WIND INTEGRATION

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Power System Operation with Large-Scale Wind Power in Liberalised Environments

Power System Operation with Large-Scale Wind Power in Liberalised Environments

PROEFSCHRIFT

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If a man knows not what harbour he is making for, no wind is favourable.

L. A. Seneca

General Summary

Reason for this research
Our society revolves around electricity. Most electricity comes from electric power stations that use coal and natural gas. These are reliable and affordable fuels, but they also have disadvantages. The supply of fossil fuels is finite and unevenly distributed across the earth. Besides, conventional power stations emit greenhouse gases. There is an urgent need for sustainable alternatives, such as wind power. The disadvantages of wind are that sometimes it is blowing and sometimes it is not and that it is unpredictable. The generation of electricity must however equal demand at all times. This makes the integration of wind power in the electricity system more difficult.

Goal and method
This Ph.D.-thesis is about the question what are the consequences of the integration of a lot of wind power for the existing power system. What problems do we run into and what solutions are available? Is it possible to produce one third of the electricity demand with onshore and offshore wind energy? To come to an answer to these questions, first, it has been calculated how much electricity the future wind parks would produce, and when. This information has been added to an existing power system simulation model. This simulation model calculates which power stations must be turned on and off at which moment to provide in the electricity demand throughout the year. Electricity exchange with other countries is also calculated. The simulations provide a picture of the reliability, costs and emissions of the generation of electricity, with and without wind power. A second simulation model, developed in this research, computes how the power system reacts to wind energy during certain circumstances, for example during a storm. By combining the two models, possible problems with the integration of wind power in the existing power system become clear. The possible solutions, such as flexible electric power plants and energy storage, are also investigated by using these models.

Wind variations and forecast errors
Electricity demand changes continuously: for example, during the day we use much more electricity than at night. On top of that, the supply of wind power changes, because some-

times it is very windy and sometimes there is almost no wind. These two uncertainties are examined simultaneously in the simulations in order to explore the worst combinations. The results indicate that more wind power demands for more flexibility of the existing power stations. Sometimes more reserves are needed, but much more often the power stations must reduce their output to make room for wind power. It is important to compute the commitment of the power stations again and again using the latest wind forecast. Then it is possible to reduce forecast errors and to integrate wind power better into the system.

If the wind is or is not blowing...
It turns out that the Dutch power stations will be able to set off the variations in demand and wind supply at any moment in the future, provided that actual and improved wind forecasts are taken into account. There are however limits to the integration of wind power. This is, for example, because coal-fired power plants cannot be turned off just like that. Therefore, if there is a lot of wind and little demand, there will be a surplus of wind power. Instead of the often posed question 'What to do when the wind does not blow?', the question 'What to do with all the electricity if it is very windy at night?' is much more relevant. An important solution for this lies in the international trade of electricity, because foreign countries can often use this surplus. Besides, expanding the 'opening hours' of the international electricity market is favourable for wind power. At present, electricity companies determine how much electricity they will buy or sell abroad one day ahead. Then, the international market closes. The wind forecast is still inaccurate one day ahead. Wind power can be integrated better if the time difference between trade and the making of the wind forecast would be smaller, for example one or only a few hours.

Integrating wind power into the power system
The integration of wind energy in the Dutch system would provide a reduction of the operating cost of the system as a whole of € 1.5 billion a year. This is because the wind is free, while coal and natural gas are not. By using less coal and natural gas, also the emission of CO_2 decreases by 19 million tons a year. This research also shows that with the amounts of wind energy investigated here, no facilities for energy storage have to be developed. The results indicate that international electricity trade is a promising and cheaper solution for the integration of wind power. Also making power stations more flexible turns out to be a better solution. For example, the use of heat boilers allows for a more flexible operation of combined heat and power stations, which consequently can clear the way for wind during the night. Also a second electricity cable to Norway seems to be a good alternative for building pumped hydro power energy storage in the Netherlands itself.

Recommendations for further research
This Ph.D.-research focuses on the Netherlands especially. Further research should consider the situation in other countries in a better way, especially that in Scandinavia. The electricity markets should be investigated on a European scale. Further research is also needed on the capacity of the electricity network in Europe. The future lies in a better cooperation between different countries and markets; this way, differences in electricity demand and the supply through sustainable energy sources can be bridged better and more easily.

Algemene Samenvatting

Aanleiding voor dit onderzoek
Onze samenleving draait op elektriciteit. De meeste elektriciteit is afkomstig van elektriciteitscentrales die kolen en aardgas gebruiken. Dit zijn betrouwbare en betaalbare brandstoffen, maar ze kennen ook nadelen. De voorraad fossiele brandstoffen is eindig en ongelijk verdeeld over de aarde. Daarnaast stoten conventionele centrales broeikasgassen uit. Er is dringend behoefte aan duurzame alternatieven, zoals windenergie. Het nadeel van wind is dat het soms wel en soms niet waait en dat wind onvoorspelbaar is. Het aanbod van elektriciteit moet echter op elk moment gelijk zijn aan het verbruik. Dit bemoeilijkt de inpassing van windenergie in het elektriciteitssysteem.

Doel en werkwijze
Dit proefschrift gaat over de vraag wat de gevolgen zijn van de inpassing van veel windenergie voor het bestaande elektriciteitssysteem. Tegen welke problemen lopen we aan en welke oplossingen zijn er beschikbaar? Is het mogelijk om met windenergie op land en op zee éénderde van de elektricteitsvraag te produceren? Om deze vragen te beantwoorden, is eerst berekend hoeveel elektriciteit de toekomstige windparken zouden produceren, en wanneer. Deze informatie is toegevoegd aan een bestaand simulatiemodel van de elektriciteitsvoorziening. Dit simulatiemodel berekent welke centrales op welk moment aan- en uitgezet moeten worden om gedurende het hele jaar in de elektriciteitsvraag te voorzien. Ook wordt de uitwisseling met andere landen berekend. De simulaties geven een beeld van de betrouwbaarheid, de kosten en de emissies van de opwekking van elektriciteit, met en zonder windenergie. Een tweede simulatiemodel, dat voor dit onderzoek is ontwikkeld, berekent daarna hoe het elektriciteitssysteem reageert op windenergie tijdens bepaalde omstandigheden, bijvoorbeeld tijdens een storm. Door de twee modellen te combineren, wordt duidelijk wat de eventuele problemen zijn bij de inpassing van windenergie in het bestaande elektriciteitssysteem. Ook de mogelijke oplossingen, zoals flexibele centrales of energieopslag, zijn onderzocht met deze modellen.

Variaties en voorspellingsfouten van wind
De vraag naar elektriciteit verandert continu: overdag gebruiken we bijvoorbeeld veel meer elektriciteit dan ’s nachts. Het aanbod van windenergie varieert ook, want soms waait het

hard en soms bijna niet. Deze twee onzekerheden worden in de simulaties tegelijkertijd onderzocht om de meest ongunstige combinaties te bekijken. De resultaten geven aan dat windenergie vraagt om een grotere flexibiliteit van de bestaande elektriciteitscentrales. Soms zijn er meer reserves nodig, maar veel vaker zullen de centrales juist hun productie moeten verlagen om ruimte te maken voor wind. Het is belangrijk om de inzet van de elektriciteitscentrales steeds opnieuw te berekenen met de laatste windvoorspelling. Het is dan mogelijk voorspellingsfouten te verminderen en windenergie beter in te passen.

Als het wel of niet waait...
Het blijkt dat de Nederlandse elektriciteitscentrales de variaties in vraag en windaanbod ook in de toekomst op elk moment kunnen opvangen, mits er gebruik wordt gemaakt van actuele en verbeterde windvoorspellingen. Er zijn wel grenzen aan de inpassing van windenergie. Dit komt bijvoorbeeld omdat een kolencentrale niet zomaar kan worden uitgezet. Als er veel wind is en weinig vraag, ontstaat er een overschot aan wind. In plaats van de vaakgehoorde vraag 'Wat doen we als het niet waait?' is de vraag 'Waar laten we alle elektriciteit als het 's nachts hard waait?' veel relevanter. Een belangrijke oplossing hiervoor zit in internationale handel van elektriciteit, omdat het buitenland dit overschot vaak wel kan gebruiken. Daarnaast is een verruiming van de 'openingstijden' van de internationale elektriciteitsmarkt gunstig voor windenergie. Momenteel bepalen de elektriciteitsbedrijven een dag van tevoren hoeveel elektriciteit ze in het buitenland gaan kopen of verkopen. Dan sluit de internationale markt. De windvoorspelling is één dag tevoren nog onnauwkeurig. Windenergie kan beter worden ingepast als het tijdsverschil tussen de handel en het maken van de windvoorspelling kleiner is, bijvoorbeeld één of enkele uren.

Inpassing van windenergie in het elektriciteitssysteem
De inpassing van windenergie in het Nederlandse elektriciteitssysteem kan zorgen voor een vermindering van de productiekosten van het totale systeem van € 1,5 miljard per jaar. Dat komt omdat de wind gratis is, terwijl kolen en aardgas dat niet zijn. Door minder kolen en aardgas te verstoken, neemt ook de CO_2-uitstoot af met 19 miljoen ton per jaar. Dit onderzoek wijst ook uit dat er met de onderzochte hoeveelheden windenergie geen voorzieningen voor energieopslag hoeven te komen. De resultaten geven aan dat internationale elektriciteitshandel een veelbelovende en goedkopere oplossing is voor de inpassing van windenergie. Ook het flexibeler maken van elektriciteitscentrales is een betere oplossing. Het gebruik van warmteboilers zorgt bijvoorbeeld voor een flexibelere bedrijfsvoering van warmtekrachtcentrales, die daardoor 's nachts ruimte kunnen maken voor wind. Ook een tweede elektriciteitskabel naar Noorwegen lijkt een goed alternatief voor het bouwen van waterkrachtopslag in Nederland zelf.

Aanbevelingen voor verder onderzoek
Dit promotie-onderzoek richt zich vooral op Nederland. Verder onderzoek zou de situatie in andere landen beter moeten bekijken, vooral die van Scandinavië. De elektriciteitsmarkten moeten op Europese schaal worden onderzocht. Ook is verder onderzoek nodig naar de capaciteit van het elektriciteitsnet in Europa. De toekomst ligt in een betere samenwerking tussen verschillende landen en markten; zo zijn verschillen in elektriciteitsvraag en aanbod vanuit duurzame bronnen beter en gemakkelijker te overbruggen.

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CHAPTER 1

Introduction

1.1 Development of Renewable Energy

1.1.1 Energy and Sustainability

Modern society is critically dependent on its energy supply, in particular the supply of electricity. Electricity provides light, heating, cooling, communication and transportation and powers a wide range of industrial processes. Electrical energy presently comprises about fifteen percent of energy demand in the world [80], but this percentage is considerably higher for developed societies and tends to increase. Moreover, electricity consumption is strongly correlated with economic growth: economic growth allows further use of electric appliances which in turn increases electricity demand [121]. In the past three decades, economic growth has been an important factor in tripling the electricity consumption worldwide. The continuing development of economies such as China and India will increase the demand for electrical energy much further, while the United States, Japan and Europe will still need increasing amounts of electricity to provide for growth of consumption and to power the ever growing number of applications.

In 1987 the United Nations' World Commission on Environment and Development (WCED), chaired by Ms. Gro Harlem Brundtland, published its report 'Our Common Future' [187]. This publication and the work of WCED has put environmental issues on global and national political agendas. The Brundtland report defines the concept of sustainable development as *development that meets the needs of the present without compromising the* *ability of future generations to meet their own needs*. Sustainable development crucially depends on the availability of energy resources which are both environmentally sound and economically viable. The report specifically touched sustainability aspects of energy, such as efficiency, conservation and impacts on public health [176]. Two decades later, there is now a widespread consensus that dramatic changes in electricity generation and energy use in general are needed in order to decrease CO_2 emissions and adverse effects on global warming [159].

At present, electricity is produced largely by large power plants using coal, natural gas, hydro or nuclear fission as primary energy source. These generation technologies are generally affordable and reliable and have been used in power systems for decades. An important disadvantage of the use of fossil fuels and uranium however is their finiteness, making power generation from these resources inherently unsustainable. A second disadvantage which applies especially to natural gas and uranium is the unequal distribution of fuel supplies between regions, creating fuel dependencies between them and possibilities for exercising political influence. A third disadvantage is the emission of greenhouse gases, in particular CO_2, when burning coal, oil and natural gas for power generation. This disadvantage does not apply to nuclear fission, but has the disadvantage of nuclear waste and the development of new installations is difficult in many countries. Large hydro does not have the drawbacks of fossil fuel-powered generation since it uses a sustainable supply of rainfall for power generation. However, its potential has already been exploited for a large part, especially in developed countries, and the construction of new large installations has considerable challenges of its own kind [103]. New plants are likely to be located far from load centres, requiring bulk power transmission over large distances. Also, the creation of hydro reservoirs requires flooding of vast areas, which has devastating effects on local environments. Clearly, there are limits to the extent that conventional generation technologies can be part of a future, sustainable power supply.

In the past decades, new power generation technologies have been developed which do not have the disadvantages of the technologies above. Renewable energy technologies such as biomass, geothermal, wind power, solar photovoltaics, tidal and wave power make use of the natural energy sources (biomass, the earth's heat, wind, sunlight, water flows) for the generation of electricity. The contribution of the renewable energy sources (RES) in power generation has been increasing rapidly in the past years, but is presently still small at about 2% of the total energy demand [80]. RES have disadvantages of their own as well, of which the most important two are cost and controllability. Most renewable power generation technologies are for the moment still more expensive than conventional technologies and therefore require (governmental) support in order to make them feasible. The second disadvantage of renewable power is that they are mostly less controllable than conventional generation since the primary energy source cannot be controlled (geothermal, hydro and biomass are the exceptions). Therefore, the integration of large amounts of renewables into the power system is technically and economically challenging.

1.1.2 Promotion of Renewables

At the moment, the advantages of renewables are valued such that governments have developed policy instruments aimed at the promotion of renewables. Governmental policy is formulated in order to create a level playing field for renewables by targeting the higher cost and lower controllability of these technologies.

Since the advantages of renewables are mostly externalities benefiting society rather than the project developer (i.e. less fuel dependency and emissions), governmental support schemes may be used in order to return these added values to the investor. Such schemes narrow the gap between investment and operation cost of RES and the revenues from energy sales on power markets. Often, support mechanisms are organised as a long-term fixed price (€/MWh) for feeding renewable energy into the power system. Such a fixed feed-in tariff implies a guaranteed long-term income for electrical energy generated by RES, providing a stable, long-term guarantee of revenues for the sustainable energy producer and thus a shelter for market risks. Feed-in tariffs have proven to be very effective in promoting wind power development, e.g. in Denmark, Germany and Spain [113, 114]. Another way to support RES is to subsidise the difference between generation cost and the received electricity price ('unprofitable top') or to provide investment tax reductions. A third option is to internalise the societal benefits of renewables through the issuing of 'green certificates' in combination with a quotum obligation or emission ceilings. A certificate of origin represents the right to emit a certain amount of emissions and this right is tradable, providing the investor with additional revenues. Demand for certificates is stimulated by mandating requirements for the share of renewables or by defining emission limits. Such a tradable green certificate system introduces a separate market mechanism for the environmental value of electricity generation from RES and compensates renewable energy producers for the environmental benefits they provide [117].

Due to their lower controllability, renewables introduce additional uncertainty in the operation of power systems. The lower controllability of most renewables must be solved by the power system, which is a technical challenge requiring additional control actions from conventional generation units and of renewables themselves. Since such control actions come at a certain cost, the system integration of renewables is also an economic challenge. These challenges are generally taken away from the producer since governments often formulate regulation stating that renewables are assigned as prioritised production. This means that renewables have first access to the system and that the system integration aspects are to be taken care of by the power system operator rather than the producer. In case renewable power is not prioritised, the integration cost have to be taken by the project developer.

1.1.3 Wind Power

Wind power has a number of benefits that set it apart from other renewables. First of all, its primary energy source, the wind, is globally available in abundance both on land (onshore) and at sea (offshore). Secondly, wind power investment cost is relatively low, for example compared to solar photovoltaics. Furthermore, the environmental quality of wind turbines is high. Wind power generates enough electricity within around six months to compensate for all energy used during material extraction, turbine construction, installation, operation, demolition and recycling [36, 178], with life-spans designed for twenty years. Even though wind turbines have an effect on the landscape, which is not appreciated by everyone, the impacts of wind turbines on nature and wildlife are small, especially if wind turbines are sited well.

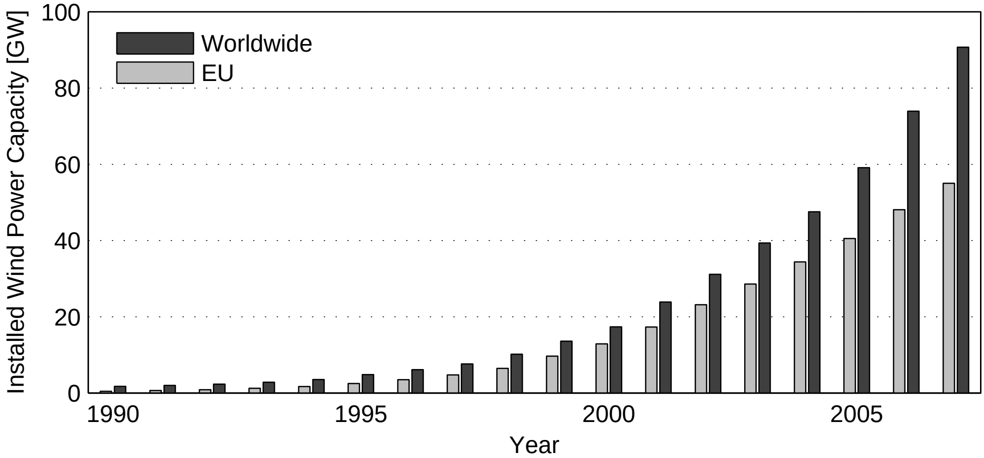

Figure 1.1: Development of wind power worldwide and in the European Union [51].

Since wind power is a sustainable, globally applicable and increasingly cost effective power generation technology, governmental support mechanisms for renewables have sparked a considerable growth of especially wind power. In Fig. 1.1, the globally installed wind power capacity is shown from 1990 up to present. Before 1990, wind power capacity was mainly located in the US. Europe experienced a large growth in wind power in the nineties, especially in Germany, Spain and Denmark. In the past years, also other countries such as for instance China are installing increasing amounts of wind power. End 2007, 91 GW had been installed worldwide, of which 52 GW in the European Union. European targets include 70 GW by 2010 and 180 GW by 2020, of which 60 GW located offshore [51].

1.1.4 Wind Power in the Netherlands

The Netherlands is often associated with windmills. The perception that windmills are typically Dutch can be traced back to the 17$^{\text{th}}$ century, in which the country flourished both economically and culturally. It was however not until the 1970s before wind energy became a part of the Dutch energy policy. By that time, it became clear that fossil fuel reserves were finite and that depletion of resources should be prevented. The oil crises of 1973 and 1979 sparked the political debate on energy and new energy policy goals were set in the first White Paper on Energy [45]. The development of new technologies such as combined heat and power (CHP), energy from waste and wind power was encouraged by funding new initiatives and coordinating further research, for example on power system integration [86, 118].

