbine capacity

No operation
In all other cases there is no storage or production.

2.3.2 Specification of the storage facility

The storage facility is described by the following parameters

Storage capacity	[$MWh_{production}$]
Basin level at begin of year	[$MWh_{production}$]
Pump capacity	[MW]
Turbine capacity	[MW]
Pump efficiency	[-/-]
Turbine efficiency	[-/-]
Optimization control time span	[h]

2.4 CONVENTIONAL CAPACITY

The dispatch of a conventional unit in a time segment t is depends on the actual demand for electricity in time segment t and the dispatch ranking of the unit.

To construct a cost supply curve, the Short Term Marginal Generation Costs and the electric size (power) of a unit needs to be known. The short Term Marginal

Generation Costs are calculated with Equation 5**Fout! Verwijzingsbron niet gevonden.**.

$$STMGC_y = 3.6 \cdot \frac{FC}{\eta_{operational,y}} + 3.6 \cdot f_{CO2} \cdot \frac{P_{CO2}}{\eta_{operational,y}} \cdot \frac{1}{1000}$$

Equation 5

$STMGC_y$	STMGC for unit y	[EUR/MWh]
FC	Fuel Costs	[EUR/GJ_{LHV}]
f_{CO2}	CO2 emission factor of fuel	[kgCO2/GJ_{LHV}]
P_{CO2}	Price of CO2	[EUR/tonne]
$\eta_{operational,y}$	Operational electrical efficiency	[-/-]

The sum of all variable costs influences dispatch decisions. For the sake of simplicity the variable operating and maintenance costs are not included in the model. For large scale units, these are typically in the range of 3 – 4 EUR/MWh. For reasons of simplicity, these costs were not included. By not including these costs, an error of 3-4 EUR/MWh is introduced in the electricity prices.

Fixed costs, such as capital costs and personnel costs do not influence dispatch decisions.

The electric capacity of the unit is corrected for aging and unavailability with Equation 6**Fout! Verwijzingsbron niet gevonden.**.

$$P_{operational} = P_{design} \cdot LF \cdot AF \cdot OF$$

Equation 6

$P_{operational}$	Operational Power	[MW]
P_{design}	Design Power	[MW]
LF	Load Factor	[-/-]
AF	Availability Factor	[-/-]
OF	Operational Factor	[-/-]

The electric efficiency of the unit is corrected for aging with Equation 7**Fout! Verwijzingsbron niet gevonden.**.

$$\eta_{e,operational} = \eta_e \cdot OF$$

Equation 7

$\eta_{e,operational}$	Operational efficiency	[-/-]
η_{design}	Design efficiency	[-/-]
OF	Operational Factor	[-/-]

The operational factor is determined on the basis on average curves for aging. These curves are based on in house data. The correction factor for Gas Turbine

Combined Cycle (GTCC) plants is in the range of 1 – 0.975 and for Pulverised Coal (PC) fired units in the range of 1 – 0.95.

2.4.1 Design efficiency

Calculations of the design efficiency are made with the heat and mass balances software GateCycle™ (GE Energy, 2007).

Conventional Coal fired power plants.

Coal fired steam turbine plants are simplified to a system consisting out of a steam boiler, Steam Turbine (ST) with High Pressure (HP), Medium Pressure (MP) and condensing (LP) section, condenser and Boiler Feed Water (BFW) pump. This simplified system is visualized in Figure 12**Fout! Verwijzingsbron niet gevonden.**.

Based on isentropic efficiency of the steam turbine, condenser pressure and steam turbine inlet steam parameters, the reheat pressure is optimized and the steam cycle efficiency calculated with the mass and heat balance program GateCyle™. Auxiliary power requirements for Fuel handling and DeNOX and DeSOX units are estimated to be 4 MW per 100 MW electricity produced.

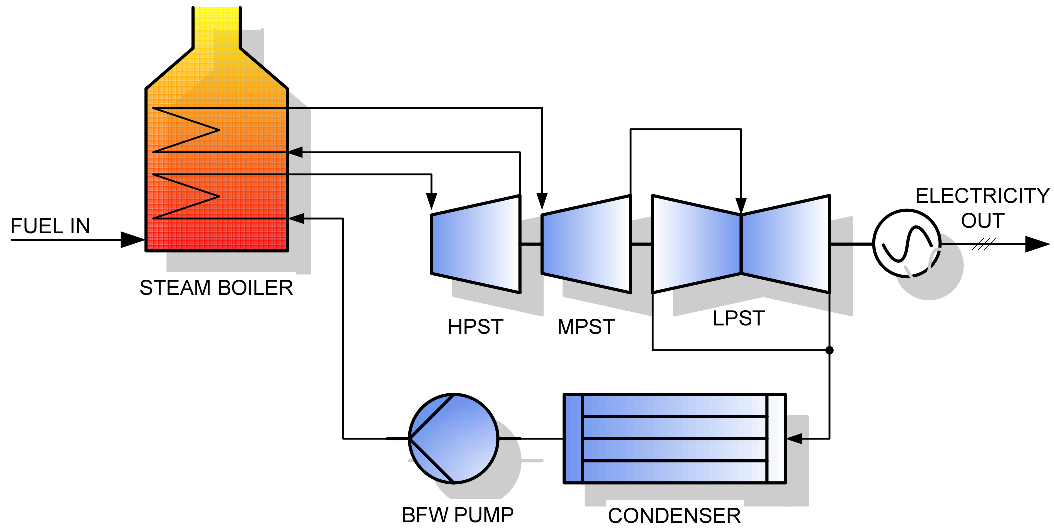


Figure 12: Simplified Process Flow Diagram of a steam turbine plant.

Conventional Natural gas fired power plants.

The steam cycle (including boiler feed water pumps and generator losses) is modelled with Gate Cycle, based on the specified turbine inlet and reheat temperatures and pressures. Auxiliary power requirements estimated to be 1 MW per 100 MW electricity produced.

Combined Cycle and Combi power plants.

The plants are modelled in Gate Cycle^{TM}, based on a gas turbine specification from the Gas Turbine World Handbook. The steam cycle properties are chosen according to the specifications.

Combined Cycle plants are simplified to a system consisting out of a Gas Turbine (GT), Heat Recovery Steam Generator (HRSG), Boiler Feed Water (BFW), condenser and steam turbine consisting out of a High Pressure (HP), Medium Pressure (MP) and condensing (LP) section. This simplified system is visualized in Figure 13**Fout! Verwijzingsbron niet gevonden.**.

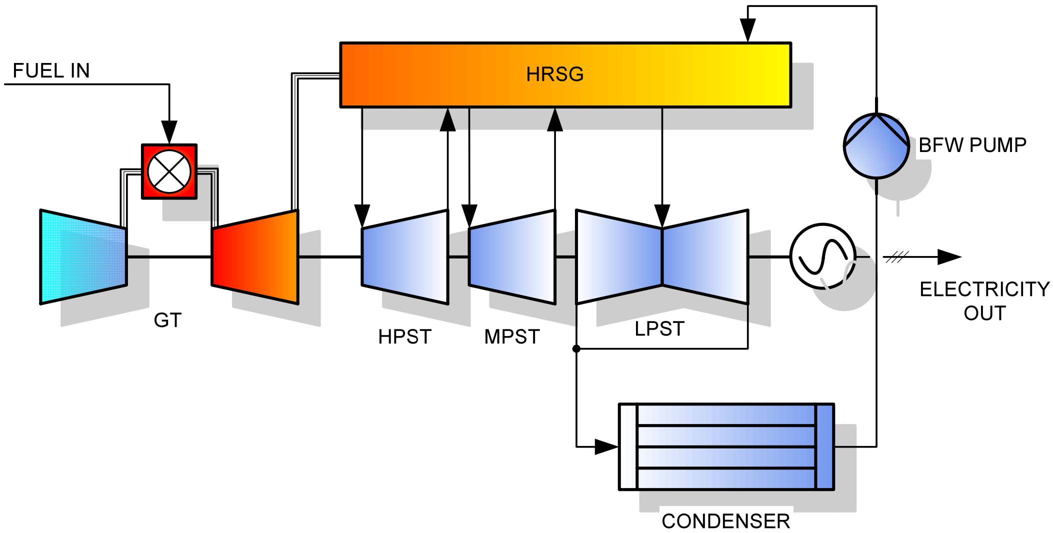


Figure 13: Simplified Process Flow Diagram of a combined cycle plant.

The efficiency and exhaust gas flow and temperature of the specified Gas Turbine (GT) are taken from literature (Gas Turbine World Handbook 1991 – 2008). The steam cycle is designed based on the exhaust gasses of the gas turbine (flow and temperature), specified steam conditions, the assumed isentropic efficiencies of the steam turbine and condenser pressure.

2.4.2 CHP Units

A significant amount of CHP capacity is installed in The Netherlands at the end of 2008:

	Electrical Capacity	Thermal Capacity
Installation type	**MWe**	**MWth**
Gas Engine	3026	4230
Steam turbine	2667	3500
Combined Cycle	5441	6757
Gas Turbine	1067	3594
Other	18	19

Total	**12219**	**18101**

Table 4: Installed CHP capacity in The Netherlands (source Statistics Netherlands, 2009).

A rough subdivision is made in three types of CHP-units:

1. Large scale plant with steam extraction from the steam turbine for low temperature heat (district heating). Examples are Amer 9 and Diemen 33
2. Small scale plants producing low temperature heat. Examples are Gas engines in supplying heat to green houses.
3. Small Industrial CHP plants

Large scale CHP plants

The large scale power plants with steam extraction for district heating are modelled in GateCycle™ as 100% power plants: without steam extraction, with a full condensing steam turbine.

Small scale CHP plants

Small scale CHP plants are not modelled individually, but in blocks of 500 MW. All small scale CHP plants are assumed to be delivering hot water. Their efficiency for STMGC calculation is the same as for industrial CHP plants, as described in the subsequent paragraph below.

Industrial CHP plants

Industrial CHP plants are typically characterised by having a fairly constant heat demand (and supply) throughout the year. For these plants a correction is made to the generation efficiency.

Most (industrial) CHP units are equipped with back up (steam) boilers for the case the CHP-unit is not available or the electricity prices are to low to be competitive.

For the correction of the efficiency all fuel savings are contributed to electricity generation by subtracting the avoided fuel- and CO2 costs from the backup steam boilers from the STMGC.

This is illustrated with a calculation example of a CHP system with the following parameters:

η_{el}	Average electrical efficiency of CHP unit	0.40	[-/-]
η_{th}	Average thermal efficiency of CHP unit	0.40	[-/-]
$\eta_{th,bsb}$	Thermal efficiency of backup steam boiler	0.90	[-/-]

To generate 40 units of electricity, 100 units of fuel are consumed; in the process 40 units of (useful) heat were generated as well. In the situation without CHP 40 / 0.9 =

44.4 units of fuel are required. The required fuel energy for the electricity production is 100 - 44.4 = 55.6 units of fuel to produce 40 units of electricity. The fuel efficiency, with all savings allocated to electricity production is 40/55.6 = 72%

The allocation of all fuel savings due to CHP to electricity production is expressed in Equation 8**Fout! Verwijzingsbron niet gevonden.**.

$$\eta_{fuel} = \frac{1}{\frac{1}{\eta_{el}} - \frac{\eta_{th}}{\eta_{el} \cdot \eta_{bsb}}}$$

Equation 8

2.4.3 Nuclear capacity

Nuclear units are specified by their capacity, efficiency and fuel costs. The fuel costs are chosen arbitrary such that the STMGC are near 10 Eur/MWh, ranking nuclear capacity highest in the merit order of conventional capacity.

2.5 BALANCING SUPPLY AND DEMAND

All generators that supply electricity to the grid are so called Programme Responsible Parties (PRPs). PRPs communicate their E-programmes (planned amounts of generated or consumed electricity per 15 minutes) ahead in time to the Transmissions System Operator (TSO).

Deviations from the E-programme are settled by the TSO (TenneT): financially and physically.

Physical: Power not supplied to the grid by a PRP has to be generated by capacity contracted by the TSO.
Financial: The TSO charges the PRP for the resulting imbalance.

2.5.1 Imbalance of conventional generators

On the electricity market there is probably always a situation of imbalance: consumption of electricity is forecasted with models, and these forecasts have an error, therefore reserve capacity is planned. To account for planning of control and reserve capacity the model lets all units run on 95% of their base load capacity.

2.5.2 Imbalance of Wind power generators

The planned wind power production is based on forecasting models. These models have a typical error, described by the Capacity Normalized Mean Absolute Forecast Error (CNMAE). It was found by D. Duguet and J. Coelingh (B. Duguet and J. Coeling, Simulated Imbalance of 8000 MW Wind Power, Ecofys, Rapport, Wind04071, 2006), that the CNMAE for a 6 hour forecast lag was between 8.5 and 11.5 %. From this results is concluded that the 99.7% confidence interval is in the range of approximately +/- 40% of the forecast.

To allow wind electricity producers to deviate from the E-programme, the model plans 40% of the forecast wind power production as (conventional) reserve capacity: When 10 GW of wind power production is forecasted, 4 GW of conventional capacity is planned as a spinning reserve. This reserve can ramp up quickly from 0 to 4 GW in approximately 50 minutes at 2%/min. (De regelbaarheid van elektriciteitscentrales, Een quickscan in opdracht van het Ministerie van Economische Zaken, TU Delft, 20 april 2009)

Fout! Verwijzingsbron niet gevonden. is introduced to illustrate the impact of wind energy on the production planning in the electricity supply. The figure presents the planning for scenarios ranging from 0 to 10 GW of production from wind turbine capacity and a constant electricity demand of 13 GW. When electricity production from wind increases, less conventional units are planned to run full load. The amount of capacity producing at part load increases, while the required spinning reserve capacity increases. In this example a demand of 13 GW can be supplied by maximum 10 GW of wind capacity. More is not possible, since the remaining 3 GW will be supplied by units running on part load.

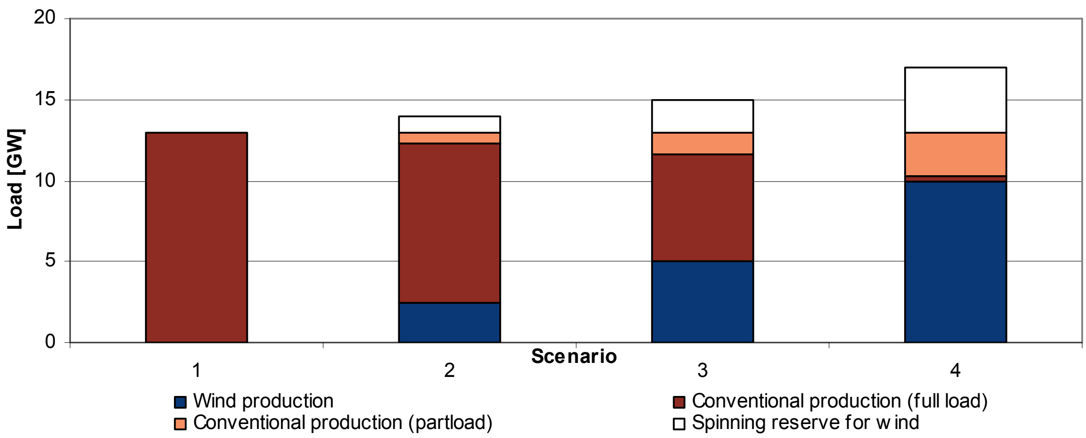


Figure 14: The impact of wind energy on capacity planning in four scenarios.

2.5.3 Determining the costs for spinning reserve capacity planning

Regardless whether the reserve capacity is reserved from units from the portfolio of the PRP, contracted by other producers or contracted by the TSO, costs are involved. These costs consist out of:

- **Opportunity costs**
  By not producing, the unit looses margin. This is especially the case for units that have low STMGC compared to the electricity price at that time.

- **Inefficiency costs**
  Units are less fuel efficient when they are operated at part load, This causes increase in STMGC due to increased fuel costs and CO2 costs.

It is assumed that the bid price for suppliers of reserve capacity is equal to sum of the opportunity costs and the inefficiency costs.

The reserve capacity costs calculation involves 4 steps:

1. The required reserve capacity is calculated from the planned wind power production.
2. The conventional capacity that can still produce at full load is calculated.
3. The price setting unit for reserve capacity is determined.
4. The opportunity costs and inefficiency costs for the price setting unit are calculated.

Calculation of the required reserve capacity

The required reserve capacity for a modeled time segment is calculated with Equation 9**Fout! Verwijzingsbron niet gevonden.**.

$$E_{imb} = P_{wind} \cdot 0.4 - P_{turbine}$$

Equation 9

Where:

E_{imb}	Require reserve capacity	[MW]
P_{wind}	Forecasted wind energy power	[MW]
$P_{turbine}$	Turbine capacity from storage	[MW]

Determining the conventional capacity that can produce at full load

The model reduces the amount of capacity producing at part load: 1 GW of spinning reserve can be delivered by 5 GW installed capacity running at 80% load or by 1.7 GW installed capacity running at 40% load. It is assumed that the last option is the case: the conventional capacity running on part load is kept minimal. The conventional capacity that can still produce at full load is calculated with Equation 10**Fout! Verwijzingsbron niet gevonden.**.

$$E_{\min} = E_c + E_{imb} - \frac{E_{imb}}{1 - PLF}$$

Equation 10

Where:

E_{min}	Conventional capacity producing at full load	[MW]
E_c	Demand – renewable production	[MW]
PLF	Part load factor (0.4)	[-/-]

Determining the price setting unit

The unit required to produce E_{min} is the unit with the lowest STMGC that is required to run part load: for this unit the opportunity costs will be the highest. It is therefore assumed that the unit that supplies E_{min} is the unit that set's the price for the reserve capacity at the specified moment.

Calculation of the reserve capacity costs

The final step is to calculate the opportunity costs and the inefficiency costs of the price setting unit. The sum of these costs is considered to be equal to the price for reserve capacity for the time segment.

The opportunity costs are calculated with Equation 11**Fout! Verwijzingsbron niet gevonden.**.

$$OC = STMGC(E_c + E_{imb}) - STMGC(E_{\min})$$

Equation 11

Where:

OC	Opportunity Cost	[EUR/MWh]
STMGC ()	Function to return the STMGC	[EUR/MWh]

The inefficiency costs are calculated with Equation 12**Fout! Verwijzingsbron niet gevonden.**.

$$IC = \frac{STMGC(E_{imb})}{PLEF} - STMGC(E_{imb})$$

Equation 12

Where:

IC	Part load Efficiency loss Cost Correction	[EUR/MWh]
PLEF	Part Load Efficiency Factor (0.8)	[-/-]

The reserve capacity price = OC + IC.

The above equations (**Fout! Verwijzingsbron niet gevonden.** to **Fout! Verwijzingsbron niet gevonden.**) are only valid for a model with a time segment of 1 hour (so 1 MW production capacity produces 1 MWh during one time segment).

2.5.4 Example of a cost of reserve capacity planning calculation

An example is provided of a reserve capacity planning calculation for 1 time segment. The cost-supply-curve in Figure 15 is provided to support the following example.

For a certain time segment, the demand + international export/import from the grid (m1 + m6 – m7) is 13 GW. The wind forecast was 5 GW. The forecast accuracy is +/- 40%. A surplus of wind production can be compensated by blade pitch control of the turbines. A shortage of wind power will have to be compensated by (hot/spinning) conventional reserve. For the capacity planning this will have the following consequences:

5 GW of electricity production from wind.
6.7 GW of installed conventional capacity is planned at full load.
3.3 GW of installed conventional capacity is planned at part load (40%, 1.3 GW).

If necessary the 3.3 GW installed capacity running at part load (producing 1.3 GW) can be ramped up to 3.3 GW.

The unit on the position of 11.7 GW on the merit order is the unit with the highest opportunity costs from all units that are planned for part load operation. It is therefore assumed that this unit is the price setting unit for reserve capacity for this time segment. With **Fout! Verwijzingsbron niet gevonden.** and **Fout! Verwijzingsbron niet gevonden.** the opportunity costs and inefficiency costs are calculated. The price for spinning reserve capacity for a time segment is equal to the sum of the opportunity cost and inefficiency cost.

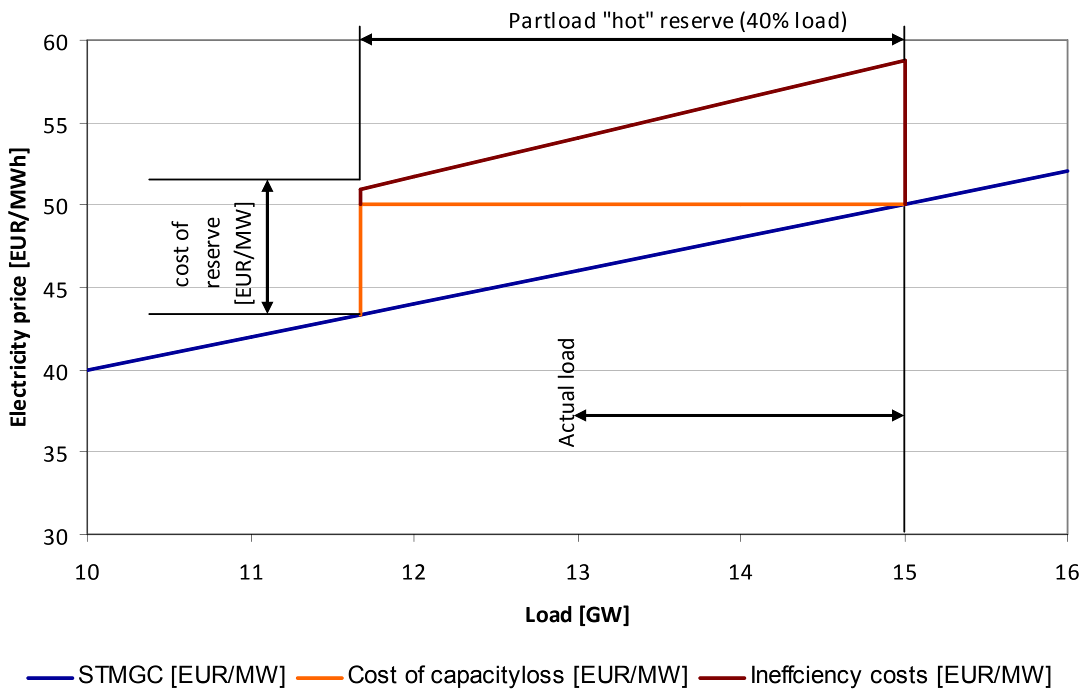


Figure 15: determining the price for reserve capacity in a time segment.

It is often stated that conventional capacity will always have to be available for the moments that there is no wind energy production. True as this is, it is not the complete story. Because at moments when there is (lots) of electricity production from wind, conventional power plants (with favourable ramp-up abilities) will have to be producing electric power to provide sufficient ramp-up capabilities due to possible deviations of the production from the forecast.

To give the reader a better understanding about how the reserve capacity is modelled, Figure 16**Fout! Verwijzingsbron niet gevonden.** is provided. This figure contains 3 graphs. The upper graph displays the electricity production planning by wind capacity, other capacity and conventional capacity over the time. The middle graph shows the required reserve capacity planning over the time and the bottom graph shows the market price of this reserve capacity (the loss in GM and losses by lower efficiency) in [EUR/MW].

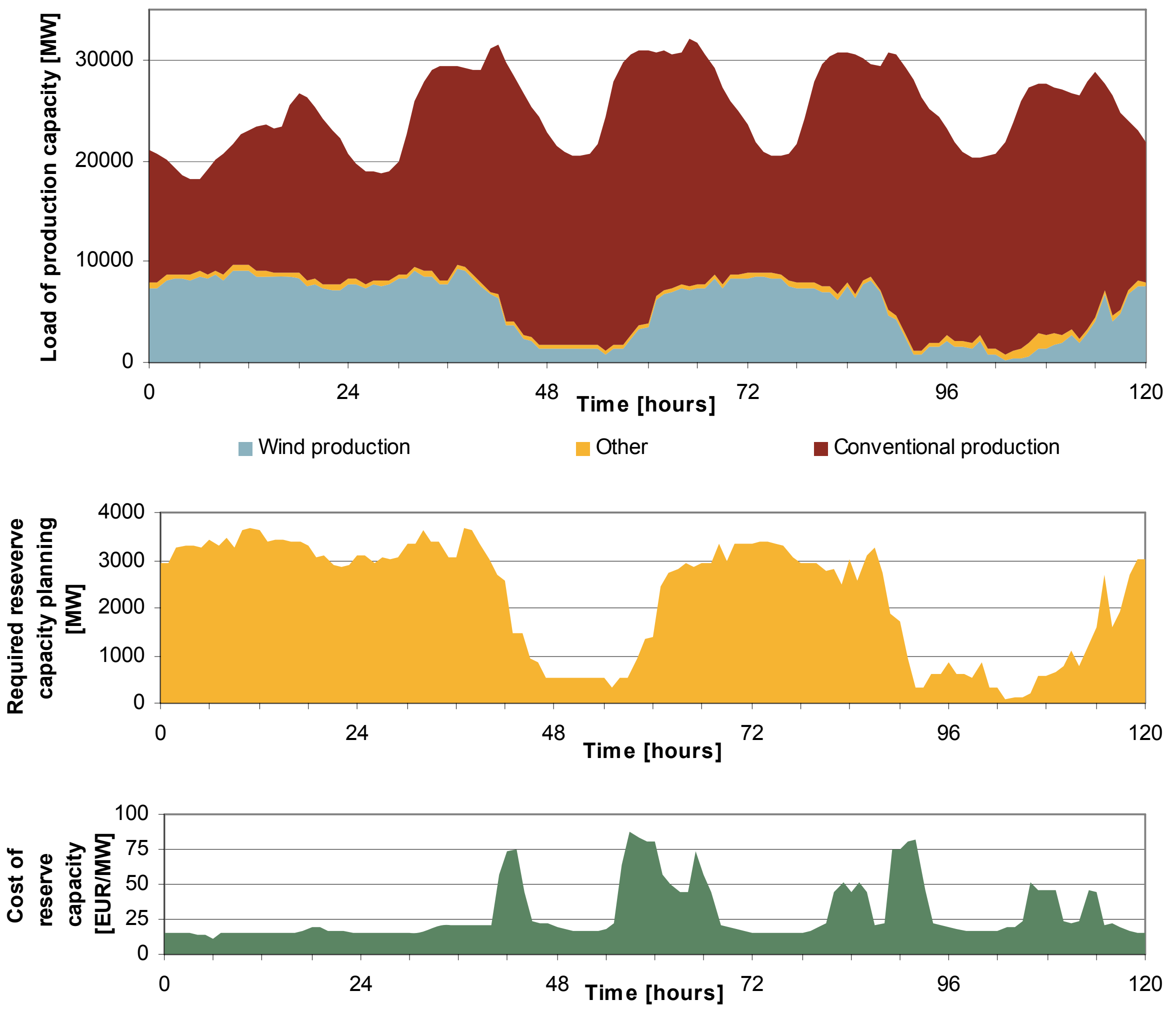


Figure 16: Five days of electricity production with the required reserve capacity planning for wind imbalance and the market price of this reserve capacity.