One of the first test-turbines developed in the Netherlands was a two bladed 300 kW horizontal axis turbine (HAT, 1981). Based on the results obtained from measurements on this prototype, Dutch manufacturers became engaged in the design and production of commercial turbines such as the 400 kW Newec-25 (1982) and the 1 MW Newec-45 (1985). Notably, the development of a 3 MW turbine (Grohat) was initiated as early as in 1983 but not followed by a commercial design. In 1985, a pilot wind power plant of eighteen 300 kW Holec turbines was developed with an active involvement of the Dutch Generating Board SEP[1]. SEP was involved in the research on the system integration of wind power in the 1980s and noted that a significant improvement in cost and performance was needed [64]. Technical problems and the associated financial risks were common for all Dutch manufacturers. From the early 1990s, foreign turbine manufacturers began to take over the Dutch market. Danish and German turbines were considered to have a better price-performance ratio due to their reliability and size. The absence of a strong Dutch market for wind turbines and a lack of collaboration between turbine owners, manufacturers and research institutes resulted in a stagnation of innovation [92]. This eventually led to the disappearance of all Dutch wind turbine manufacturers, although a small number of new manufactures has emerged recently.

In 1985, the Dutch government formulated the target for onshore wind power capacity of 1000 MW installed by the year 2000. This capacity was however not reached before 2004, which may be explained by the absence of an accessible market for small market players, no coherent governmental commitment to wind power and an inconsistent and changing energy policy [1]. Permission procedures (local planning) are also regarded as a weak link in the development of wind power in the Netherlands [21]. Current installed capacity (end 2008) equals around 2100 MW, of which 247 MW located offshore and around 1850 MW onshore [189]. The Netherlands has a large potential for wind power and national targets for end 2011 include 4000 MW onshore and 700 MW offshore. Furthermore, a target of 6000 MW offshore wind power has been formulated for the year 2020 [47]. It is this latter target that is part of the rationale behind this research work.

1.2 Wind Power and Power Systems

1.2.1 Developments in Wind Power

In the past decade, wind power has evolved into a significant renewable energy source which continues to grow rapidly (Fig. 1.1). Not only has the installed capacity of wind power grown considerably, also the size of individual wind turbines has increased dramatically (Fig. 1.2). The increase in turbine size is driven by a number of factors, including a better use of available onshore sites, cost reduction (especially for offshore) and spatial considerations [65]. A second trend in wind power development is the increased size of wind park projects, partly enabled by increased turbine size. Instead of individual wind turbines, wind power projects increasingly comprise groups of up to hundreds of wind turbines. A third trend that has only emerged in recent years, but is predicted to continue, is the development of large wind parks offshore. This is largely enabled by the increased size of wind turbines, but is also caused by difficulties in planning new wind park projects onshore (Not-In-My-BackYard, NIMBY). The available space offshore allows for the development of wind parks with generation capacities comparable to those of conventional power plants. End 2007, a total of around 900 MW [51] was installed offshore with tens of GWs planned for development in the North Sea and the Baltic Sea.

The increased size of wind power projects and the development of large offshore wind parks brings about a number of opportunities on the one hand, and challenges on the other. Opportunities include larger power and energy outputs and improved technical capabilities.

[1] Samenwerkende ElektriciteitsProducenten, Dutch Electricity Generating Board until 1998

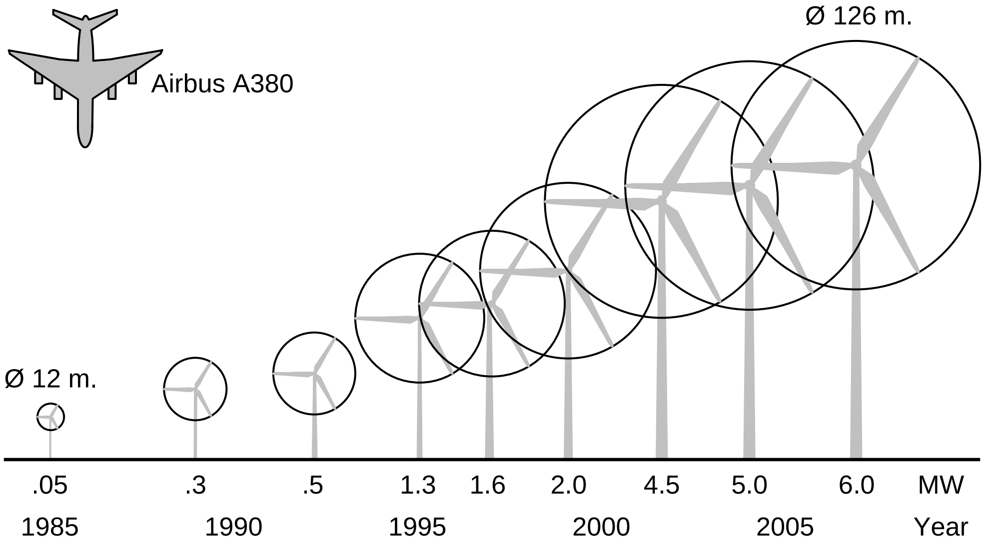

Figure 1.2: Development of size and rating of wind turbines (prototypes).

The larger power and energy outputs however simultaneously present rather fundamental challenges due to the uncontrollability of the primary energy source, the wind. A first challenge of using wind as a primary energy source for power generation is its variability: wind speeds fluctuate on timescales varying from seconds to seasons. This means that the output of wind turbines fluctuates as well, depending on the relationship between wind speed and wind turbine output power. A second challenge is that wind speed depends on a large number of meteorological factors that can only be forecast up to a limited extent. As wind speed variations can only be predicted with accuracies decreasing with the forecast lead time, it is not possible to accurately assess wind power output for longer time-ranges. As the amount of wind power installed in power systems increases, the impacts of wind power's variability and limited predictability become significant as well from the point of view of a reliable operation of power systems.

1.2.2 Electrical Power Systems

The overall purpose of power systems is to supply electricity to consumers in a safe, reliable, and economic way. The primary structure of traditional power systems comprises power generation, transmission and distribution to consumers, or loads (Fig. 1.3). A so-called hierarchical, vertical structure is based upon a limited number of large, central power plants delivering electricity to a large number of loads [138]. Power flows from generation into high-voltage transmission networks and then into medium- and low-voltage distribution networks, hence only in a top-down, 'vertical' direction. The advantages of interconnected, vertically integrated power systems include economies of scale in power generation, increased reliability, a reduction of reserve margins and aggregation of load variations. Presently, increasing amounts of distributed generation are connected to the low-voltage networks. This

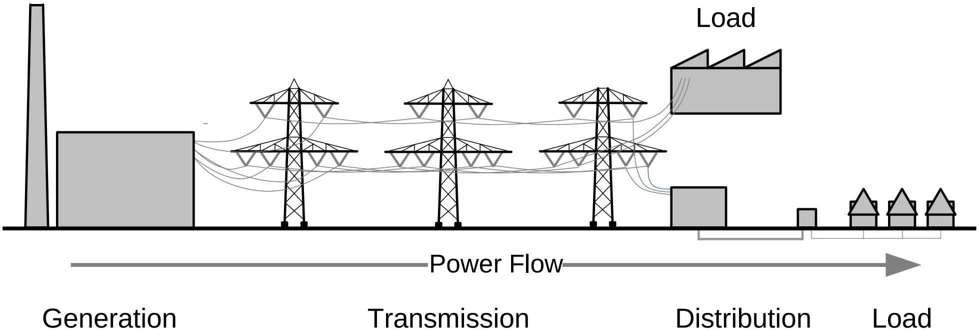

Figure 1.3: Overview of a traditional power system structure.

trend increasingly leads to bi-directional power flows in the distribution system [145].

In observing the primary structure of power systems, it is important to note that electrical energy as such cannot be stored in significant amounts. Electrical power is consumed at the same moment it is generated. For a reliable power supply it is therefore essential to maintain a precise balance between demand (total system load including transmission and distribution losses) and generation. It is in principle possible to maintain the power balance by adjusting both generation and demand, but historically, mostly the central generation units have been used to follow the demand at all times. The operation of power systems is therefore critically dependent on the capabilities of generators for balancing the load.

Power Generation

For the generation of electrical power, traditionally, primary energy sources such as coal and natural gas are used. The primary energy source is combusted to generate heat which is used in a steam-cycle to convert the thermal energy into mechanical energy, which is then used to power electric generators which produce electricity. Nuclear units are based on the same principle, but use nuclear fission as the energy source. For hydro power, the gravitational energy of water in large reservoirs is converted into kinetic energy and then into mechanical energy using hydro turbines, which drive electric generators.

Power generation in traditional power systems is based on controllable primary energy sources: fossil fuels (or water) are stored until they are used for power generation. The advantages of using large-scale, central generation units based on fossil fuels is that the primary energy can be fully controlled: hence a relatively small number of generation units suffices to control the power balance in the entire power system. The benefits of conventional generation have made it possible that nowadays, system load can vary widely and freely during the day and during the year. As long as sufficient generation capacity is installed to match the system load at all times, generators will be able to ensure a reliable operation of the system.

For the operation of power systems with significant amounts of renewables, the importance of conventional generation will remain or may increase even further in order to guarantee a reliable power supply. The other way around, the integration of large amounts of renewables may in future require the system load to be more attuned to power generation availability.

Transmission

Power transmission is carried out at high voltage over long distances from central generation units to the load centres. Power transformers are used to transform generated power to a high voltage and to transform power to lower voltage levels near the loads. Historically, transmission capacity was planned integrally with generation capacity, based on load forecasts. With the liberalisation of electricity sectors in the past decade, generation planning is decoupled from transmission planning. Generation investments are done by generating companies while transmission system operators (TSOs) are responsible for transmission planning and reliable system operation in their areas. In order to serve the market, it is the task of the TSO to ensure that transmission capacity is sufficient for the connection of all new generation capacity and for market trading.

Distribution and Load

Power distribution is done at medium- and low-voltage levels over shorter distances, carrying power from the power transformers connected to the transmission system to the consumers. Distribution systems were originally designed as 'passive' networks: no generation was connected to these grids. Because of a number of developments, including the liberalisation of the electricity sector and growth of renewables, increasing numbers of relatively small generators are being connected near the loads. This influences the operation of distribution systems, i.e. the power flows become more diverse and power generation at that levels makes them more 'active' [145].

Liberalisation of the Electricity Sector

In the past decade, the electricity sector has gone through some important restructuring processes. With the liberalisation of the electricity sector, ownership of generation became decoupled from transmission. Generation units are now operated by commercial parties with the objective of maximising profit and electrical energy is traded on markets much like other commodities. Since electrical energy cannot be stored in significant amounts, different markets have emerged for different timescales, ranging from long-term (yearly to monthly, such as ENDEX) and day-ahead (such as APX Spot) to hour-ahead (such as APX Intraday), allowing a close match of supply and demand up until the moment of operation. In real-time, the TSO uses power reserves made available by market parties to maintain the power balance. This can also be organised as a market.

The restructuring of the electricity sector has a number of impacts on the operation of power systems. The planning and operation of generation units is more and more governed by market prices and each individual market party optimises its portfolio for profit maximisation. Furthermore, energy transactions take place on increasingly international markets rather then on a national scale. The market-driven operation of generation units and international aspects of power system operation are particularly relevant for the system integration of wind power. This is because wind power may influence market prices and a pread of wind power over a larger area reduces its overall variability.

1.2.3 Integration Aspects of Wind Power

The variability and limited predictability of wind power have raised concerns about the impacts on power system reliability and cost. The impacts of wind power on power systems can roughly be divided into local impacts and system-wide aspects [155], taking into account both the electrical aspects of wind turbines and the characteristics of the wind. Furthermore, the connection of wind power challenges the planning and operation of the grid. Another aspect is the formulation of grid-code requirements especially for wind power. Last, the design of electricity markets also has consequences for the system integration of wind power. All of these aspects are discussed below.

Local Impacts

The integration of small-scale wind power mostly involves the connection of individual wind turbines to distribution grids. The local impacts of wind power therefore mainly depend on local grid conditions and the connected wind-turbine type, and the effects become less noticeable with the (electrical) distance from the source. The observed phenomena include changed branch flows, altered voltage levels, increased fault currents and the risk of electrical islanding, which complicate system protection, and possibly power quality problems, such as harmonics and flicker [158]. Modern wind turbines are equipped with versatile power electronics and can be designed to mitigate some of these problems [115]. The rest must be captured by strict grid requirements and new designs for the distribution networks.

System-Wide Impacts

System-wide impacts are largely a result of the variability and limited predictability of the wind and mainly depend on a number of factors, including wind power penetration level, geographical dispersion of wind power and the size of the system [73]. As more wind power is installed in power systems, the possible impacts of wind power increase. A large geographical dispersion of wind power may reduce some of these impacts however, especially if these are related to wind power variability. The system-wide impacts of wind power on power systems include impacts on power system dynamics, [2, 146, 155], load-frequency control [37] and power reserves [44, 70]. Furthermore, the operation of other generation units in the system may be influenced by wind power thereby the system operation cost and emissions [39, 70, 176]. The system-wide aspects of wind power relevant to this research project are covered in Section 1.3.

Grid Connection Aspects

Large wind power projects and especially offshore wind parks challenge the planning and operation of transmission grids. Availability of wind energy is often best in remote, open areas far away from demand. Transmission systems, already used by existing generation capacity, are often not dimensioned to also accommodate large-scale wind power or are simply not available nearby. Grid connection challenges are not only technical, but also include economical issues (cost for offshore wind power connection), spatial planning aspects (long permission procedures), the low capacity factor of transmission capacity for wind power [20] and legal issues [94, 188]. As a result of wind power connection, transmission bottlenecks may occur, which may be solved by a number of solutions, including grid reinforcement [40] or phase shifting transformers [177], wind energy curtailment, or even local storage [109].

Grid Codes

With increasing wind power penetration levels, an increasing number of countries is adopting grid codes with requirements for wind turbines. The objective for this is to manage the impacts that wind power may have on the power system due to its specific characteristics. Since the grid code requirements for wind power are implemented on a national scale, a wide range of technical requirements now exists between countries [82]. Important requirements specified in most of these codes include operational ranges for voltage and frequency, active and reactive power control requirements, wind turbine behaviour in case of a voltage dip (the so-called fault ride-through behaviour of wind turbines) and turbine communication with the operator or transmission system operator (TSO). With some modern wind turbines capable of fulfilling such strict grid-code requirements, wind farms are increasingly capable of supplying ancillary services necessary for reliable power system operation just like conventional generation technologies [172].

Market Designs

Apart from the technical integration aspects of wind power associated with the variability and limited predictability of wind power, the integration of wind power in electricity markets has also become a subject of interest. Since wind power forecast errors increase with the forecast lead time, wind power cannot be scheduled as long in advance as conventional generation. Therefore, a number of market aspects are of importance for wind power integration, including market closure-times, the design and size of the market for balancing reserves and the geographical size of the system/market wind power is integrated into [72, 73]. A final aspect relevant for wind power is the organisation of support schemes for wind power, which can be to prioritise wind power over other generation technologies, to integrate wind power into the market. In the latter case, market parties must take into account the risks of wind power in their market strategies [109].

1.3 Research Objective and Approach

From the integration aspects discussed above, it has become clear that wind power introduces a wide range of challenges for power system operation. In order to formulate a clear research objective, it is necessary to describe the aspects of power systems and power system operation most relevant to this research. Using the description, the scope of the research can then be defined and a definition is made.

1.3.1 Research Scope

Power System

Power systems are large technical systems comprising power generation, transmission, distribution and consumption. A more formal definition of a power system is *a network of one or*

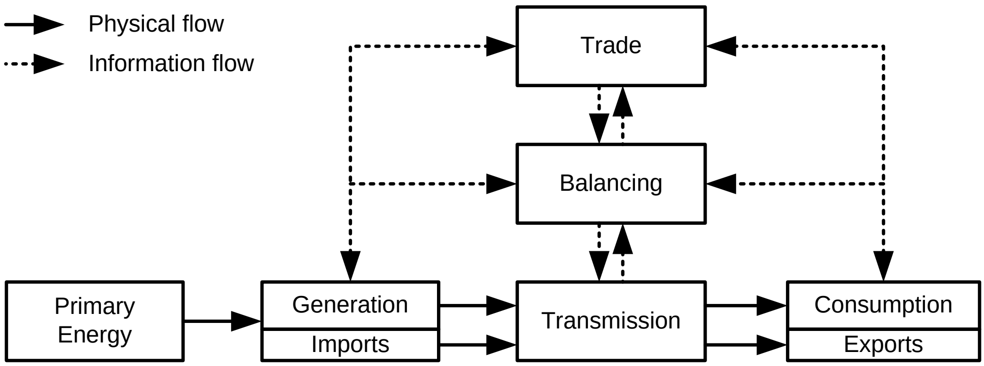

Figure 1.4: Organisational structure of a liberalised power supply [95].

more electrical generation units, loads, and/or power transmission lines, including the associated equipment electrically and mechanically connected to the network [77]. Thus, power systems comprise all electrical and mechanical parts of generation resources, transmission facilities and loads in operation. Power systems may be part of larger, interconnected systems (i.e. the Netherlands is part of the European UCTE[2] interconnection). Interchanges between power sub-systems (inter-area or international exchanges) are in fact also part of the system and hence fall under this definition. The definition does however not include a number of non-technical aspects which, nowadays, can no longer be detached from power system operation.

Since the liberalisation of electricity sectors in the last decade, a number of power system components as well as control- or information-based processes essential for power system operation have become subject to market conditions. The operation of generation units is now mainly determined by prices set on national and international markets and economic incentives are important also in power system balancing. Thus, market-economic aspects and strategic behaviour of market parties have become part of both generation planning and system operation. Furthermore, international markets for emission trading have emerged and provide incentives for market parties to make their fuel mix more sustainable. In order to arrive at a system scope comprising all aspects relevant for this thesis, the limited, technical definition above must be extended to incorporate these aspects as well.

In Fig. 1.4, the organisational structure of a liberalised power supply is shown. The picture presented here comprises not only the electricity network but also the generation system, including use of fuels, the power system operation control structure and trading platforms facilitating it. Primary energy (heat from natural gas/coal/nuclear fission and kinetic energy from water or wind) is converted into electrical energy. Power is physically transmitted and distributed to consumers via the grid, but the amounts have to be agreed upon by the market parties. Generation and load may be located in neighbouring systems or countries, leading to international trade and exchanges. During real-time operation, it is important to ensure that the balance between generation and load is maintained, which is the responsibility of the system operator (often the transmission system operator, TSO).

[2]Union for the Co-ordination of Transmission of Electricity

Power System Stability

Wind power has impacts on the operation of power systems and thereby on power system stability. Power system stability has been defined as *the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact* [100]. Thus power systems can be regarded as stable if it is in balanced operation and is able to either maintain this operating state or regain a balanced operating state different from the original when subjected to a disturbance.

In order to allow a more detailed investigation of power system stability, three kinds of stability have been distinguished: rotor angle stability, voltage stability and frequency stability, where each can be classified in further detail (Fig. 1.5 [100]). Rotor angle stability refers to the ability of synchronous machines in a power system to remain in synchronism after being subjected to a disturbance. It primarily concerns the electromechanical oscillations in power systems. Voltage stability refers to the ability of a power system to retain steady voltages at all buses in the system after being subjected to a disturbance. It depends on the provision of reactive power in the system. Frequency stability comprises the ability of a power system to retain a steady frequency after significant disturbances.

It is important to state that the power system as such must be studied considering both electrical and mechanical aspects, and the three types of stability identified are interrelated. Frequency stability and voltage stability both depend on the ability to maintain or restore equilibrium between generation and demand in the system. Furthermore, voltage stability may also be associated with rotor angle instability for certain system states. A clear distinction between frequency stability and voltage stability can be made when considering that system frequency is a system-wide parameter directly related to the active power balance [32], while voltage is a more local parameter resulting from the reactive power balance associated with power transmission in particular. Thus, when considering the impact of wind power variability and limited predictability of wind power on balancing generation and load in power system operation, frequency stability is the most relevant.

Frequency Stability

System frequency is a common factor in alternating current (ac) power systems, being the central indicator of the mismatch between the generation and the demand. The electric frequency is a measure for the rotation speed of the synchronised generators in the system. Assessment of power system frequency stability generally falls in the category of long-term dynamics of power systems (tens of s to min.), although also short-term frequency stability (s) has been identified [100].

Short-term frequency stability mainly concerns rapid changes such as frequency drops following a significant generation outage (s), while long-term frequency stability generally refers to the composite, dynamic performance of generation and load maintaining system frequency and returning it to its rated value (min.). Even though the passive contribution of system load should not be neglected, generators are equipped with control systems that actively take care of frequency regulation and are therefore considered to be decisive for the system's dynamic performance [157]. Since different generators have different control capabilities, the dynamic performance of the system highly depends on the generation units

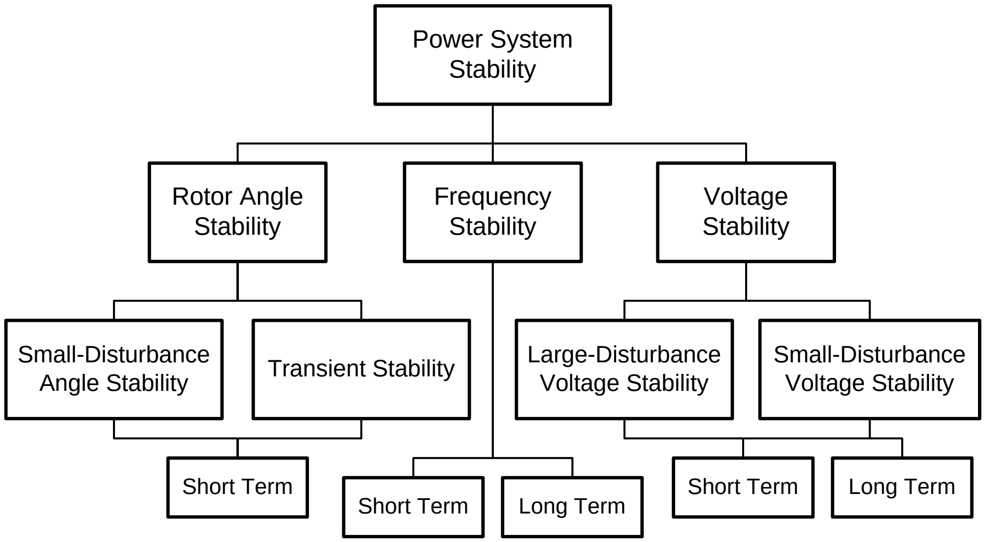

Figure 1.5: Classification of power system stability [100].

in operation. Thus, longer term aspects of power system operation such as daily generation schedules and planned unit unavailability also have an impact on the dynamic performance of the system during operation and thereby on frequency stability.

In Fig. 1.6, the time horizon of different generation and system operation aspects relevant to balancing generation and load in power systems is shown [89, 147, 174]. Short-term frequency stability merely comprises primary control, while long-term frequency stability concerns secondary control and unit despatch. Both kinds of frequency stability depend on longer-term aspects determining the operation of generation units: only scheduled units are available for power balancing during operation.

Power-Frequency Balance

In electric power systems, power generation and demand must be in equilibrium in order to maintain the power-frequency balance. This balance concerns the active power balance and system frequency directly associated with this balance. Since it is possible for the power system to be in equilibrium at a steady frequency different from its set-point value, both power and frequency are of importance when considering frequency stability. Disturbances in the power balance by changes in generation or load, or both, result in system frequency deviations from the set-point. In case of a power deficit (generation $<$ load), part of the kinetic energy stored in the rotation of the generators is consumed, the speed drops and therefore and system frequency goes down, and vice versa.

Primary and Secondary Control

Since electricity as such cannot be stored in significant amounts, the actual generation is continuously adapted in order to match the load. To handle changes in generation (and load),

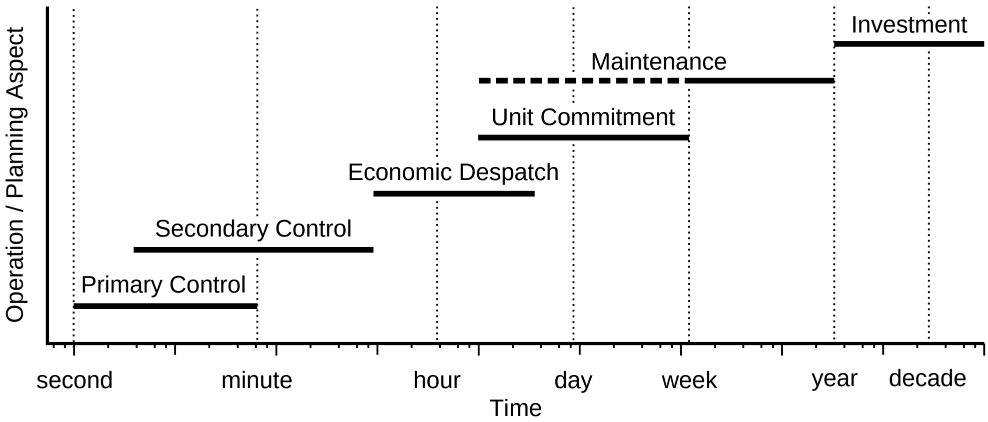

Figure 1.6: Time horizon of power generation planning and operation aspects [89, 147, 174].

reserve generation capacity is held to have power reserves quickly available when needed. Primary reserves have the objective of responding fast to frequency changes in order to restore the power balance and stabilise system frequency. Secondary reserves are then used to return system frequency to its set-point value [169]. The functioning of primary and secondary reserves ultimately depends on the dynamic capabilities of generation units in operation, and thereby on the operation schedules of generation units. With more wind power in the system, less conventional generation capacity may be available for providing these reserves, while more may actually be needed.

Unit Commitment and Economic Despatch

Scheduling of generation units is done based on load forecasts and the economics and technical characteristics of the available generation units. This involves the calculation of the optimal selection of units for power generation for a certain period of time (hours to days) [174] called unit commitment. Important parameters in unit commitment include start-up and shut-down cost, minimum up- and downtimes and operating cost. The economic despatch performs the actual distribution of the total load between committed units, which is optimised for each operating state while taking into account all economic and technical aspects of the units. The outputs of unit commitment and economic despatch (UC–ED) are the generation-unit operation-schedules. From these, an estimation of the associated use of fossil fuels and emission of greenhouse gases can be calculated as well. UC–ED is challenged by wind power due to its variability and limited predictability, which come on top of existing variations and uncertainties of the load.

Availability of Generation

Unit availability may be reduced due to technical reasons, leading to unexpected or forced unit outages with a duration of hours to days. Longer-term planned maintenance reduces the availability of generation units as well, with extents depending on generation technology and operation-strategy considerations, but typically in ranges of weeks to months. On the very long term, generation investments determine the availability of generation technologies and thereby their technical capabilities, which ultimately determines the power-frequency behaviour during power system operation.

1.3.2 Problem Statement

Power System Balancing with Wind Power

In the past decade wind power has become the fastest growing renewable energy technology (absolute numbers) and this development can be expected to continue. Due to the variability and limited predictability of the wind speed, the output of wind turbines cannot be controlled to the same extent as conventional generation technologies. Currently, conventional generation plays a pivotal role in maintaining the power balance between generation and demand. Wind power challenges power system balancing in two ways. On the one hand, wind power introduces additional variations and uncertainty. On the other hand, provided the wind is available for longer periods of time, the presence of wind power reduces the amount of conventional generation capacity scheduled and available for balancing purposes.

The impacts of wind power on power system operation comprise different time scales ranging from seconds to weeks. On the shorter time-scale, ranging from seconds (s) to minutes (min.), wind power has a direct impact on system frequency, the central parameter for the power balance between generation and load. Primary and secondary reserves are used for maintaining this balance. On the longer time-scale, ranging from hours to weeks, wind power influences the economic despatch and commitment of conventional generation units. Wind power reduces the output level and/or operating hours of the conventional generation units while these units are crucial for the compensation of the wind power's variability and limited predictability. The question is, to what extent large-scale wind power can be integrated into power systems while maintaining reliable operation.

Research Objective

As shown in Section 1.2.3, wind power has a wide range of impacts on power system operation and design. The local impacts of wind power, i.e. changed branch flows and power quality aspects, have already been studied extensively and generally these impacts can be managed [73, 115]. The system-wide aspects of wind power integration become relevant at high wind power penetration levels and some of these aspects have been studied as well. The impacts of modern wind turbines (i.e. variable-speed technologies) on short-term voltage stability [2] and rotor-angle stability [155] have been found to be small, also for larger wind penetrations. The remaining aspects of wind power that challenge power system operation are related to its variable output and limited predictability, and therefore to short-term and long-term frequency stability. The central research objective for this thesis is then:

To investigate the impacts of large-scale wind power on power system frequency stability and to explore measures to mitigate negative consequences, if any.

In order to achieve this research objective, a number of steps must be taken. Each of these steps comprises a sub-objective directly related to the overall research objective:

- The first sub-objective is to investigate the characteristics of large-scale wind power generation on the short- and long-term. Wind speeds and wind power output must be quantified for future wind park locations in a consistent manner. Furthermore, the overall variability and predictability of large-scale wind power must be quantified for both the short- and long-term.
- The second sub-objective is to develop a methodology for the exploration of the impacts of wind power on the commitment and economic despatch of conventional generation units. This must be applied to obtain insight into changes in system reliability, operation cost and emissions as a result of large-scale wind power. Also, the methodology should allow for assessing the short-term operation schedules of conventional generation units.
- The third sub-objective is to develop a methodology for the investigation of short-term frequency stability with large-scale wind power. Since the impacts of wind power are firmly dependent on the conventional generation units in operation, representative conventional generation-unit schedules developed under the second sub-objective, must be applied as a starting point for this analysis. The methodology should allow for the exploration of power-frequency control and the impact of large-scale wind power on it. As soon as these three sub-objectives are met, the first part of the research objective is achieved.
- The fourth, and final sub-objective is to explore solutions facilitating the system integration of wind power. Using the insights obtained above into the relevant system parameters, the need for integration solutions can be assessed and their costs and benefits quantified. Thus, optimal solutions for system integration of large-scale wind power can then be determined and the second part of the research objective is attained.

Focus and Demarcation

The focus is on the technical aspects of power systems and power system operation, while taking into account market/economic and environmental aspects. The technical focus of this research is explicitly on the active power balance and does not concern the consequences for the power flows in the network. As a guideline for power system balancing, the operational requirements of the UCTE interconnection are applied.

The developed methodologies are illustrated on a predicted future layout of the Dutch power system. The Netherlands has a very large potential for wind power, in particular offshore, the target being 6000 MW offshore wind power under consideration for 2020, provides a good starting point for a case-study on large-scale wind power integration. Furthermore, the Netherlands' power system has a number of characteristics which make this exercise even more challenging, such as the absence of energy storage facilities, the composition and technical characteristics of the Dutch generation mix (in particular the large shares of combined heat and power (CHP) units and of distributed generation), the large difference between off-peak and peak load and the Netherlands' geographical position in the emerging Western-European electricity market. The conventional generation mix of the Netherlands is kept the same regardless of wind power; generation investment costs and exploring an optimal generation mix for wind power fall outside the scope of this thesis.

1.3.3 Approach

The approach of this research closely follows the discussion in Section 1.3.2. The first step is the quantification of the variability and predictability of wind power. This is done using literature research on wind speed and wind-power modeling and by the creation of time series for 2 GW wind power up to an installed capacity of 12 GW (4 GW onshore, 8 GW offshore) in the Netherlands. By extrapolation of the load data made available by Dutch TSO TenneT, time series of the system load are developed as well. Using these time series, a first exploration is done in order to identify worst combinations of load and wind power.

The second step involves the extension and use of the existing steady-state simulation tool PowrSym3 for unit commitment and economic despatch (UC–ED) of generation units. Before the liberalisation of the Dutch electricity sector, PowrSym3 was used for the optimisation of the UC–ED of the Dutch generation system by the former Dutch Electricity Generating Board SEP. The database of this simulation tool is maintained by the Dutch TSO TenneT. At the start of this research project, no inputs for wind parks or wind-power forecasts were available and no interaction was possible with the Netherlands' neighbouring power systems. International exchange with neighbouring systems were not explicitly taken into account. The tool is extended to include system equivalents of Germany, Belgium and France. Furthermore, because of new high-voltage direct current (HVDC) connections to Norway (2008) and the United Kingdom (2011), representations of the Scandinavian and the UK's power systems are incorporated. The tool is then fed with time series of system load and wind power and applied to simulate the impacts of wind power on UC–ED of the Dutch system under a wide range of scenarios and assumptions.

The third step involves the development of a calculation tool suitable for the simulation of short-term frequency stability. A dynamic model is elaborated in the simulation environment MATLAB/Simulink. In the time range relevant for this investigation (s to 15 min.) a coherent frequency behaviour of the interconnected system is assumed, aggregating the rotating masses of generators. The model is used for the simulation of the dynamic behaviour of generation units (power frequency control), load (frequency dependent) and wind power (short-term power fluctuations). System and control aspects affecting the time-scale of interest are modeled explicitly while aspects with time characteristics considerably below this time-scale (i.e. transients) are neglected. Longer time aspects are taken into account by using selected steady-states from the UC–ED simulation as realistic starting points for the dynamic simulations. The modeling approach is validated using a full dynamic representation of the New England test system in PSS/SINCAL. The dynamic simulation tool is then used to simulate the impacts of wind power on (short-term) frequency stability taking into account the Dutch market design and the requirements for wind power.

For the fourth step, both tools are used for system simulations while taking into account various solutions for system operation and power system balancing with large-scale wind power. The UC–ED tool is used for annual simulations, delivering results regarding operational reliability, economic efficiency and environmental quality. The results of the simulations are applied in a cost-benefit analysis to gain insight into the value of possible integration solutions. The dynamic simulation tool is used for assessing the performance of power-frequency control mechanisms under different market designs and taking into account different solutions for power balancing (i.e. use of conventional generation, heat-boilers, energy storage). The simulation procedure can be used to analyse technical and economic opportunities of changes in market design and control mechanisms in order to integrate large quantities of wind power.

1.3.4 Research Framework: We@Sea

The Dutch government is considering a target for the development of 6000 MW of wind power in the Dutch part of the North Sea by 2020. In order to meet this target, knowledge and technical expertise are required to build and operate these wind farms in a reliable and efficient way. The provision of a subsidy for gaining such expertise and knowledge was the driving force in the formation of the consortium We@Sea (Wind energy at Sea). The objective of We@Sea is the acquisition of knowledge in order to facilitate a sound implementation (minimisation of risks) of wind power in the North Sea. The experience of the first two offshore wind parks in Dutch waters will be used. Application of acquired knowledge and experiences is a continuous process, in which We@Sea wants to play an active role. The We@Sea consortium has over thirty industrial and research partners.

The organisation of We@Sea consists of two foundations: the We@Sea foundation and the We@Sea/Bsik foundation. The first foundation is an organisation aiming for the acquisition of offshore wind power knowledge. The We@Sea foundation has obtained a subsidy (Bsik) for the research and development program 'Large-scale wind power generation offshore'. The We@Sea/Bsik foundation is an intermediary for this subsidy from the Dutch governmental agency for sustainability and innovation, SenterNovem, to the different research an development projects. These projects comprise seven research lines covering technical, economical, market, installation and environmental aspects of large-scale offshore wind power and have a total budget exceeding € 26 million.

The Ph.D. program of We@Sea tackles some of the more academic questions that require a deeper scope and longer period of knowledge and technology development and of which the outcome and benefits are less certain at the outset. The Ph.D. programme comprises eleven Ph.D. projects, three of which fall under research line 3: Energy transport and distribution. The aim of the research project 'Grid Stability', which has led to this thesis, is to facilitate large-scale integration of wind power in the electrical power system by the development of solutions for problems in maintaining the power balance.

1.4 Thesis Outline

The structure of this thesis reflects the research objective and its sub-objectives formulated above. Every chapter starts with a short introduction, presenting the most relevant topics to be treated and stating the specific contributions of this research, and ends with a summary and conclusions on the main findings. The thesis' overall structure is presented in Fig. 1.7.

In Chapter 2, the development of wind power in relation to system load estimates is discussed. Taking the Netherlands as a case-study, wind speed time-series for on- and offshore measurement locations are used for the development of wind power time-series at current and predicted wind park locations for capacities up to 12 GW (4 GW onshore, 8 GW offshore). Time series for system load and wind power are analysed in combination in order to develop duration curves, providing a first glance of the possible impacts of large-scale wind power on the operation of the Dutch power system.

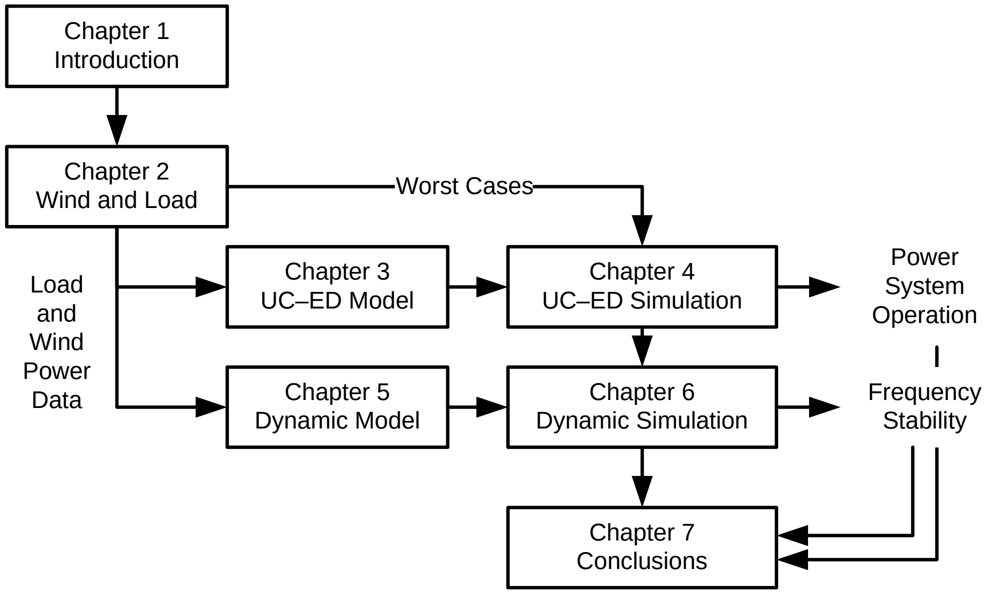

Figure 1.7: Overview of chapters and structure.