3. DATA

In this chapter is explained on which data the calculations in this chapter are based, where this data is originating from and which corrections were made to it.

3.1 WEATHER DATA

The electricity production from the sources Solar PV, Wind and Micro CHP is depend on the weather. All Weather data is originating from the Royal Netherlands Meteorological Institute. Data series for temperatures, solar radiation and potential wind are used.

3.1.1 Temperature

The data series for temperature are selected, based on the number of degree days. Degree days are a measurement for the severity of a winter. Degree days are defined by summation of the average natural day temperatures below 18 ºC from November 1, till March 31, as in Equation 13**Fout! Verwijzingsbron niet gevonden.**.

$$D = \sum \max\left[\left(18 - T_{avg}\right), 0\right]$$

Equation 13

Where:

D	Number of degree days	[ºC day]
Tavg	average day temperature	[ºC]

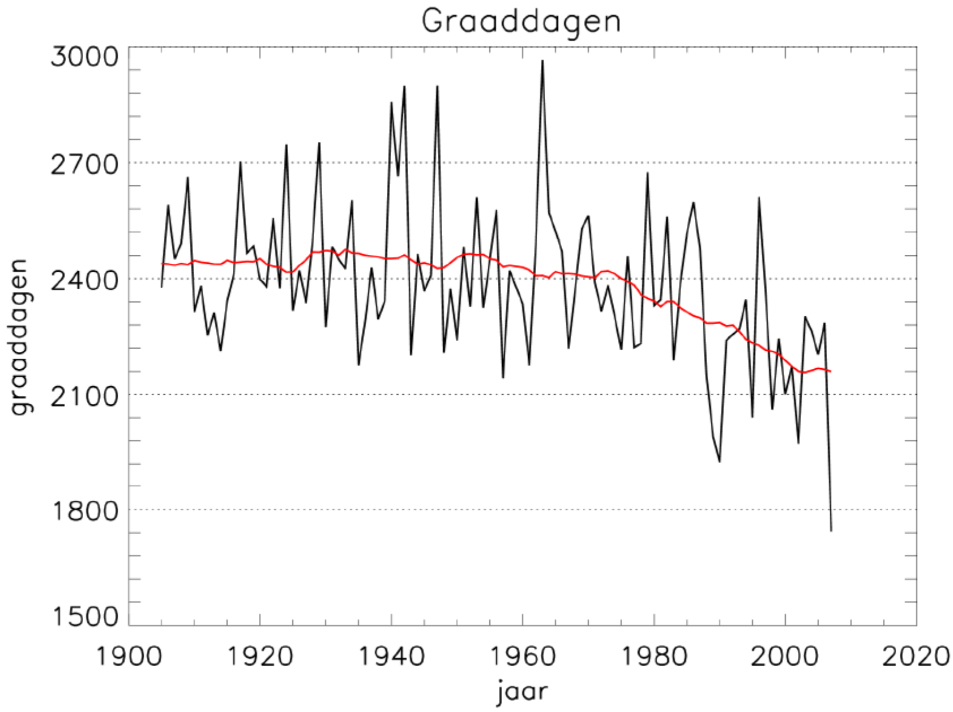


Figure 17: Degree days per year since 1990 (Wever, 2008).

Over the period 1900 - 2008
The coldest winter is 1962/1963 with 2965 degree days,
The mildest winter is 2006/2007 with 1743 degree days,

The winter of 2000 is chosen for the base scenario temperatures for micro CHP calculations.

3.1.2 Solar radiation

The sunniest year is 2003, with 2022 hours of sun shine.
The least sunny year is 1988, with 1218 hours of sun shine.
Average (1971-2000) is 1524 hours of sunshine per year, the year 2000 comes close (1532 hours of sunshine)

Royal Netherlands Meteorological Institute measures the solar radiation at station “De Bilt”. The radiation data for 2000 is used in the base scenario for solar PV calculations. The solar radiation in the year 2000 is plotted in Figure 18.

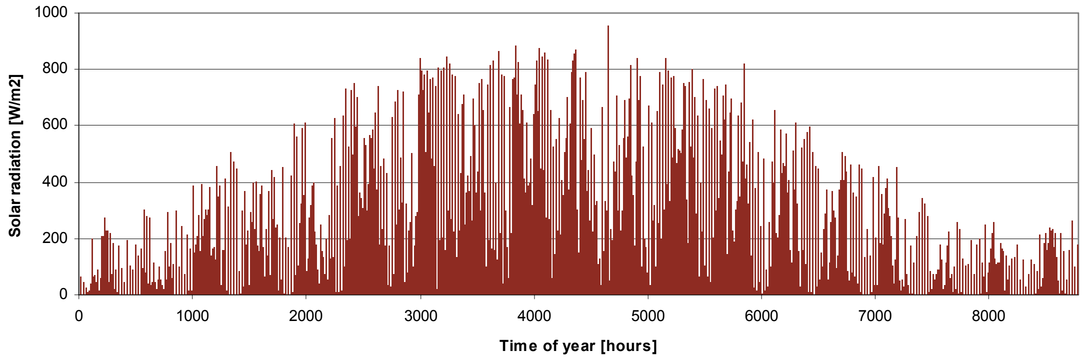


Figure 18: Solar radiation measured at weather stattion "De Bilt" over the year 2000.

3.1.3 Wind

For the wind data series, the so called potential wind data series, provided by the Royal Netherlands Meteorological Institute are used. *The potential wind is:*

- *wind that is corrected for the effects of shelter from buildings or vegetation.*
- *over land an estimate of the wind speed that could have been measured at 10 m height if the station's surroundings was free of obstacles and flat with a roughness that is equal to that of grass (roughness length = 0.03 m).*
- *over sea an estimate of the wind speed that could have been measured at 10 m height over water with a roughness that equals that of water in high wind speed conditions (roughness length = 0.002 m).*
- *more homogeneous both in wind direction, space and time as a result of the corrections compared to the measured wind speed.*

- *derived from hourly averaged wind speed; the wind direction is a 10-minute average which is not different from the measured wind direction.*

The correction is:

- *derived from a gustiness analysis of the stations series itself.*
- *a function of wind direction. This function can change in time.*
- *is not fixed for at least a few years to come; because of this the potential wind speed may also be adjusted.*

(Royal Netherlands Meteorological Institute)

Data range selection method

Wind years are selected on the average wind power density.

The wind power density is calculated:

Pw = ½ rho v^3

Selected data

Over the period 1990 – 2008:

- 2003 is the least windiest year (lowest average potential wind power density (137 W/m2)
- 1994 is the windiest year (highest average potential wind power density (242 W/m2)
- 2004 is average an average year, with an average potential wind power density of (191 W/m2)

Above data were based on the Schiphol weather station, since the weather station at “De Bilt” is sheltered. The data for potential wind for the year 2004 is used as model input for the base scenario.

Wind Turbines

Wind turbine manufactures such as Enercon and Vestas publish the Power-Velocity curves of their wind turbines.

3.2 ELECTRICITY DEMAND

TenneT, the Transmission System Operator (TSO) in the Netherlands, publishes system data, as required by the EC (no. 1228/2003), under the authority of the Office of Energy Regulation.

The following data is used:

- Programmed Imports [MWh/PTU]
- Programmed Exports [MWh/PTU]

- Measured Feed [MWh/PTU]

PTU = Program Time Unit (1 PTU = 15 minutes)

TenneT mentions the following about the quality of their data:

The consumption figures relate to the consumption of electricity in the Netherlands, excluding the direct consumption of electricity generated by small local production units such as wind turbines and combined heat and power (CHP) units. In addition, the so-called 'industrial consumption' of electricity generated and consumed on-site by large companies is not included in the figures. The latter type of consumption cannot be measured by TenneT on the national transmission grid because it is the outcome of a local process. Figures published by Statistics Netherlands (CBS) indicate that this type of decentralised and industrial electricity production currently amounts to approx. 6% of observed consumption. In other words, the figures published by TenneT represent approx. 94% of total electricity consumption in the Netherlands. (TenneT)

3.3 FUELS

The following emission factors for the fuels are used:

Natural Gas:	56	$kgCO_2/GJ_{LHV}$
Pulverized Coal:	95	$kgCO_2/GJ_{LHV}$
Blast Furnace Gas:	260	$kgCO_2/GJ_{LHV}$

With respect to the allocation of emissions, blast furnace gas is a special case. The majority of emissions can (and should) be allocated to steel production. In this study 95 $kgCO_2/GJ_{LHV}$ is allocated to electricity production, the remaining 165 $kgCO_2/GJ_{LHV}$ is allocated to steel production.

3.4 CONVENTIONAL POWER PLANTS

TenneT, the Transmission System Operator (TSO) in the Netherlands, publishes the installed capacity and fuel type.

The following data are provided for each production unit:

- connected party: name of the connected party
- location: location of the connection of the production unit
- unit: name of the production unit
- address details of the connection:
- date: date to which the report applies
- fuel: solar, wind, water, biomass, coal, gas, oil, nuclear, other
- capacity: reported production capacity of the production unit, expressed in MW

Another source of power plant data is the UDI World Electric Power Plants Data Base (WEPP, 2008). This database is maintained by Platts, UDI Products Group. The coverage of the database for medium to large sized power plants is considered comprehensive. The following data from this database is used:

- Gas Turbine type
- Date of commissioning
- Steam Turbine Inlet Temperature
- Steam Turbine Reheat Temperature

Combined with the condenser pressure, these parameters are used to calculate the unit's design efficiency. The following design parameters were used to calculate the unit's design efficiency:

3.4.1 Design parameters

Stack temperature: 90 ºC

Ambient conditions (ISO conditions):
Air temperature: 15 ºC
Relative humidity: 60%

Steam turbine efficiencies:
ST > 100 MWe: isentropic expension efficiency: 90%
ST < 100 MWe: isentropic expansion efficiency: 85%
Moisture in exit steam: 12 %

Condenser pressure:
Seawater cooling: 0.02 bara
River cooling (> 250 MWe): 0.03 bara
River cooling (< 250 MWe): 0.04 bara
Air cooled condenser: 0.1 bara

4. VALIDATION OF THE MODEL

The model is validated on historic data. In this chapter is described to what degree the results generated with the model correlate with historic data (were possible).

4.1 WIND ENERGY

Statistics Netherlands (CBS) provides the installed capacity for onshore wind turbines per year, specified for the hub height. A rough subdivision is made for different wind regimes. According to Statistics Netherlands (2009), most wind turbines are located in provinces that neighbour the North Sea and the province of Flevoland.

Windpark	Park 1	Park 2	Park 3	Park 4	Park 5
Hub height (m)	60	60	80	100	100
Location	On-shore	On-shore	On-shore	On-shore	Off-shore
Wind regime (KNMI station)	IJmuiden	Schiphol	Schiphol	Soester B	K13
Availability factor	0.8	0.8	0.8	0.8	0.95
Surface roughness [m]	0.03	0.03	0.03	0.5	0.002
Turbine type	E82	E82	E82	E82	E82
Installed capacity 2002 [MW]	68	274	283	44	0
Installed capacity 2003 [MW]	68	316	442	81	0
Installed capacity 2004 [MW]	64	334	534	141	0
Installed capacity 2005 [MW]	63	353	592	216	0
Installed capacity 2006 [MW]	60	368	705	317	108
Installed capacity 2007 [MW]	49	377	758	457	108
Installed capacity 2008 [MW]	44	380	775	694	228

Table 5: Properties of simulated wind capacity in The Netherlands.

The terrain roughness classifications from Davenport (1960) are used. The reference wind speed is used from historic measurements by the Royal Netherlands Meteorological Institute. The technology information is used in the form of the installed capacity (MW) and a P-v-curve for the type of wind turbines in this park.

Based on historical data for hourly potential wind speeds and installed capacities (Table 5), the electricity production from wind was modelled and compared to the actual production, as recorded by Statistics Netherlands.

The results of the simulation are plotted in Figure 19.

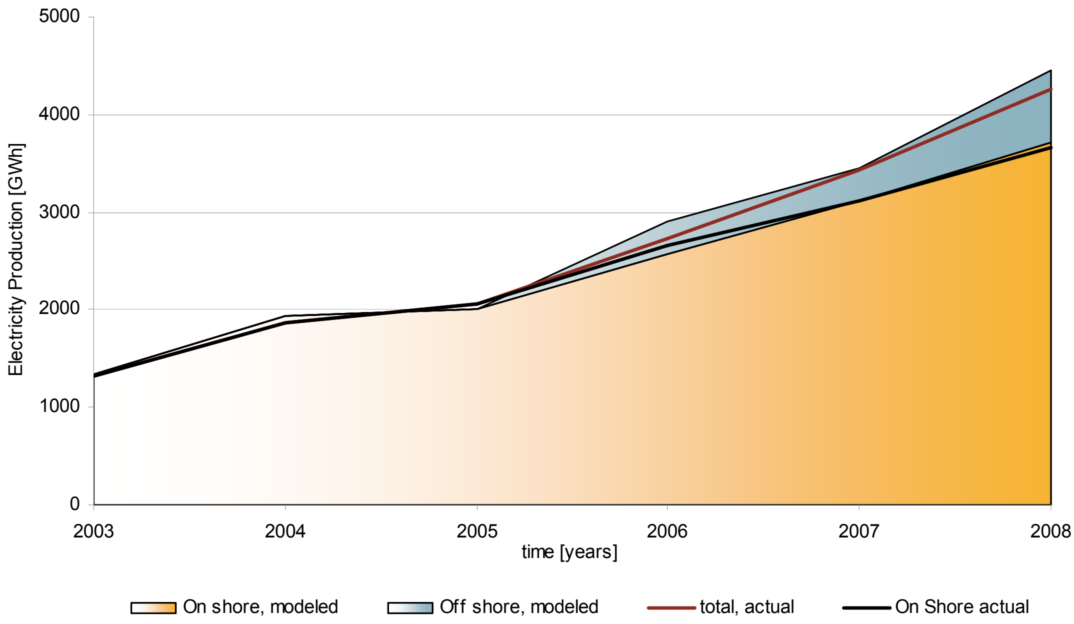


Figure 19: Modelled and actual historic electricity production from wind.

As can be concluded from the graph there is a deviation between the model predictions and historic production in the range of +10 -10 %. This deviation is considered acceptable for the purpose of this study.

4.2 SOLAR PV

Statistics Netherlands provides statistics for the installed PV capacity and the electricity produced from this source over the period 1998 till 2007. The model input requires installed capacity in [m^2], while Statistics Netherlands expresses the capacity in [Wp]. To convert this, it is assumed that the PV-panels have a capacity of 150[Wp / m^2]. Furthermore it is assumed that the average PV-panel efficiency in the Netherlands is 10%. The results of the model and the statistics are compared in Table 6**Fout! Verwijzingsbron niet gevonden.**.

Year	Installed Capacity [MWp] (CBS)	Electricity Production [GWh] (CBS)	Modelled Electricity production [GWh]	Relative Error
1998	6	3,5	3,4	-1,5%
1999	9	5,3	6,0	12,3%
2000	13	7,7	8,1	5,3%
2001	21	13,1	13,9	6,1%
2002	26	17	17,4	2,3%
2003	46	30,7	34,0	9,6%
2004	50	33,1	33,3	0,6%
2005	51	34,2	35,1	2,4%
2006	53	35,2	36,2	2,8%
2007	53	35,7	35,5	-0,7%

Table 6: Historic Installed PV capacity and production (CBS) compared to modelled production of electricity from PV.

From the results in **Fout! Verwijzingsbron niet gevonden.** is concluded that the method and assumptions for the calculation of electricity generation from PV are well validated.

4.3 MICRO CHP

Public available data for production from micro CHP units was not found to validate the models outcomes for micro CHP.

4.4 ELECTRICITY STORAGE

There is no large scale electricity storage in operation in the Netherlands. In this study an electricity storage system is simulated with the following characteristics:

Storage capacity	16000	[$MWh_{production}$]
Basin level at begin of year	2000	[$MWh_{production}$]
Pump capacity	2000	[MW]
Turbine capacity	2000	[MW]
Pump efficiency	0.90	[-/-]
Turbine efficiency	0.90	[-/-]
Control time span	24	[h]

If the specified system would have been operational in 2008 and was operated with the described control philosophy (in 22) The effects on the electricity supply would have been as described by Figure 20**Fout! Verwijzingsbron niet gevonden.**.

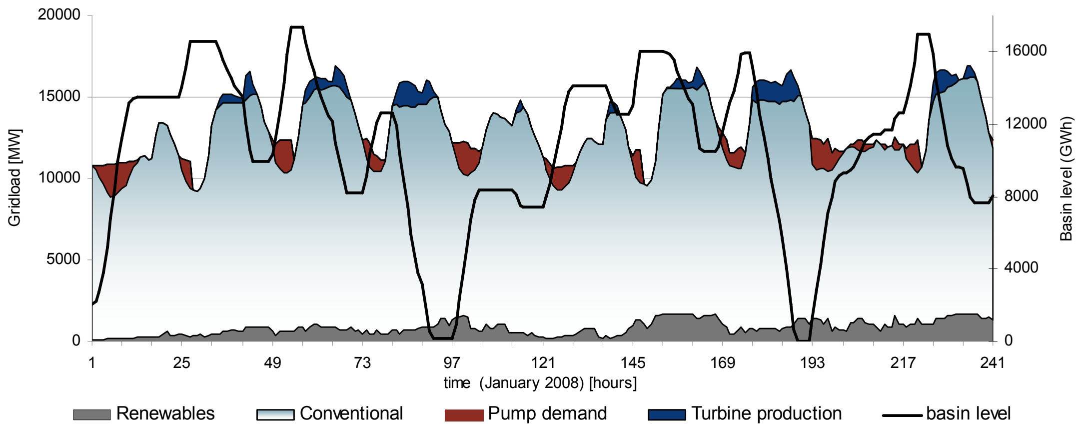


Figure 20: Behaviour of a hypothetical storage facility in January 2008 in the Netherlands and it's concequences for the electricity supply.

Figure 20**Fout! Verwijzingsbron niet gevonden.** suggests reasonable behaviour of the facility. However, since there is no electricity storage in the Dutch electricity supply it cannot be compared to an actual storage system in the Netherlands. In Belgium a storage facility (COO-I & COO-II) is in operation. It's planned operation during the first ten day's of September 2009 is described in Figure 21**Fout! Verwijzingsbron niet gevonden.**. The figure is based on published data by the Belgium Grid Operator (Elia, 2009).

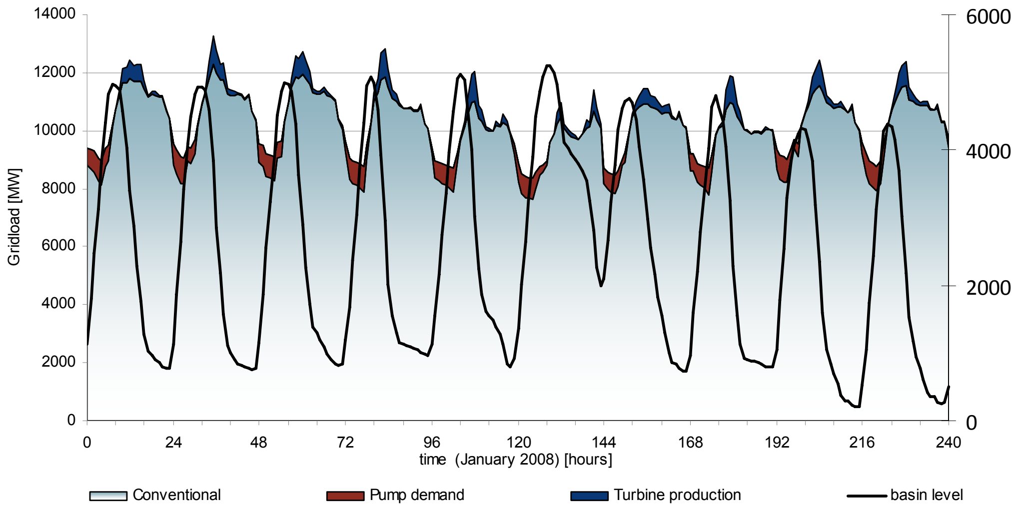


Figure 21: Operation of COO-1&2 and it's consequences for Belgium's electricity supply (ELIA, 2009).

The facility of COO-I and COO-II can be approached with the following parameters:

Storage capacity	6000	[$MWh_{production}$]
Basin level at begin of year	0	[$MWh_{production}$]
Pump capacity	1101	[MW]
Turbine capacity	1164	[MW]
Pump efficiency	0.9	[-/-]
Turbine efficiency	0.9	[-/-]
Control time span	24	[h]

Subsequently the model was fed with the electricity load demand curves of the Belgian grid and the resulting modelled operating is described by Figure 22**Fout! Verwijzingsbron niet gevonden.**.

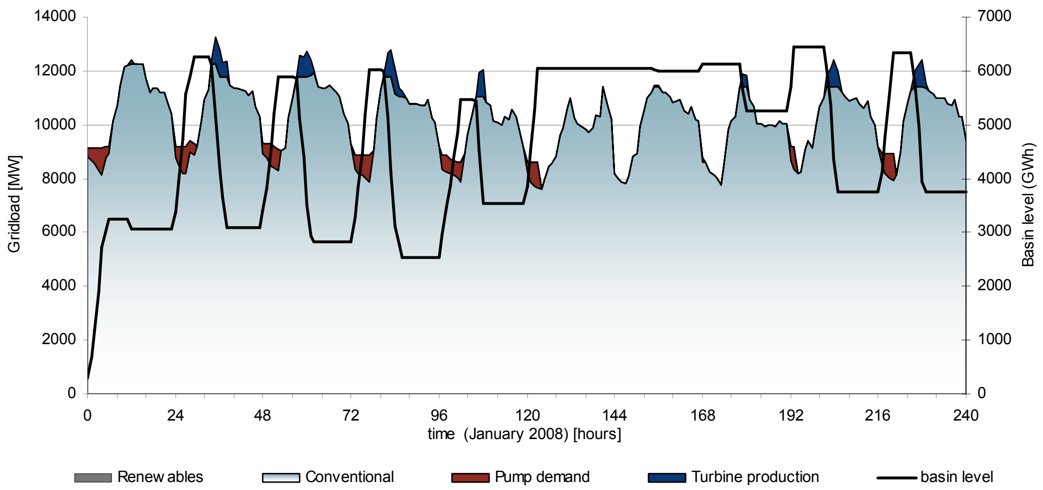


Figure 22: Modelled operation of COO-1&2 and it's consequences for Belgium's electricity supply.

As can be observed from comparing **Fout! Verwijzingsbron niet gevonden.** with **Fout! Verwijzingsbron niet gevonden.**, there is quite a difference in the operation of the model and the reality. In reality approximately twice as much electricity is stored and produced than modelled.

About the difference between historic data and the modelled results can be speculated The systems were build in the 1970's, at the time of the construction of Belgium's nuclear power plants. Nuclear power is the dominant source of electricity in Belgium. It can be characterised to be harder to control than conventional (fossil fuel fired) units.

The operation of COO 1 & 2 doesn't only decrease the difference between the peak and off peak demand for electricity production, it also decreases the speed (slope angle) by which the electricity production has to adapt to the change in demand.

The Belgian pumped storage allows production units to ramp-up and ramp-down slower than the change in electricity demand and decreases the difference between peak and off-peak demand, while the modelled pumped storage only decreases the difference between peak and off-peak demand.

4.5 CONVENTIONAL UNITS

Several data sources are available for verifying the modelled results, this includes:

- Published CO2 emissions for different production sites, from emissieregistratie.nl and emissieautoriteit.nl.
- CBS statistical information for fuel consumption for electricity production in the Netherlands (Statistics Netherlands, 2009, Electricity, production specified to fuel).
- Electricity prices.

The modelled results for the CO2-emissions are presented in Table 7 (3rd column, RUN 1), they are compared with the actual emissions. These figures can be used to manually tune the model. The availability factor can be corrected in such a way that the modelled CO2-emissions per unit match with the actual emissions per unit. A second run was done, and the results of this run (with adapted load factors) are in the most right column.

The more times this procedure is repeated, the more the modelled results will converge with historic data.

Site	Owner	2007 Modeled CO_2 emissions RUN 1	2007 Actual CO_2 Emissions	2007 Modeled CO_2 Emissions RUN 2
0	*0*	*ktonne/yr*	*ktonne/yr*	*ktonne/yr*
IJmuiden IJM1	Nuon	2064	2439	2439
Velsen (VN25, 24, G1)	Nuon	3910	4337	4026
Buggenum	Nuon	1539	1270	1270
Hemweg (HW7, HW8)	Huon	4011	4414	4225
Amercentrale (A81, A91)	Essent	7137	6035	6035
Maasvlakte (MV-1, MV-2)	E.on	6494	6355	6355
Borselle	EPZ	2385	1703	1714
Gelderland G-13	Electrabel	3536	3129	3128
Eemshaven (EC3-7, EC20)	Electrabel	5624	4463	4699
UNA Diemen DM33	Nuon	649	574	601
Lage Weide (LWE5, LWE6)	Nuon	587	567	625
Merwedekanaal (MK10-12)	Nuon	691	441	539
Moerdijk MD-1	Essent	677	591	658
ROCA ROC3	E.on	567	660	727
Swentibold	Essent	512	709	798
Galileistraat	E.on	516	339	351
Harculo	Electrabel	456	419	484
UNA Purmerend PU-1	Nuon	143	106	126
Bergum (BG10, BG20)	Electrabel	1128	813	1050
EPZ Donge DG-S1	Essent	177	126	174
Clauscentrale (CC-A, CC-B)	Essent	1208	1715	2238
TOTAL		**44011**	**41205**	**42262**

Table 7: Modelled Emissions compared to actual emissions.

For the whole market the fuel consumption and centralized electricity production can be compared with the public statistics available from Statistics Netherlands. This comparison is made in Table 8

Primary Energy	Model output 2007		Actual 2007 (CBS)	
	Electricity (TWh)	**Fuel input (PJ)**	**Electricity**	**Fuel Input**
Coal	25	231		214
BFG + COG	3	23		28
Natural Gas	37	282		280
Nuclear	4			
Total	68		68	

Table 8: Modelled conventional electricity production per fuel type compared to actual production.

Statistics Netherlands provides figures that are somewhat lower for electricity production from coal. All coal fired units in the model consume 100% coal, while in reality this is not the case. For start-ups, they are Natural Gas fired, but more important, some coal fired power stations co-fire a significant amount of biomass, in the model this is not taken into account. According to Statistics Netherlands 1711 GWh of electricity was produced from co-firing biomass (in coal fired power plants). This is approximately 15 PJ of Fuel (assuming 40% efficiency). If this amount of fuel is subtracted from the models result for coal consumption, the result is 216 PJ: close to the 214 PJ from Statistics Netherlands.

5. ASSUMPTIONS OF THE FUTURE TILL 2030

The purpose of this chapter is to give the reader insight in the assumptions of the future that were made for the base scenario. The assumptions underlying the scenario are to a large extent made by others such as the Netherlands Bureau for Economic Policy Analysis and Energy Research Centre of the Netherlands.