In Chapter 3, the unit commitment and economic-dispatch model for system simulation studies with large-scale wind power is discussed. First, the simulation model is described in detail and the structure and optimisation logic is presented. Then, the in- and output data are discussed and the system components are reviewed, including the relevant power system aspects: generation, transmission, control areas (including interconnections), and system load. Furthermore, the creation of new models for thermal conventional generation units, hydro power, energy storage and international exchanges is shown.

Chapter 4 investigates the impacts of wind power on unit commitment and economic despatch. An overview of the different simulation parameters is presented: technical, economical and environmental. Then, the system to be simulated is specified in detail, comprising generation units, load and operation requirements in the Netherlands and in neighouring areas. The system simulations performed incorporate wind power penetration level and availability and flexibility of international markets as variables. Finally, the simulation results are presented and a cost benefit analysis of balancing solutions is performed.

In Chapter 5, the power system dynamic model for the simulation of frequency stability is developed. Power-frequency control and market designs for wind power are discussed in detail and applied to the elaboration of a continuous-time simulation model, which includes primary and secondary control. The modeling approach is validated using the New-England test system, the simulation model itself is validated using UCTE data.

Chapter 6 presents an overview of the impacts of large-scale wind power on the short-term power system operation. The simulation parameters include the power balance and energy balance from the perspective of the system operator and individual market parties. The system to be simulated is specified with respect to Dutch market parties, generation portfolios and secondary control parameters. The simulation procedure is discussed, which involves the selection of worst cases for wind power and load, simulation of these cases using the UC–ED tool, selection of units for secondary control and finally the choice of a certain short-term balancing strategy. Then, system simulations are set-up for a range of wind power levels and market designs and the simulation results are presented.

In Chapter 7, the conclusions of this research are presented and recommendations for further research are made.

CHAPTER 2

System Load and Wind Power

2.1 Introduction

In this chapter, system load and wind power data are developed, analysed and made available for use as inputs for the simulations to be performed later. Before going into the development of these data, it is important to realise what their intended applications are: use as input for simulations of unit commitment and economic despatch and for frequency-stability simulations. Since these simulations comprise different time-scales, different time resolutions are used for which different data-sets are required. Existing work on the use of wind power and load data in simulation studies are discussed.

The contribution of this chapter is twofold. First, quantitative data are developed for large-scale wind power foreseen to be installed and these data are processed for use in system simulation studies. A methodology developed dr. Gibescu and dr. Brand [57] for wind power integration studies is applied for the developmenttion of wind power data taking into account correlations. Second, detailed insight is gained into wind power's variability and unpredictability on a power system scale. A first assessment of the possible impacts of wind power on power system operation is made by data analysis. The methodologies presented in this chapter are applied here for the development of load and wind power data for simulation studies of the Dutch system, but are generally applicable.

This chapter is organised as follows. First, adequate time resolutions are determined for the development of data series for this research. System load data are investigated for periodic variations (i.e. hourly, weekly) and extrapolated for the load expected in the year 2014, using the Dutch system as a case-study. Then, a methodology is presented for the development of wind power data from wind speed measurements. A statistical interpolation method is used for the generation of wind speed time-series for onshore wind power and offshore wind parks. Using the same methodology, lead-time dependent time-series of wind power forecast errors are developed. The relation between wind speed and wind power is investigated for different wind turbine technologies. Wind park production time-series and power system-aggregated wind power output time-series are then developed for the long- and short-term using aggregated wind park power curves. System load and wind power are aggregated in order to developte load-less-wind power duration curves, providing a first view on the impact of wind power at power system level.

2.2 System Load

2.2.1 Data Time Resolution

The research objectives distinguish between a long- and a short-term horizon, for power system operation and frequency stability, respectively. The long-term horizon covers unit commitment and economic dispatch (UC–ED), a steady-state optimisation process taking into account generation cost and international trading possibilities, done in the hour (h.) to week time-horizon. The short-term horizon comprises power system balancing, involving primary and secondary control and subject to operation requirements formulated in the second (s) to minute (min.) time range. For the development of data, the time resolutions associated with these must be determined. These are set based on power system operation requirements and market trading horizons applicable to the Netherlands.

Optimisation of unit commitment and economic dispatch is a long-term activity. Typically, the time resolution for such simulations is one hour, being the time resolution for spot markets and for international exchange schedules throughout Europe [110]. System operational requirements as set by UCTE for secondary control are specified for 15 min. time intervals. Similarly, the imbalance (secondary reserve) market in the Netherlands applies a time resolution of 15 min. Taking into account that the continuous-time simulations of power system balancing use the simulation results of the UC–ED schedule as a starting point, the time resolution for UC–ED in this research is also set to 15 min.

Power system balancing is a time-continuous process involving primary and secondary control. Operation requirements for primary control as specified by UCTE include an action beginning within a few seconds (s) and a full activation within 30 s. The frequency and the power exchanges must start returning to their set-point values as a result of secondary control after 30 s with the correction completed within 15 min. [169]. Data used by UCTE for monitoring primary control and system frequency has a time resolution of 4 s. Measurements of the system frequency are used by the transmission system operator (TSO) for the development of a reference signal for secondary control, updated every 4 s [162]. Based on this information, the time resolution for simulations of power system balancing is set at 4 s.

2.2.2 Development of Load Data

This research takes the Netherlands' power system in the year 2014 as a base-case. For the estimation of the system load for the year 2014, aggregated load data obtained from

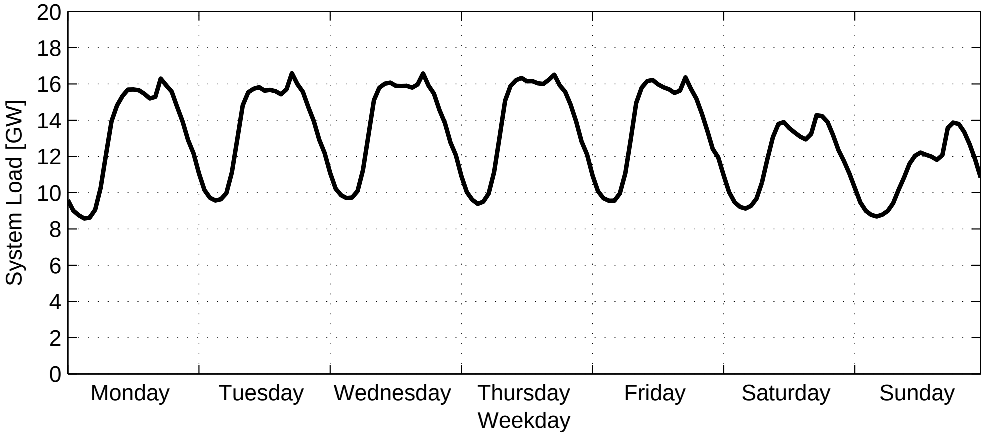

Figure 2.1: System week load-profile in the Netherlands, week 2, 2007 [171].

UCTE and the Dutch TSO TenneT are used. TenneT TSO monitors the total generation of all larger ($\geq$ 60 MW) generation units and international exchange levels on a 5 min. resolution. Smaller, distributed generation (DG) units are not measured directly so no data are available for those units. The aggregated generation of these is estimated using available data on installed capacity. It is assumed that the pattern of this distributed generation is 50% constant and is 50% variable with the load, with the annually produced energy totaling the difference between consumption, conventional generation and international exchange.

For this research, aggregated system load data for the year 2007 are used as a reference. In Fig. 2.1, the Dutch system load is shown for the second week of 2007 (Monday to Sunday). Clearly, a daily, working-day and a weekend-day pattern can be identified. The characteristics and patterns of the load enable an accurate daily prediction of system load for operational purposes. Other patterns in system load include seasonal [138] and trends over several years. Over the past decades, power demand in Western-Europe has grown by an average of 1–3% annually [166].

For the development of load data for the year 2014, load data for 2007 have been extrapolated to 2014 using an annual growth factor of 2%, based on historical data used for the development of scenarios for TenneT TSO's Quality and Capacity Plan 2008–2014 [164]. With a total electricity consumption of the Netherlands of 112 TWh in 2007, annual consumption in 2014 would amount to 126 TWh. It is assumed that no change in the load pattern takes place and that the load profile increases uniformly. It can be noted that this assumption does not take into account possible, but uncertain developments like growth of the use of air conditioning during summer, energy savings or the future use of electric cars. For the short-term dynamic simulations, it is assumed that system load data do not show fast variations apart from the gradual variation between two 15 min. time resolutions. Short-term system load is therefore estimated by linear interpolation of the 15 min. time resolution used for the longer-term simulations. The data interpolation is illustrated in Fig. 2.2.

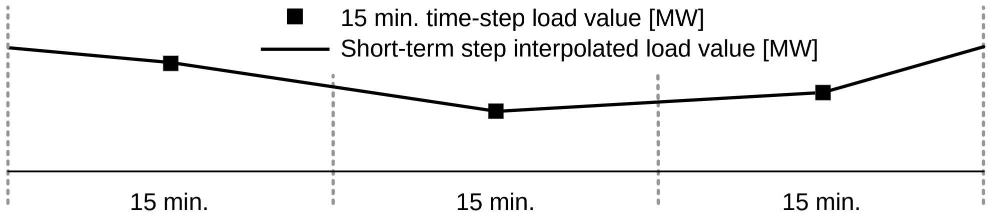

Figure 2.2: Interpolation of 15 min. data for the short-term simulations.

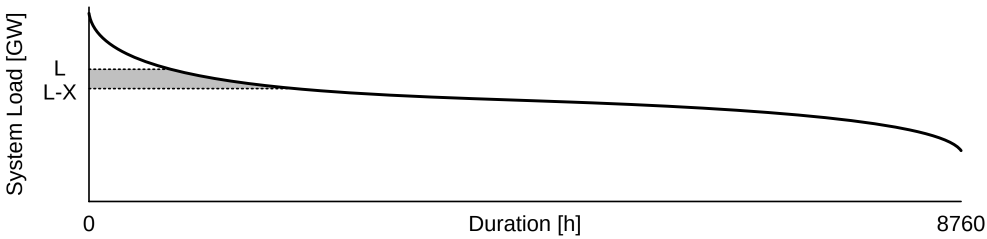

Figure 2.3: Example of a load duration curve with a generation unit's annual energy yield.

2.2.3 Load Duration Curves

Load duration curves have long been used in long-range generation planning and for reliability calculations. The curves can be used to estimate the energy that is produced over a year by each generation unit. Suppose a unit with generation capacity X and a load level L to be produced, then the unit's annual yield comprises the area captured between hour 0, the load duration curve and the two horizontal lines at load levels L and $L - X$, as illustrated in Fig.2.3. There are however important limitations to the application of duration curves for generation despatch, since duration curves incorporate neither chronology nor consider actual generation unavailabilities [106]. Since load levels are re-organised in a decremental order, all chronological aspects (minimum uptimes and downtimes, ramp rates etc.) are lost. This makes an analysis of power system operation difficult.

In this chapter, duration curves are applied for the observation of the number of hours in a year that the load level exceeds a certain value with and without wind power. This provides a rough estimate of the yearly operational hours for base-load, medium-load or peak-load generation units. In Fig. 2.4, the load duration curves are shown for the years 2007 and 2014. Duration curves are developed again later on for aggregated load and wind power and provide a first estimation of the impacts of wind power on power system operation.

2.3 Development of Wind Speed Data

2.3.1 Literature Background

At present, no wind power data are available that allow a chronological simulation of future large-scale wind power onshore and offshore, such as done in this research. Specific

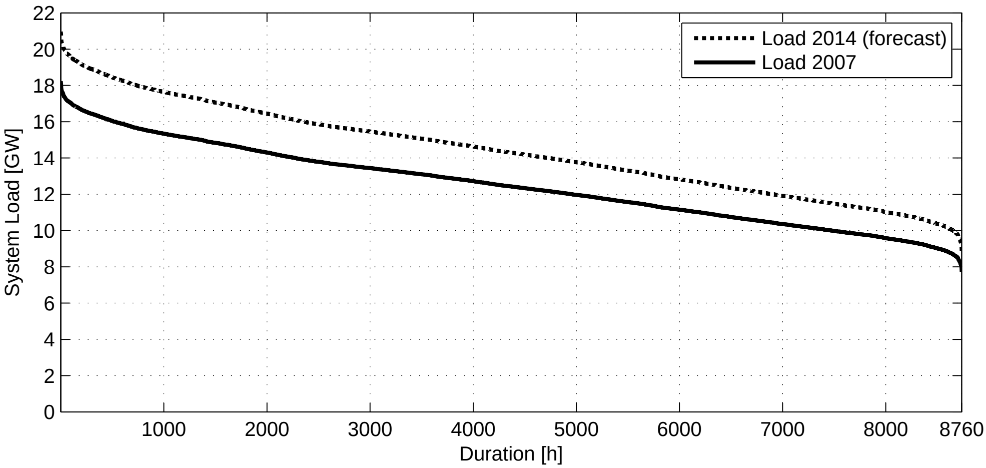

Figure 2.4: Load duration curves for the Netherlands in 2007 and 2014 (forecast).

data must therefore be developed, based on available measurements of wind speed. The time-series aspects of wind speed data for the development of wind power data are of critical importance. Furthermore, spatial correlations exist between wind speeds at different locations. The aggregated variability and unpredictability of wind park outputs are not correctly assessed in case spatial correlations of wind speeds are not taken into account, since geographical spreading of wind power leads to smoothing effects of the total output [122]. Approaches based on probability distribution functions (i.e. Weibul) such as (embedded) Markov-chain models or the Shinozuka algorithm [91] are thus insufficient for this research.

Existing wind power integration studies generally do not include all wind speed characteristics required for chronological simulation studies. In reference [37], cross-correlations between wind park locations are specifically taken into account using power spectrum density (PSD) functions and wind speed coherence (spatial correlation). However, rather than using wind speed measurements, reference [37] develops synthetic wind speed data-series based on wind speed distributions by application of the Shinozuka method. Furthermore, the logarithmic approach applied for height transformation is insufficient for an accurate estimation of wind speeds at turbine hub-height. Reference [44] uses only synthesised wind speed data, providing insufficient guarantee of a correct representation of wind power. Combinations of measured and synthesised wind speed time series are used for the assessment of hourly wind power variations in [71].

The correlation of wind speeds in park-sized areas are analysed in [123] with the inclusion of wind direction, velocity and fluctuation effects. The study shows that power variations exceeding 10 min. time intervals are most important, rather than the variations within 10 min which balance out between different wind parks. Correlation coefficients of the output of distant wind turbines differ considerably between days and the smoothing effects among wind farms distributed over hundreds of km. are not so significant [122]. Thus, the impacts of wind power variability on power system operation must be predominantly considered in the 10 min and above time ranges and this variability is considerable, even over large distances.

2.3.2 Methodology

Wind Speed Data

For the investigation of large-scale wind power in this research, wind power generation is modeled using actual wind speed measurements, numerical weather-prediction (NWP) data and the relationship between wind speed and power. Wind speed data are obtained from the Royal Dutch Meteorological Institute (KNMI, [185]). Ten minute average wind speeds measured with an accuracy of 0.1 m/s at 18 locations (6 inland, 6 coastal, 6 offshore) between January 1, 1996 and December 29, 2002 are used to develop a model for the interpolation of wind speed data onshore and offshore. The actual wind speed data used for the development of wind power time-series concern 10 min. wind speed averages with the same accuracy measured between May 31, 2004 and June 1, 2005. Furthermore, numerical weather-prediction data are used for 7 weather stations for the same period in order to estimate wind speed forecast errors. Data regarding the meteorological stations for which the used data are obtained are provided in Appendix A.

The methodology for the development of wind power data applied here is elaborated and presented in detail in [57]. First, wind speed time-series are used to determine periodic effects such as daily wind patterns. The use of time-series guarantees that correlations of wind speeds (variations over space and time) are automatically taken into account. The wind speed data are transferred from measurement height to wind turbine hub-height. The data are then transferred from the measurement sites to existing and foreseen locations of wind parks by linear interpolation, taking into account the spatial correlation between the sites. Finally, wind speed forecast errors are estimated using the same method and subsequently used to develop wind speed forecasts for each location. Wind speed and forecast time series are then used for the generation of wind power time-series and wind power forecasts. Below, an overview of the methodology is provided.

Wind Speed Time-Series Model

Analysis of the wind speed measurement data reveals that the sample variance of the wind speed increases with the average wind speed [57]. In order to suppress this so-called heteroscedasticity, a variance stabilising transformation [23] is applied and the logarithm of the wind speed is used instead of wind speed itself. In order to arrive at a suitable wind speed time-series model, any periodic effects in the wind patterns must be investigated first. In Fig. 2.5, the average daily wind pattern is plotted for each of the wind speed measurement locations. The lower curves correspond to locations onshore and the upper ones to offshore. It can be observed that onshore measurement locations have a typical maximum occurring around midday, offshore locations have a rather flat daily profile with a higher average, and coastal locations fall somewhere in between.

The wind speed time-series model used for this research includes a daily effect that varies smoothly with the geographic locations. The log wind speed at a location x and time t, $w(x,t)$ is modeled as

$$w(x,t) = \mu(x,t) + \epsilon(x,t) \tag{2.1}$$

where $\mu(x,t)$ is a deterministic variable representing the daily wind pattern and $\epsilon(x,t)$ is a zero-mean random process variable representing shorter-term variations around the daily

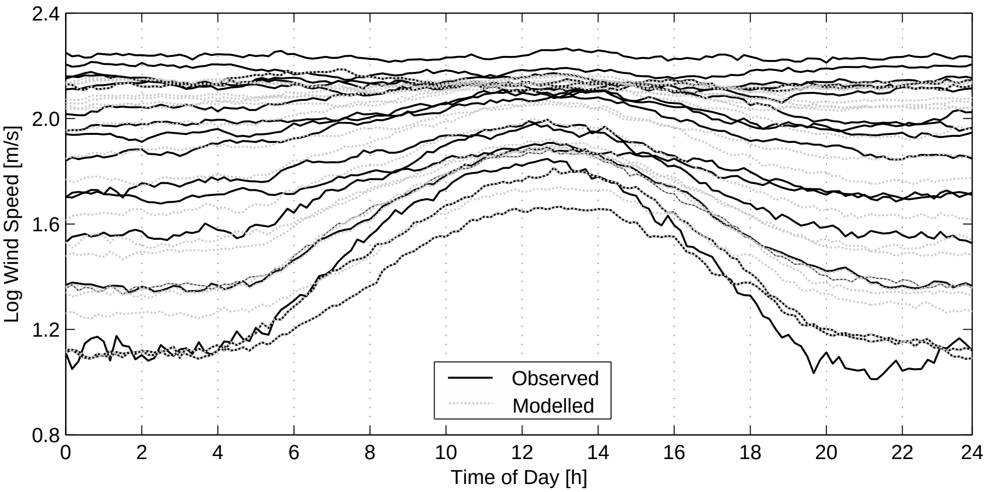

Figure 2.5: Daily wind speed pattern for the measurement locations and for interpolated sites.

mean. It can be noted that the covariance structure of $\epsilon(x,t)$ must take into account the geographical correlations between different locations, especially considering the limited surface of the Netherlands.

Height Transformation

The measurement height for the wind speed data (sensor height, ∼10 m) used in this research does not correspond to the hub height of modern wind turbines (70–120 m). Therefore, a height transformation must be applied to the wind speed time-series from the measurement height to the turbines' hub height. The relationship between wind speed and height is determined by the so-called vertical wind speed profile, a logarithmic function. The vertical wind speed profile is commonly estimated by local roughness-lengths [180], a measure for the presence of local objects in the landscape influencing the air flow. Local roughness-lengths are however difficult to determine accurately for onshore locations. Another way to estimate the vertical wind speed profile is to use two other location dependent parameters [18]: the friction velocity, a measure for kinematic stress (turbulence) in the air flow which can be estimated using horizontal speed measurements [184], and the average Obukhov (or stability) length, a measure for the height above ground of this turbulence; assuming a stable vertical wind speed-profile [57], [176].

Using $\mu(z_s)$ as the 10 min. average wind speed and $\sigma(z_s)$ as its associated standard deviation at sensor height z_s, the average wind speed at wind turbine hub-height $\mu(z_h)$ and the associated standard deviation $\sigma(z_h)$, are estimated using [18]

$$\hat{\mu}(z_h) = \mu(z_s) + \sigma(z_s)\left(ln\left(\frac{z_h}{z_s}\right) + 5\frac{z_h - z_s}{L_{esti}} \right) \tag{2.2}$$

where the ˆ represents estimated values and L_{esti} the Obukhov length, and associated in that,

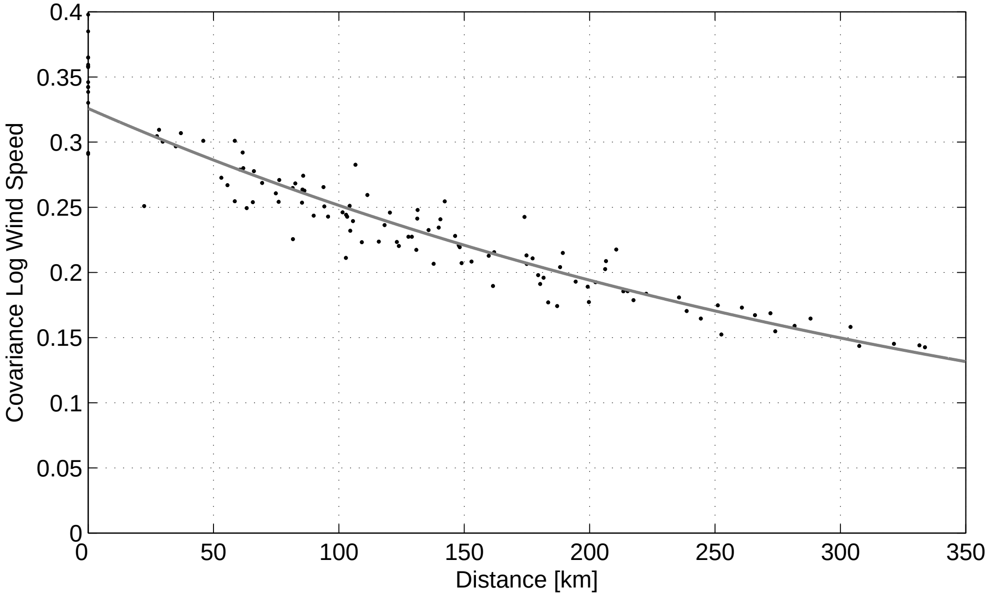

Figure 2.6: Wind speed covariance versus distance for the eighteen measurement sites.

$$\hat{\sigma}(z_h) = \sigma(z_s). \tag{2.3}$$

For some wind speed measurement locations, only the 10 min. wind speed averages $\mu(z_s)$ are available while the standard deviations $\sigma(z_s)$ are not. Since the interactions between water surfaces and the air are well-known, for offshore locations, $\sigma(z_s)$ can be estimated using only the sensor height z_s and the friction velocity u_*. Eq. 2.2 is used by approximating $\hat{\sigma}(z_h)$ as a function of the friction velocity u_* only [18]

$$\hat{\sigma}(z_h) = 2.5u_* \tag{2.4}$$

where u_* is calculated using

$$\mu(z_s) - 2.5u_* \left(ln\left(\frac{z_s g}{K u_*^2}\right) + 5\frac{z_s}{L_{esti}} \right) = 0 \tag{2.5}$$

where g is the gravitational acceleration (9.81 m/s^2) and K Charnock's constant for surface roughness at sea (0.011). The factor 2.5 is based on $1/\kappa$ where $\kappa = 0.4$ is the Von Kármán constant, which describes the logarithmic velocity profile of, in this case, the air near the sea's surface [107]. For onshore locations, the wind speed standard deviation is used to provide an estimate of the friction velocity.

Wind Speed Interpolation

In order to obtain the wind speeds at other locations, a linear, spatial interpolation is applied for all locations within the boundary of the measurement locations. For locations outside this boundary, nearest-neighbour interpolation is applied. For the estimation of the random component $\epsilon(z,t)$, the covariance $cov(\epsilon(z_1,t),\epsilon(z_2,t))$ between two locations $z_1(x_1,y_1)$ and $z_2(x_2,y_2)$ is calculated. In Fig. 2.6, wind speed covariances (here: a measure for the correlation of wind speed variations between locations) are plotted versus the distance between measurement locations. Assuming that covariance approaches zero at large distances, it is modeled through an exponential decay:

$$cov(\epsilon(z_1,h),\epsilon(z_2,h)) = Ce^{-a||z_1-z_2||} \tag{2.6}$$

Parameters C and a are estimated using a least square fit, also shown in Fig. 2.6, with $1/a$ as the characteristic distance or decay parameter. Translation of this decay-fit from log wind speed to wind speed gives a characteristic distance of 610 km, a value in line with values reported in [59, 71].

The locations for thirteen onshore and 25 offshore wind parks are determined, as shown in Appendix B. The wind speeds at these locations are estimated by interpolation of the wind speed data at the eighteen measurement locations (Appendix A). The linear interpolation takes into account the spatial correlations among multiple sites to arrive at wind speed time-series for existing and foreseen wind power locations [57]. The results are cross-validated by removing one location from the n-site measurement set at a time and using the remaining n-1 measurement sites to estimate it.

Linear interpolation is also been used to construct the lag-1 (auto-)covariances (Fig. 2.6). Correlations between subsequent 10 min. intervals are also taken into account. It is assumed that the wind speed time series have the Markov property: given the measurements at time t, and the measured and interpolated values at time $t-1$, the interpolated values at time t are independent of values at previous time steps $t-k$, for $k>1$. The obtained 10 min. averages of wind speed at the foreseen wind park locations are then converted to 15 min. averages.

Wind Speed Forecast Errors

The 15 min. averaged wind speed time-series developed above are applied using the forecast methodology for wind power AVDE (Aanbodvoorspelling Duurzame Energie, in English: supply forecast of renewable energy). This method developed in [19] is a physical one with a statistics module output comparable to the approach applied in [102] and takes into account the local influences of roughness, obstacles, and stability on wind speeds at the specified height. The forecasts are based on underlying runs of the atmospheric High-Resolution Limited Area Model (HIRLAM). HIRLAM numerically approximates the physical state of the atmosphere at 6 h. intervals with initial conditions taken from recent observations. The wind speeds approximated by HIRLAM are post-processed by AVDE into 15 min. averaged wind speed at hub-height for two onshore and five offshore measurement locations. These approximated wind speeds are then compared to the measured wind speeds to obtain wind speed forecast errors. Using the same method applied for interpolating wind speed data, the wind speed forecast errors are interpolated to the foreseen locations, and finally added to the interpolated wind speeds to develop forecast wind speed time series at the locations of interest. Since the time-dependency of wind speeds is taken into account in the wind speed interpolation method, time-dependence is automatically included in the forecast time series as well.

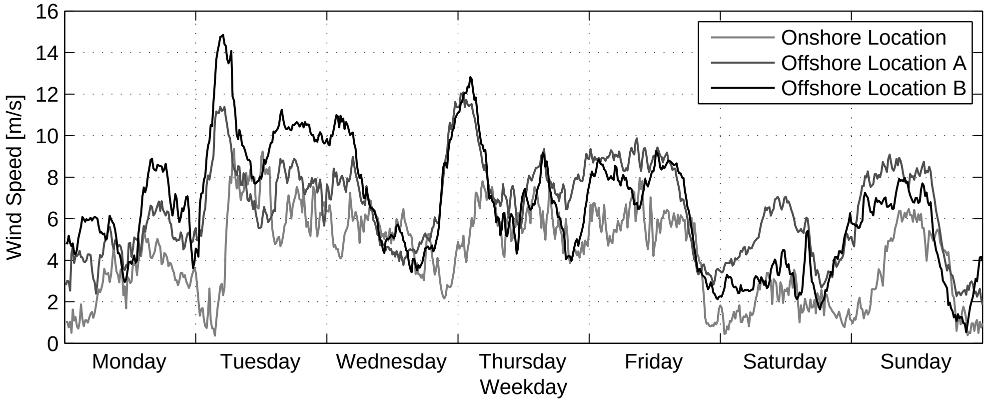

Figure 2.7: Calculated wind speeds for one week for one onshore and two offshore locations.

The minimum lead-time of the NWP-model fed forecasting method used here is 6 h. The first 0–6 h. are filled-in by a persistence-based forecasting method fed by real-time measurement data. For this, the 12–36 h. ahead aggregated wind power forecast errors are modeled as a first-order auto-regressive moving average (ARMA) process:

$$\phi(t) = a\phi(t-1) + b\gamma(t-1) + \gamma(t) \tag{2.7}$$

where $\gamma(t) \sim \mathcal{N}(0, \sigma)$ is a zero-mean, normally-distributed noise term of standard deviation σ. The a, b and σ parameters of the ARMA process are estimated via the MLE (Maximum Likelihood Estimator) method [23]. One 1–36 h. ahead wind power forecast is developed for each hour of the year.

2.3.3 Results

The methodology presented above is used to generate one year of 15 min. average wind speed time-series for specified onshore and offshore locations. The time-series for all locations are consistent with respect to correlations in time and geography. Furthermore, wind speed forecasts are developd for the same locations for each hour, with a 15 min. resolution, for forecast lead-time of up to 36 h. while also respecting the correlation structure among the various locations. Fig. 2.7 illustrates the generated wind speed data for three locations, for one week. The generated time-series are used to develop wind power time-series for individual wind park locations.

2.4 Development of Wind-Power Data

2.4.1 Literature Background

Different methodologies exist for the development of wind power from wind speed data and include the use of wind turbine power curves, aggregated wind park power curves and statistical modeling [141]. Power curves for the conversion of wind speed to wind power are commonly used for the transformation of measured and synthetic wind speed data-series [44, 176]. Drawback of using a wind turbine power curve for the estimation of an entire wind park is that it over-estimates wind power variations near cut-out wind speeds, especially offshore where distances between wind turbines are significant. A methodology for the development of wide-area, aggregated wind park power curves is presented in [128], enabling the development of wind power data based on locational shares of the total capacity spread out over large geographical areas. However, this methodology does not allow for the development of wind power data for separate locations, which is necessary for developing different wind power penetration scenarios consisting of specific combinations of wind parks.

For this research, wind power has been modeled using multi-turbine power curves to compute the power output for any given wind speed at individual wind park locations. The methodology developed in [57] was applied, which uses regionally averaged power curves dependent on the wind park's area and the standard deviation of the wind speed at the park's location. The locations of onshore wind parks are determined by extrapolating the present distribution of onshore wind turbines in the Netherlands to larger wind power capacity levels, taking into account provincial targets [189]. Locations of offshore wind parks are based on a selection of locations proposed in [46] and under consideration in [125]. By far most wind park locations are in an area of approximately $80 \cdot 100$ km.^{2}, to the West of Hoek van Holland–Den Helder, and a small section of the Wadden Sea, north of Groningen, as can be seen in Appendix B (Fig. B.1).

Below, the relation between wind speed and wind power is presented and investigated for different wind turbine types. Power curves of different wind turbine types are presented and multi-turbine power curves are developed. Then, wind power data series are developd for different installed capacities onshore and offshore.

2.4.2 Relationship between Wind Speed and Wind Power

Wind speed and wind power are governed by a third order relationship. The actual relationship between wind speed and the wind power output of a wind turbine is defined by the wind turbine power curve, defining the amount of power generated by the wind turbine P_{wt} at wind speed v

$$P_{wt} = \frac{\rho}{2} c_p(\lambda, \theta) A_r v^3 \tag{2.8}$$

in which ρ is the density of air [kg/m^3], c_p the power coefficient of the wind turbine, λ the tip speed ratio between the turbine blade tip speed v_t [m/s] and the wind speed upstream the rotor v [m/s], θ the blade pitch angle [°] and A_r the swept area of the turbine rotor blades [m^2]. Wind turbines control their λ and θ and thereby C_p in order to maintain rated electric power generation at higher wind speeds and to prevent mechanical overloading of the turbine's moving components and structure. The maximum power coefficient C_p of an ideal wind turbine rotor is $16/27$ which is known as the Lanchester–Betz–Joukowsky limit [175]. Since it is only possible to maximise C_p for a limited range of wind speeds, the design and control of C_p and the wind turbine are such that the conversion efficiency is highest at the wind speed range where most energy can be captured.

2.4.3 Wind Speed – Wind Power Conversion

Wind speeds can be converted to wind power using wind turbine's wind speed–power curves based on the fundamental relationship of Eq. 2.8. Apart from the power coefficient, which is specifically designed for different wind classes, wind speed–power curves are also determined by wind turbine technology and type.

Wind Turbine Technology Concepts

Throughout the development of wind power in the past decades, different wind turbine technology concepts have been used, each with different power curves. These concepts can be categorised by generator type. The four most commonly used generator systems for wind turbines are the fixed speed wind turbine with induction generator (type A), variable speed with variable rotor resistance (type B), variable speed with doubly fed induction generator (type C) and direct drive turbine with permanent magnet generator (type D) [66, 140].

The first, turbine technology concept comprises a three-bladed, fixed rotational speed wind turbine with a multi-stage gearbox. This so-called Danish concept has a standard induction (asynchronous) squirrel-cage generator directly coupled to the grid. The generation output is usually governed by passive stall-regulated control using blades with a fixed angle, although active stall concepts are used. This turbine concept was widely used until the late 1990s by manufacturers NEG-Micon (now Vestas), Bonus Energy (now Siemens) and Nordex for wind turbines up to 1.5 MW.

Since the late 1990s, most wind turbine manufacturers have changed to variable speed for power levels from about 1.5 MW and up. The limited variable-speed concept type B involves a multi-stage gearbox connected to a wound-rotor induction generator with a variable generator rotor-resistance used for power output and pitch control. This concept has been used since the mid-1990s mainly by manufacturer Vestas. The variable speed concept type C involves a multi-stage gearbox connected to a doubly-fed induction generator and a power-electronic convertor connected to the turbine's rotor winding, with a rating equal to $\sim$30% of the rated power of the generator. The generation output is governed by control of the pitch angle of the wind turbine's blades. The concept is still widely used by manufacturers as Vestas, GE Wind, Gamesa Eolica and Nordex.

Already since the early 1990s, some wind turbine manufacturers have applied gearless generator concepts with so-called direct-drive generators (type D), mainly to reduce failures in gearboxes and lower maintenance needs. The direct-drive concept involves a gearless multi-pole synchronous generator and a power-electronic convertor with a rating equal to the generator's nominal power. This concept is used mainly by the manufacturer Enercon.

The different turbine concepts have different power curves. Wind speed–power curves[1] for each type of wind turbine are shown in Fig. 2.8, assuming an air density of 1.225 kg/m^3 and no noise constraints for turbine operation. Modern types C and D involve turbines with larger capacities, while type A does not produce a flat power curve at wind speeds exceeding 15 m/s (rated wind speed). Regions of the power curves of special interest for power system integration are the range of 5–15 m/s, where changes in wind speed correspond to relatively large changes in electrical power output, and the cut-out speed (20 m/s for NEG-MICON

[1] Power curves are obtained from http://www.windpower.org/, http://www.enercon.de/ and Vestas Wind Systems A/S

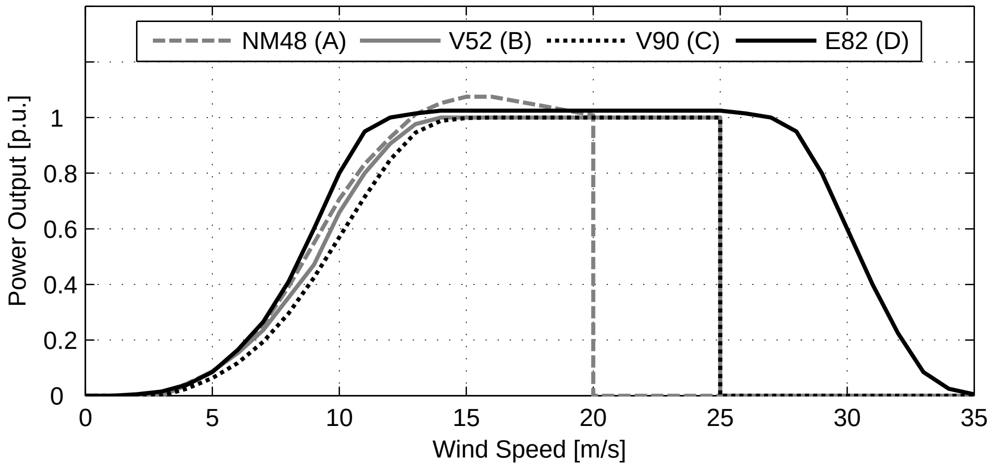

Figure 2.8: Wind turbine power curves for the NEG-MICON NM48 (A), Vestas V52 (B), Vestas V90 (C) and Enercon E82 with storm control (D).

NM48, 25 m/s for Vestas V52 and V90), around which the power output of the wind turbine alternates between full and no power.

Development of Long-Term Wind Power Data

A differentiation is made between long-term simulations (UC–ED, 15 min. time resolution) and short-term simulations (frequency stability, 4 s). For the development of long-term data for regional onshore wind power output and offshore wind parks, the multi-turbine approach developed in [57] is used. This approach makes use of the distance between wind turbines within a wind park to develop a Gaussian filter (normal distribution function), estimating the wind speed deviations at wind turbine locations around the park's average wind speed. For each wind park, a location-dependent power curve is developed based on the local standard deviation of wind speed and the geographical size of the wind park. The approach ignores park effects such as wind turbine wakes. Park effects may slightly alter annual yields [97] but are considered here to be negligible compared to the assumptions made regarding wind park locations, distances of turbines and wind park lay-out and the differences in energy content between various wind years.