All the assumptions made for the scenario are described in this chapter. The assumptions can be ordered in three levels: (1) Structural drivers, (2) Energy, (3) Electricity market. An overview is provided in Table 9.

Level	Main assumptions	Assumptions made by
Structural Drivers	Population Growth, Economic Growth, political choices, internationalisation, etc.	Netherlands Bureau for Economic Policy Analysis (CPB) and Netherlands Environmental Assessment Agency (PBL).
Energy	Energy Demand, Fuel prices, Energy prices, Electricity Demand, Export	Energy research Centre of the Netherlands
Electricity Market	Installed Capacity, Fuel mix, Technologies, Load patterns,	Jacobs

Table 9: Levels of assumptions.

5.1 LEVEL 1: STRUCTURAL DRIVERS

In 2005 the Energy Research Centre of the Netherlands and Environmental Assessment Agency (NMP) published reference emission estimates, for the four scenarios of the study Welfare, Prosperity and Quality of the Living Environment (www.welvaartenleefomgeving.nl). These estimated are an elaboration of the emissions that occur in 4 different scenarios of the future.

The scenarios about the future were constructed by the Netherlands Bureau for Economic Policy Analysis (CPB) and Netherlands Environmental Assessment Agency (PBL). The four scenarios are mainly based on two main uncertainties about the future:

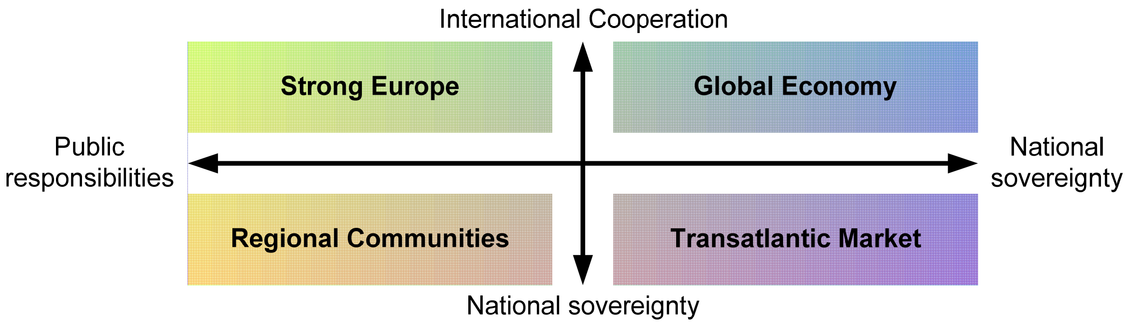
1. To which extent will nations and international trade blocks cooperate and exchange, giving up some of their cultural identity and sovereignty?

2. How will governments balance between market forces and a strong public sector?

These international political choices determine four possible scenarios for the Netherlands:

Global Economy	Emphasis on international cooperation and private responsibilities.
Strong Europe	Emphasis on international cooperation and public responsibilities.
Transatlantic Markets	Emphasis on national sovereignty and private responsibilities.
Regional Communities	Emphasis on national sovereignty and public responsibilities.

(source: www.welvaartenleefomgeving.nl)



The consequences for energy consumption and related effects were elaborated for these 4 scenario' s by Dril and Elzenga (2005). Of these four scenario's the Global Economy (GE) scenario corresponds the most with current policy and has been used the most intensively according to Daniëls and van der Maas (2009). The results for the GE scenario were updated in August 2009 in the UR-GE scenario, by Daniëls and van der Maas (2009).

The main assumptions behind the GE and UR-GE scenarios are:

- Free international trade, but hardly international political integration.
- Substantial revision of the collective sector and strong individualization.
- Individual responsibility of citizens
- Governments restrict to political services
- International competition and innovation incentives
- More market processes in education and mobility of the higher educated workers
- Strong growth in productivity
- 2.1% economic growth

5.2 LEVEL 2: ENERGY

Most assumptions are taken from the UR-GE scenario. There is also a UR-GE(h) version. These results are based on higher energy prices. For this study the UR-GE results will be used:

5.2.1 Fuel prices

Fuel prices from UR-GE scenario:

Fuel	Unit	2015	2020	2030
Crude Oil price	[EUR/GJ]	8,07	8,59	8,89
Natural Gas price	[EUR/GJ]	6,07	6,42	6,74
Coal price	[EUR/GJ]	2,01	2,03	2,1

The results of the UR-GE scenario assumes a CO2-price of 35 EUR/tonne in 2020. The CO2-price in the European Emission Trading Scheme (ETS-III) will be dependent on the cap of allowable emissions, the flexibility of the Market to adapt to the cap and the allowable CDM and JI credits (Kyoto). The following development of the CO-price is assumed: 2015: 20 Eur/tonneCO2, 2020: 35 Eur/tonneCO2, 2030: 50 Eur/tonneCO2. The fuel and CO2 prices are graphically represented by Figure 23**Fout! Verwijzingsbron niet gevonden.** and Figure 24**Fout! Verwijzingsbron niet gevonden.**.

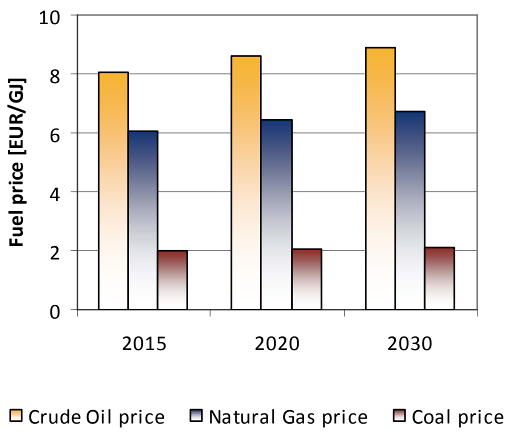


Figure 23: Assumed fuel prices developments according to UR-GE.

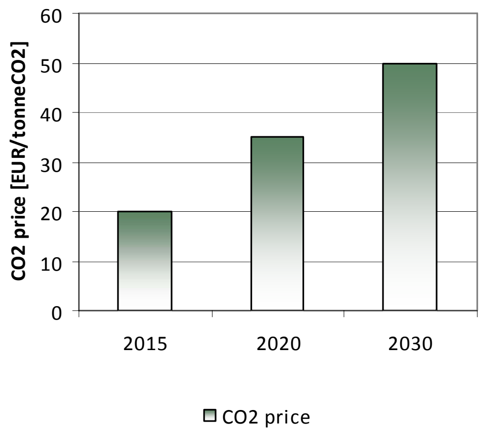


Figure 24: Assumed CO2-price developments.

Since different fuel have different emissions factors, the emission costs are not only depended on the carbon price, but on the fuel type as well. In **Fout! Verwijzingsbron niet gevonden.** the CO2 costs are included in the fuel prices.

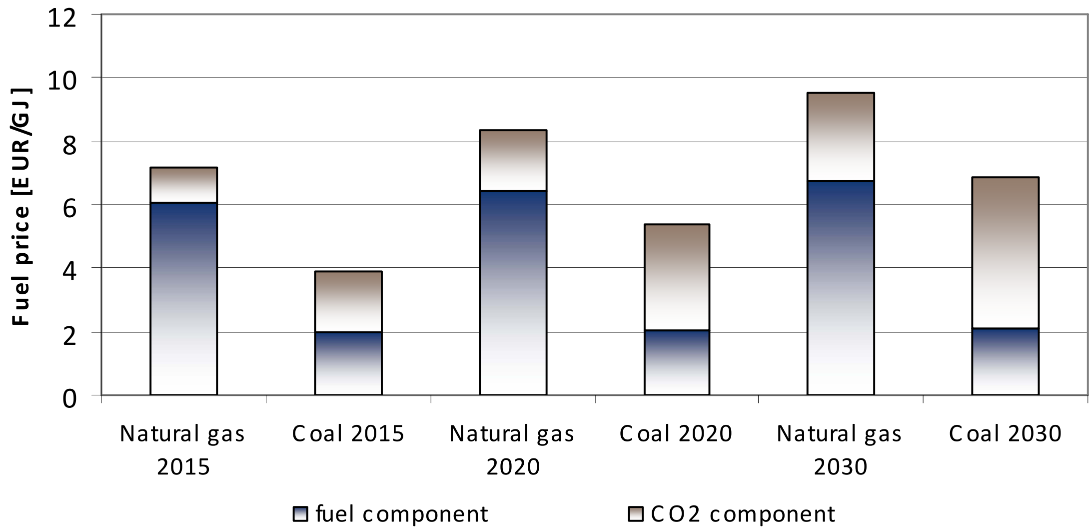


Figure 25: The effects of the CO2-price on the fuel costs.

Figure 25**Fout! Verwijzingsbron niet gevonden.** shows that, when the carbon costs are included in the fuel prices, the difference between fuel prices becomes smaller in 2030. The effect of these (assumed) prices is that the STMGC of electricity from natural gas or coal will be the same in the range of 55 – 60 EUR/MWh.

5.2.2 Electricity demand

The assumptions made about future electricity demand are listed in Table 10**Fout! Verwijzingsbron niet gevonden.**.

Year	Electricity demand	Source
2008	124 TWh	CBS
2015	139 TWh	ECN: UR-GE
2020	157 TWh	ECN: UR-GE
2030	193 TWh	ECN: UR-GE

Table 10: Historic and assumed future electricity demand.

This development of electricity demand as assumed by the UR-GE scenario corresponds with approximately 2% annual growth in electricity demand, corresponding with historic growth in electricity demand.

5.2.3 Electricity Import-Export balance

The Netherlands has favourable locations for base load electricity production plants. These are the coastal locations: Borssele, Maasvlakte, Ijmond and Eemshaven. As will be shown in the following example, the production costs of electricity at coast location are 5 - 7 EUR/MWh less than for locations near rivers, were the required cooling demand is supplied by cooling towers.

Example
The efficiency of a steam cycle with ultra supercritical steam parameters (Inlet: 285 bar_a, 600 ºC, reheat: 620 ºC) and seawater cooling (condenser pressure: 0.02 bar_a) has an efficiency of 45.5 %. The same steam turbine, located inland, with cooling water from a river and/or cooling towers is 0.05 bar_a. The efficiency now drops to 43.5 %. Another important advantage of a coast location is the lower fuel transportation cost (approx. 0.50 EUR/GJ for coal).

Since the Netherlands has a significant potential for CO2 storage, the presence of nearby locations reduce the CO2 transportation costs.

Property	Unit	Coast	River
Condenser Pressure	[Bara]	0.02	0.05
Steam cycle efficiency	[-/-]	0.455	0.435
Fuel costs	[EUR/GJ]	2	2.5
CO2costs	[EUR/ton]	20	20
Emissions factor	kgCO2/GJ	95	95
Fuel consumption	[GJ/MWh]	7.9	8.3
CO2 emissions	[kgCO2/MWh]	752	786
STMGC	**[EUR/MWh]**	**30.9**	**36.4**

Table 11: A comparison of a state of the art baseload plant on a coast location and river location.

The difference of over 5 EUR/MWh (Table 11) in the STMGC makes the Dutch coast locations more competitive than locations near German rivers. This difference in STMGC is a driver for replacing German generation capacity with capacity on Dutch coast locations.
The assumption that the Netherlands will become an electricity exporting country is also backed by the UR-GE scenario, which has the following figures for electrity exports:

Year	Electricity export (TWh)	Source
2008	-16	Statistics Netherlands
2015	30	ECN UR-GE scenario
2020	25	ECN UR-GE scenario
2030	20	ECN UR-GE scenario

This integration of Dutch and German electricity markets is also illustrated by the acquisition of the German TSO Transpower (E.on, 1 of 4 German TSO's) by the Dutch TSO TenneT in November 2009.

5.3 THE ELECTRICITY MARKET

5.3.1 Electricity demand load pattern

The domestic electricity demand consists of a demand of electricity measured on the high voltage grid, demand for electricity by own consumption of generators and demand for electricity on private company networks. It is assumed that their shares remain the same in the period from 2008-2030: Grid: 82,3 %, Consumption of generators: 3,3% and private networks: 13,9 %

Based on the assumptions from UR-GE for domestic demand and exports, the domestic electricity production is assumed to be as listed in **Fout! Verwijzingsbron niet gevonden.** and described by Table 12**Fout! Verwijzingsbron niet gevonden.**.

Electricity demand		**2008**	**2015**	**2020**	**2030**
Public Grid	[TWh]	102.3	112.9	127.9	157.6
Exports	[TWh]	-15.8	30.0	25.0	20.0
Consumption of generators	[TWh]	4.0	6.8	7.3	8.5
Private (company) networks	[TWh]	17.2	19.4	21.9	26.9
Domestic Electricity Production	**[TWh]**	**107.7**	**169.0**	**182.0**	**213.0**

Table 12: Domestic electricity production.

Just as important as the total demand is the load pattern. It is assumed that the load pattern changes linear in respect to the reference load pattern according to Equation 14**Fout! Verwijzingsbron niet gevonden.**.

$$\frac{P_{t,y}}{E_y} = \frac{P_{t,ref}}{E_{ref}}$$

Equation 14

Where:

$P_{t,y}$	Load for timesegment t in year y	[MW]
$P_{t,ref}$	Load for timesegment t in the year of the reference load pattern	[MW]
E_y	Electricity demand in year y	[TWh]
E_{ref}	Electricity demand in the year of the reference load pattern	[TWh]

It also assumed that the export is higher during the day time than during the night. The export profile is the same for every day. The assumed load pattern of the export is described by Figure 27**Fout! Verwijzingsbron niet gevonden.**.

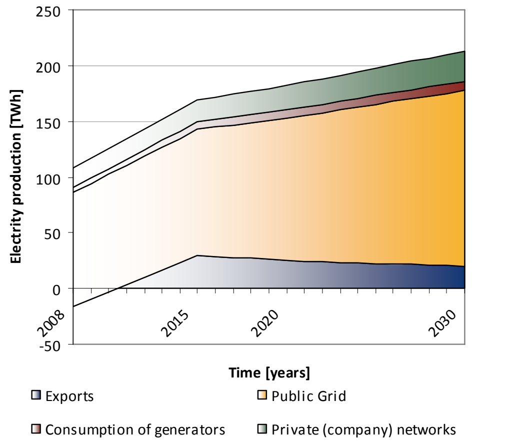


Figure 26: Breakdown of domestic electricity production.

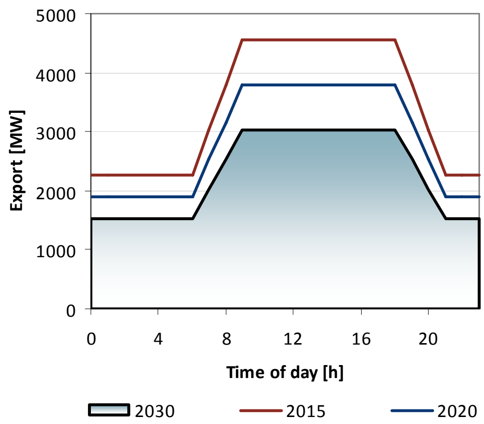
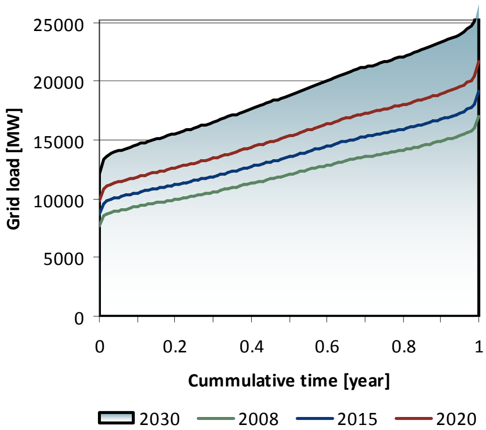


Figure 27: Load profile of electricity export over a day.



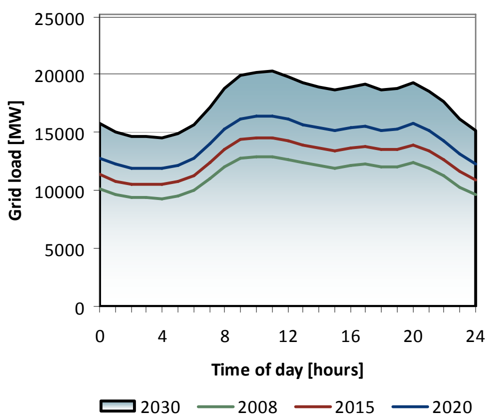


Figure 28: Domestic demand for electricity in 2008, 2015, 2020 and 2030. (Left: demand for cumulative time, right: a sample day profile.)

5.3.2 Electricity Supply

The assumed type and amount of installed electricity generating capacity in 2030 is based upon:

- Current installed capacity (2009)
- Planned capacity expansions (2009-2015)
- Short Term Marginal Generation Costs (STMGC)
- Investment Costs (CAPEX)

Assumptions:

- It is assumed that all current Gas fired capacity with efficiencies over 50% is still in use in 2030.

- It is assumed that all coal fired capacity installed after 1990 is still in operation in 2030.
- It is assumed that all planned (2009-2013) capacity is build and in operation in 2030.

To meet the rise in electricity (and export) demand, additional capacity has to be installed. The main factors that determine these investment decisions are the STMGC and CAPEX.

Applying the assumptions made above this will mean for the installed conventional capacity:

For the year 2015:
- All currently installed coal fired capacity is still operational.
- All currently installed gas fired capacity with design efficiencies higher than 50% is still operational.
- All currently installed CHP capacity is operational.

For the year 2020:
With all investments currently planned, the market will be saturated. It is assumed that no further conventional capacity will be built in the period 2015-2020.

For the year 2030:
Coal fired capacity, commissioned in 1990 and later will still be in operation.
Gas fired capacity with design efficiencies of 55% and higher will still be operational.

Further investment decisions for conventional capacity will be based on the Short Term Marginal Generation Costs (STMGC) and the Cost of Electricity (COE). The STMGC will be used to estimate the operating time per year. The selection will be based on the COE at the given operating time. Both STMGC (in the case of Carbon Capture and Storage) and COE will be explained in the two following paragraphs **Fout! Verwijzingsbron niet gevonden.** and **Fout! Verwijzingsbron niet gevonden.**.

5.3.3 Short Term Marginal Generation Costs

The Short Term Marginal Generation Costs are calculated with **Fout! Verwijzingsbron niet gevonden.**. For plants equipped with CCS the STMGC are calculated with Equation 15**Fout! Verwijzingsbron niet gevonden.**.

$$STMGC = 3.6 \cdot \frac{FC}{\eta} + 3.6 \cdot f_{CO2} \cdot (1 - r_{CO2}) \cdot \frac{P_{CO2}}{\eta} + r_{CO2} \cdot f_{CO2} \cdot 3.6 \cdot \frac{S_{CO2}}{\eta}$$

Equation 15

STMGC	Short Term Marginal Generation Costs for unit y	[EUR/MWh]
FC	Fuel Costs	[EUR/GJ_{LHV}]
f_{CO2}	CO2 emission factor of fuel	[tonneCO2/GJ_{LHV}]

r_{CO2}	recovery factor of CO2	[-/-]
P_{CO2}	Price of CO2 emissions	[EUR/tonne]
S_{CO2}	Price of CO2 storage	[EUR/tonne]
η	Electrical efficiency	[-/-]

The STMGC were calculated for Industrial CHP plants, Combined Cycle (Natural gas) plants, Coal fired plants and Coal fired plats with Carbon Capture and Storage (CCS). For these calculations the (technology) assumptions from **Fout! Verwijzingsbron niet gevonden.** are used.

Technology (2020)	Eff.	Fuel Price	Emission factor	Capture rate	CO2 storage price
	[-/-]	[EUR/GJ]	[kgCO2/GJ]	[-/-]	[EUR/ton]
Industrial CHP	0.82	6.42	56	0	15
Combined Cycle	0.62	6.42	56	0	15
Coal	0.48	2.03	95	0	15
Coal + CCS	0.38	2.03	95	0.85	15

Table 13: Technology assumptions for 2020 - 2030.

In the CO2-price range of 20 – 80 Euro/tonne the STMGC of electricity produced from coal + CCS are the lowest, followed by industrial CHP and Combined Cycle. This can be calculated with Equation 15**Fout! Verwijzingsbron niet gevonden.** and the results as a function of the CO2 price are shown in Figure 30**Fout! Verwijzingsbron niet gevonden.**.

Dispatch decisions are made on the basis op STMGC, investment decisions are more complicated. An other important driver is the Cost Of Electricity (COE). The COE as a function of the CO2-price is shown in Figure 29**Fout! Verwijzingsbron niet gevonden.**.

5.3.4 Cost Of Electricity

The Cost of Electricity (COE) = STMGC + CCOE
The Capital costs are calculated with Equation 16**Fout! Verwijzingsbron niet gevonden.**.

$$CCOE = \frac{\alpha \cdot I \cdot 1000}{OT}$$

Equation 16

CCOE	Capital Cost of Electricity	[EUR/MWh]
I	Total Installed Cost of equipment	[EUR/kW]
OT	Load	[hours/year]
α	Annuity factor	[-/-]

Where the annuity factor (α) is calculated with Equation 17**Fout! Verwijzingsbron niet gevonden.**.

$$\alpha = \frac{i}{1-(1+i)^{-LT}}$$

Equation 17

α	Annuity factor	[-/-]
i	Interest rate	[-/-]
LT	Economic Life Time of equipment	[years]

System	Investment	Interest rate	Operation	Economic life time	annuity factor	Capital cost
	[EUR/ kW]	[-/-]	[hrs/ year]	[years]	[-/-]	[EUR/MWh]
Industrial CHP	700	0.15	7500	25	0.15	14.4
Combined Cycle	700	0.15	7500	25	0.15	14.4
Coal	1400	0.10	7500	25	0.11	20.6
Coal + CCS	2400	0.10	7500	25	0.11	35.3

Table 14: Capital costs of electricity from different technologies.

The specific investment costs in **Fout! Verwijzingsbron niet gevonden.** are originating from Seebrechts (2009).

A higher annuity factor was chosen for Industrial CHP and Combined Cycle plants. The profitability of CHP-plants is dependent on both a demand for Electricity and heat and is therefore considered to be a more risky investment than a 100% power plant. For Combined Cycle plants, there is more risk involved because natural gas prices are more volatile than coal prices.

Both the STMGC and COE are plotted as a function of the CO2-price in **Fout! Verwijzingsbron niet gevonden.** and **Fout! Verwijzingsbron niet gevonden.**.

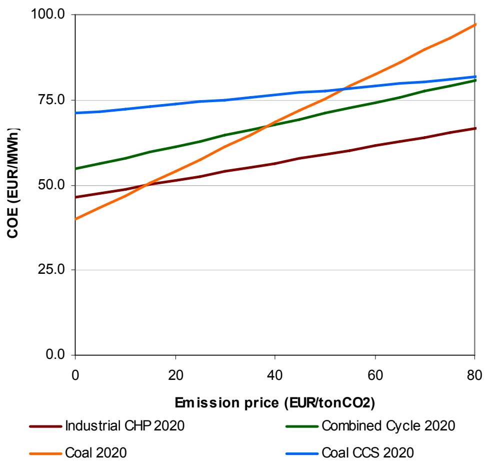


Figure 29: Cost of Electricity as a function of CO2-price.

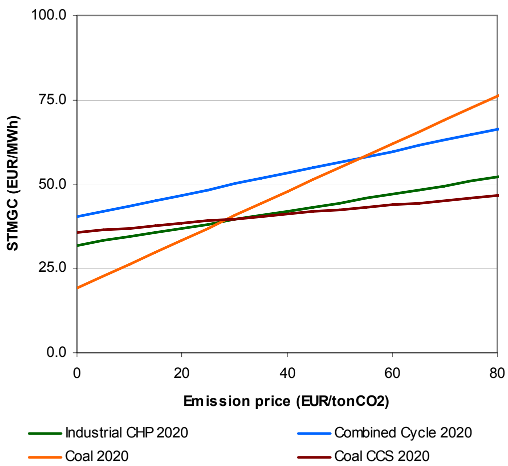


Figure 30: Short Term Marginal Generation Costs as a function of CO2-price.

The Total investment cost for CHP is considerably lower than for Coal + CCS. Therefore it is assumed, that for base load electricity generation the maximum industrial CHP potential will be used. Further base load demand is fulfilled with natural gas fired combined cycle units, nuclear capacity and existing/planned coal fired units.

Coal fired capacity, equipped with a CCS facility will be limited to subsidised demo units, since under the assumed CO2-prices Coal + CCS is still to expensive compared to other technologies.

5.4 INSTALLED CAPACITY

The consideration made in the preceding paragraphs of this chapter lead to assumptions made about the installed capacities. The installed assumed installed capacity is summarized in Table 15**Fout! Verwijzingsbron niet gevonden.** and graphically described by Figure 31**Fout! Verwijzingsbron niet gevonden.**. In the following paragraphs more details are provided.

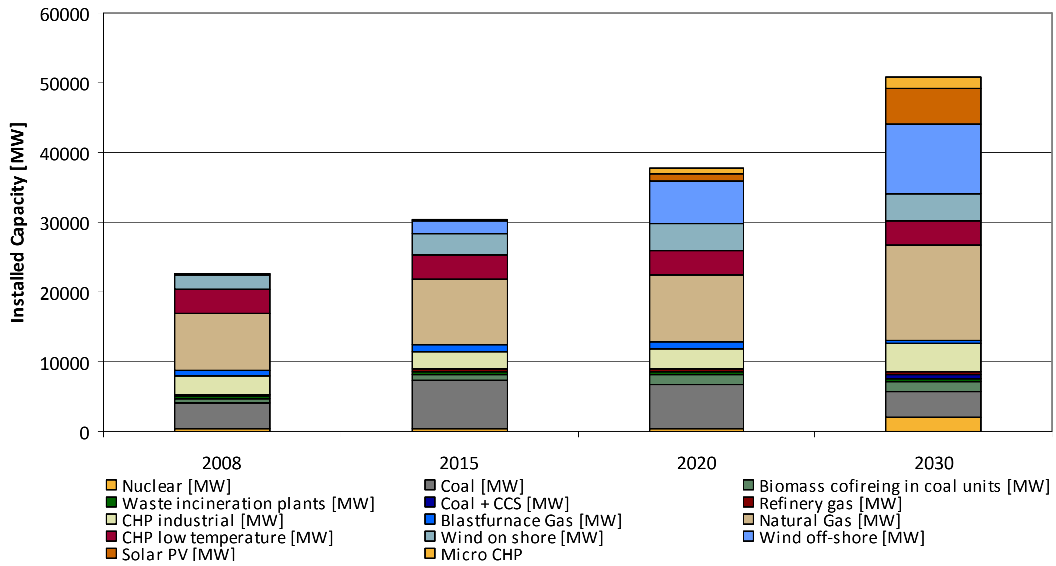


Figure 31: Installed capacities historic and assumptions about the future.