The method establishes a regionally averaged speed–power curve for each wind park by applying a distance scale and Gaussian filter to the single-turbine power curve. The filter originates from the local wind climate, taking into account regional variations of wind speeds based on exponential decay. The width σ_F of the Gaussian filter is calculated from

$$\sigma_F = \sigma\sqrt{0.5\left(1 - e^{-D_{ave}/D_{decay}}\right)} \tag{2.9}$$

where σ is the standard deviation of the local wind speed, D_{ave} is the distance scale (average distance between locations) and D_{decay} is the characteristic distance of the decay of correlation.

Since the individual turbine locations are not known, the distance scale D_{ave} must be estimated. Considering a wind park with area A with N wind turbines, the length scale L that characterises the area, can be defined as

$$L = \sqrt{A/\pi} \tag{2.10}$$

The average distance scale D_{ave} can be estimated from the minimum and maximum distance distance between two turbines D_{min} and D_{max}. Introducing the area per turbine location A_T as

$$A_T = \frac{A}{N} \tag{2.11}$$

and the corresponding characteristic length scale for each turbine L_T as

$$L_T = \frac{A}{\pi N}, \tag{2.12}$$

D_{min} is estimated as 2*L_T, while D_{max} is estimated as 2*L. The average distance scale D_{ave} is estimated to be

$$D_{ave} = \frac{d_{max} + 2d_{min}}{3} = \frac{2}{3}\sqrt{\frac{A}{\pi}}\left(1 + \frac{2}{\sqrt{N}}\right). \tag{2.13}$$

In this research, the wind park area A is related to a Dutch province for the onshore parks and to an individual wind farm for the offshore. The area of an individual park is approximated by the area of a rectangle with sides depending on the number of turbines N and the rotor diameter and capacity of the wind turbines. For the onshore locations, it is assumed that these comprise the most common type C or D turbines with power curves as presented in Fig. 2.8. Each onshore turbine has an installed power of 2 MW and a rotor diameter of 80 m and the onshore wind turbines are spaced at 400 m (five times rotor diameter). Offshore wind parks are assumed to consist of 5 MW C-type turbines, since wind turbine of this capacity presently available are of this type. It is assumed that offshore wind turbines have rotor diameters of 120 m and are spaced by 720 m (six times rotor diameter) based on practical experiences with existing offshore wind parks.

The multi-turbine curves for individual wind parks are obtained by applying the above Gaussian filter (σ_F) to the wind turbine power curves, delivering a multi-turbine curve for each wind park. Fig. 2.9 shows an example of a multi-turbine curve developed for an offshore wind park using the method explained in [57]. The influence of the Gaussian filter is most visible around the cut-out wind speed (25 m/s), where the wind turbine alternates between full power and no power. This illustrates how the wind speed deviations from the wind park's average wind speed at individual turbine locations result in a smoothing of the wind park's power curve. The wind speed data developed above for each wind park location can be multiplied with the parks' multi-turbine power curve in order to develop wind power data.

The last step for the development of the wind power time-series for each wind park is the incorporation of the unavailability of wind turbines. This can be done in different ways, with a full Monte Carlo outage approach delivering the most accurate results. The large number of wind turbines ($\sim$1000 for the smallest penetration level) and the aggregation of wind power output at system level makes that the added value of this approach is limited compared to an

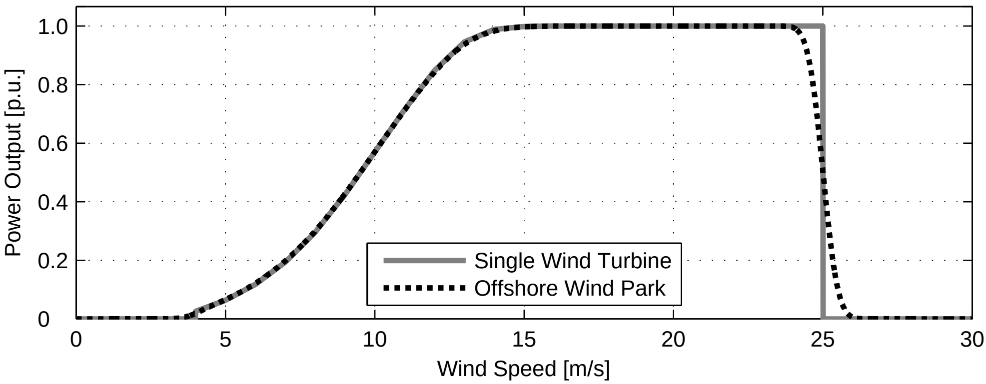

Figure 2.9: Example of a multi-turbine power curve for an offshore wind park.

averaged availability rate. Therefore, wind turbine availability rates are assumed to be constant at 98% for onshore wind turbines and 95% for offshore turbines, the latter due to more difficult access. It can be noted that availability rates for wind turbines placed offshore may well be lower than this figure [173]. High availability is however a crucial design parameter for offshore wind projects and can be regarded as a conservative approach from a power system integration point of view.

Short-Term Wind Power Variations

The power curves used above are based on wind turbine measurements in areas with low turbulence intensity, and with the wind coming directly toward the front of the turbine. Local turbulence and wind gusts hitting the turbine from varying directions influence the actual power produced by the wind turbine on the shorter time-scales, especially in wind speed ranges below rated wind speed ($<$ 15 m/s), although the impacts of such wind speed variations on the power output of wind turbine types C and D may be mitigated to a certain extent by the control of the power-electronics converter [144]. Also, the (virtual) inertia of the rotating mass of the rotor (estimated around 3–4 s) filters out the fastest output variations [156].

Typically, wind turbine models for a dynamic analysis of power systems consist of aerodynamical, mechanical and electrical subsystems, which describe the interactions between the different aspects of wind turbines for time-scales of ms to s [2, 155]. Also, aggregated wind park models have been developed for these time-scales [3]. For the time resolution of 4 s required for this research (frequency stability, primary control), however, such models have little value, since these short-term variations of wind power have a negligible correlation between different wind park locations [122], [123]. For a larger area of geographically dispersed wind parks, the s and min variations are found to be insignificant [127]. In this research, therefore, wind power output is considered to be equal to the mean value of the wind speed in the long-term simulations. Short-term wind power data are obtained by linear interpolation between the mean 15 min values in the same way as for the load (Fig. 2.2).

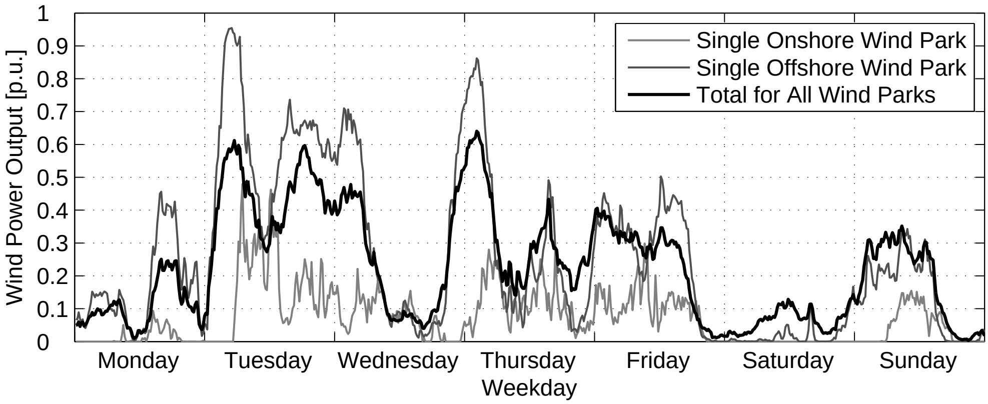

Figure 2.10: Calculated generation of two single wind parks and aggregated total output for all wind parks for one week.

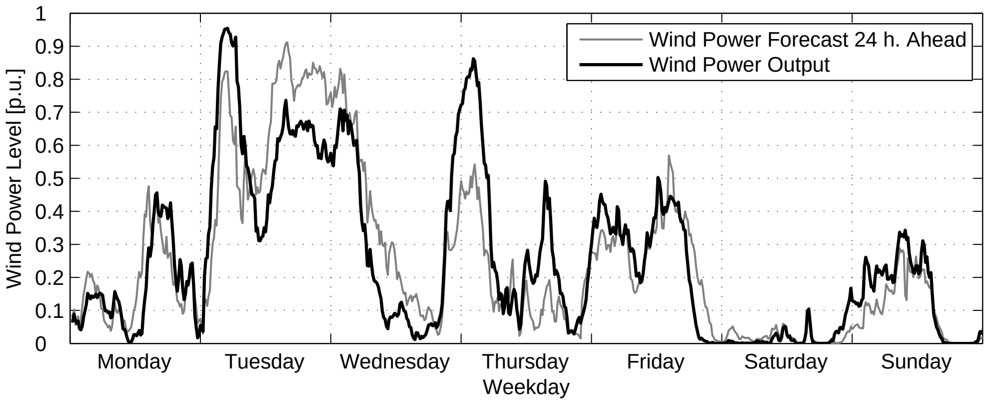

Figure 2.11: Generation and forecast (24 h. ahead at each hour) of an offshore wind park.

2.4.4 Results

Application of the methodology presented above results in a one year, 15 min. resolution time-series of wind power output for the specified onshore and offshore wind parks. Furthermore, wind power forecasts are developd for each wind park. In Fig. 2.10, the calculated power output for two wind parks is illustrated for the same week and locations as shown in Fig. 2.7 (onshore wind park and offshore wind park B). Furthermore, the total output for all modeled wind parks is shown. Clearly, the geographical spreading of onshore and offshore wind parks leads to a certain amount of smoothing, resulting in a less variable aggregated total power output. Still, the variations are significant between days and hours of this week.

Fig. 2.11 illustrates the resulting wind power forecast output for a lag of 24 h. ahead, for the same offshore wind park as shown in Fig. 2.10. Depending on the hour of the week, the 24 h.-ahead wind power forecast (same average forecast error for each timestep) is a surplus or a shortage (Tuesday), out of phase (Sunday), or both.

2.5 Analysis of System Load and Wind Power Data

Wind power utilisation factors (actual over rated output annually) of 26% and 47% for onshore and for offshore, respectively, for this particular set of annual wind data, wind turbines, locations and availability rates. It is important to note that wind energy supply and thereby wind power utilisation factors vary considerably between years [142]. Because of this, the impacts of a certain installed capacity of wind power on power system operation may vary between years and also the specific worst-case combinations of wind power and load. Since only one year of wind speed data was available for this research, it is important to consider different wind power installed capacities. This also allows for investigating the extent to which certain system integration issues aggravate with the amount of wind power installed. The wind power penetrations developed here are: 2 GW onshore, 4 GW (3 GW onshore, 1 GW offshore), 6 GW (4 GW onshore, 2 GW offshore), 8 GW (4 GW offshore), 10 GW (6 GW offshore) and 12 GW (8 GW offshore), the latter producing 41 TWh for this particular wind year or 33% of the annual consumption in 2014. The wind power locations onshore and offshore assumed here are based on available information with respect to present policies and permit applications and are shown in Appendix B.

2.5.1 Load-less-Wind-Power Duration Curves

The impacts of wind power on system operation can only be correctly assessed in combination with the system load, since it is the aggregated total load minus the wind power that the rest of the generation must be able to balance. Following the given load profiles and the estimated wind power time-series, load and wind power data can be aggregated for each 15 min. interval, effectively, by regarding wind power as negative load. Load-less-wind power duration curves can be drawn up for each wind power scenario by arranging the aggregated totals in order of decreasing size. The duration curves obtained differ between different data years of system load and wind power, but provide a good impression of the main issues. The combination of system load data of 2007 with wind speed data of 2004 and 2005 is allowed since the data are combined for the corresponding time, incorporating seasonal and diurnal variations of both.

Fig. 2.12 shows the result of an estimate of load-less-wind power duration curve for the year 2014. The figure shows a load duration curve for 2014 as well as six load-less-wind power duration curves based on the wind speed data-year used in this research. Due to the small probability of maximum load, occurring only a few hours a year, the probability of maximum wind power at this same moment is slim. As a result of this, the maximum of load-minus-wind power is only a little lower than the maximum load, for this data-set of load and wind power they are 19.4 GW (12 GW wind power) compared to 21.0 GW (0 GW wind power). Lower loads occur much more often than the maximum load, therefore the probability of wind power to be significant at these moments is higher. Thus, wind power must be regarded as an energy source rather than a generation capacity source, even though it must be noted that wind power does contribute to generation capacity adequacy [15, 176]. Since the area below the duration curves must be covered by conventional generation, it follows that

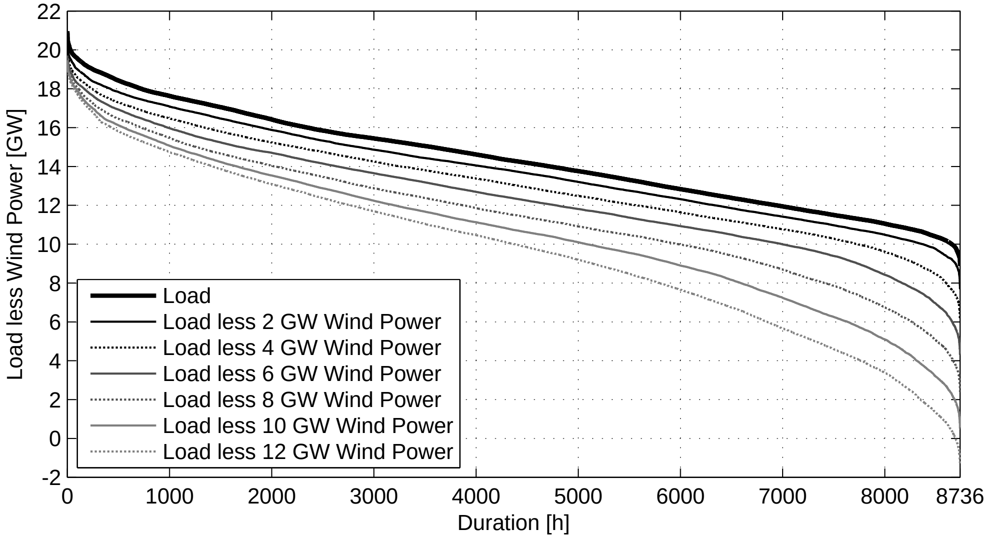

Figure 2.12: Load-less-wind power duration curves for 0–12 GW installed capacity.

the amount of full load hours for conventional generation decreases as the amount of installed wind power capacity increases. Importantly, the minimum load level decreases from 8.9 GW (0 GW wind power) down to -1.4 GW (12 GW wind power). Therefore, base-load units have to be taken out of operation much more often in order to prevent so-called minimum-load situations, in which the generation threatens to exceed the load.

2.5.2 Aggregated Power Variations

In this research, the variations of wind power and load are aggregated at the system level using the 15 min. time resolution defined for the UC–ED calculations. Wind power variations must be considered in combination with load variations since these may counterbalance each other out, thereby reducing the overall power variations, or the opposite may happen. For the aggregation of power variations, the data underlying Fig. 2.12 are used, but now by considering the differences between consecutive time steps. Positive and negative power variations ($P_t - P_{t-1}$) are then separated and sorted in decreasing order of magnitude, resulting in load-less-wind power variability duration curves as presented in Fig. 2.13, with the left graph zooming in on the annual extremes: certain combinations of variations in system load and wind power increase the maximum power variations in certain periods during the year.

Data analysis shows that with only load, downward power variations occur more often than upward (58% versus 42% of time), morning ramp-up of load is steeper than evening ramp-down); at the same time, upward variations exceed downward in size (maxima of +1406 MW/ 15 min. and -812 MW/15 min, respectively). As the amount of wind power increases, upward and downward variations become more symmetrical due to the symmetry of upward and downward variations in wind power: for 12 GW of installed wind power, downward power variations occur 56% of time. As can be expected with large-scale wind power,

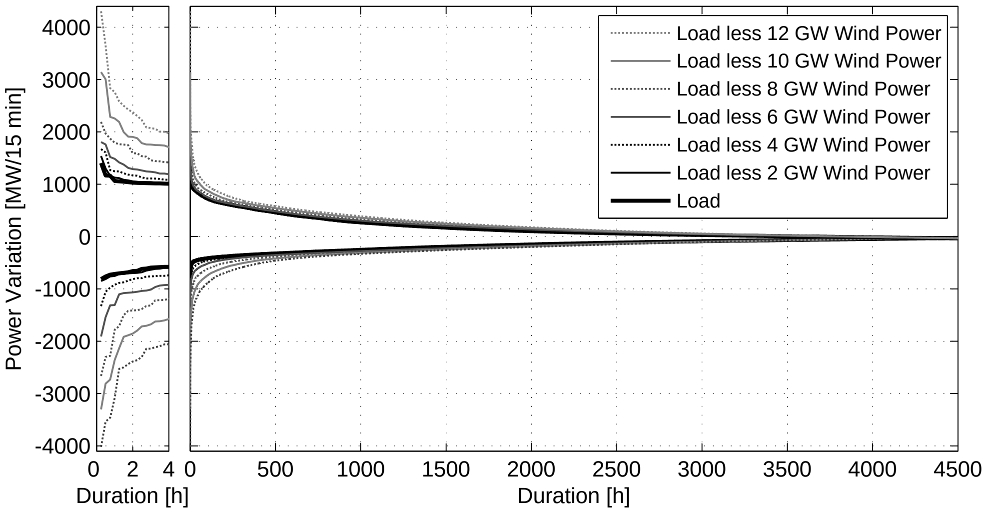

Figure 2.13: Load-less-wind power variability duration curves for 0–12 GW wind power.

maximum upward and downward power variations increase significantly, to +4421 and -4019 MW/15 min. respectively for 12 GW wind power. Although it follows from Fig. 2.13 that wind power increases the overall amount of power variability in the system, variations in system load continue to dominate. Clearly, wind power only marginally increases the total power variation most of the time. Only during extreme circumstances, occurring in less than 1% of the year for 12 GW wind power, the aggregated power variations are larger than the existing load-only maxima.

2.5.3 Wind Power Forecast Errors

A correct prediction of wind power is key for an efficient incorporation of the power variations due to load and wind power. The wind speed forecast time series developed in Section 2.3.2 are converted into wind power forecasts using the multi-turbine wind speed–power curves. A wind power forecast is developd for 15 min. intervals for forecast lags of 15 min. to 36 h. ahead, with a prediction error increasing with the forecast lead time. In Fig. 2.14 the capacity normalised standard deviation of the prediction error for the 0–36 h. ahead wind power forecast is shown for 12 GW wind power capacity. The figure illustrates how the forecast error drops by approximately 50% from the 36 to the 2–3 h. ahead prediction. A similar observation is made in [69].

Statistical analysis of the forecast data shows that about 99% of the probability mass is within $\pm 3\sigma$, which for the 12 GW installed wind power and a +36 h. lag translates to about 6 GW or 50% of installed capacity. The normalised standard deviation is comparable in size and tends to the values reported in [54], for an aggregate of 30 wind parks in Germany. The forecast data developed in this research have been compared to data from the Danish system operator Energinet and show that the mean absolute percent error of the day-ahead forecast is in very good agreement (7.83% versus 6.57% for the Danish data).

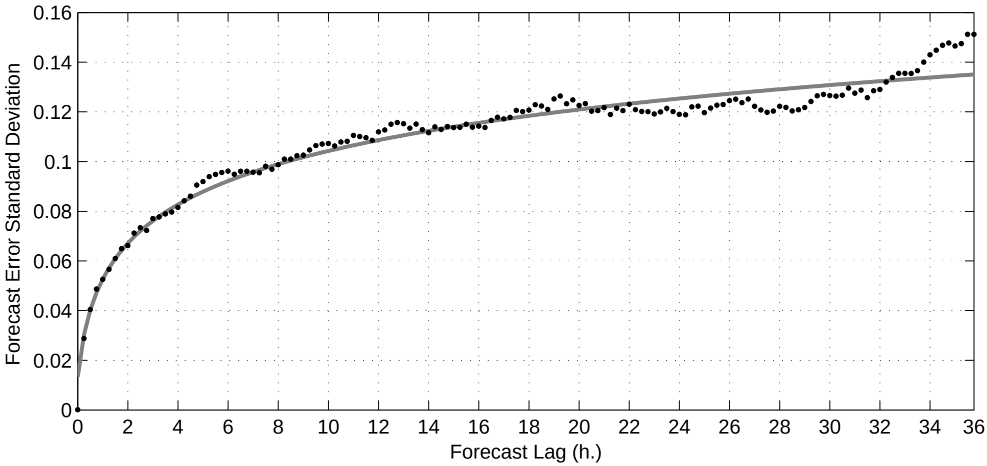

Figure 2.14: Normalised standard deviation of wind power forecast error for 12 GW wind power.

2.6 Summary and Conclusions

In this chapter, a set of data comprising 15 min. average time-series for for a whole year for system load and for wind power have been developd and analysed. Wind speed time-series have been developed by interpolation of wind speed measurements to existing and foreseen wind park locations, taking into account the spatial correlations. Using the wind speed time series and park-aggregated power curves, wind power output and wind power forecasts have been developed for use in simulations of unit commitment and economic despatch and shorter-term stability simulations. Wind power installed capacities scenarios range from 2 GW to 12 GW, the latter of which would supply around 41 TWh annually or 33% of consumption in 2014 in the Netherlands based on the data and assumptions used. For a first impression of the likely impacts of wind power on power system operation, duration curves and aggregated power variation curves have been developed for system load-less-wind power.

From the load-less-wind-power duration curve it can be concluded that wind power decreases the annual maximum system load only marginally, while wind power covers a considerable part of load during most of the year. Large-scale wind power significantly affects minimum load levels, requiring additional flexibility of conventional generation units (shut-downs) to accomodate high wind power levels during moments of low load. Another important conclusion is that although wind power adds additional variations to the power system, load changes continue to dominate overall variability also for large installed wind power capacities. Most aggregated variations of load and wind power are within the present variability range of only load, but incidental combinations of load and wind power require significant additional power reserves for balancing. A third finding is that wind power forecast errors are significant in the day-ahead (12–36 h.) time range. Wind power forecast errors are reduced by 50% when comparing an average day-ahead forecast to an average 2–3 h. ahead forecast.

CHAPTER 3

Unit Commitment and Economical Despatch Model

3.1 Introduction

Unit commitment in itself is a straightforward concept: a generation unit is committed when it is on-line: either generating or immediately capable of generating electric power. The optimisation of unit commitment is however not an easy task since it must take into account all possible reasons for bringing units on-line or shutting them down [174]. After unit commitment has been decided upon, despatch is then performed, distributing system load between the committed units such that overall operating cost are lowest. Unit commitment and economical despatch (UC–ED) are two optimisation tasks (ED being a sub-set of UC) requiring different optimisation procedures and comprising different time frames. Unit commitment decisions are nowadays assessed typically once or twice a day, while generation despatch is carried out throughout the day. With the reasonable predictability of system load, intra-day calculations for unit commitment are in principle necessary only when unexpected, significant changes occur in generation (e.g. outages) or demand. This changes when significant amounts of wind power must be taken into account, since its variations are more difficult to predict.

The emergence of international markets and the growth of wind power have complicated the optimisation of UC–ED in the sense that more variables and uncertainties (i.e. market prices, wind power forecasts) must be taken into account. In liberalised markets, the generation units owners are responsible only for supplying their own customers (i.e. long-term contracts and short-term trading agreements). Each individual owner therefore optimises the UC–ED of the generation units under its control, taking into account the market price. For existing systems, ideal markets in princple lead to the same outcome regarding the scheduling of generation as would have been the case with central optimisation. Thus, there is merely a conceptual difference between markets and the traditional generation scheduling (i.e. market participant price bids instead of operating cost minimisation). Therefore, solutions for the traditional central optimisation of UC–ED based on cost are still highly relevant [25].

The contribution of this chapter is twofold. First, an existing UC–ED optimisation tool is extended to include models for wind power, interconnectors to neighbouring power systems, additional thermal unit types and energy storage facilities. Second, a methodology is developed for studying the impact of market gate-closure times on the optimal UC–ED schedules. Also, the model's database is organised into separate classes, enabling the creation of large numbers of internally consistent simulation scenarios. The additions make the UC–ED tool usable for international system integration studies of large-scale wind power in liberalised environments.

The chapter is organised as follows. First, a literature overview is provided on available tools and procedures for UC–ED and the contribution of this thesis to the development of such tools and procedures is stated. Then, the simulation tool is investigated in detail and the structure and optimisation logic are presented, including the needed input data and the desired output. Models for all relevant power system aspects are included: generation, transmission, control areas (including interconnections), and system load. Furthermore, the creation of models for thermal conventional generation units, hydro power, energy storage, international exchanges and the model integration of wind power are shown.

3.2 Literature Overview and Contribution of this Thesis

Unit commitment is a large-scale (many units), mixed-integer, and non-linear programming problem. The optimisation of unit commitment therefore requires significant computational effort, explaining the substantial research efforts in this area over the past decades. Unit commitment may be optimised using different techniques, including the use of mixed-integer linear programming, dynamic programming, Lagrangian relaxation, heuristics and other approaches [25, 136]. The optimisation methods have different strengths and weaknesses and a wide range of UC–ED tools has been developed for the optimisation of different generation systems.

3.2.1 Overview of relevant UC–ED Tools

A wide range of tools has been developed for the simulation of UC–ED or electricity market operation ranging from weekly operations planning to generation unit investment planning. Even though these models have different characteristics, making them more suitable for different applications, they all have the objective of simulating the scheduling of the generation system while optimising total cost. Taking into account the focus of this research, only chronological tools capable of system simulation including wind power are discussed,

Model	Optimisation	Application
Balmorel	LP	Investment, Policy Assessment
EnergyPLAN	LP	Policy Assessment
PowrSym3	Heuristics/DP	Operation Cost, Investment Assessment
SIVAEL	DP	Operation Cost, Investment Assessment
WILMAR	LP	Investment Assessment

Table 3.1: Characteristics of UC–ED models with CHP optimisation.

with specific attention to the incorporation of combined heat and power units, an essential aspect of the Dutch generation system. The characteristics of the tools discussed below are summarised in Table 3.1.

The Danish SIVAEL tool [139] is capable of minimising total system cost while supplying local heat and power demand. The optimisation is based on dynamic programming and takes into account maintenance, reserves, wind power and its forecast errors and international exchanges. This UC–ED tool has been applied in [70] for system integration studies of large-scale wind power in Denmark. Another Danish tool, EnergyPLAN [105], has been developed to analyse and design system integration strategies for renewables, in particular wind power, taking into account investments and market design. This tool also comprises heat and power, generation schedules and international exchanges, but is focused on the assessment of regulatory mechanisms rather than technical aspects of power systems.

Balmorel [143] is a bottom-up partial equilibrium tool that can provide estimates of future electricity spot prices. It comprises key technical aspects of power system operation, including transmission lines and emissions. The Balmorel tool has characteristics similar to those of the WILMAR tool [112] which is used to simulate alternative solutions for the integration of large-scale wind power into interconnected power systems and thereby provides input to decision makers. WILMAR uses stochastic linear programming to optimise scenario trees (i.e. transition probabilities) for possible wind power generation forecasts for each hour. The model consists of two parts, one for the day-ahead market and one for the intra-day and regulation markets, using an hourly time-step. The model has been applied for the exploration of different integration solutions for wind power, for example heat boilers for the flexibilisation of combined heat and power (CHP) plants [111]. The E2M2s model, which is similar to the Wilmar model but considers a different stochastic approach for the representation of wind power variability and unpredictability, was used to investigate the use of compressed air energy storage [161] and transmission capacity extentions [11] for wind power integration. The use of stochastic modelling approaches for incorporating wind power may however limit applications for the modelling of large systems or international studies with wind power.

PowrSym3

The UC–ED tool used in this thesis is PowrSym3$^{\text{TM}}$, developed from the 1980s onwards by Operation Simulation Associates, Inc. and the former Dutch utility SEP with support from the Tennessee Valley Authority. PowrSym3 is a multi-area, multi-fuel, chronological generation cost simulation model for electrical power systems including combined heat and power, energy storage and energy limited fuel contracts [131]. PowrSym3 is a rolling UC–ED optimisation tool, i.e. UC–ED are updated every simulation state based on best available load and wind power forecast, while taking into account technical constraints following from previous states. The tool allows different simulation time-steps and 15 min. time-step was applied in this research PowrSym3 applies heuristics, or computer intelligence based on operational experience, for an initial optimisation of the UC–ED. The solution obtained from the heuristics is used as an input for a so-called 'smart' dynamic programming algorithm for further optimisation of the unit commitment. The model is capable of using multiple processors running in parallel for very large system studies, by use of a master server handling the database and co-ordinating the different jobs between different computers. PowrSym3 is used for optimisation of operation cost and generation capacity planning by utilities throughout the world, including TVA (USA), Western Power (AUS) and Transelectrica (RO). A previous version of PowrSym3 was applied in the late 1980s by the former Dutch utility SEP for economical analysis and capacity credit calculation of 1000 MW wind power in the Netherlands by the year 2000 [63].

The reasons for choosing to use PowrSym3 for this research are the following. The first is that the model's database contains validated models for the existing conventional generation units in the Netherlands. PowrSym3 has been used in the centrally organised optimisation of the UC–ED of the Dutch generation units up until 1998, when unbundling of the Dutch power sector started. Since then, the database has been maintained by Dutch TSO TenneT and the model continues to be used for system studies and adequacy forecasts [165]. In order to obtain additional modeling data and for validating the generation unit models, interviews have been held with the six largest Dutch utilities (balance responsible parties, or in the Netherlands, program responsible parties, PRPs). The second reason for using PowrSym3 is that little effort had to be spent on the development of a simulation tool, the acquisition of data and the validation of both. This allows efforts to be concentrated on the operation of the power system rather than the model, which is in line with the approach of the research consortium We@Sea. Finally, the use of PowrSym3 enabled a very useful exchange of expert knowledge with TenneT TSO, which has extensive experience with these kind of simulations.

3.2.2 Contribution of this Thesis

At the start of this research, the database of PowrSym3 comprised validated models of the largest seventy power generation units in the Netherlands and models for sixteen heat areas. The database did not include any of the following aspects: wind power, conventional generation unit ramp rates, energy storage, cross-border interconnections or international exchanges. The contribution of this thesis lies in the extension of PowrSym3 to include the following, additional aspects, both in the model itself and in the database:

- Wind power, by making wind power and forecast data suitable for use by the tool
- Ramp rates, by consulting market parties and using literature research to esitimate these
- Hydro power and energy storage, by developing new models in the tools database
- Interconnections and international exchanges, by developing new areas representing neighbouring countries of the Netherlands

Apart from these additions, additional thermal power unit models are developed to represent planned generation units. Furthermore, a methodology is developed for the simulation of different market gate closure times and wind power forecast errors. By a sequence of simulations and some input and output data processing, the method can be used to provide realistic generation schedules based on wind power forecasts. These schedules are then used as fixed input data for intra-day simulations which use updated wind power forecasts, available after gate-closure of international markets. This addition is now being included by OSA to become an integral part of the optimisation logic of PowrSym3. Furthermore, the database has been re-organised in such a way that it is possible to create large number of internally consistent simulation scenario's within very short time-spans.

The contributions made to the development of TenneT TSO's database in PowrSym3 make it a highly useful tool for system studies. The tool is now very suitable to investigate power system operation with large-scale wind power, international markets and integration solutions for wind power.

3.3 Simulation Model

The generation cost simulation model PowrSym3 comprises a number of aspects discussed below. The optimisation includes probabilities of generation unit outages and captures all relevant chronological aspects by rolling UC–ED, most importantly the operational flexibility of conventional generation units. First, the modeling of generation unavailability due to outages is elaborated upon and a choice between different options is made. Then, the general model and simulation structure of PowrSym3 is presented. Following this, the annual, weekly and short-term optimisation methodology is described. Furthermore, different simulation attributes that must be defined beforehand are discussed. Finally, an overview is given of the input and output data.

3.3.1 Generation Outages

Outages comprise all events leading to a (partial) unavailability of generation units in the system. A differentiation can be made between unforced or planned outages, such as due to scheduled maintenance, and forced outages, such as due to unexpected technical failures of the unit. In order to capture generation unavailability, derating of generating capacity has been suggested in order to minimise the computational effort but this is only suitable if large capacities of one generation technology are present in the system. An improvement of the derating method comprises the addition of analytical approximations for the calculation of outages, in particular the use of cumulants for the representation of the equivalent load distribution between generation units [160]. Modern computers have however made it possible to fully incorporate generation outages by probability density functions, to be used in long-term chronological simulations.

Planned Outage Models

Planned outages are usually scheduled with the objective of minimising opportunity losses or the loss-of-load probability (LOLP), a widely used reliability measure in generation planning. This can be done by scheduling maintenance when prices are assumed to be low (low load periods) or by distributing maintenance between different units over different periods, resulting in a rather constant generation adequacy during the year. Planned maintenance has important impacts on power system operation, in particular cost and system reliability, but also on reserve levels and total emissions [179]. Different models are available for the simulation of planned outages, four of which are included in Powrsym3:

- Pre-scheduled maintenance
- Calculated maintenance schedule
- Combined maintenance schedule

The pre-scheduled maintenance is in fact a manually prepared maintenance schedule or reference planning that serves as an input to the simulation. Disadvantages of this method are the implicit choices made which are not necessarily related to the system under investigation. Therefore, its impact on the simulation results is unclear. It is also difficult to adapt the schedule to a different generation portfolio. A calculated maintenance schedule is based on an assessment of the LOLP for a given period. The conventional method of calculating the LOLP of a given power system comprises the computation of a cumulative outage probability table, determining the generation deficiency for each load level and summing all deficiency probabilities [181]. The advantage of the calculated one is mainly its focus on reliability, leading to an equal reserve margin throughout the year. A pre-scheduled maintenance schedule can also be combined with a calculated schedule. For accurate results during shorter periods, a weekly reliability model is available.

For this research, maintenance is assumed to be scheduled such that LOLP is levelised throughout the year, with most maintenance scheduled at periods of relatively low load. PowrSym3 calculates the maintenance schedule taking into account expected system load (hourly values) and the maintenance probabilities of individual units. Generation units may be assigned to maintenance groups, for which rules may be given regarding minimum capacity available etc. PowrSym3 will deliver an identical schedule for a particular simulation set-up for each run (repeatable results).

Forced Outage Models

Different models for forced outages included in PowrSym3 are:

- Fixed outage schedule
- Derating method
- Gradient derate method
- Random Monte Carlo
- Selected sample Monte Carlo
- Semi-guided Monte Carlo

A fixed outage schedule has the benefit of being fast to compute since it requires no iterations for convergence, but can only be applied for specific short-term operational studies. The derating method reduces the capacity of generation units by the forced outage rate. This method is also fast and in general applicable, but has the disadvantage that it may result in considerable errors in the computation of the reliability indices [68]. Therefore also the estimation of the operation of peak-load units or other units with limited operational hours is incorrect. The gradient derate method [131] is a similar method that approaches the derating method after several simulation hours and is suitable only for short-term operational studies.

The random Monte Carlo method calculates the expected unit operation hours by averaging a number of outage scenarios created by a random number generator. The outage length is specified as a simulation input and a new set of random draws is made at the beginning of each simulation period (week, month or year) comprising all generation units. A unit is in or out for a certain duration, either fixed or defined by certain probability function. The selected sample Monte Carlo is a less thorough method using only a limited number of Monte Carlo draws, which offers reduced calculation times at a limited expense of accuracy [131]. The semi-guided Monte Carlo method [152] produces statistically balanced forced outage schedules for extended time periods only (i.e. a year), requiring only a single iteration for convergence.

For this research, the random Monte Carlo method is applied since it is the most accurate method available in the tool and has acceptable calculation times. With a lack of data on outages, a fixed outage length of 24 h. is assumed. For the annual simulations of the UC–ED of the Dutch system, it has been shown that the simulation results (operation cost, generation unit operating hours) converge sufficiently within a single iteration, making the simulations very fast.

3.3.2 Optimisation Structure

PowrSym3 applies three execution time horizons: annually or monthly, weekly and an hourly or different short-term operational time step. The annual horizon is mainly used for reliability calculation and maintenance scheduling, the weekly for the simulation of outages and the scheduling of hydro and energy storage units, and the hourly for the actual simulation of unit operation.

Annual Simulation Horizon

Before the start of each simulation, the model reads input files for system load, load in neighbouring areas, local heat demands, wind power data and the data describing the power system itself (input and output data are discussed in more detail in Section 3.3.4). The annual simulation horizon comprises the scheduling of maintenance and the selection of expansion units, which is not applicable here. The reliability model computes the annual loss of load probability (LOLP) in hours per year using the cumulant method [160]. After calculation of the LOLP, load carrying ability and capacity surplus/deficit are calculated relative to a specified reliability index. This index may then be used for an annual optimisation of the maintenance schedules, as discussed in Section 3.3.1. The flow diagram is shown in Fig. 3.1.