Installed capacities		**2008**	**2015**	**2020**	**2030**
Wind on shore	[MW]	1893	3000	4000	4000
Wind off-shore	[MW]	228	1800	6000	10000
Solar PV	[MW]	57	150	800	5000
Micro CHP	[MW]	0	130	1000	1600
Nuclear	[MW]	490	490	490	2090
Natural Gas	[MW]	8097	9480	9480	13530
Coal	[MW]	3655	6842	6331	3591
Biomass cofiring in coal units	[MW]	600	913	1424	1424
Coal + CCS	[MW]	0	0	0	800
Refinery gas	[MW]	301	301	301	301
Waste incineration plants	[MW]	346	346	346	346
Blastfurnace Gas	[MW]	983	983	983	600
CHP industrial	[MW]	2497	2500	3000	4000
CHP low temperature	[MW]	3490	3500	3500	3500
Peaker (NG)	[MW]	3000	3000	3000	3000
Total installed	**[MW]**	**25037**	**32522**	**39231**	**52358**
Total installed conventional	**[MW]**	**22513**	**27226**	**28085**	**33012**
Total installed renewable	**[MW]**	**2524**	**5296**	**11146**	**19346**

Table 15: Historic and assumed future capacity.

In the subsequent paragraphs the developments for the specific generating technologies are described.

5.4.1 Wind capacity

For the year 2015:

The assumption for the wind capacity for 2015 is based on the available budget by this administration for offshore wind parks: this is for 950 MWe.

Site	Applicant	Permit	Distance to coast [km]	Installed capacity [MW]
West Rijn	Airtricity	yes	37	259
Breeveertien II	Airtricity	yes	60	349
Brown Ridge Oost	Brown Ridge Oost	yes	74	282
Den Helder I	Airtricity	yes	63	468
Tromp Binnen	RWE	yes	75	295
Beaufort	NUON	yes	24	279
BARD Offshore NL1	Bard Engineering	yes	56	300
GWS Offshore NL1	Global WindSupport	yes	56	300
EP Offshore NL1	Eolic Power	yes	56	275
Q10	Eneco	yes	23	153
Scheveningen Buiten	Evelop	yes	28	212
Q4-WP	Q4-WP	yes	24	78
Total				**3250**
permits issues				**2807**
subsidies available				**950**

Table 16: Permit applications for off shore windparks. (Ministry of Transport, Public works and Water Management, 2009)

It is assumed that a total of 10 GW wind capacity is installed, 4 GW on shore, 6 GW off-shore. The capacity is divided in 5 turbine parks (1 off shore, 4 on shore).

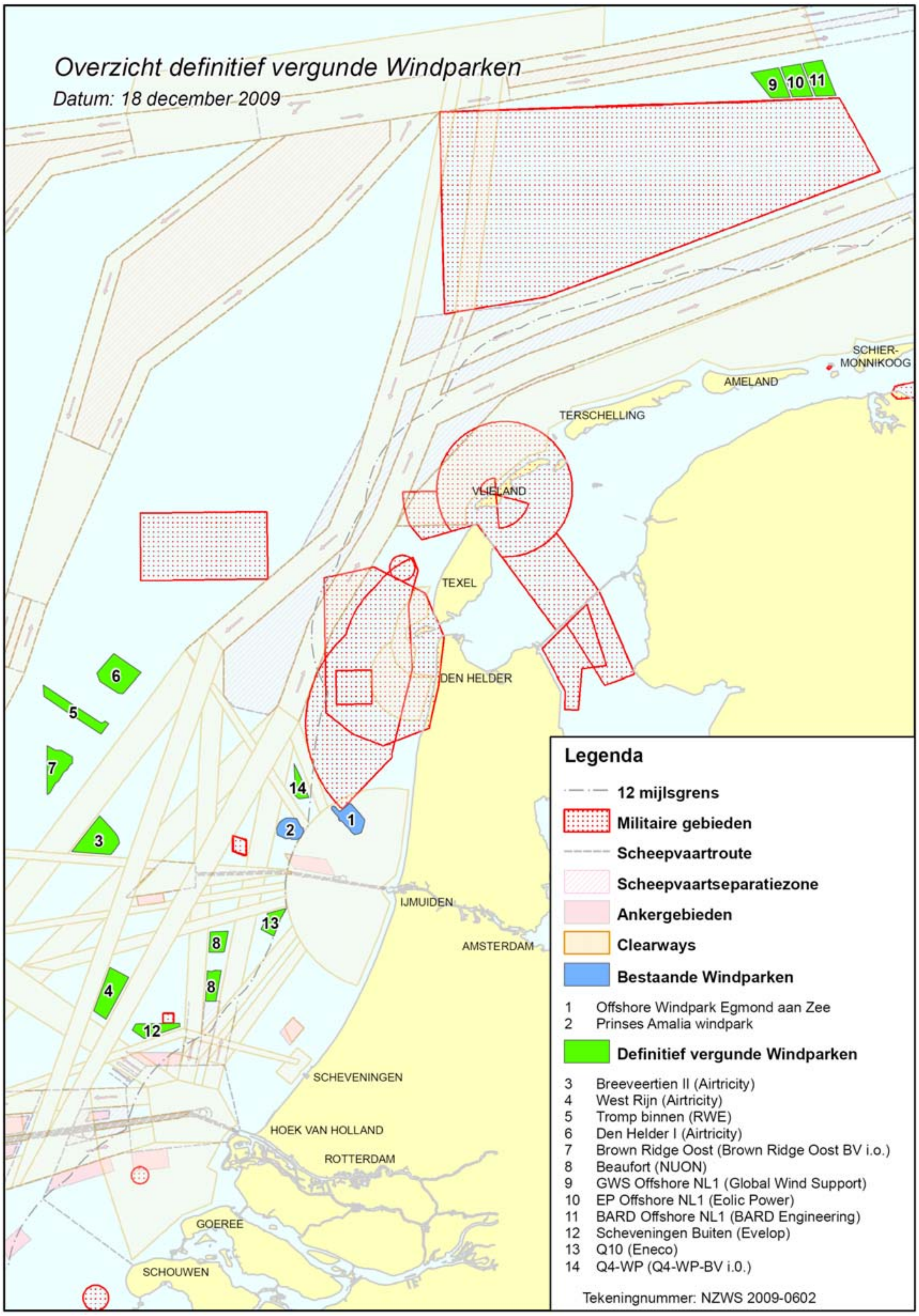


Figure 32: Overview of granted permits for Off-shore windparks. (Ministry of Transport, Public works and Water Management, 2009)

The onshore wind turbine capacity is supposed to grow to 3000 MW in 2015.

For the years 2020 and 2030:
The government's ambitions of 4 GW on shore and 6 GW off shore wind turbine capacity are assumed to be realised by 2020. For 2030 further growth is assumed.

Windpark	Park 1	Park 2	Park 3	Park 4	Park 5
Hub height (m)	60	60	80	100	100
Location	On-shore	On-shore	On-shore	On-shore	Off-shore
Wind regime (KNMI station)	IJmuiden	Schiphol	Schiphol	Soesterberg	K13
Availability factor	0.8	0.8	0.8	0.8	0.7
Surface roughness [m]	0.03	0.03	0.03	0.5	0.0002
Turbine type	E82	E82	E82	E82	E82
Installed capacity 2008 [MW]	682	530	615	94	228
Installed capacity 2015 [MW]	841	765	1058	100	1800
Installed capacity 2020 [MW]	1000	1000	1500	500	6000
Installed capacity 2030 [MW]	1000	1000	1500	500	10000

Table 17: Assumptions about the installed capacity of wind turbines.

It is assumed that the average Power-velocity curve of the windparks will improve gradually over the years from the curve of the Enercon E82 wind turbine in 2015 to the Vestas V110 wind turbine in 2030.

Further more it is assumed that the wind parks are operated with a gradual shutdown strategy (as in Figure 33). In an abrupt shutdown strategy, which is the current standard, all wind turbines would shutdown collectively if the 15 minute average wind speed exceeds 25 m/s. This behaviour creates the potential for the electricity supply to loose hundreds to thousands of MW production capacity in seconds to minutes. With a gradual shutdown strategy, as proposed by Gibescu et al. (2008), wind turbines shutdown earlier and the loss in production capacity is more gradual and at the same time better predictable, since they the turbines shutdown over a range of wind speeds instead of a certain set point.

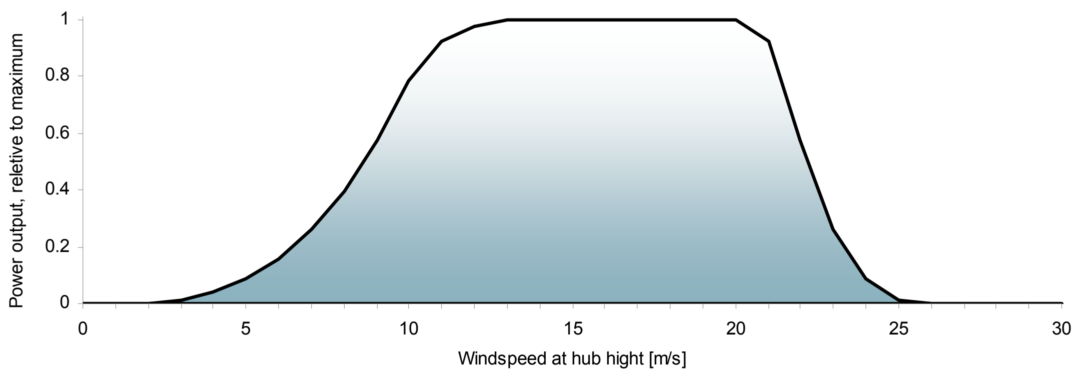


Figure 33: Consequences for the average power-velocity curve of a wind park with gradual shutdown strategy.

5.4.2 Solar PV capacity

The government aims at 532 GWh of electricity production from PV in 2020. The average growth is approximately 25% per year resulting in approximately 800 MW installed in 2020. From 2020 to 2030 the amount of Solar Capacity is assumed to grow to 5000 GW

Countries like Spain and Germany have proven that such growth rates are possible. In Germany the installed capacity grew from 54 MWp in 1998 to 5351 MWp in 2008 (58% growth per year). In the EU in 2008 the installed PV capacity more than doubled from 4592 MWp to 9533 MWp (EPIA, 2009).

5.4.3 Micro CHP capacity

It is assumed that by 2030 1.6 mln units of 1 kWe are installed. The total capacity is 1600 MWe. GasTerra, Cogen and Slim met Gas project 1.3 million households in 2020 and approximately 4 million in 2030.

5.4.4 Industrial CHP Capacity

An overview of the industrial CHP units in the model with natural gas as primary fuel is listed in Table 18.

Operator	Unit	year	Pth	Pe	T-eff	E-eff	Status	bsb eff	fuel eff
			[MW]	[MW]					
AKZO	Delesto 1	1987	162	145	46%	39%	Oper.	90%	79.6%
Essent	Moerdijk 1	1997	222	235	42%	43%	Oper.	90%	79.4%
Essent	Elsta	1998	477	472	44%	42%	Oper.	90%	80.5%
AKZO	Delesto 2	1999	322	285	47%	40%	Oper.	90%	82.0%
Shell	Pernis GT	1999	83	53	54%	33%	Oper.	90%	80.7%
Essent	Swentibold	1999	199	207	43%	43%	Oper.	90%	83.4%
Air Liquide	Pernis Extension	2007	318	324	42%	41%	Oper.	90%	77.5%
NAM	Schoonebeek	2009	197	128	52%	32%	Un. C.	90%	76.3%
Essent	Helmond 1 + 2	1999	21	22	40%	37%	Oper.	90%	66.6%
Essent	Den Bosch HTB	1994	38	25	53%	33%	Oper.	90%	78.6%
Essent	Bergen op Zoom	1995	28	24	38%	36%	Oper.	90%	61.6%
Essent	Enschede	1985	47	43	40%	35%	Oper.	90%	63.2%
Essent	Eindhoven	1995	51	41	49%	38%	Oper.	90%	82.4%
Essent	Klazinaveen	1995	59	52	41%	35%	Oper.	90%	63.6%
Essent	Erica	1995	59	52	41%	35%	Oper.	90%	63.6%
Essent	Salinco	1994	67	38	55%	30%	Oper.	90%	77.4%
Nuon	Kleefsewaard	1993	46	34	48%	35%	Oper.	90%	75.8%
Nuon	Emmtec	1980	51	26	56%	27%	Oper.	90%	73.3%

Table 18: Overview of industrial CHP units.

The design efficiency as described in the table above is the electrical efficiency, with al CHP-savings attributed to electricity production.

5.4.5 Nuclear capacity

It is assumed that in the period from now till 2030 one nuclear power plant will be constructed and the existing one will remain in operation. The utility company Delta is operating the only nuclear power plant in the Netherlands and has started the permitting for another (Delta, 2009a). This will lead to 1790 MW of installed nuclear capacity after 2025.

Owner	Unit	Capacity	fuel	Design Eff.	Comm. Date
Delta	BS20	490	NU	33%	1973-2033
Delta	BSxx	1300	NU	33%	2025

Table 19: Overview of installed nuclear capacity.

5.4.6 Coal fired power plants

It is assumed that all planned coal fired capacity will be built. And no new coal fired capacity will be installed after 2015. After 2015 only one new coal fired unit, equipped with CCS will be commissioned in 2025. An overview of the coal fired units is presented in Table 20**Fout! Verwijzingsbron niet gevonden.**.

Owner	Unit	Pwr	year	ST In P	ST in T	RH T	RH P	COND P	ST EFF	B EFF	Net eff	Status
		[MW]		[bara]	[ºC]	[ºC]	[bara]	[bara]				
Essent	Amer 81	**645**	1980	175	540	540	48	0.03	40.6	95.0	**38.6**	O
Electrabel	G13	**635**	1981	177	535	535	48	0.03	40.5	95.0	**38.5**	O
E.on	MV1	**520**	1975	178	535	535	47	0.02	41.3	95.0	**39.2**	O
E.on	MV2	**520**	1975	178	535	535	47	0.02	41.3	95.0	**39.2**	O
EPZ	BS 12	**420**	1987	182	543	543	49	0.02	41.5	95.0	**39.4**	O
Nuon	HW 8	**680**	1994	260	540	568	41	0.02	43.1	95.0	**40.9**	O
Essent	A 91	**600**	1993	269	540	568	50	0.03	42.4	95.0	**40.3**	O
Nuon	Bugg	**235**	1993								**39**	O
E.on	MV3	**1100**	2012	285	600	620	70	0.02	45.4	95.0	**43.2**	U
Electrabel	MV4	**800**	2012	285	600	620	70	0.02	45.4	95.0	**43.2**	U
RWE	STKC-A	**800**	2013	285	600	620	70	0.02	45.4	95.0	**43.2**	U
RWE	STKC-B	**800**	2013	285	600	620	70	0.02	45.4	95.0	**43.2**	U
Essent	A10	**0**	2014									C
Nuon	IJM3	**800**	2025						38.0	0.95	**37**	H

Table 20: Overview of coal fired capacity.
O = operation, U = under construction, P = permit submitted, C = cancelled, H = hypothetical, Green: source: WEPP or press release by owner, Blue: assumed

The assumptions in **Fout! Verwijzingsbron niet gevonden.** about the units MV3, MV4, STKC-A/B are based on E.on (2008), Electrabel (2009b) and RWE (2009)

5.4.7 Natural gas fired power plants

An overview of the units in the model with natural gas as primary fuel is listed in Table 21.

Owner	Unit	Year	PWR	D CC EFF	Status dec 2009
			[MW]		
Nuon	DM33	1995	252	54.7%	operational
Nuon	LWE6	1995	248	54.0%	operational
Electrabel	EC-3	1996	352	55.6%	operational
Electrabel	EC-4	1996	352	55.6%	operational
Electrabel	EC-5	1996	352	55.6%	operational
Electrabel	EC-6	1996	352	55.6%	operational
Electrabel	EC-7	1996	352	55.6%	operational
Electrabel	ROC3	1996	184	53.4%	operational
Intergen	Rijnmond 1	2004	783	56.8%	operational
Delta / GDF	Sloecentrale Unit 10	2009	431	59.4%	operational
Delta / GDF	Sloecentrale Unit 20	2009	431	59.4%	operational
Electrabel	FL40	2010	447	58.9%	under construction
Electrabel	FL50	2010	447	58.9%	under construction
Intergen	Rijnmond 2	2010	433	58.5%	under construction
Essent	CC-C1	2011	444	58.5%	under construction
Essent	CC-C2	2011	444	58.5%	under construction
Essent	CC-C3	2011	444	58.5%	under construction
Eneco/Dong	Enecogen-1	2011	444	58.5%	under construction
Eneco/Dong	Enecogen-2	2011	444	58.5%	under construction
Essent	MD-2	2011	429	58.3%	under construction
Adv. Power	EC-8a	2013	400	59.5%	permit submitted
Adv. Power	EC-8b	2013	400	59.5%	permit submitted
Adv. Power	EC-8c	2013	400	59.5%	permit submitted
Essent	A10	2021	450	61.0%	hypothetical
Essent	A11	2021	450	61.0%	hypothetical
Electrabel	Harculo81	2022	450	61.0%	hypothetical
Electrabel	Harculo82	2022	450	61.0%	hypothetical
Nuon	LW7	2023	450	61.0%	hypothetical
Essent	A12	2026	500	61,5%	hypothetical
Essent	A13	2026	500	61,5%	hypothetical
Electrabel	G14	2026	500	61,5%	hypothetical
Electrabel	G15	2026	500	61,5%	hypothetical

Table 21: Overview of natural gas fired units.

Concerning the units in Table 21, the following sources where used to base the assumption on:

Unit:	**source**
All operational units	WEPP (2008)
Sloecentrale Unit 10 and sloecentrale Unit 20	Delta (2009b)
Fl40 and FL50	Electrabel (2009a)

Intergen II	Intergen (2007)
CC-C1, CC-C2 and CC-C3	Essent (2009a)
Enecogen I & II	Eneco (2009)
MD-2	Essent (2009b).
EC-8a, EC-8b, EC-8c	Advanced Power (2008).

5.4.8 Peakers

An overview of the peaker units in the model with natural gas as primary fuel is listed in Table 22.

Owner	Unit	Capacity [MW]	fuel	Design Efficiency.
Peakers	P1	1000	NG	50.0%
Peakers	P2	1000	NG	48.0%
Peakers	P3	1000	NG	45.0%
Peakers	P4	2000	NG	40.0%
Peakers	P5	1000	NG	37.0%
Peakers	P6	1000	NG	35.0%
TOTAL		**7000**		

Table 22: Overview of peaker units.

5.4.9 Blast Furnace Gas fired power plants

An overview of the units in the model with blast furnace gas as primary fuel is listed in Table 23.

Owner	Unit	capacity [MW]	year	design eff.
Nuon	VN25	361	1986	40.90%
Nuon	IJM01	145	1997	48.10%
Nuon	IJM02	200	2018	50.00%

Table 23: Overview of units fired on blast furnace gas.

5.5 THE STORAGE SCENARIO

There are three existing initiatives for large scale electricity storage in the Netherlands:

Inverse Offshore Pump Accumulation System (IOPAS), also known as the Energy Island. The energy island is to be constructed in the North Sea, near the coast of the province of Zeeland. Dikes surround an artificial lake 40 meters below sea level. Electricity is "stored" by pumping water out of the lake and to "produce" electricity sea water will flow through turbines into the lake. The system was designed by KEMA and Bureau Lievense for Delta, Eneco, E-on Benelux, EPZ, Essent, Nuon and TenneT. See **Fout! Verwijzingsbron niet gevonden.** for an artist impression of this system. The properties of this project are listed in Table 24**Fout! Verwijzingsbron niet gevonden.**.

Underground Pump Accumulation System (UPAS).

This system consists out of two water basins: one above ground and one at approximately 1400 meters depth. The substantial difference in altitude between the two basins allows less water to be circulated than for the Energy Island. The initiative is from a consortium by Essent, NUON, E-ON Wasserkraft GmbH, Sogecom en Royal Haskoning. See **Fout! Verwijzingsbron niet gevonden.** for a schematic representation of this system. The properties of this project are listed in Table 24**Fout! Verwijzingsbron niet gevonden.**.

Compressed Air Energy Storage (CAES).

To store electricity, the system will compress air en store it underground in salt caverns. To produce electricity, the compressed air is used in a natural gas fired combined cycle plant. The properties of this project are listed in Table 24**Fout! Verwijzingsbron niet gevonden.**.

Figure 34: An artist impression of the IOPAS or Energy Island.

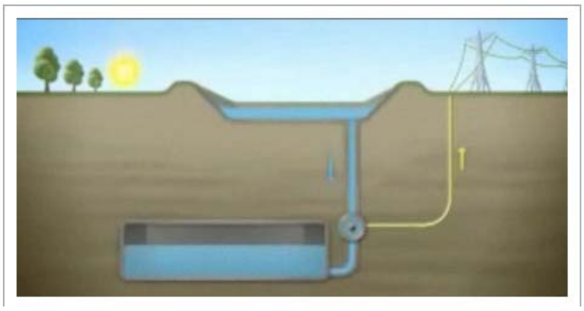


Figure 35: A schematic representation of the UPAS

Storage system		IOPAS	UPAS	CAES
Production Capacity	MW	1670	1400	1500
Pump Capacity	MW	1670	1400	1500
Storage capacity	MWh	20000	16000	20000
Cycle efficiency	%	45-77	79	60
Planned unavailability	%	2	2	6
Unplanned unavailability	%	2	2	4
Variable O&M costs	[EUR/MWh]	0.6	0.6	3.5
Fixed O&M costs	[mln EUR/yr]	10	11	18
Start cost	[kEUR]	0	0	180
Construction time	[Years]	6	5	3
Investment costs	[mln. EUR]	1800-2450	2090	965

Table 24: Properties of the proposed storage systems. (Source: Boonekamp, 2008).

Properties of the modelled storage system

The storage scenario is exactly the same as the base case, with an exception that a storage system will be in place with the following specification:

Storage capacity	16000	[$MWh_{production}$]
Basin level at begin of year	4000	[$MWh_{production}$]
Pump capacity	2000	[MW]
Turbine capacity	2000	[MW]
Pump efficiency	0.90	[-/-]
Turbine efficiency	0.90	[-/-]
Control time span	24	[h]

6. RESULTS FOR THE QUANTIFICATION OF COSTS AND BENEFITS

In this chapter the most relevant results regarding the first objective of this study are presented. This chapter contains the results for the costs and benefits for the climate, economy, investors, electricity suppliers and consumers of electricity for the years 2015, 2020 and 2030.

Only the most relevant results are presented in this chapter. The complete model results for all cases are listed in Appendix 2.

6.1 GENERAL

The results from the base scenario will be presented for the following 6 cases:

Case	Description
2015 B	Base case for 2015 (without storage).
2015 S	Case for 2015, with 2000 MW storage.
2020 B	Base case for 2020 (without storage).
2020 S	Case for 2015, with 2000 MW storage.
2030 B	Base case for 2030 (without storage).
2030 S	Case for 2015, with 2000 MW storage.

Concerning important intermediate results, where there is no difference in the results between the base case and storage case (such as the merit order), no distinction is made between the base case and the storage case.

6.2 MERIT ORDER

Since the dispatch ranking is based on the Short Term Marginal Generation Costs (STMGC), the STMGC for the conventional units are calculated. The results for the dispatch ranking (STMGC [EUR/MWh]) of the units and their utilization (hours/year) are displayed in Figure 36**Fout! Verwijzingsbron niet gevonden.**.

The figure contains a lot of information and may require some explanation: On the vertical axis is the electricity price, on the horizontal axis the load on conventional units (demand + export + storage pump demand – generation from PV, wind and micro CHP – imports – storage turbine generation). The curve displays the relation between the load on conventional units and the price for electricity (cost-supply curve).

A distinction has been made by the fuel type of the units (the color of the area). For each time segment exactly enough units are dispatched in the order of their STMGC (from left to right) until all the demand is fulfilled. Therefore units to the left are utilised more than the units on the right. As a result base load demand is fulfilled with the units on the left and peak load demand with the (more expensive) units on the right.

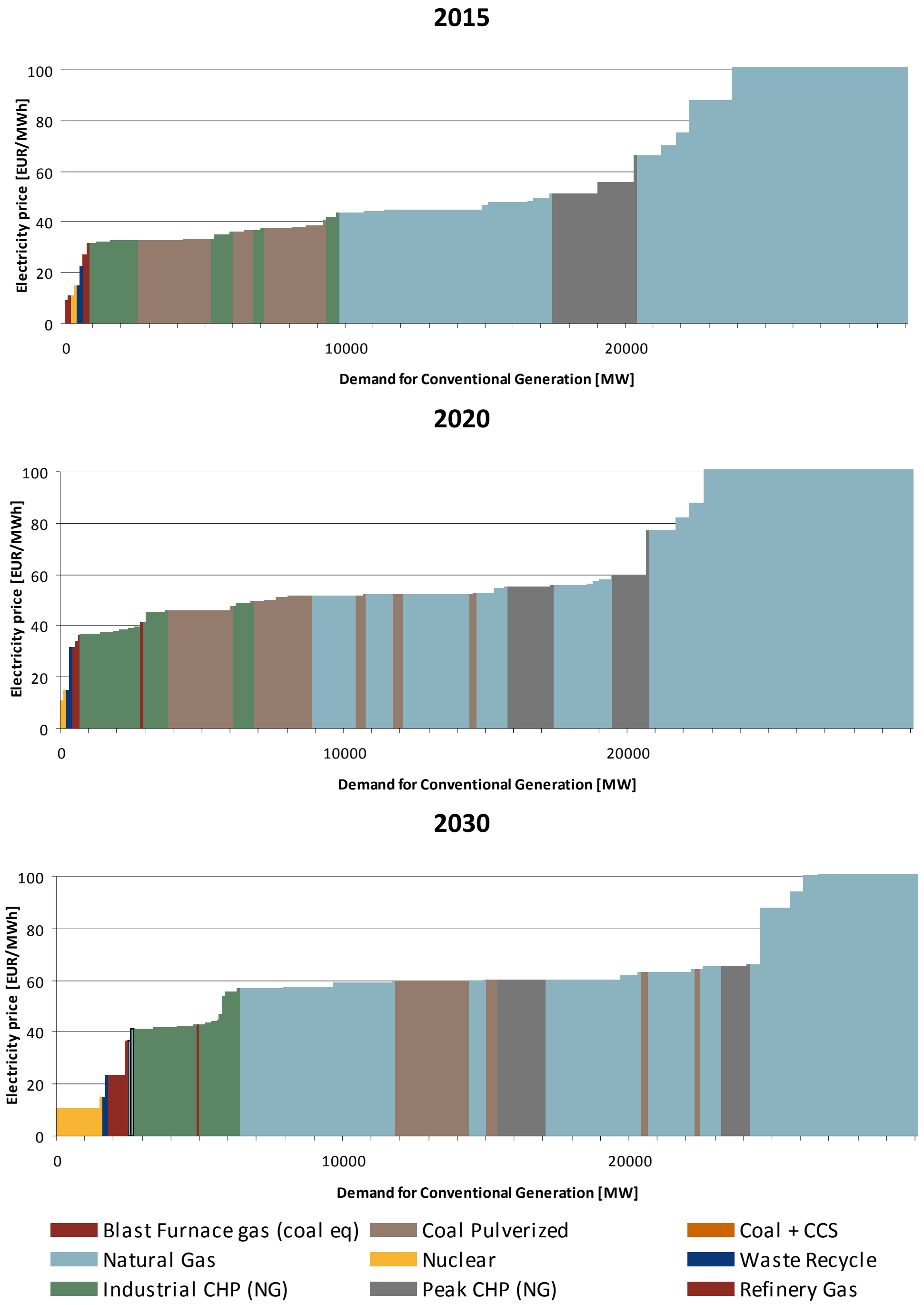


Figure 36: Merit order of conventional capacity, specified to fuel type including load curves for base and storage scenarios.

Flexibility

As renewable capacity is increased from 2015 to 2030, the amount of base load part of the demand (modelled running 8760 hours/year) for conventional generated electricity is decreased from approx 11 GW in 2015 to 2030 approx 7 GW in 2030.

The demand for more flexible capacity (modelled running less than 8760 hours/year) increases from 14 GW in 2015 to 23 GW in 2030.

Merit order
Under the influence of increasing costs for CO2 emissions, coal fired capacity will be ranked lower in the merit order. This can be seen in 2020 (Assumed CO2-price: 35 EUR/tonne), where the 2 least efficient coal fired units (Amer 81 and Gelderland 13) will be placed in between efficient Natural Gas fired Combined Cycle plants. And in 2030 (Assumed CO2-price: 50 EUR/tonne), where all coal fired capacity without Carbon Capture and Storage (CCS) is placed in between Natural Gas fired Combined Cycle Combined Cycle plants.

From Figure 36**Fout! Verwijzingsbron niet gevonden.** can be observed that in 2030 two coal fired units (Hemweg 8 and Amer 91) will be operating for less than 3000 hours per year. These plants are not capable for running this flexible and economical and will therefore probably be decommissioned.

A similar situation will probably arise for the units Amer 81 and Gelderland 13 in 2020. However, these effects are not taken into account.

Coal or Natural Gas

At CO2 prices below 20 EUR/tonne. Coal fired plants have clearly lower STMGC than Natural Gas fired plants. At higher CO2 prices, as assumed for 2020 and 2030, this difference becomes less distinct and natural gas fired technologies (CHP, Combined Cycle) progress to the left of the merit order and their utilization will increase.

Another important observed effect is that the slope angle of the electricity cost-supply curve becomes less steep in the range of approximately 7 GW to 20 GW. In 2015 the price increase over this 13 GW of power is approximately 35 [EUR/MWh produced]. In 2030 it is approximately [5 EUR/MWh produced]. This is caused by the (assumed) high CO2 price of 50 EUR/MWh in 2030.

The influence of renewable capacity on utilization of conventional plants

The influence of renewable capacity in the electricity market (green scenario) is quantified by comparing it with the same electricity market, without the renewable capacity (grey scenario).

The production of electricity from renewable plants causes conventional plants to be utilized less in a scenario with a large amount of renewable capacity. To demonstrate this effect The load duration curve in Figure 37**Fout! Verwijzingsbron niet gevonden.** is presented. In this figure two curves describe the load [hours/year] on conventional units.

Renewable capacity as PV and wind, which are characterized by having a STMGC of (near) zero, will influence the electricity prices. This influence is described by the electricity price duration curves in Figure 38**Fout! Verwijzingsbron niet gevonden.**.

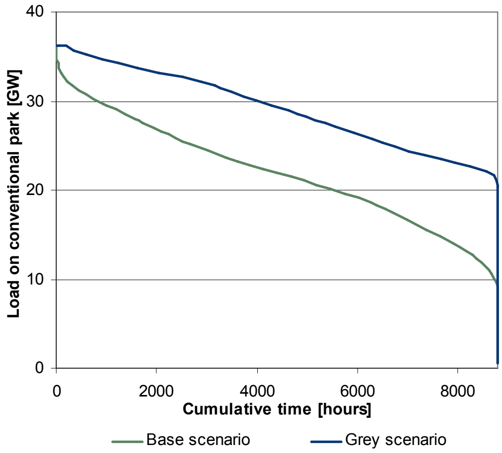


Figure 37: Load duration curve for conventional units for grey and base scenario (2030).

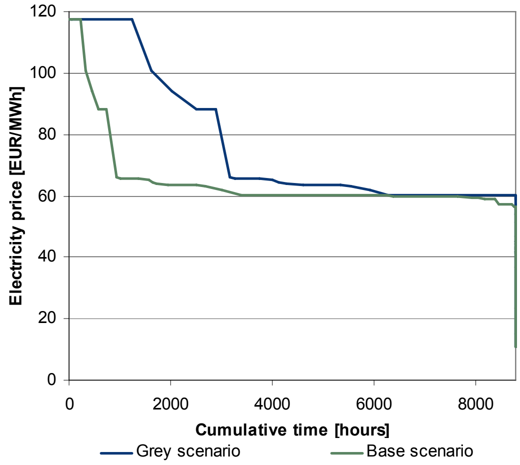


Figure 38: Price duration curve for grey and base scenario (2030).

As can be concluded from **Fout! Verwijzingsbron niet gevonden.**, increased installed wind and PV capacity decreases the peak electricity prices. This will affect the utilisation of the power plants. To illustrate how the presence of PV and wind capacity influences the utilisation of conventional units listed for some units in Table 25**Fout! Verwijzingsbron niet gevonden.**.

Rank	Unit	Capacity	STMGC	Grey	Green
		[MW]	[EUR/MWh]	[hours]	[hours]
1	BS20	490	10.9	8784	8784
2	BS40	1600	10.9	8784	8784
…	…	…	…	…	…
29	A11b	500	56.6	8784	8783
30	G14a	500	56.6	8784	8778
31	G14b	500	56.6	8784	8752
…	…	…	…	…	…
47	FL40	447	59.8	8784	6544
48	FL50	447	59.8	8783	6368
49	Bugg	235	60.1	8778	6263
…	…	…	…	…	…
65	EC-5	352	63	4974	2239
66	EC-6	352	63	4798	2088
67	EC-7	352	63	4617	1941
…	…	…	…	…	…
77	P4	500	94	2037	458
78	P5	500	101	1614	318
79	P6	500	117	1247	219
…	…	…	…	…	…

Table 25: Utilisation of units a grey scenario and in a scenario with renewable capacity (base).

Since the more expensive power plants are utilized less, electricity prices should be consequently lower when the amount of installed renewable capacity is increased. This will eventually result in less (economic) potential for trading of electricity with electricity storage.

6.3 THE ELECTRICITY SECTOR

6.3.1 The generation mix

The changes to the fuel mix are small. In 2015 the storage facility will cause some more natural gas from efficient combined cycle plants, at the cost of lower production from low temperature CHP's (Mainly greenhouses). The storage increases the demand for electricity, this is caused by the losses that occur during pumping for storage of electricity and in the turbine for the production of electricity.

The results for (changes in) the generation mix are listed for the 6 cases in Table 26**Fout! Verwijzingsbron niet gevonden.**. For coal, natural gas and CHP peakers, changes were caused due to the storage (highlighted).

Scenario	**2015 B**	**2015 S**	**2020 B**	**2020 S**	**2030 B**	**2030 S**
Electricity from source	**[TWh]**	**[TWh]**	**[TWh]**	**[TWh]**	**[TWh]**	**[TWh]**
BFG (coal eq)	2.4	2.4	2.4	2.4	1.1	1.1
Coal Pulverized	57.9	57.9	56.0	56.3	25.0	25.4
Coal + CCS	0.0	0.0	0.0	0.0	6.0	6.0
Natural Gas	58.3	59.2	50.9	50.9	65.5	65.6
Nuclear	3.7	3.7	3.7	3.7	15.6	15.6
Waste Recycle	2.1	2.1	2.1	2.1	2.1	2.1
Wind On Shore	5.6	5.6	8.2	8.2	9.7	9.7
Wind Off Shore	5.8	5.8	19.4	19.4	36.1	36.1
Industrial CHP (NG)	18.7	18.7	22.4	22.4	29.9	29.9
Peak CHP (NG)	10.3	9.8	10.7	10.8	11.0	10.9
Micro CHP fuel NG	0.2	0.2	1.4	1.4	2.2	2.2
Solar PV	0.1	0.1	0.8	0.8	4.7	4.7
Refinery Gas	2.1	2.1	2.1	2.1	2.1	2.1
TOTAL	**167.2**	**167.7**	**180.2**	**180.5**	**211.0**	**211.3**

Table 26: The generation mix for 6 cases.

A storage with a capacity of 16 GWh that would run a full cycle every day would have the potential to replace 5.8 TWh natural gas generated electricity by 5.8 / 0.81 = 7.2 TWh of electricity produced from coal. The changes are in all cases less than 0.5 TWh.

It is concluded that a 2000 MW storage has a small effect on the generation mix, relative to the total electricity production and relative to what is possible with a 2000 MW storage.

It is common to present the generation mix in a pie-chart. The observed consequences from electricity storage are too small to be evident in a pie-chart. Three pie-charts (for 2015, 2020 and 2030) of the generation mix are presented In Figure 39**Fout! Verwijzingsbron niet gevonden.**.

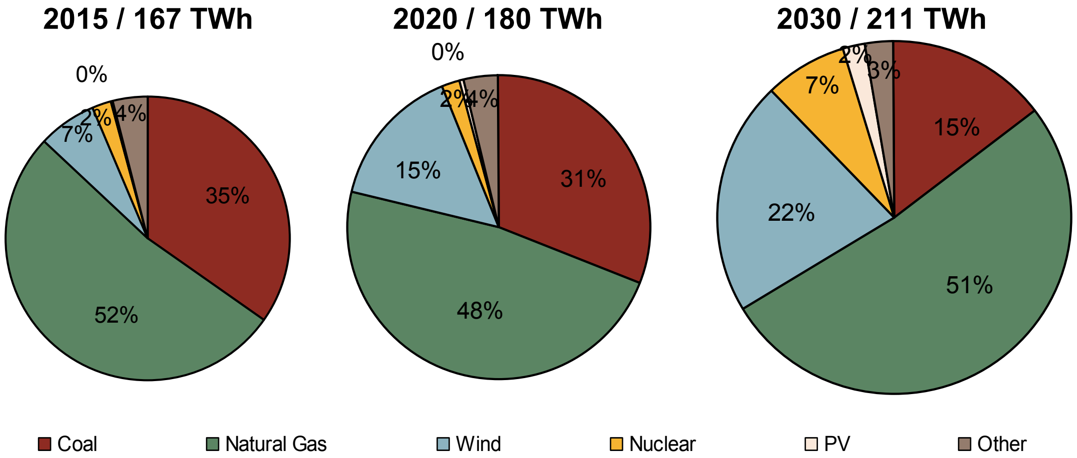


Figure 39: Electricity generation specified to origin for 2015, 2020 and 2030.

Fout! Verwijzingsbron niet gevonden. makes clear that the share of coal will decrease in the generation mix. This is the consequence of two assumptions: The first being that it is assumed that after 2015 no more coal fired capacity without CCS is installed. The second being the high CO2 price: it causes the electricity generated by coal fired units more expensive, compared to natural gas fired combined cycle units.

6.3.2 Energy consumption

The results for the fuel consumption (including nuclear) for electricity generation are listed in **Fout! Verwijzingsbron niet gevonden.**. The presence of a storage in the electricity supply will make a trading possible, so capacity with lower STMGC will be utilized more than capacity with higher STMGC.

The consequences are that in 2015 coal will be given the preference over natural gas, while in 2030 the opposite behaviour is observed.

Case →		2015 B	2015 S	2020 B	2020 S	2030 B	2030 S
Electricity from renewable sources	[TWh]	11.5	11.5	28.4	28.4	50.5	50.5
Electricity from fossil fuels	[TWh]	156	156	152	152	161	161
Fossil Fuel consumption	[PJ]	1145	1144	1107	1106	1106	1106
Fuel conversion efficiency	[-/-]	48.9%	49.1%	49.3%	49.5%	52.3%	52.3%

Table 27: Fuel consumption from electricity production.

*From the results of **Fout! Verwijzingsbron niet gevonden.** is concluded that there is no change in total fuel consumption due to the presence of an electricity storage in the electricity supply.*

Another source of emissions is the requirement for sufficient spinning reserve capacity to cope with the situation were the wind production deviates from the forecast. This capacity is delivered by conventional power plants running at part load. In Table 28**Fout! Verwijzingsbron niet gevonden.** the results for the reserve capacity for wind power are listed.

The results presented in **Fout! Verwijzingsbron niet gevonden.** include a so called *fossil fuel penalty*. This is the amount of fossil fuel that is consumed to supply spinning reserve for wind turbine generators in addition to the fuel that was consumed for the planned production of electricity. Related to the fossil fuel penalty is the CO2 penalty. These emissions are the CO2 emissions resulting from the fossil fuel penalty and are additional to the CO2 emissions resulting from the planned electricity production.

Scenario		2015 B	2015 S	2020 B	2020 S	2030 B	2030 S
Wind energy production	[TWh]	11.4	11.4	27.7	27.7	45.8	45.8
Fossil fuel penalty (reserve power)	[PJ]	8.1	0.0	19.6	2.3	28.2	9.5
CO2 penalty (reserve power)	[Mtonne]	0.62	0.00	1.49	0.18	1.88	0.64
Emission factor wind energy	[kgCO2/MWh]	54	0	54	6.5	41	14

Table 28: Fuel consumption and related CO2 emissions from (hot) reserve capacity.

*From the results in **Fout! Verwijzingsbron niet gevonden.** is concluded that the availability of spinning reserve capacity comes at the cost of increases fuel consumption and CO2 emissions, that a storage facility reduces the requirements for fossil fuel fired reserve capacity and will lead to a reduction in CO2 emissions related to reserve capacity. The estimated emissions reduction resulting from decreased part load operation is estimated to be 2015: 0.62 Mtonne, 2020: 1.31 Mtonne and 2030: 1.24 Mtonne.*

The model calculated an emission factor of wind, by taking into account the required part load operation of conventional power plants.

6.3.3 CO2 emissions

The CO2 emissions from all electricity produced in the Netherlands is listed in Table 29**Fout! Verwijzingsbron niet gevonden.**. In this table a distinction has been made between emissions related to electricity production and emissions related to part load operation to supply the reserve capacity necessary at times of (high) production from wind.

Scenario	2015 B	2015 S	2020 B	2020 S	2030 B	2030 S
	[Mtonne]	[Mtonne]	[Mtonne]	[Mtonne]	[Mtonne]	[Mtonne]
Electricity Production	81.6	81.5	78.8	78.8	57.1	57.3
Partload Operation	0.62	0.00	1.49	0.18	1.88	0.64
Total	*82.2*	*81.5*	*80.3*	*79.0*	*59.0*	*57.9*

Table 29: CO2emissions from electricity production and part load operation (to supply reserve capacity).

An important remark about the absolute CO2-emissions should be made. Depending on the case, approximately 17 % of the electricity is generated by CHP-units. The resulting CO2-emissions are those that are allocated to electricity production according to Equation 8**Fout! Verwijzingsbron niet gevonden.**. Different methods for allocation exist and would lead to other results. This does not influence the total CO2 emissions in the Netherlands, but it will make a difference in the allocation from emissions resulting from heat production or emissions resulting from electricity production.

The described allocation issue may become problematic when emissions rights for one sector are allocated (i.e. basic chemical production), while they are auctioned for the other sector (i.e. electricity production).

The emission reduction that is caused by the inclusion of an electricity storage in the electricity supply can be calculated from the case results in Table 29**Fout! Verwijzingsbron niet gevonden.**. The emission reduction, caused by the storage is listed in Table 30**Fout! Verwijzingsbron niet gevonden.**.

Scenario	2015	2020	2030
	[Mtonne]	[Mtonne]	[Mtonne]
Structural Change Electricity Production	0.06	-0.03	-0.16
Reduced Partload Operation	0.62	1.31	1.24
Total Reduction	*0.68*	*1.29*	*1.08*
Reduction, relative to sector emissions	*0.8%*	*1.6%*	*1.8%*

Table 30: CO2 emissions reduction resulting from the electricity storage.

*From Table 30**Fout! Verwijzingsbron niet gevonden.** is concluded that a 2000 MW electricity storage can reduce the CO2 emissions with approximately 1.3 and 1.1 Mtonne in respectively 2020 and 2030.*

6.3.4 Wholesale electricity prices

The wholesale electricity prices are calculated for the 6 cases of the base scenario the prices are specified to Peak (day-time: from 08:00 to 20:00), Off Peak (evening and night: from 20:00 in the evening to 08:00 in the morning) and baseload (from 0:00 to 24:00). The results are listed in Table 31**Fout! Verwijzingsbron niet gevonden.**.

Scenario	2015 B	2015 S	2020 B	2020 S	2030 B	2030 S
	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]
Peak (08:00 - 20:00) Price	63	58	69	65	69	66

Off Peak (20:00 - 08:00) Price	48	49	55	55	62	61
Base (24h) Price	55	53	61	59	65	64

Table 31: Wholesale electricity prices

The results in Table 31**Fout! Verwijzingsbron niet gevonden.** show that the electricity prices in the cases with storage are consequently lower. This price reduction is shown in Table 32**Fout! Verwijzingsbron niet gevonden.**.

With increasing installed renewable capacity the question can be raised whether the subdivision of peak and off-peak is still functional. The results in Table 31**Fout! Verwijzingsbron niet gevonden.** show a slight price decrease as a result from the electricity storage in the off-peak price for 2030. Renewable electricity sources “disturb” the traditional day pattern of the load. In a scenario with a large installed capacity wind and PV a peak in demand can actually occur during the night.

Scenario	2015	2020	2030
	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]
Peak (08:00 - 20:00) Price	4.2	4.2	2.4
Off Peak (20:00 - 08:00) Price	-0.3	0.1	0.3
Base (24h) Price	1.7	2.0	1.2

Table 32: Reduction in wholesale electricity prices due to the electricity storage.

*From the results in Table 31**Fout! Verwijzingsbron niet gevonden.** is concluded that an electricity storage will provide an incentive for lower (peak) electricity wholesale prices.*

6.4 RESULTS FOR THE STORAGE FACILITY

6.4.1 Utilization of the storage

The main results for physical and economical operation of the electricity storage are listed in **Fout! Verwijzingsbron niet gevonden.**.Table 33

Storage Operation		2015	2020	2030
Electricity production	TWh	1.91	1.46	1.20
Electricity consumption	TWh	2.36	1.81	1.49
Operating Time (storage + production)	hours	4038	3029	2446
Electricity Costs (pumps)	mln EUR	109	96	89
Electricity Revenues (turbines)	mln EUR	119	108	88
Gross Margin (trade)	mln EUR	9	12	-1
Avoided costs for reseve capacity	*mln EUR*	*106*	*221*	*299*

Table 33: Results for the storage facility.

It is observed from the results in Table 33**Fout! Verwijzingsbron niet gevonden.** that the utilisation (electricity production, consumption and operating time) of the storage facility will decrease strongly from 2015 to 2030. The load-duration curve of the storage is displayed in Figure 40**Fout! Verwijzingsbron niet gevonden.**.

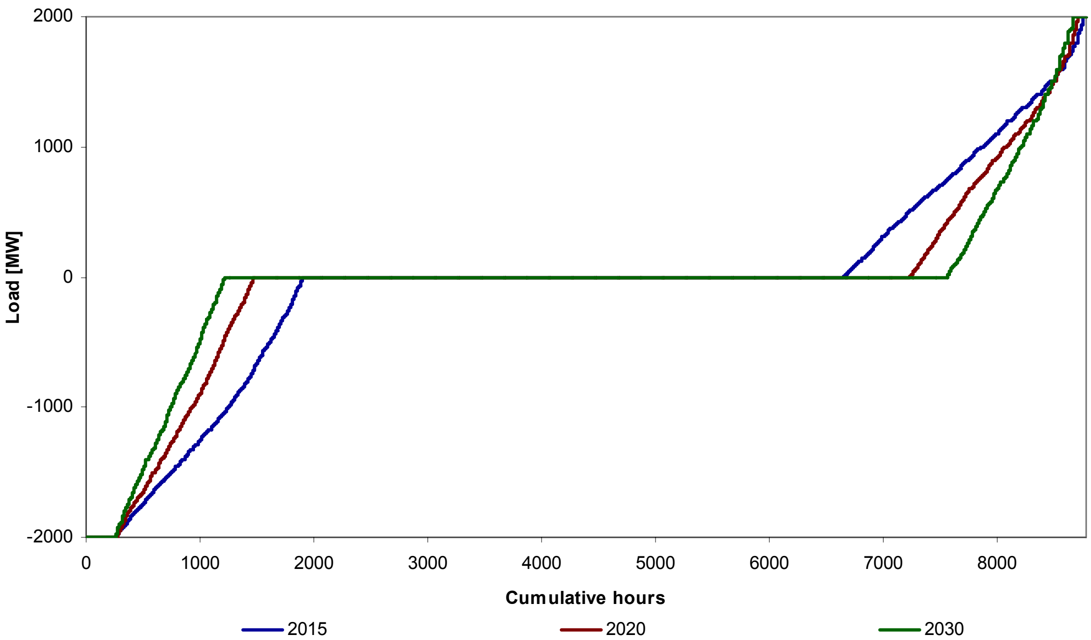


Figure 40: Load duration curve for the utilization of the storage in 2015, 2020 and 2030.

The main benefits that could profit the storage directly are the margin made on the trade of electricity and the reduced cost of part load operation to provide spinning reserve. Compared to the volume of traded electricity (1 – 2 TWh/year) and the investment costs the benefits from electricity trading are marginal.

The potential revenues from the supply of reserve capacity are much more promising. The reserve capacity can be delivered by the storage without a fuel penalty or increased CO2 emissions. Since the gross margin made on the trade of electricity is small, the opportunity costs, for not producing electricity with the turbines, are small as well.

Since the electricity storage will be in competition with other suppliers of reserve capacity it is unlikely that all the avoided costs for reserve capacity, as listed in the bottom row of Table 34**Fout! Verwijzingsbron niet gevonden.**, can be benefited from by the storage operation.

It is concluded that for 2020 and 2030 no significant earning can be made from the trading of electricity. The economical potential of electricity storage must be sought in the supply of reserve capacity on a (still hypothetical) market for reserve capacity. As the installed capacity of wind turbines in the electricity supply increases, the market for reserve capacity is estimated to grow to 200 and 300 mln EUR/year in respectively 2020 and 2030.

6.5 FINANCIAL PERFORMANCE OF THE SECTOR

The gross margin, specified to the source of primary energy from which the electricity was generated, is listed in Table 35**Fout! Verwijzingsbron niet gevonden.** for the 6 cases.

Case	2015 B	2015 S	2020 B	2020 S	2030 B	2030 S
Gross Margin specified to source	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**
BFG (coal eq)	72	68	59	54	21	20
Coal Pulverized	1109	1009	723	609	180	133
Coal + CCS	0	0	0	0	168	161
Natural Gas	646	501	612	446	577	439
Nuclear	160	154	185	177	840	821
Waste Recycle	84	81	98	94	106	103
Wind On Shore	292	287	466	460	595	592
Wind Off Shore	305	300	1092	1083	2201	2197
Industrial CHP (NG)	393	360	506	462	649	613
Peak CHP (NG)	134	83	176	123	111	79
Micro CHP fuel NG	8	8	66	63	105	103
Solar PV	8	8	50	47	302	297
Refinery Gas	96	92	95	91	87	85
TOTAL	**3308**	**2951**	**4128**	**3709**	**5943**	**5642**

Table 34: Financial performance of the electricity sector.

To facilitate the possibility to draw conclusion from these results a summary is made in Table 35**Fout! Verwijzingsbron niet gevonden.**.

Scenario	Absolute [mln EUR]			Relative to base case		
	2015	2020	2030	2015	2020	2030
Renewable generators	-11	-18	-12	-1.8%	-1.1%	-0.4%
Non-renewable generators	-346	-399	-279	-13%	-16%	-11%

Table 35: Summary of difference in gross margin due to storage.

*From Table 35**Fout! Verwijzingsbron niet gevonden.** and Table 34**Fout! Verwijzingsbron niet gevonden.** can be concluded that the operation of an electricity storage has the potential to decrease the gross margin from all electricity generators (as a result from lower wholesale prices) due to the possibility of storing the electricity and that the gross margin from the non-renewable generators could decrease strong, while the gross margin from the renewable generators is hardly affected.*

Earlier in this chapter was explained how increased electricity production drives down the prices on the electricity market by Figure 37 and Figure 38**Fout! Verwijzingsbron niet gevonden.Fout! Verwijzingsbron niet gevonden.**. The same figures are used again, with 2 more curves added: the load duration curve for the storage case for the year 2030 in Figure 41**Fout! Verwijzingsbron niet gevonden.** and Figure 42 price duration curve for the storage case for the year 2030 in **Fout! Verwijzingsbron niet gevonden.**.

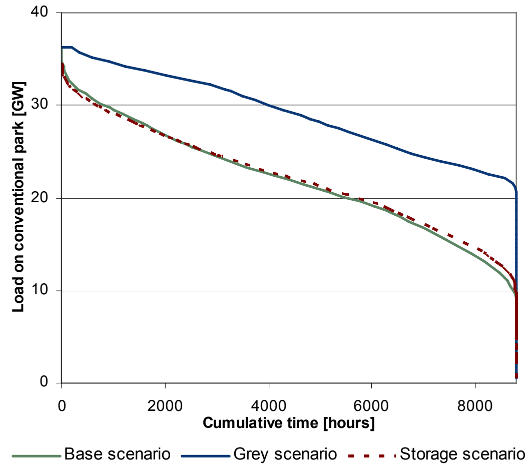


Figure 41: Load duration curve for conventional units for grey, base and storage cases in 2030.

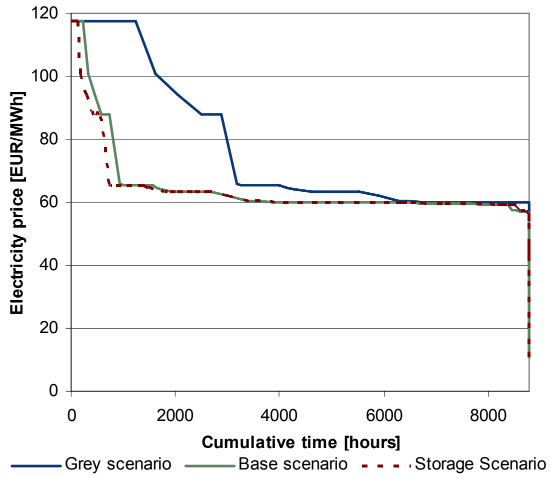


Figure 42: Pirce duration curve for grey, base and storage cases in 2030.

The load duration curve for the storage case in **Fout! Verwijzingsbron niet gevonden.** shows a slight decrease of “peak” capacity and increase in “base” capacity. The effects on the electricity prices are more substantial. **Fout! Verwijzingsbron niet gevonden.** displays the electricity price duration curves. It can be seen that the influence of renewable capacity has a major influence on the peak-price surface (blue and green lines). The storage further decreases the area with high peak prices (red dashed line).

7. RESULTS FOR THE SENSITIVITY ANALYSIS

As formulated in the study objective the sensitivity of the results is investigated for changes in fuel and CO2 prices, load patterns and the amount and type of installed capacity.

The sensitivity to the assumptions is analysed for the year 2030 only.

7.1 SENSITIVITY ON ASSUMPTIONS OF THE FUEL AND CO2 PRICES.

7.1.1 Fuel price scenario's

To investigate the sensitivity of the results three fuel price scenario are assumed: A coal favoured fuel price scenario, a mixed fuel price scenario and a natural gas favoured price scenario. The price scenarios are listed in Table 36. For reference the fuel and CO2 prices from the base case are included.

Scenario		Reference	Coal favoured	Mixed	Natural Gas favoured
CO2	EUR/tonne	50	50	50	50
Natural Gas	EUR/GJ	6.74	12	8	6
Coal	EUR/tonne	2.1	2	2	2

Table 36: Fuel price scenario' s for sensitivity analysis.

The effects of the described scenarios for 3 “typical” (2030) plants are as follows:

Typical CHP plant:
Fuel: Natural Gas
Efficiency: 78% (CHP efficiency as defined in **Fout! Verwijzingsbron niet gevonden.**)

Typical Combined Cycle:
Fuel: Natural Gas
Efficiency: 59%

Typical Steam Turbine Plant:
Fuel: Pulverised Coal
Efficiency: 43%

The prices in the scenario's lead to the simplified merit orders:

Coal favoured prices:	1. Coal	2. CHP	3. NG
Mixed	1. CHP	2. Coal	3. NG
Gas favoured prices:	1. CHP	2. NG	3. Coal

The STMGC for the specified typical (2030) plants are presented in Figure 43**Fout! Verwijzingsbron niet gevonden.**. This figure presents simplified (only typical coal, natural gas and CHP plants) ranking of power plants on the STMGC and the difference in STMGC for the 3 chosen sensitivity scenarios.

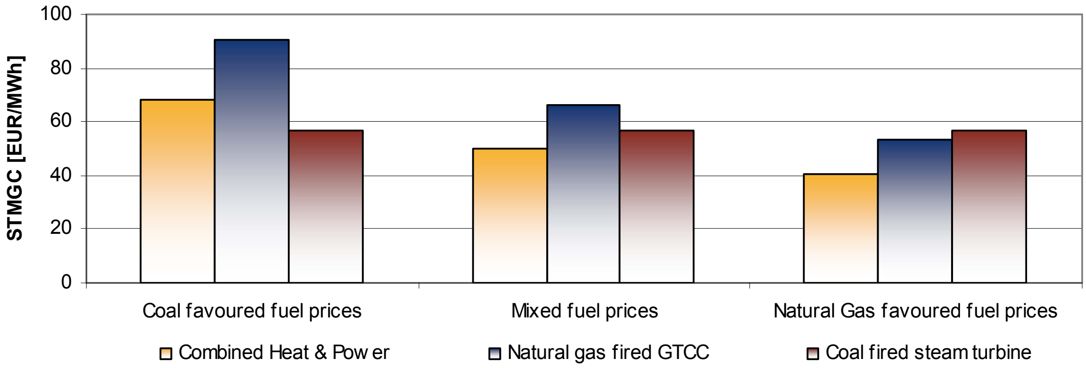


Figure 43: STMGC for three fuel price scenarios.

The following 6 cases are used to investigate the sensitivity to fuel price changes:

Case	**Description**
2030-c B	2030 scenario with coal favoured fuel prices and no storage.
2030-c S	2030 scenario with coal favoured fuel prices and storage.
2030-m B	2030 scenario with mixed fuel prices and no storage.
2030-m S	2030 scenario with mixed fuel prices and storage.
2030-g B	2030 scenario with natural gas favoured prices and no storage.
2030-g S	2030 scenario with natural gas favoured prices and storage.

7.1.2 The generation mix

The results for the sensitivity analysis on fuel prices for the generation mix are listed in Table 37**Fout! Verwijzingsbron niet gevonden.**. The positions where changes occur are highlighted.

Scenario	**2030-c B**	**2030-c S**	**2030-m B**	**2030-m S**	**2030-g B**	**2030-g S**
Electricity from source	**[TWh]**	**[TWh]**	**[TWh]**	**[TWh]**	**[TWh]**	**[TWh]**
BFG (coal eq)	1.1	1.1	1.1	1.1	1.1	1.1
Coal Pulverized	37.4	37.4	36.6	37.0	10.3	10.0
Coal + CCS	6.0	6.0	6.0	6.0	6.0	6.0
Natural Gas	42.7	42.0	53.5	53.6	74.9	75.3
Nuclear	15.6	15.6	15.6	15.6	15.6	15.6
Waste Recycle	2.1	2.1	2.1	2.1	2.1	2.1
Wind On Shore	9.7	9.7	9.7	9.7	9.7	9.7
Wind Off Shore	36.1	36.1	36.1	36.1	36.1	36.1
Industrial CHP (NG)	28.9	29.3	29.8	29.8	29.9	29.9
Peak CHP (NG)	22.7	23.3	11.6	11.5	16.3	16.5
Micro CHP fuel NG	2.2	2.2	2.2	2.2	2.2	2.2
Solar PV	4.7	4.7	4.7	4.7	4.7	4.7
Refinery Gas	2.1	2.1	2.1	2.1	2.1	2.1

TOTAL	211.4	211.7	211.3	211.6	211.0	211.3

Table 37: The generation mix for 6 cases for sensitivity on the fuel scenario.

From the results is in **Fout! Verwijzingsbron niet gevonden.** is observed that:

- For the coal favoured fuel price scenario, the storage will not increase the amount of electricity generated from coal, more electricity will be generated with natural gas by CHP, less with conventional generation with natural gas.
- In the mixed fuel scenario, 0.4 TWh more electricity will be generated from coal. This is a minor change compared to a possible 5.8 TWh.

7.1.3 Energy consumption

Case →		2030-c B	2030-c S	2030-m B	2030-m S	2030-g B	2030-g S
Electricity from renewable sources	[TWh]	50.5	50.5	50.5	50.5	50.5	50.5
Electricity generated from fuels	[TWh]	161	161	161	161	160	161
Fuel consumption	[PJ]	1125	1123	1139	1140	1060	1059
Fuel conversion efficiency	[-/-]	51.5%	51.7%	50.8%	50.9%	54.5%	54.7%

Table 38: Fuel consumption from electricity production.

Scenario		2030-c B	2030-c S	2030-m B	2030-m S	2030-g B	2030-g S
Wind energy production	[TWh]	45.8	45.8	45.8	45.8	45.8	45.8
Fossil fuel penalty (reserve power)	[PJ]	28.8	9.7	29.4	9.9	26.7	9.0
CO2 penalty (reserve power)	[Mtonne]	2.1	0.7	2.1	0.7	1.6	0.5
Emission factor wind energy	[kgCO2/MWh]	45	15	46	15	35	12

Table 39: Fuel consumption and related CO2 emissions from spinning reserve capacity.

From Table 38**Fout! Verwijzingsbron niet gevonden.** and Table 39**Fout! Verwijzingsbron niet gevonden.** is concluded that the fuel savings for the natural gas favoured fuel price scenario are less than for the mixed or coal favoured fuel prices.

7.1.4 CO2 emissions

The CO_2 emissions for all six cases of the sensitivity analysis on fuel prices are listed in Table 40**Fout! Verwijzingsbron niet gevonden.**.

Scenario	2030-c B	2030-c S	2030-m B	2030-m S	2030-g B	2030-g S
	[Mtonne]	[Mtonne]	[Mtonne]	[Mtonne]	[Mtonne]	[Mtonne]

Electricity Production	62.6	62.5	63.1	63.3	49.5	49.3
Partload Operation	2.06	0.69	2.08	0.71	1.62	0.54
Total	*64.7*	*63.2*	*65.2*	*64.0*	*51.2*	*49.9*

Table 40: CO2emissions from electricity production and partload operation (to supply reserve capacity).

Scenario	2030 Coal	2030 Mixed	2030 Gas
	[Mtonne]	[Mtonne]	[Mtonne]
Structural Change Electricity Production	0.11	-0.20	0.21
Reduced Partload Operation	1.37	1.38	1.07
Total Reduction	*1.48*	*1.18*	*1.28*
Relative Reduction	*2.3%*	*1.8%*	*2.5%*

Table 41: CO2 emissions reduction resulting from the electricity storage.

*From Table 41**Fout! Verwijzingsbron niet gevonden.** is concluded that, as a consequence of changing fuel prices, the absolute emissions reduction caused by the storage will change. The reduction is the smallest in the mixed scenario, which is closest to the prices in the base scenario. It is concluded that the emission reduction from storage is estimated conservative in the base price scenario.*

7.1.5 Wholesale electricity prices

The results for the six cases to test for sensitivity to the fuel prices are listed in Table 42**Fout! Verwijzingsbron niet gevonden.**.

Scenario	2030-c B	2030-c S	2030-m B	2030-m S	2030-g B	2030-g S
	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]
Peak (08:00 - 20:00) Price	104	100	77	74	65	62
Off Peak (20:00 – 08:00) Price	89	89	68	68	58	58
Base (24h) Price	95	93	72	71	61	60

Table 42: Wholesale electricity prices

The results in Table 42**Fout! Verwijzingsbron niet gevonden.** show that the electricity prices in the cases with storage are consequently lower. This price reduction is shown in Table 43**Fout! Verwijzingsbron niet gevonden.**.

Scenario	2030 Coal	2030 Mixed	2030 Gas
	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]
Peak (08:00 - 20:00) Price	3.8	2.8	2.2
Off Peak (20:00 - 08:00) Price	-0.1	0.2	0.2
Base (24h) Price	1.5	1.3	1.1

Table 43: Reduction in wholesale electricity prices due to the electricity storage.

*From Table 43 **Fout! Verwijzingsbron niet gevonden.** is concluded that the reduction in electricity prices, caused by the storage will be lower with more gas favored fuel prices and higher for coal favored fuel prices.*

7.1.6 Utilisation of the storage facility

The results for the storage operation are listed in Table 44**Fout! Verwijzingsbron niet gevonden.**.

Storage Operation		**2030 Coal**	**2030 Mixed**	**2030 Gas**
Electricity production	TWh	1.20	1.20	1.20
Electricity consumption	TWh	1.49	1.49	1.49
Operating Time (storage + production)	hours	2446	2446	2446
Electricity Costs (pumps)	mln EUR	122	97	82
Electricity Revenues (turbines)	mln EUR	134	99	82
Gross Margin (trade)	mln EUR	12	1.8	-0.6
Avoided costs for reseve capacity	*mln EUR*	*664*	*315*	*249*

Table 44: Results for the storage facility.

*From Table 44**Fout! Verwijzingsbron niet gevonden.** is concluded that the profitability of the storage operation will become less when fuel prices develop to be more gas favoured.*

7.1.7 Performance of the sector

Scenario	**2030-c B**	**2030-c S**	**2030-m B**	**2030-m S**	**2030-g B**	**2030-g S**
Gross Margin specified to source	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**
BFG (coal eq)	54	52	29	28	17	16
Coal Pulverized	1312	1255	453	403	127	84
Coal + CCS	348	339	211	203	144	137
Natural Gas	761	537	599	440	607	481
Nuclear	1310	1286	952	931	776	759
Waste Recycle	170	166	121	118	97	95
Wind On Shore	845	846	655	653	556	553
Wind Off Shore	3135	3151	2425	2425	2057	2054
Industrial CHP (NG)	845	798	694	655	626	594
Peak CHP (NG)	460	412	132	94	136	107
Micro CHP fuel NG	171	168	121	118	96	94
Solar PV	449	441	337	331	283	278
Refinery Gas	151	148	103	100	79	76
TOTAL	**10011**	**9599**	**6831**	**6499**	**5601**	**5328**

Table 45: Financial performance of the electricity sector.

To facilitate the possibility to draw conclusion from these results. A summary is made in Table 46**Fout! Verwijzingsbron niet gevonden.**.

Scenario	Absolute [mln EUR]			Relative to base case		
	2030-c	2030-m	2030-g	2030-c	2030-m	2030-g
Renewable generators	-9.0	8.2	10.6	-0.2%	0.2%	0.4%
Non-renewable generators	418	321	260	7.7%	9.8%	11.1%

Table 46: Summary of financial performance.

*From Table 46**Fout! Verwijzingsbron niet gevonden.** is concluded that the storage will decrease the profitability of conventional generators strong, while its influence on the profitability of renewable generators is marginal.*

7.2 SENSITIVITY ON THE ASSUMED LOAD PATTERN

To investigate the sensitivity of the assumed load pattern on the results, different scale factors from the reference load pattern were used. Two new load patterns were instructed from scaling the base scenario load pattern with a factor of 0.5 and 1.5 around the average electricity demand. The effects of this scaling are visualised in Figure 43**Fout! Verwijzingsbron niet gevonden.**.

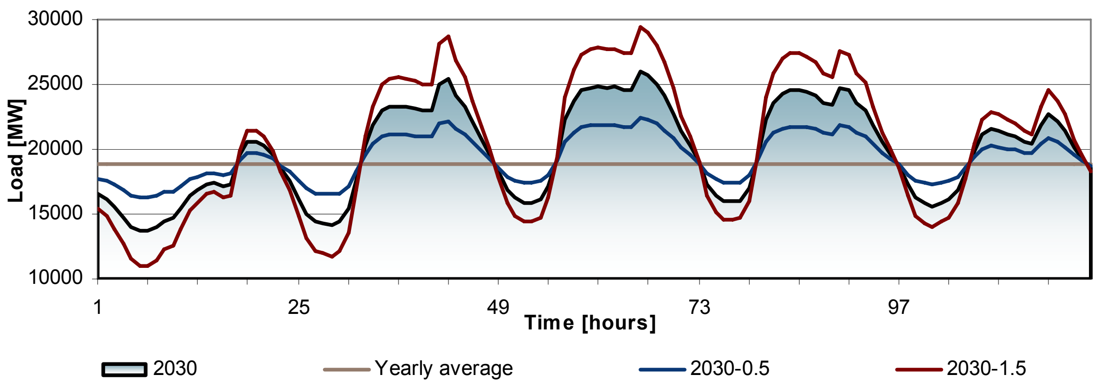


Figure 44: The scaling of the load pattern.

The main properties of the sensitivity scenarios are listed in Figure 45**Fout! Verwijzingsbron niet gevonden.**.

Case		Base case	2030-0	2030-0.5	2030	2030-1.5
Pattern scale factor	[-/-]	1	0	0.5	1.0	1.5
Minimum load	[MW]	12069	18912	15490	12069	8647
Maximum load	[MW]	26569	18912	22741	26569	30398
Average load	[MW]	18912	18912	18912	18912	18912
Grid demand	[TWh]	166	166	166	166	166
Export	[TWh]	20	20	20	20	20
Private networks	[TWh]	27	27	27	27	27
Total demand	[TWh]	213	213	213	213	213

Figure 45: Description of the changes properties of the sensitivity cases for the load pattern.

For the 2030-1.5 case additional capacity was installed to be able to full fill the demand: 1 GW of gas fired Combined Cycle plants (efficiency 60%) and 4 GW of additional peak units. (30% efficiency).

The variations in load patterns result in the following 6 cases to be analysed:

Case:	**Description:**
2030-0.5 B	2030 case with a load pattern factor of 0.5 without storage
2030-0.5 S	2030 case with a load pattern factor of 0.5 with storage
2030-B	2030 case with a load pattern factor of 1 without storage
2030-S	2030 case with a load pattern factor of 1 with storage
2030-1.5 B	2030 case with a load pattern factor of 1.5 without storage
2030-1.5 S	2030 case with a load pattern factor of 1.5 with storage

The results for cases 2030-B and 2030-S were presented earlier, but will be listed again for reference purposes.

7.2.1 The generation mix

The results for the sensitivity analysis on the load pattern for the generation mix are listed in Table 47**Fout! Verwijzingsbron niet gevonden.**.

Scenario	**2030-0.5 B**	**2030-0.5 S**	**2030 B**	**2030 S**	**2030-1.5 B**	**2030-1.5 S**
Electricity from source	**[TWh]**	**[TWh]**	**[TWh]**	**[TWh]**	**[TWh]**	**[TWh]**
BFG (coal eq)	1.1	1.1	1.1	1.1	1.1	1.1
Coal Pulverized	26.1	26.7	25.0	25.4	21.4	21.5
Coal + CCS	6.0	6.0	6.0	6.0	6.0	6.0
Natural Gas	65.2	65.2	65.5	65.6	71.2	71.4
Nuclear	15.6	15.6	15.6	15.6	15.6	15.6
Waste Recycle	2.1	2.1	2.1	2.1	2.1	2.1
Wind On Shore	9.7	9.7	9.7	9.7	9.7	9.7
Wind Off Shore	36.1	36.1	36.1	36.1	36.1	36.1
Industrial CHP (NG)	29.9	29.9	29.9	29.9	29.8	29.9
Peak CHP (NG)	10.2	10.0	11.0	10.9	9.0	8.8
Micro CHP fuel NG	2.2	2.2	2.2	2.2	2.2	2.2
Solar PV	4.7	4.7	4.7	4.7	4.7	4.7
Refinery Gas	2.1	2.1	2.1	2.1	2.1	2.1
TOTAL	**211**	**211**	**211**	**211**	**211**	**211**

Table 47: The generation mix for 6 cases for sensitivity on the fuel scenario.

From the results is observed that for the coal favoured fuel scenario, the storage wil not increase the amount of electricity generated from coal, more electricity will be generated with natural gas by CHP, less by conventional generation with natural gas. In the mixed fuel scenario, 0.4 TWh more electricity will be generated from coal by operating the storage.

7.2.2 Energy consumption

The results for the energy consumption for the production of electricity are listed in Table 48**Fout! Verwijzingsbron niet gevonden.**. The energy consumption (and related emissions) as a consequences of the planned reserve capacity are listed in table 49**Fout! Verwijzingsbron niet gevonden.**.

*From Table 48**Fout! Verwijzingsbron niet gevonden.** and Table 49**Fout! Verwijzingsbron niet gevonden.** is concluded that the changes in the load pattern lead to different results for the reduction in fuel consumption or CO2-emissions from the electricity storage for the cases with a load profile with a smaller "amplitude".*

Case →		**2030-0.5 B**	**2030-0.5 S**	**2030 B**	**2030 S**	**2030-1.5 B**	**2030-1.5 S**
Electricity from renewable sources	[TWh]	50.5	50.5	50.5	50.5	50.5	50.5
Electricity Generated from fuels	[TWh]	160	161	161	161	160	161
Fuel consumption	[PJ]	1104	1107	1106	1106	1101	1101
Fuel conversion efficiency	[-/-]	52.3%	52.3%	52.3%	52.3%	52.5%	52.6%

Table 48: Fuel consumption from electricity production.

Scenario		**2030-0.5 B**	**2030-0.5 S**	**2030 B**	**2030 S**	**2030-1.5 B**	**2030-1.5 S**
Wind energy production	[TWh]	45.8	45.8	45.8	45.8	45.8	45.8
Fossil fuel penalty (reserve power)	[PJ]	28.2	9.5	28.2	9.5	28.1	9.5
CO2 penalty (reserve power)	[Mtonne]	1.9	0.6	1.9	0.6	1.8	0.6
Emission factor wind energy	[kgCO2/MWh]	41	14	41	14	40	13

Table 49: Fuel consumption and related CO2 emissions from spinning reserve capacity.

7.2.3 CO2 emissions

The emission reduction that is caused by the inclusion of an electricity storage in the electricity supply can be calculated from the case results in Table 50**Fout! Verwijzingsbron niet gevonden.**. The emission reduction, caused by the storage is listed in Table 51**Fout! Verwijzingsbron niet gevonden.**.

Scenario	**2030-0.5 B**	**2030-0.5 S**	**2030 B**	**2030 S**	**2030-1.5 B**	**2030-1.5 S**
	[Mtonne]	**[Mtonne]**	**[Mtonne]**	**[Mtonne]**	**[Mtonne]**	**[Mtonne]**
Electricity Production	57.4	57.8	57.1	57.3	55.6	55.7
Partload Operation	1.89	0.64	1.88	0.64	1.83	0.62
Total	*59.3*	*58.4*	*59.0*	*57.9*	*57.5*	*56.3*

Table 50: CO2 emissions from electricity production and partload operation (to supply reserve capacity).

Scenario	2030-0.5	2030	2030-1.5
	[Mtonne]	[Mtonne]	[Mtonne]
Structural Change Electricity Production	-0.36	-0.16	-0.03
Reduced Partload Operation	1.25	1.24	1.21
Total Reduction	*0.89*	*1.08*	*1.18*
Relative Reduction	*1.5%*	*1.8%*	*2.1%*

Table 51: CO2 emissions reduction resulting from the electricity storage.

From the results in Table 51**Fout! Verwijzingsbron niet gevonden.** is concluded that the emissions reduction from the storage is higher in the case of a load pattern with higher "amplitude".

7.2.4 Wholesale electricity prices

The results for the wholesale electricity prices for the 6 cases are listed in Table 52**Fout! Verwijzingsbron niet gevonden.**. These results show that the electricity prices in the cases with storage are consequently lower. This price reduction caused by the storage, that is derived from these results is listed in Table 53**Fout! Verwijzingsbron niet gevonden.**.

Scenario	2030-0.5 B	2030-0.5 S	2030 B	2030 S	2030-1.5 B	2030-1.5 S
	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]
Peak (08:00 - 20:00) Price	63	62	69	66	69	68
Off Peak (20:00 - 08:00) Price	61	61	62	61	61	61
Base (24h) Price	62	61	65	64	64	64

Table 52: Wholesale electricity prices

Scenario	2030-0.5	2030	2030-1.5
	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]
Peak (08:00 - 20:00) Price	1.1	2.4	1.8
Off Peak (20:00 - 08:00) Price	0.1	0.3	0.1
Base (24h) Price	0.6	1.2	0.7

Table 53: Reduction in wholesale electricity prices due to the electricity storage.

From these results is observed that the price reduction is strongest in the (base) scenario without scaling of the load curve. It must be noted that that the installed capacity was minimally adjusted for the change in load curves (in the 2030-1.5 scenario additional capacity was necessary to be able to supply all the demand in the peak's.

7.2.5 Utilisation of the storage facility

The results for the storage operation are listed in Table 54**Fout! Verwijzingsbron niet gevonden.**. The results suggest that the storage will be utilised less (in terms of running hours and pumped/produced electricity) but with more margin when the “amplitude” of the load curve is increased.

Storage Operation		**2030-0.5**	**2030**	**2030-1.5**
Electricity production	TWh	1.35	1.20	1.13
Electricity consumption	TWh	1.67	1.49	1.40
Operating Time (storage + production)	hours	2945	2446	2180
Electricity Costs (pumps)	mln EUR	101	89	82
Electricity Revenues (turbines)	mln EUR	87	88	85
Gross Margin (trade)	mln EUR	-14	-0.8	3.0
Avoided costs for reseve capacity	*mln EUR*	*214*	*299*	*285*

Table 54: Results for the storage facility.

7.2.6 Performance of the sector

The financial results (gross margin) are specified to primary energy source and conversion technology and are listed in Table 55**Fout! Verwijzingsbron niet gevonden.**. To facilitate the possibility to draw conclusion from these results. A summary is made in Table 56**Fout! Verwijzingsbron niet gevonden.**.

From the summary in Table 56**Fout! Verwijzingsbron niet gevonden.** is observed that the changes in financial performance are much smaller in the sensitivity cases than in the base case.

Scenario	**2030-0.5 B**	**2030-0.5 S**	**2030 B**	**2030 S**	**2030-1.5 B**	**2030-1.5 S**
Gross Margin specified to source	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**
BFG (coal eq)	18	18	21	20	21	20
Coal Pulverized	76	53	180	133	179	145
Coal + CCS	152	149	168	161	165	161
Natural Gas	281	223	577	439	651	538
Nuclear	798	789	840	821	832	821
Waste Recycle	100	99	106	103	105	103
Wind On Shore	587	586	595	592	591	591
Wind Off Shore	2177	2176	2201	2197	2188	2192
Industrial CHP (NG)	569	552	649	613	634	612
Peak CHP (NG)	39	24	111	79	112	89
Micro CHP fuel NG	99	98	105	103	105	103
Solar PV	290	288	302	297	304	298
Refinery Gas	82	81	87	85	86	85
TOTAL	**5269**	**5135**	**5943**	**5642**	**5973**	**5757**

Table 55: Financial performance of the electricity sector.

To facilitate the possibility to draw conclusion from these results. A summary is made in Table 56**Fout! Verwijzingsbron niet gevonden.**.

Scenario	Absolute [mln EUR]			Relative to base case		
	2030-0.5	2030	2030-1.5	2030-0.5	2030	2030-1.5
Renewable generators	3.3	12	2.1	0.1%	0.4%	0.1%
Non-renewable generators	130	289	214	5.9%	10.2%	7.4%

Table 56: Summary of financial performance.

From **Fout! Verwijzingsbron niet gevonden.** is concluded that the impact of electricity storage on the gross margin will be less for the case with a load profile with a “smaller” amplitude.

7.3 SENSITIVITY ON ASSUMPTIONS FOR THE INSTALLED CAPACITY

To facilitate the objective to investigate the sensitivity to assumptions on the installed capacity two “extreme” scenarios are introduced next to the base scenario for 2030:

- A grey scenario: without any installed renewable capacity.
- An extreme green scenario with 24 GW of installed wind capacity.

The results of this analysis will be presented on the basis of 6 cases:

Case	**Description**
2030-grey B	2030 scenario, without renewable capacity, without storage
2030-grey S	2030 scenario, without renewable capacity, with storage
2030-B	2030 scenario, without storage
2030-S	2030 scenario, with storage
2030-xgreen-B	2030 extreme green scenario, without storage
2030-xgreen-S	2030 extreme green scenario, with storage

The grey scenario
Regarding the cases 2030-grey B and 2030-grey S, the following changes were made in respect to the base case:
1. All renewable (wind on-shore, wind off-shore and PV) capacity was removed.
2. In the 2030-grey S case, 2 GW of natural gas fired capacity had to be added, to secure the supply of electricity.
3. In the 2030-grey B case, 3 GW of natural gas fired capacity had to be added to secure the supply of electricity.

The extreme green scenario
Regarding the cases 2030-xgreen B and 2030-xgreen S, the following changes were made in respect to the base case:

- In the extreme green scenario an additional 9700 MW off shore wind capacity is installed.
- To allow the electricity supply to be flexible enough to allow the inclusion of 24 GW wind capacity, 10 GW of natural gas fired Combined Cycle plants are substituted by aero derivative type open cycle gas turbines, of the type GE LMS100.

The LMS100 type of gas turbine can cold start and ramp up to base load capacity in 15 minutes. This gas turbine is rated 100 MWe at an efficiency of 45% under ISO conditions.

The consequences for the installed natural gas fired capacity are listed in Table 57**Fout! Verwijzingsbron niet gevonden.** and **Fout! Verwijzingsbron niet gevonden.** (changes are marked).

Owner	Unit	Year	PWR	D CC EFF	Status dec 2009
			[MW]		
Nuon	DM33	1995	252	54.7%	Operational
Nuon	LWE6	1995	248	54.0%	Operational
Electrabel	EC-3	1996	352	55.6%	Operational
Electrabel	EC-4	1996	352	55.6%	Operational
Electrabel	EC-5	1996	352	55.6%	Operational
Electrabel	EC-6	1996	352	55.6%	Operational
Electrabel	EC-7	1996	352	55.6%	Operational
Electrabel	ROC3	1996	184	53.4%	Operational
Intergen	Rijnmond 1	2004	783	56.8%	Operational
Delta / GDF	Sloecentrale Unit 10	2009	431	59.4%	Operational
Delta / GDF	Sloecentrale Unit 20	2009	431	59.4%	Operational
Electrabel	FL40	2010	447	58.9%	under construction
Electrabel	FL50	2010	447	58.9%	under construction
Intergen	Rijnmond 2	2010	433	58.5%	under construction
Essent	CC-C1	2011	444	58.5%	under construction
Essent	CC-C2	2011	444	58.5%	under construction
Essent	CC-C3	2011	444	58.5%	under construction
Eneco/Dong	Enecogen-1	2011	444	58.5%	under construction
Eneco/Dong	Enecogen-2	2011	444	58.5%	under construction
Essent	MD-2	2011	429	58.3%	under construction
Adv. Power	EC-8a	2013	400	59.5%	permit submitted
Adv. Power	EC-8b	2013	400	59.5%	permit submitted
Adv. Power	EC-8c	2013	400	59.5%	permit submitted
Changed	LMS1	2021	500	45.0%	Sensitivity
Changed	LMS2	2021	500	45.0%	Sensitivity
Changed	LMS3	2022	500	45.0%	Sensitivity
Changed	LMS4	2022	500	45.0%	Sensitivity
Changed	LMS5	2023	500	45.0%	Sensitivity
Changed	LMS6	2026	500	45.0%	Sensitivity
Changed	LMS7	2026	500	45.0%	Sensitivity
Changed	LMS8	2026	500	45.0%	Sensitivity
Changed	LMS9	2026	500	45.0%	Sensitivity
Changed	LMS10	2027	500	45.0%	Sensitivity

Table 57: Changes in the natural gas fired capacity in the extreme green scenario.

Windpark	Park 1	Park 2	Park 3	Park 4	Park 5
Hub height (m)	60	60	80	100	100
Location	On-shore	On-shore	On-shore	On-shore	Off-shore
Wind regime (KNMI station)	IJmuiden	Schiphol	Schiphol	Soesterberg	K13
Availability factor	0.8	0.8	0.8	0.8	0.7
Surface roughness [m]	0.03	0.03	0.03	0.5	0.0002
Turbine type	E80	E80	E80	E80	E80
Installed capacity 2030 grey [MW]	0	0	0	0	0
Installed capacity 2030 [MW]	1000	1000	1500	500	10000
Installed capacity 2030 extreme green [MW]	1000	1000	1500	500	19700

Table 58: Changes in the installed wind capacity for the grey and extreme green scenarios.

7.3.1 The generation mix

The results for the sensitivity analysis on installed capacity for the generation mix are listed in Table 59**Fout! Verwijzingsbron niet gevonden.**. The changes in the storage case in respect to the base case are highlighted.

Scenario	**2030-grey B**	**2030-grey S**	**2030 B**	**2030 S**	**2030-xgreen B**	**2030-xgreen S**
Electricity from source	**[TWh]**	**[TWh]**	**[TWh]**	**[TWh]**	**[TWh]**	**[TWh]**
BFG (coal eq)	1.1	1.1	1.1	1.1	0.9	0.9
Coal Pulverized	33.3	33.3	25.0	25.4	22.0	22.1
Coal + CCS	6.0	6.0	6.0	6.0	5.8	5.9
Natural Gas	102.0	102.3	65.5	65.6	37.5	36.9
Nuclear	15.6	15.6	15.6	15.6	15.5	15.6
Waste Recycle	2.1	2.1	2.1	2.1	2.1	2.1
Wind On Shore	0.0	0.0	9.7	9.7	9.7	9.7
Wind Off Shore	0.0	0.0	36.1	36.1	71.1	71.1
Industrial CHP (NG)	29.9	29.9	29.9	29.9	26.9	27.6
Peak CHP (NG)	19.0	19.2	11.0	10.9	10.5	10.5
Micro CHP fuel NG	0.0	0.0	2.2	2.2	2.2	2.2
Solar PV	0.0	0.0	4.7	4.7	4.7	4.7
Refinery Gas	2.1	2.1	2.1	2.1	2.1	2.1
TOTAL	**211.1**	**211.6**	**211.0**	**211.3**	**211.0**	**211.4**

Table 59: The generation mix for 6 cases for sensitivity on the installed capacity.

From the results on the sensitivity cases for the generation mix is observed that:

In the extreme green 2030 case the storage system will increase the potential of nuclear, coal + carbon capture and storage and industrial CHP. These are typical base load generating technologies. Especially for nuclear plants it is hard to adjust the power production. In the extreme green case a nuclear power plant was modelled to be switched off in time segments with a high electricity production from wind. (under the assumption that renewable energy is always given preference). In reality this is very unlikely to happen, since it is easier to turn down / switch off wind turbines than nuclear units.

7.3.2 Fuel consumption

The results for the fuel consumption by the electricity supply are listed in **Fout! Verwijzingsbron niet gevonden.** Table 60 and Table 61**Fout! Verwijzingsbron niet gevonden.**. From these results is observed that fuel savings by the electricity storage are only achieved in the grey case.

It is concluded that electricity storage does not lead to fuel savings of the electricity supply in an extreme green scenario, but it does in a grey scenario. Since reduction of part load operation is the measure of emission reduction by the storage, no reductions are in the grey or extreme green scenario.

Case →		**2030-grey B**	**2030-grey S**	**2030 B**	**2030 S**	**2030-xgreen B**	**2030-xgreen S**
Electricity from renewable sources	[TWh]	0.0	0.0	50.5	50.5	85.5	85.5
Electricity Generated from fuels	[TWh]	211	212	161	161	125	126
Fuel consumption	[PJ]	1451	1446	1106	1106	898	898
Fuel conversion efficiency	[-/-]	52.4%	52.7%	52.3%	52.3%	50.3%	50.4%

Table 60: Fuel consumption from electricity production.

Scenario		**2030-grey B**	**2030-grey S**	**2030 B**	**2030 S**	**2030-xgreen B**	**2030-xgreen S**
Wind energy production	[TWh]	0.0	0.0	45.8	45.8	80.8	80.8
Fossil fuel penalty (reserve power)	[PJ]	0.0	0.0	28.2	9.5	0.0	0.0
CO2 penalty (reserve power)	[Mtonne]	0.0	0.0	1.9	0.6	0.0	0.0
Emission factor wind energy	[kgCO2/MWh]	-	-	41	14	0	0

Table 61: Fuel consumption and related CO2 emissions from (hot) reserve capacity.

7.3.3 CO2 emissions

The results for the CO2-emissions in the sensitivity analysis on the grey and extreme green scenario are listed in Table 62**Fout! Verwijzingsbron niet gevonden.**. The changes from the storage cases in respect to the base cases are listed in Table 63***Fout! Verwijzingsbron niet gevonden.***.

Scenario	2030-grey B	2030-grey S	2030 B	2030 S	2030-xgreen B	2030-xgreen S
	[Mtonne]	[Mtonne]	[Mtonne]	[Mtonne]	[Mtonne]	[Mtonne]
Electricity Production	79.3	79.1	57.1	57.3	44.6	44.5
Partload Operation	0.00	0.00	1.88	0.64	0.00	0.00
Total	*79.3*	*79.1*	*59.0*	*57.9*	*44.6*	*44.5*

Table 62: CO2emissions from electricity production and partload operation (to supply reserve capacity).

Scenario	2030 grey	2030	2030 xgreen
	[Mtonne]	[Mtonne]	[Mtonne]
Structural Change Electricity Production	0.28	-0.16	0.08
Reduced Partload Operation	0.00	1.24	0.00
Total Reduction	*0.28*	*1.08*	*0.08*
Relative Reduction	*0.36%*	*1.8%*	*0.17%*

Table 63: CO2 emissions reduction resulting from the electricity storage.

7.3.4 Wholesale electricity prices

The results for the peak, off peak and base load electricity prices in the grey and extreme green scenario are listed in Table 64**Fout! Verwijzingsbron niet gevonden.**. The changes from the storage cases in respect to the base cases are listed in Table 65**Fout! Verwijzingsbron niet gevonden.**. It is observed that the larger the renewable share in the electricity supply becomes, the smaller the electricity price reduction from the electricity storage becomes.

From the results on sensitivity analysis on the installed capacity is concluded that the larger the share of renewable capacity becomes, the smaller the electricity price reduction becomes.

Scenario	2030-grey B	2030-grey S	2030 B	2030 S	2030-xgreen B	2030-xgreen S
	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]
Peak (08:00 - 20:00) Price	95	85	69	66	67	66
Off Peak (20:00 - 08:00) Price	65	65	62	61	57	58
Base (24h) Price	78	73	65	64	61	62

Table 64: Wholesale electricity prices

Scenario	2030 grey	2030	2030 xgreen
	[EUR/MWh]	[EUR/MWh]	[EUR/MWh]

Peak (08:00 - 20:00) Price	10.3	2.4	0.9
Off Peak (20:00 - 08:00) Price	0.3	0.3	-1.0
Base (24h) Price	4.7	1.2	-0.2

Table 65: Reduction in wholesale electricity prices due to the electricity storage.

7.3.5 Utilisation of the storage facility

The results for the storage operation in the grey and extreme green scenarios are are listed in Table 66**Fout! Verwijzingsbron niet gevonden.**. From the results is observed that in scenario's with more increased renewable capacity the utilisation (electricity production, consumption and operating time) decreases. The gross margin was observed to be the largest in the grey scenario and so was the reduction in electricity prices.

From the sensitivity analysis on the installed capacity is concluded that a storage facility will be utilised the most in a scenario with the least renewable capacity installed.

Storage Operation		2030 grey	2030	2030 xgreen
Electricity production	TWh	2.01	1.20	1.12
Electricity consumption	TWh	2.49	1.49	1.40
Operating Time (storage + production)	hours	4062	2446	2115
Electricity Costs (pumps)	mln EUR	151	89	71
Electricity Revenues (turbines)	mln EUR	187	88	85
Gross Margin (trade)	mln EUR	36	-0.8	14
Avoided costs for reseve capacity	*mln EUR*	*0*	*299*	*0*

Table 66: Results for the storage facility.

7.3.6 Performance of the sector

The results of the sensitivity analysis on the installed capacity for the grey and extreme green scenario on the gross margin of the sector are listed in Table 67**Fout! Verwijzingsbron niet gevonden.**. In Table 68**Fout! Verwijzingsbron niet gevonden.** a summary is made with a distinction renewable/non-renewable.

From the results in **Fout! Verwijzingsbron niet gevonden.** is observed that there is no/marginal loss in Gross margin for the renewable capacity and large loss in Gross margin for the non-renewable capacity. This loss for the non-renewable capacity becomes greater in scenario's relatively less in scenarios with less renewable installed.

Scenario	**2030-grey B**	**2030-grey S**	**2030 B**	**2030 S**	**2030-xgreen B**	**2030-xgreen S**
Gross Margin specified to source	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**	**[mln EUR]**
BFG (coal eq)	36	31	21	20	19	18
Coal Pulverized	666	489	180	133	184	159
Coal + CCS	248	220	168	161	151	150
Natural Gas	2270	1638	577	439	364	295
Nuclear	1050	977	840	821	786	790
Waste Recycle	134	124	106	103	98	99
Wind On Shore	0	0	595	592	530	544
Wind Off Shore	0	0	2201	2197	3885	3981
Industrial CHP (NG)	1051	911	649	613	577	567
Peak CHP (NG)	437	313	111	79	112	95
Micro CHP fuel NG	0	0	105	103	94	95
Solar PV	0	0	302	297	301	300
Refinery Gas	116	106	87	85	81	81
TOTAL	**6008**	**4809**	**5943**	**5642**	**7182**	**7173**

Table 67: Financial performance of the electricity sector.

To facilitate the possibility to draw conclusion from these results. A summary is made in Table 68**Fout! Verwijzingsbron niet gevonden.**.

Scenario	**Absolute [mln EUR]**			**Relative to base case**		
	2030-c	**2030-m**	**2030-g**	**2030-c**	**2030-m**	**2030-g**
Renewable generators	0.0	12	-109	-	0.4%	-2.3%
Non-renewable generators	1199	289	118	20.0%	10.2%	4.8%

Table 68: Summary of loss in financial performance.

8. RESULTS FOR EXTREME SITUATIONS

In this chapter the results for extreme situations are presented. Two extreme situations for 2020 and 2030 are described in more detail:

- The situation with minimum demand for electricity and maximum production from renewable sources
- The situation with maximum demand for electricity and minimum production from renewable sources.

The results for both situation are listed for a case with storage and a case without storage for the year 2020 and 2030.

8.1 EXTREME SITUATIONS IN 2020

Details about the time segments that meet the criteria for extreme situations, as mentioned above, are listed in Table 69**Fout! Verwijzingsbron niet gevonden.**. For a case with storage and a case without storage.

Renewable production		**maximal**	**maximal**	**minimal**	**minimal**
Demand		**minimal**	**minimal**	**maximal**	**maximal**
storage		**no**	**yes**	**no**	**yes**
Time Segment		4204	4204	420	420
Hour of the day		04:00-05:00	04:00-05:00	12:00-13:00	06:00-07:00
Domestic demand	[MW]	13622	13622	23210	23210
Export	[MW]	1894	1894	3788	3788
Pump / Storage	[MW]	0	1815	0	0
Total load	**[MW]**	**15516**	**17331**	**26998**	**26998**
wind production	[MW]	7400	7400	101	101
pv production	[MW]	0	0	58	58
micro CHP	[MW]	118	118	206	206
conventional production	[MW]	7998	9814	26633	24633
Turbine / Storage	[MW]	0	0	0	2000
Total production	**[MW]**	**15516**	**17331**	**26998**	**26998**
Required reserve capacity	[MW]	2960	960	40	0
Cost of resere capacity	[EUR]	33065	11664	8059	0

Table 69: Results for extreme situations in 2020.

8.1.1 Minimum demand, maximal renewable production

From the results in Table 69**Fout! Verwijzingsbron niet gevonden.** can be observed that the maximum observed electricity production from wind is approximately 7400 MW. This is significantly less than the installed capacity of 10 000 MW in 2020. The difference is caused by the unavailability of wind turbines (planned and unplanned).

The situation in the time segment can be made more extreme, by assuming 100% availability of the wind turbines and no export of electricity. In this situation renewable production is 10000 MW and conventional production is 3622 MW. The minimal conventional production to provide 4000 MW of reserve capacity is 2667 MW. So even at the most extreme possible (unlikely) situation the system can absorb all electricity production from wind and provide enough reserve capacity.

8.1.2 Maximum demand, minimal renewable production

In a situation with maximum demand the storage can supply the peak of 2000 MW. As a result the total amount of installed capacity to supply the maximum demand in the year can be reduced with the production capacity of the storage.

8.2 EXTREME SITUATIONS IN 2030

The results that were presented for 2020 are listed for 2030 as well in Table 70**Fout! Verwijzingsbron niet gevonden.**.

Renewable production		**maximal**	**Maximal**	**minimal**	**maximal**
Demand		**minimal**	**Minimal**	**maximal**	**minimal**
Storage		**no**	**yes**	**no**	**yes**
Time Segment		5839	5839	420	420
Hour of the day		07:00-08:00	07:00-08:00	12:00-13:00	06:00-07:00
Domestic demand	[MW]	16580	16580	28532	28532
Export	[MW]	1515	1515	3030	3030
Pump / Storage	[MW]	0	1400	0	0
Total load	**[MW]**	**18095**	**19495**	**31562**	**31562**
wind production	[MW]	9251	9251	138	138
pv production	[MW]	792	792	361	361
micro CHP	[MW]	141	141	329	329
conventional production	[MW]	7911	9311	30734	28734
Turbine / Storage	[MW]	0	0	0	2000
Total production	**[MW]**	**18095**	**19495**	**31562**	**31562**
Required reserve capacity	[MW]	3700	1700	55	0
Cost of resere capacity	[EUR]	39261	23141	11008	0

Table 70: Results for extreme situations in 2030.

From the results is observed that under the used assumption, there is never a situation of too much renewable energy production than the system can absorb:

- Renewable production < load
- Required reserve capacity < 0.4 * (conventional production – nuclear production)

As for 2020, the extreme situation can be made more extreme by eliminating export and assuming 100% availability of renewable capacity. In this extraordinary situation the system can absorb all electricity production from wind and provide enough reserve capacity.

8.3 ELECTRICITY STORAGE IN EXTREME SITUATIONS

From the results is concluded that under the given assumptions for demand and export, an electricity supply without storage can absorb all production from renewable sources and at the same time have enough reserve capacity standby to provide security of supply.

The main advantages of an electricity storage under extreme situation is a reduction of the cost for reserve capacity and a reduction of the minimum required installed capacity.

9. RESULTS SUMMARY

In this chapter the results that are most relevant for the study objective are summarized.

9.1 ENVIRONMENT

The cost and benefits for the environment were only evaluated on the CO2-emissions from the electricity supply. The changes in CO2 emissions in a system with electricity supply are due to:

- (Day - night) trading of electricity
- Avoidance of part load operation by conventional capacity.

Trading can have both a positive or negative effect on the CO2 emissions of the electricity supply. The effect is dependent on the CO2 price, and fuel prices. In most scenarios (where coal prices are significantly lower than natural gas prices) day/night trading leads to an increase in CO2 emissions.

The results for the emissions reduction (trading, part load reduction and total) are summarized in Figure 46**Fout! Verwijzingsbron niet gevonden.**.

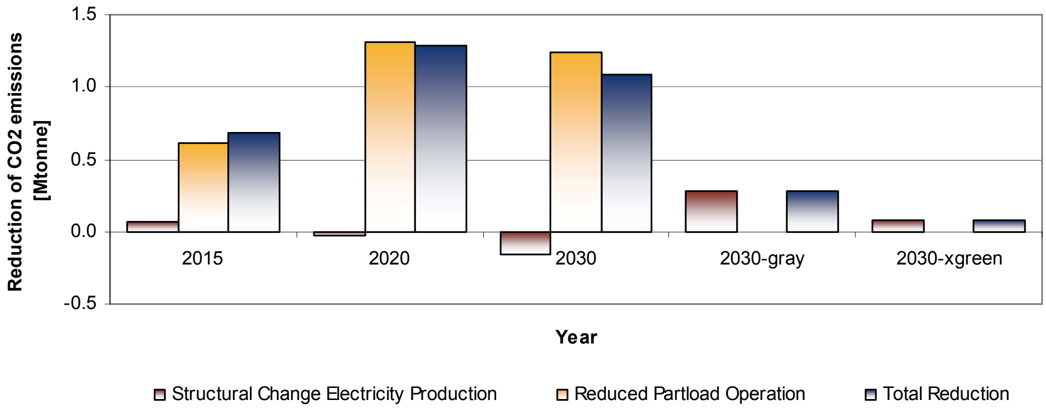


Figure 46: Changes in CO2-emissions due to the operating of an electrcity storage system.

9.1.1 Effects of trading

The strongest emission increases were found for the sensitivity cases with a load profile with smaller amplitude (0.36 Mtonne) and for the mixed fuel price scenario (0.20 Mtonne).

In most scenarios the presence of an electricity storage caused an increase of CO2 emissions from electricity trading. An important exception is the fuel price scenario with natural gas favoring fuel and CO2 prices, where the trading ability of the storage caused an emissions reduction of 0.2 Mtonne.

The effect is depending on the fuel prices and CO2 prices: with the assumed prices from ECN's UR-GE scenario the fuel shift from coal to natural gas occurs between 40 – 60 EUR/tonne (see Figure 47**Fout! Verwijzingsbron niet gevonden.**.)

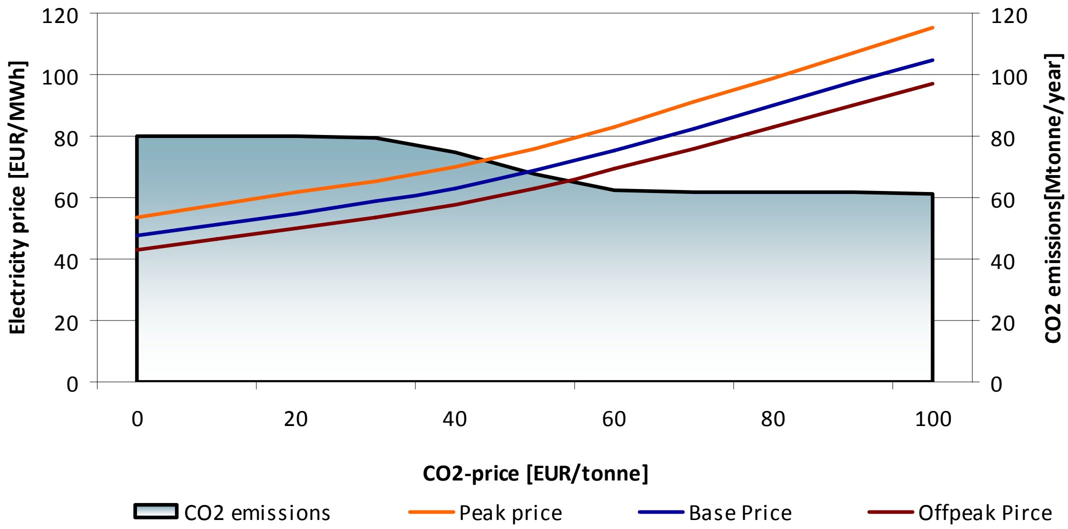


Figure 47: The observed fuel shift due to prices of fuels and CO2 emission rights (2020 scenario).

It is concluded that for coal favored price scenarios the storage will cause an increase in emissions due to day/night trading of electricity, while it will cause a decrease in emissions in natural gas favored price scenarios.

9.1.2 Effects of reduced part load operation from conventional units

In all cases of the base scenario, the electricity storage caused the conventional units to run more efficient: an emission reduction of 1.1 to 1.4 Mtonne annually was observed in the years 2020 and 2030. This reduction was caused by the avoidance of approximately 12 TWh of electricity production by conventional units running at part load.

This result was sensitive to the amount and type of installed (conventional) capacity. Both in a grey scenario with no electricity production from wind and in an extreme renewable scenario with sufficient reserve capacity of natural gas fired gas turbine peaker units the observed reduction reduced to (near) zero.

There is high demand for control and reserve capacity during period with high forecast for wind energy production (40%). In an electricity supply without storage conventional power plants will have to run at lower load, and lower efficiency to supply this control and reserve capacity. In a system with storage, most of the control and reserve capacity can be supplied by the storage.

In a system with high efficiency, rapid start gas turbine peaker units installed, the emission reduction from storage is marginal to none.

A sensitivity run was made done with an extreme green scenario, with almost doubled installed off shore wind turbine capacity. An equivalent capacity of 40% of the wind turbine capacity of high efficiency (45%) Gas Turbine peakers was installed, instead of high efficiency combined cycle plants (61.5%).

The presence of these fast start (15 min) Gas Turbine peaker units reduced the need for “hot” or “spinning” reserve and the losses that are associated with it. In such a scenario, the storage would save only 0.076 Mtonne (or 0.2 %) of CO2 emissions.

9.2 ECONOMY

In theory the economy would benefit from a decrease in wholesale electricity prices.

The observed price reductions are visualized in Figure 48**Fout! Verwijzingsbron niet gevonden.**. In all scenarios a price reduction occurs. Depending on the scenario, the reduction ranges from 1 to 10 EUR/MWh for the peak electricity prices, while not or just slightly increasing the off peak electricity price.

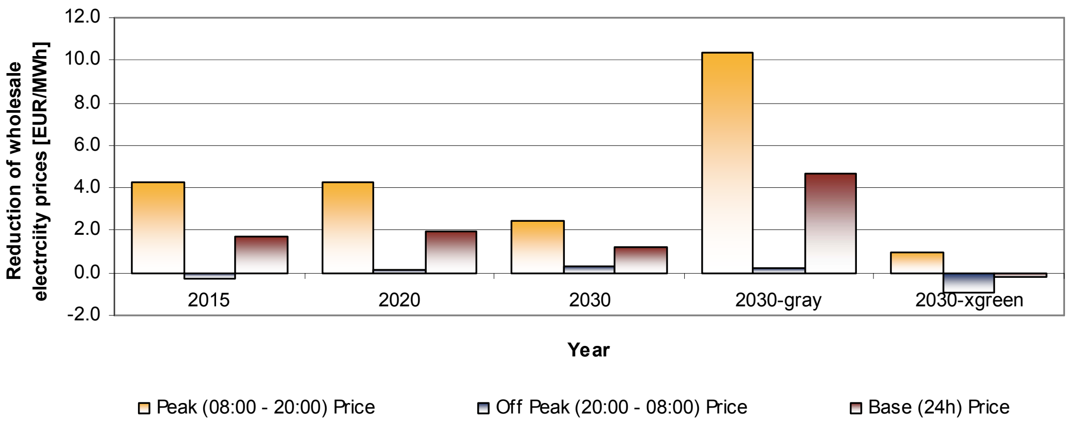


Figure 48: Modelled changes in electricity prices due to electricity storage.

In theory electricity storage would lead to significantly lower electricity prices on the market. And the operating philosophy of the electricity storage was chosen such that this would happen.

The storage system can maximize it’s earning by limiting the trading capacity: trading less volume of electricity, with higher margin (because the peak electricity price will remain higher). If the operator behaves like this, the price decreasing effect of the storage system will be limited.

9.3 INVESTORS

The income from the electricity storage is generated by income from electricity trading and the availability of capacity for imbalance control. As the electricity becomes more renewable, less income will be generated by (day) trading and more by the availability of imbalance capacity (Figure 49). This imbalance capacity can be offered to Program Responsible Parties with a large portion of wind energy in their generating portfolio or directly to the grid operator.

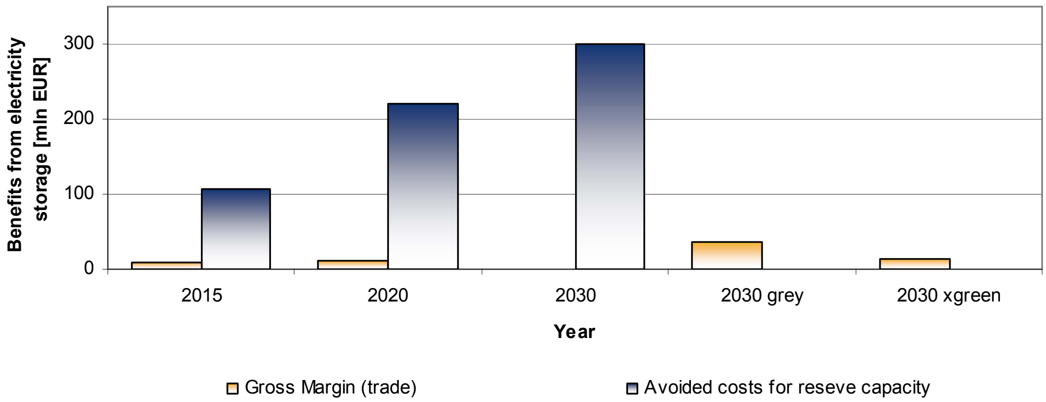


Figure 49: Gross margin and avoided reserve capacity costs for the storage.

The specific investment costs are estimated at approximately 1500 EUR/kW installed (see Table 24**Fout! Verwijzingsbron niet gevonden.** for estimated absolute investment costs of several projects). Even for the most promising case (2030) for the most promising scenario (base scenario) and under the assumption that all benefits from avoidance of part load operation would come to the investor of the storage project, the Simple Pay Back time would still be 10 years.

In all situations the Simple Pay Back time was found to be at least 10 years or more and is therefore considered not to be a potential business case as a commercial investment.

9.4 SECTOR

In general, the observed decrease in electricity prices and resulting decrease in gross margin will lessen the profitability of the assets. More specific:

- Base load plants will have slightly higher gross margin and more operating hours, making those plants more profitable

- Peak load plants will have less gross margin and less operating hours, making those plants less profitable

- Renewable generators will not or not substantially loose income due to the presence of a storage.

The relative losses to renewable and non-renewable generators are displayed in Figure 50**Fout! Verwijzingsbron niet gevonden.**.

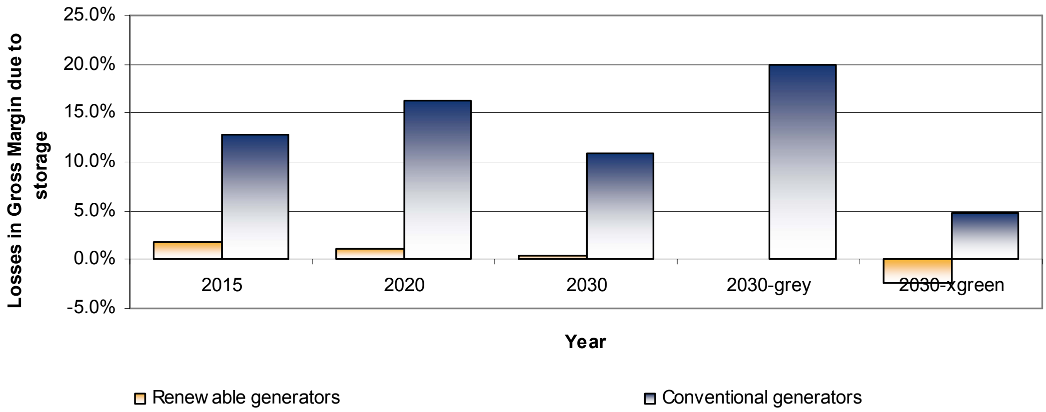


Figure 50: Losses in gross margin due to the electricity storage.

In must be noted that the presented losses are the result of lower electricity prices. Despite the market price decreasing potential of the storage, it remains questionable whether prices will actually drop. Therefore the actual realization of the modeled loss in gross margin is questionable.

Once in operation, the storage will be the most cost effective solution for balancing the grid. Conventional generators will loose income generated from reserving back-up and controlling power. This effect was not incorporated in the results.

Generators, mainly conventional units, will loose profitability due to lower electricity prices.

9.5 ELECTRICITY CONSUMERS

In theory electricity consumers should benefit from lower wholesale electricity prices and a more stable grid. This will mainly be the case for large (industrial) consumers. Households will hardly notice the lower electricity prices, since a large portion of the electricity price for households consists out of transportation costs.

10. DISCUSSION OF THE RESULTS

10.1 METHOD

10.1.1 Model accuracy

There is a slight inaccuracy in the model that causes that the production not exactly matches the demand of electricity at all moments in time. This is caused by limitations of the model: it can only dispatch units at full load (or leave them unused).

This limitation causes the electricity production always to be less than demand. For 2030 the demand was: 213.037 TWh and production was 211.032 TWh an error of 1.735 TWh or 0.8 %.

Most of the observed changes in the generation mix, that can be attributed to the electricity storage were less than this error.

Another source of inaccuracy is the models time scale. The model has 8784 time segments, based on the number of hours in a leap year. Capacity planning is in de Dutch electricity market is done on a quarterly basis: 35136 time segments In a leap year. The error in the results caused by this simplification is not known, but assumed to be small. The results from Boonekamp et al. (2008) are based on a model with an one hour time scale as well.

10.1.2 Model validation

Validation of the model against historic production and emissions figures proved that the model produces results that correspond to the actual figures. The overall results correspond well with historic data. On level of individual units, there can be substantial deviations; these deviations can be caused by, for example: (un)planned outages, differences in heat demand (CHP plants) and variations in STMGC over the year.

10.2 OPERATION PHILOSOPHY OF THE STORAGE FACILITY

The results for the storage facility indicate a limited utilization of the storage facility. In this study the utilization of the storage is defined as produced electricity / maximal production. For 1 day the maximum production is limited by the storage capacity: 16 GWh (100% utilization). The results for the utilization of the storage facility are summarized in Table 71**Fout! Verwijzingsbron niet gevonden.**.

Scenario		2015	2020	2030	2030 grey	2030 xgreen
Electricity production	[TWh]	1,9	1,46	1,2	2,01	1,12
Utilisation	[-/-]	32%	25%	20%	34%	19%

Table 71: Utilisation of the electricity storage.

A rule of thumb in the industry is that an increase in utilization results in an increase in margin. If this rule applies to a storage facility as well, it should be utilized more. The storage operating philosophy as used by the model aims at optimized peak shaving: optimizing revenues by keeping the price as high as possible, while using maximum capacity at the highest peak during the day, limited by the storage capacity.

The storage operating philosophy, as used by the model, was challenged against an operating philosophy that aims at optimized utilization. This challenging operating philosophy aims at maximum production during the peak.

The two operating philosophies are challenged for day 45 of the year 2015. The load profile of that day was based (corrected for growth in demand and export) on day 45 of 2008. All production from renewable capacity and micro CHP are set to zero.

The costs and revenues of the storage facility are depending on the electricity prices, which are depending on the cost supply curve of electricity. The electricity cost supply curve for the year 2015 is displayed in Figure 51**Fout! Verwijzingsbron niet gevonden.**.

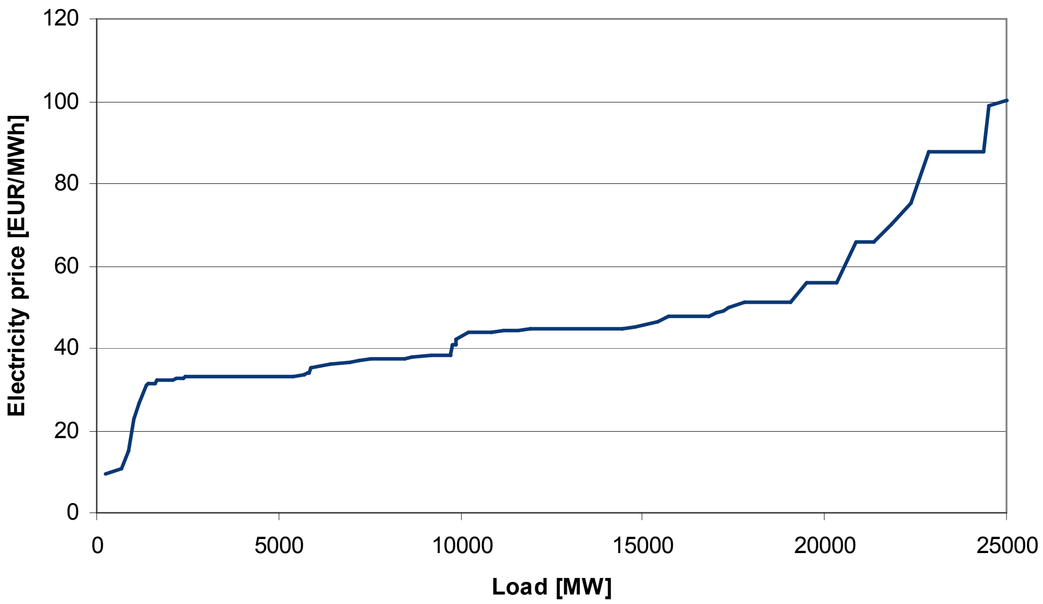


Figure 51: Electricity cost supply curve for 2015 base case.

The operation of the storage facility was modeled with two different operating philosophies: one resulting in a low utilization, the other resulting in a maximum utilization. The results are listed in Table 72.**Fout! Verwijzingsbron niet gevonden.**

		Model's operating philosophy	Challenging operating philosophy
Utilization	[-/-]	43%	100%
Electricity production	[MWh]	6872	16000
Electricity consumption	[MWh]	8590	20000
Electricity revenues	[k EUR]	604	1175
Electricity costs	[k EUR]	427	1074
Gross Margin	[k EUR]	177	101

Table 72: Results for 1 day of storage operating with two different operating philosophies.

From Table 72**Fout! Verwijzingsbron niet gevonden.** can be concluded that the models philosophy resulted in a higher margin, but less utilization. The impact of both philosophies on the load curve of day 44 is displayed in Figure 52**Fout! Verwijzingsbron niet gevonden.** and Figure 53**Fout! Verwijzingsbron niet gevonden.**. The blue sections of the bars represent additional load caused by the pumps, the red sections of the bars is a reduction of the load, caused by the turbines.

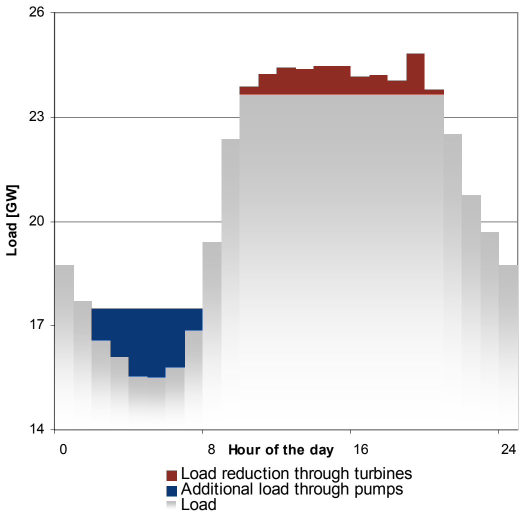


Figure 52: Changes to the load pattern under normal base philosophy.

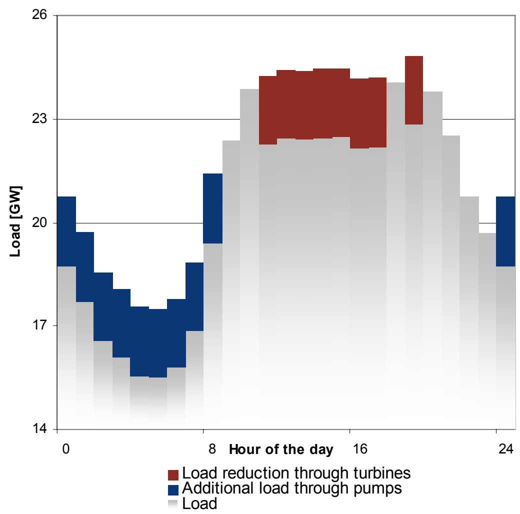


Figure 53: Changes to the load pattern under maximized utilisation of the storage facility.

The operation of the storage facility influences the electricity prices over the day as well. The impact of the storage on the electricity prices for both operating philosophies is displayed in figure 54**Fout! Verwijzingsbron niet gevonden.** and Figure 55**Fout! Verwijzingsbron niet gevonden.**. The blue sections of the bars represent a price increase due to the storage pumps, the red sections of the bars represent a price decrease due to the turbines of the storage.

From the comparison of both figures can be concluded that maximum utilization of the storage facility influences the electricity so much that the gross margin of the storage is reduced: The electricity is sold at lower prices.

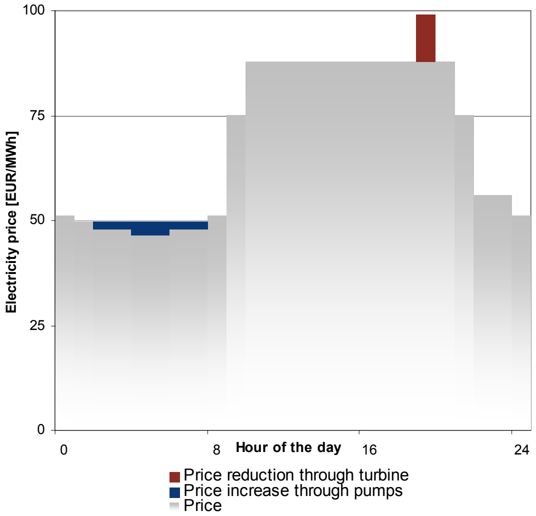


Figure 54: Impact on the electricity prices under normal operating philosophy.

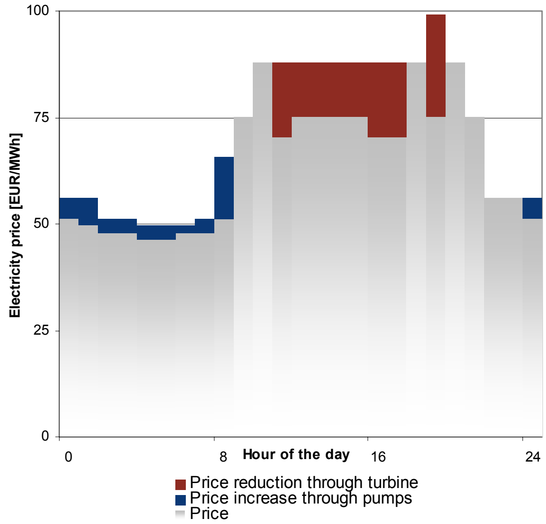


Figure 55: Impact on the electricity prices under maximum utilization.

10.3 SENSITIVITY TO ASSUMPTIONS

10.3.1 Fuel prices

The results were tested for their sensitivity on fuel prices by a coal favored and a natural gas favored fuel prices scenario.

It was found that all the (advocated) advantages of an electricity storage, such as emission reduction, electricity price reduction, profitability, will decrease when the fuel prices become more natural gas favored: at a CO2 price of 50 EUR/tonne, this means a gas price – coal price ratio of 3 or less.

10.3.2 Load pattern

From the results of the sensitivity analysis was observed that changes in price reduction due to the electricity storage and the utilization and gross margin of the electricity storage react strong to changes in the assumption of the load pattern.

It was found that the margin of the storage is increased with a greater difference in peak and off peak demand, while the gross margin was reduced in the case of a smaller difference between peak and off peak demand. For the utilization of the storage (hours/year) and the price reduction in the market the opposite was found: They become less in the case of a greater difference in demand.

It must be mentioned that the installed capacity was changed as little as possible in the sensitivity cases. It is questionable whether this is realistic, since the presence of an electricity storage increases the potential for base load units and decreases the potential for peak load units.

10.3.3 Installed capacity

It was found that assumption about the future installed capacity have a very high influence on the results. This sensitivity was found by introducing a scenario for 2030 with no renewable and a scenario with almost twice as much wind power capacity than in the base scenario.

It was found that in a grey capacity scenario, the storage is utilized approximately twice as much as in the extreme green scenario. In the grey scenario profits from electricity trade and the electricity price reduction were considerably higher than in the extreme green scenario.

It was also found that the environmental benefits of the electricity storage in an electricity supply with sufficient (40% of installed wind capacity) high efficiency gas turbine peaker units is marginal to non existent.

Assumptions about the Short Term Marginal Generation Costs (STMGC) of installed peak capacity (running 2000 hours/year or less), have a large influence on the “super” peak electricity prices. It is hard to make sound assumption for this part of the installed capacity in 2030.

10.3.4 Variable operation and maintenance costs

Variable operation and maintenance costs are neglected in the model. These are typically in the range of 3 to 4 EUR/MWh for large scale power plants, where the coal fired plants have higher variable maintenance costs than the natural gas fired plants. The main effect of this simplification is that electricity prices are estimated about 3 to 4 EUR/MWh to low. The other effect is that a fuel shift from coal to natural gas will occur at a slightly lower CO_2-price than estimated by the model, compared to the high CO2 costs, the effects of a small difference in variable O&M costs between natural gas and coal are marginal.

10.4 RESULTS FROM OTHER STUDIES

The results are compared to the publication “Onderzoek naar de toegevoegde waarde van grootschalige elektriciteitsopslag in Nederland” (Boonekamp et al., 2008)

10.4.1 CO2 emissions

Boonekamp et al. (2008), suggests an increase in CO2 emissions ranging from approximately -0.75 to 1.6 Mtonne /year (depending on the technology and scenario).

While this study estimated a smaller emission increase due to day / night trading of electricity. Another effect, which does not seem to be taken into account by the study coordinated by SenterNovem, is a substantial decrease in CO2-emissions, due to the delivery of (practically) “CO2-free” reserve capacity in the case of electricity storage.

10.4.2 Price of electricity

Boonekamp et. al. (2008) did not investigate the influence of electricity storage on the wholesale electricity prices.

10.4.3 Gross Margin of the project

Boonekamp et. al. (2008) did not calculate the gross margin of the project, but instead calculated the operational cost savings (mainly due to (change in) fuel consumption) of the Dutch electricity supply. The results for this ranges from -22 mln EUR to 165 mln EUR, depending on the scenario and technology.

Boonekamp et. al. (2008) estimated that the reduction in operational costs due to the electricity storage would increase as the installed wind capacity increases. This study indicates that the opposite is true: The revenues from electricity trading are the highest in the grey scenario. The results found in this study are considered to be more plausible, since the storage capacity of the storage system (and those investigated by SenterNovem) are too small to do any trading in electricity over more than several day’s: a 16 GWh storage is empty in 8 hours of full load production (2000 MW). The utilisation is the highest with day/night trading, since this leads to the most storage-production cycles.

Increased wind capacity however makes the production potential of the storage smaller: Electricity prices drop during times of high production from wind turbines (which occur more during day-time) and during those times the system cannot create any margin, while it can only profit for a few hours from the low electricity prices, before the storage capacity is completely filled. The result is that the system can make less storage-production cycles and therefore less margin.

10.4.4 Concluding

Taking into account that Boonekamp et. al. (2008) investigated scenario’s with systems with lower efficiencies (CAES, IOPAS) and a variable trade with other countries, these results are in line with the results found in this study, considering day/night trade alone.

However, Boonekamp et. al. (2008) did not (explicitly) take into account the costs (Capacity costs, Fuel costs and emissions) for reserve capacity planning. This study indicates that the main advantages (for emission reduction and cost reduction for the electricity supply) are in reducing the effects from planning reserve capacity.

It is concluded that the estimated effects on CO2 emissions, fuel consumption and cost reduction / gross margin from day/night trading are mostly inline with the results *from* Boonekamp et. al. (2008)*, except the effects of reserve capacity planning. The effects on the reserve capacity planning are substantial and cannot be neglected.*

11. CONCLUSIONS

The objective of this study was to quantify the costs and benefits of the integration of large scale electricity storage in the Dutch electricity supply for the environment, the economy, a possible investor, electricity suppliers and electricity consumers in 2020 and 2030.

Regarding this objective, the following conclusions are drawn:

1. A detailed, bottom up electricity market model was developed and validated. The model reproduces historic behavior of the electricity supply well.

2. The utilization of an electricity storage in an electricity supply with a substantial amount of renewable capacity is limited and produced 1.9 to 1.2 TWh of electricity of a possible 5.8 TWh. The utilization of the storage decreases as the share of wind and PV capacity increases.

3. The revenues from trading decrease with an increasing share of wind and PV: from an estimated 35 mln. EUR annually in an all grey electricity supply to zero in an electricity supply with approximately 25% of electricity generation from wind and PV. The revenues from supply of reserve capacity can potentially grow to an annual 300 mln. EUR in an electricity market with a substantial share of electricity generation from wind and PV.

4. In all situations the Simple Pay Back time was found to be at least 10 years or more and is therefore considered not to be a potential business case for a commercial investment.

5. The presence of an electricity storage results in a CO2 emissions reduction compared to a base case in the range of 1.0 to 1.5 Mtonne annually. For reference: the estimated emissions of the entire electricity supply in 2020: 79 Mtonne, 2030: 57 Mtonne.

6. Electricity generation from wind and PV will cause a strong decrease of the (peak) electricity prices. An electricity storage will further increase this effect in the range of 3 – 4 EUR/MWh.

7. In a scenario with storage the gross margin made was found to decline for all generators. In a storage scenario the gross margin of conventional generators was found to decrease 16% to 11% relative to the base case, whereas for generators of electricity from renewable sources, the gross margin was reduced by only 0.4% to 1.8% relative to the base case.

8. From the analysis of extreme situations was concluded that in extreme situations an electricity storage is not required. No situation was found for which electricity production from wind, as a result of the government targets could not be absorbed by the system from a technical point of view.

9. From the sensitivity analysis is concluded that the costs and benefits of large scale electricity storage are most sensitive to the amount of renewable installed capacity and type of installed conventional capacity in the electricity supply.

10. Gross margin from trading decreases at more installed renewable capacity, while the potential revenues from offering reserve capacity increase. at more installed renewable capacity.

11. CO2 emission reduction by the storage is strong in a system with base load type of (coal fired) capacity. CO2 emissions reduction is practically absent in an electricity supply with sufficient specialized (natural gas fired) peaker units.

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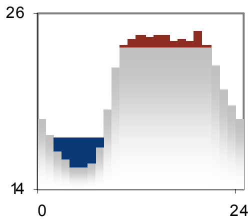
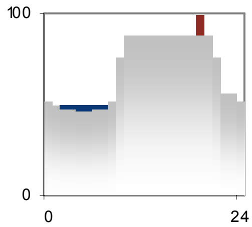
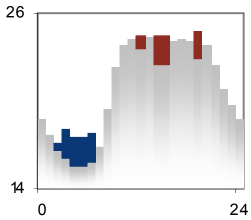
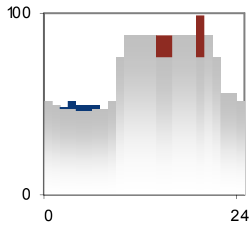
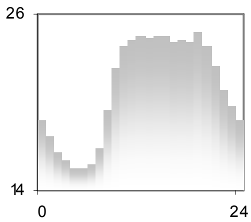
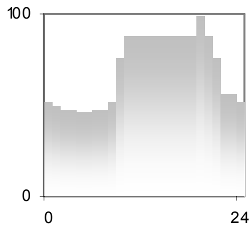
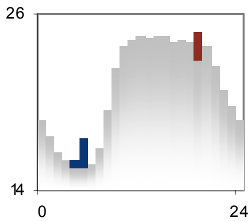
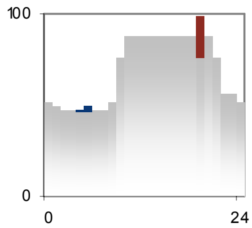
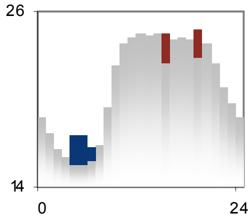
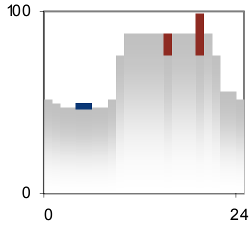
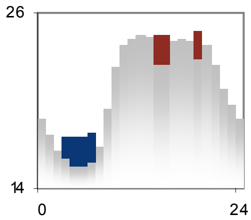
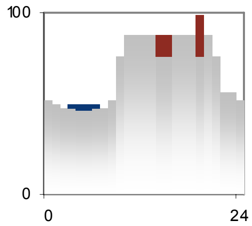
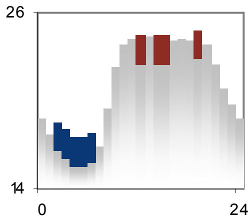
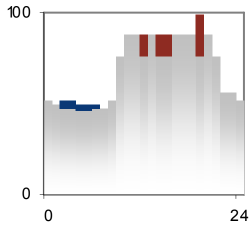
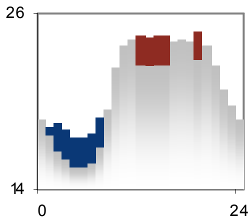
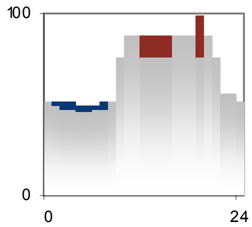
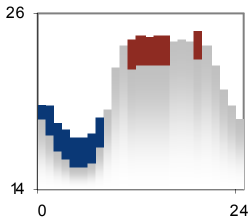
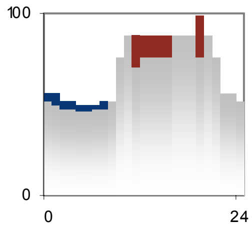
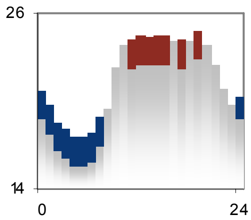
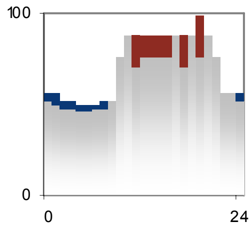
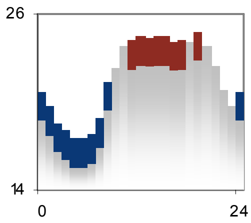
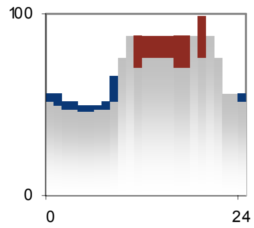
APPENDIX 1: results for the storage operation for different utilization

Utilization	Electricity product.	Electricity consumpt ion	Electrcity Revenues.	Electricity Costs	Gross Margin	Load curve	Cost Curve
[-/-]	MWh	MWh	k EUR	k EUR	k EUR		
43%	6872	8590	604	427	177		
43%	6872	8590	528	430	99		
0%	0	0	0	0	0		
13%	2000	2500	151	123	27		

25%	4000	5000	301	247	55		
38%	6000	7500	452	373	79		
50%	8000	10000	602	504	99		
63%	10000	12500	753	632	121		
75%	12000	15000	894	774	120		
88%	14000	17500	1034	914	120		

100%	16000	20000	1175	1074	101		

APPENDIX 2: MODEL RESULTS