Weekly Optimisation

The first step in the weekly execution is the determination of weekly random outage draws. The outage model selects the hourly unit outage states using a random number generator for a specified number of iterations (i.e. Monte Carlo draws). Each iteration is saved and used as input for a weekly simulation. PowrSym3 reports the expected unit availability for individual iterations and across all iterations. The unit commitment is optimised initially by heuristics based on the load prediction and wind power forecast and subsequently by dynamic programming.
Fig. 3.2 provides an overview of optimisation steps involved in the weekly optimisation process. First, hydro power stations are scheduled using a price leveling algorithm based on their

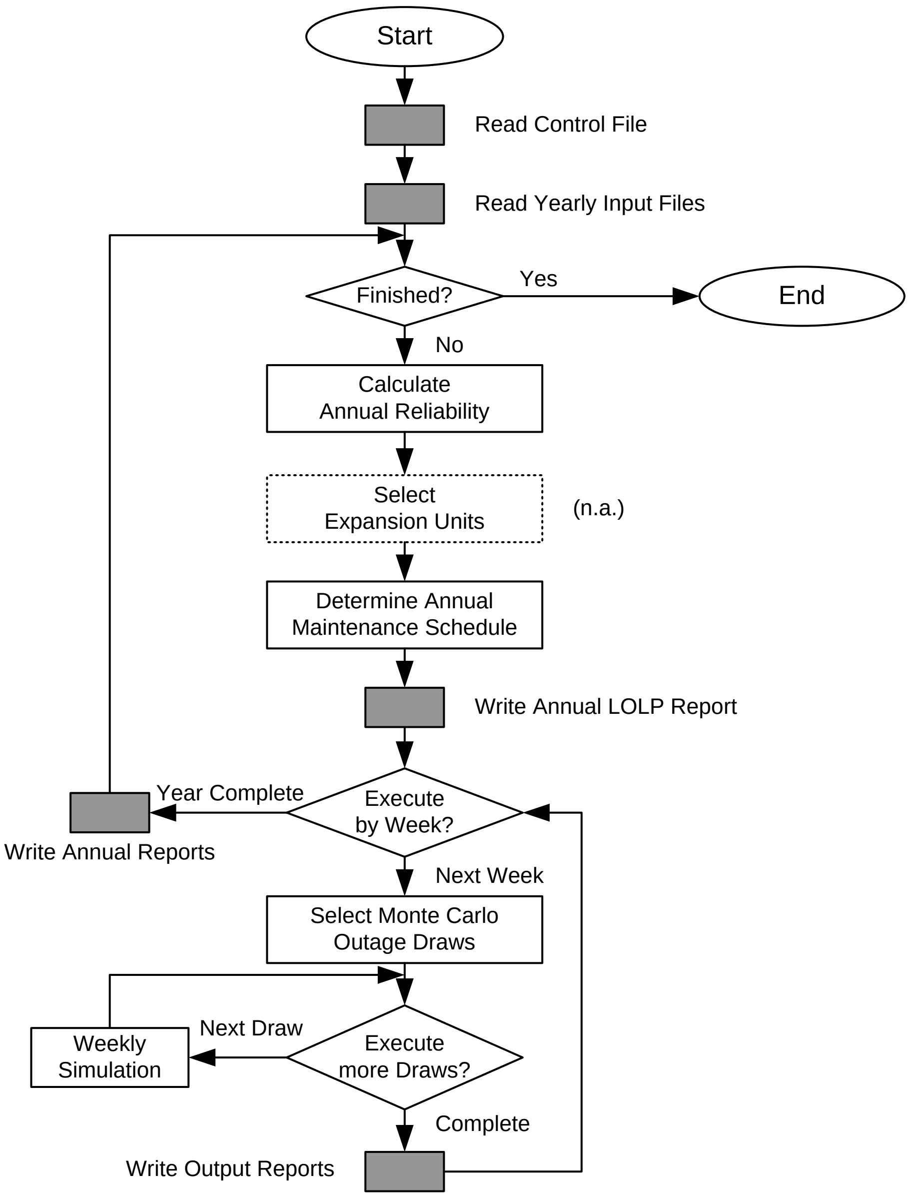

Figure 3.1: PowrSym3 annual execution flow diagram [131].

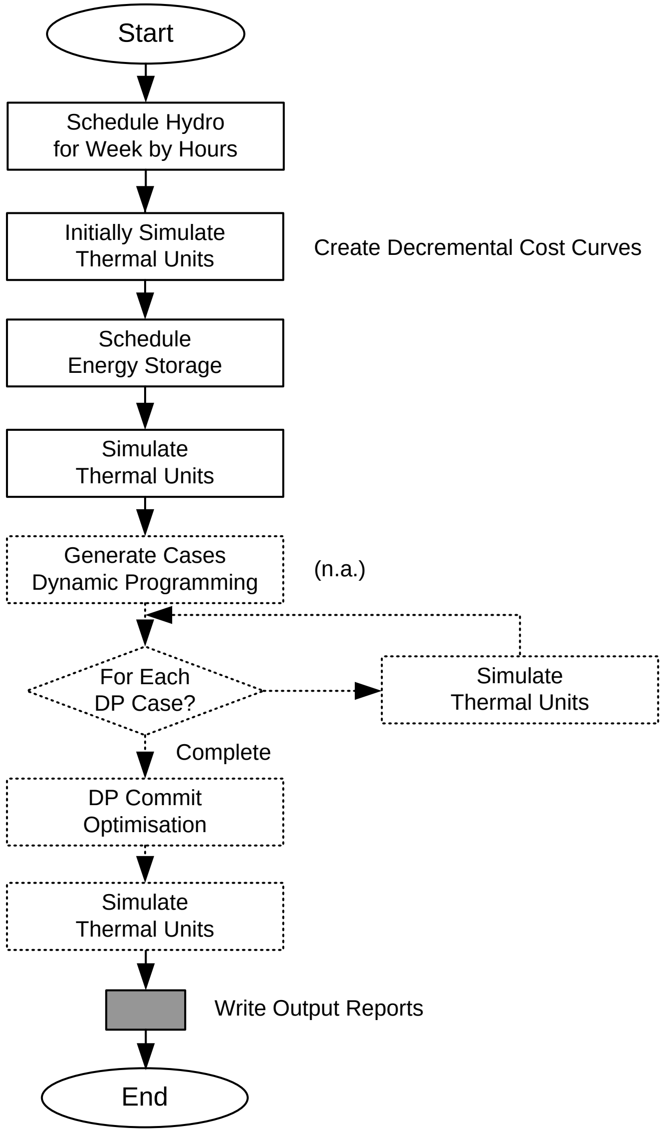

Figure 3.2: PowrSym3 weekly simulation flow diagram [131].

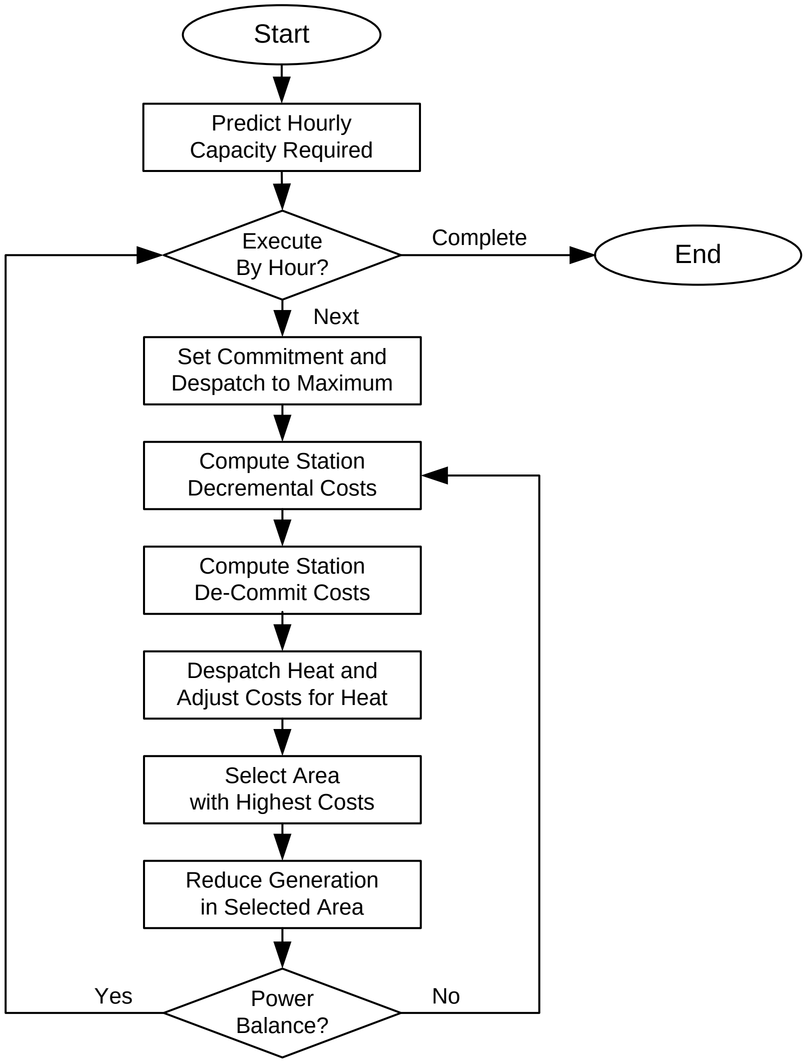

Figure 3.3: PowrSym3 thermal simulation hourly sequential method flow diagram [131].

weekly energy constraint, load prediction and wind power forecast. The hydro schedules are subject to hourly minimum and maximum generation levels and ramp rate limitations. The model then uses local heat demands, system load, wind power and wind power forecasts for the scheduling of the thermal generation units, which are also subject to technical constraints. Based on the operational cost estimates obtained here, energy storage is scheduled such that total operating cost over the week are minimised. After this, the simulation results generated by the heuristics may be optimised further using dynamic programming, which goes through the same steps as the heuristics. Finally, the simulation results are saved as formatted output reports.

Short-Term Optimisation

Unit operation is simulated on an hourly or another short time-step (i.e. 15 min. in this thesis) while preserving the chronology (Fig. 3.3). Pre-scheduled units, such as industrial or distributed generation, may be included using a fixed operating schedule for such units. The starting condition of the short-term simulation is defined by the output of the weekly simulation and the generation units' states at the end of the previous week, taking into account outages and minimum up- and downtimes. The heuristic optimisation process is done using the Equal Incremental Cost Method [131], which comprises the following steps:

1) Set all available generation units at maximum power level, taking into account operating constraints
2) Calculate decremental cost arrays for each short-term time step
3) Find the largest unit decremental cost
4) De-commit or ramp down most expensive unit(s)

The construction of the decremental cost arrays takes into account system load, heat despatch and de-commitment cost while satisfying minimum up- and downtimes and ramp rates. The cost of generating heat by CHP units are taken into account in the calculations of the marginal cost of these units. In case the system comprises different areas, decremental cost arrays are constructed for each area taking into account trans-area transmission constraints (i.e. Net Transfer Capacity, NTC, between areas), if applicable. After completion of the decrement procedure, system cost are calculated and these steps are repeated until load, heat demand and reserve requirements are balanced. The repetitive process provides marginal cost for all areas and all units. It can be noted that the must-run status of many base-load units in the Dutch system(coal, industrial CHP) reduce the complexity of unit commitment optimisation.

3.3.3 Simulation Attributes

Technical Constraints

PowrSym3 handles UC–ED as an optimisation problem, where the operating cost function is minimised within the boundary conditions of serving system load and local heat demands, and maximum integration of wind power. The UC–ED formulation includes typical generation unit parameters such as minimum up- and down-times and ramp rates as well as combined heat-and-power operating constraints. Unit commitment and despatch are optimised on a rolling, 15 min. basis to achieve minimum operating cost at the system level while all technical constraints are met, including system or transmission area load, heat demand in all

IYR	IWK	N1	N2	N3	N4	AID	A1	X1	CLASS	COMMENT
...	...	...	...	...	...	...	...	...	...	...
...	...	...	...	...	...	...	...	...	...	...

Table 3.2: Organisation of the database records

heat areas, technical capabilities of thermal units and system or area reserve requirements. All constraints are treated as 'hard' constraints which must be fulfilled at all times. System load or heat not served, if any, are therefore always the result of technical infeasibility and are specifically reported upon in the simulation results. Wind power is curtailed as a last resort only for the prevention of violations of technical constraints associated with thermal units. The technical constraints of thermal generation units are discussed further in Section 3.4.

Power Reserves

Power reserves are an essential operating attribute in the calculation of UC–ED. Operating reserves comprise spinning reserves and idle quick-starting generation units (i.e. cold reserves). Spinning reserves are defined as reserves provided by non-despatched capacity of committed generation units. During the simulations, present and future needs for power reserves are integrally assessed based on generation unit availability, load forecasts and wind power predictions (look-ahead logic).

3.3.4 Input and Output Data

All simulation input data are handled by a control file, which also saves the output data specified in it. Input data include system load, area loads, local heat demands, wind power, must-take power from distributed generation (largely CHP) and the power system data from the database.

PowrSym3 Database

The database is organised in ACCESS using the data format shown in Table 3.2. Records consist of a single line, in which IYR and IWK represent the year and week the record is applicable for, N1 to N4 are identifiers mostly used for unit numbers and hour of applicability, AID is the parameter name, A1 the generation unit or area name and X1 is the parameter's value. CLASS may be used to mark certain records, but this column had not been used before. A data exchange interface implemented in ACCESS produces the ASCII-file used as input for the calculations.

In this research, the CLASS-column has been applied to create selections of records together comprising a certain simulation set-up or scenario (i.e. fuel and emission cost, availability of international transmission capacity). A CLASS can be ticked on or off when exporting the database from ACCESS and saved as a simulation input file. This process allows the development of consistent data input files, guaranteeing reliable simulation results which can be compared between scenarios.

System Load

System load data for the Netherlands are elaborated upon in Chapter 2 and are directly imported into PowrSym3 as chronological data series. The simulations require input data series to comprise 364 days (52 weeks exactly), although the missing day is compensated in the annual results. It was decided to skip the original data of Monday 31$^{\text{st}}$ of December 2007.

Heat Loads

Annual heat load profiles for 18 existing and foreseen heat areas in the Netherlands are estimated in collaboration with the TSO and used as a simulation input. The UC–ED of CHP units is integrally optimised based on local heat demands, system load and wind power. The commitment of CHP units is driven by heat demand and depends on the availability of other options for supplying heat (i.e. heat boilers or buffers).

Wind Power

Wind power is incorporated in the simulations as a resource, meaning that wind power data are considered as available power rather than must-take (i.e. this resource can be discarded due to technical operation limits). PowrSym3 takes into account available wind power in the look-ahead logic of the unit commitment. Different options are available for doing this, such as a fixed capacity (0–100% of installed wind power capacity), the use of a separate wind power forecast data file or by assuming a perfect wind power forecast. For all options it applies that the UC–ED is updated for every hour using updated wind power forecasts (rolling UC–ED) and taking into account the wind power at each simulation step (i.e. wind power has a 15 min. data resolution, but the forecast is the seem for four consecutive data steps). It is assumed that wind power has a marginal cost of zero, thereby guaranteeing that wind power is despatched to its maximum availability unless technical constraints require wind power curtailment.

In this research, three wind power forecast options are considered: 0% wind power capacity, a rolling wind power forecast and a perfect forecast. For the rolling wind power forecast, a forecast matrix is used. The developed wind power forecast data are applied to construct these forecast matrices, consisting of columns in a quarter-hourly time-step and the rows in an hourly time-step, totaling 8701 hourly 15 min.–36 h. forecasts with a resolution of 15 min. The forecast records $\mathrm{F}_{m,n}$ with m representing the hour of the year and n the number of 15 min. forecast periods ahead are arranged like

$$\begin{bmatrix} F_{1,1} & F_{1,2} & ... & F_{1,144} \\ F_{2,1} & F_{2,2} & ... & F_{2,144} \\ ... & ... & ... & ... \\ F_{8736,1} & F_{8736,2} & ... & F_{8736,144} \end{bmatrix}$$

The matrix is constructed for each wind power penetration level and used as input for the UC–ED optimisation. Wind power forecasts are updated every hour up until real time, when the wind power data are used for despatch optimisation.

Output Data

Simulation output data are annual, weekly or short-term time-step reports following a standard layout specified by the user, or a direct output of pre-specified simulation parameters (summary reports per generation technology or area, specific simulation parameters). The standard reports contain results for each generation unit (utilisation factor, energy use, heat production, start-ups, average operating cost, etc.) and for the system as a whole (total operating cost, system emissions, LOLP, inter-area exchanges, etc.). Importantly, 15 min. generation unit operating levels (MWh/15min.) can be exported from the simulations and used for the construction of input data for the dynamic model.

3.3.5 Validation of the Simulation Model

It is assumed in this thesis that the optimisation structure of PowrSym3 is capable of incorporating wind power in power system simulations. This assumption is based on the experience of TenneT TSO with applying the tool for such studies and considering the use of PowrSym3 by utilities around the world. The heuristics and dynamic programming algorithm applied in PowrSym3 are regarded as a black box and not investigated further. The additional coding of the tool's capabilities, as was necessary during this research, is carried out by the software deloper OSA in close cooperation with the TSO. The correct incorporation of the new capabilities in the model are validated by a continuous assessment of the tool's simulation results. There has been a continuous dialogue with TenneT TSO and OSA on the development of the tool's capabilities, the validation of the tool and the simulation results obtained with it.

Every time a new version is developed and validated by OSA, several 'base' simulation runs of the Dutch system are done using the previous and the new version of the tool as a double-check. By ensuring that the simulation results are identical in every respect (cost, operation of individual units, etc.), it is validated that the existing optimisation structure of PowrSym3 is still operating correctly. Then, the new capabilities of the tool must be validated. This is done by applying the additions of the model (i.e. inclusion of wind power forecasts, energy storage, different areas and transmission constraints) in the model and investigating the simulation results. This procedure includes making sure that no technical constraints are violated (transmission and energy storage reservoir capacity limits). In case needed, the simulated cases were sent to OSA for further inspection of the simulation results and the tool's programming itself.

It is also validated that no differences occur between the simulation results of two or more cases that cannot be justified (f.e. ENS or costs increase when adding generation capacity). This is done by inspecting the simulation results in detail using selected output variables, f.e. considering the marginal unit of the system at each time step during selected weeks. Furthermore, it is validated that the differences in the results between the simulations can be explained in absolute terms as well (i.e. operating cost and emission savings by a certain amount of wind power capacity). Examples of the different simulations compared are the optimisation of areas with and without transmission capacity available between them, wind power with different forecasts, and energy storage systems with different reservoir levels and efficiencies. In case the results could not be explained satisfactorily, the software developer was always consulted to provide additional information.

3.4 Thermal Generation Unit Models

The existing database contains a large number of models for a range of power generation technologies using coal, natural gas, blast furnace gas, uranium or a mix of these energy sources as fuel. Thermal generation technologies are modeled by different datasets describing the technical parameters summarised below. For the modeling of combined heat and power (CHP) units, some additional parameters are defined.

3.4.1 Operational Flexibility

Minimum Uptime and Downtime

Minimum uptimes and downtimes make up the continuous commitment or de-commitment periods due to technical constraints, such as temperature-related limits, but also economical considerations, which are less strict. The technical minimum uptimes and downtimes as laid down in the database must therefore be regarded in close relation with the economical cost and benefits associated with the operational flexibility. Utilities identify fuel cost during start-ups, start-up failure risks and increased wear and tear as the main aspects. An important modeling factor here is whether or not generation units are able to undergo daily start-stop operation. In order to validate the minimum uptimes and downtimes, information of the TSO is used to distinguish the generation units capable of a daily start-stop operation cycle.

Commitment and Despatch Status

The commitment types of the thermal generation units are must-run or economical operation. Must-run units may generate at any operating point between minimum and maximum power (despatch based on economics) but may not be de-committed. Therefore, must-run units are only out of service due to planned or forced outages. As with minimum uptimes and downtimes, a 'must-run' status of a unit generally specifies a physical constraint, whereas the operation of the generation units is in fact dictated by economical considerations.

The generation units not having a must-run status are committed and despatched based solely on minimisation of total operating cost. This also applies for pumped storage, reservoir hydro and wind power. It can be noted that, since wind power has very low cost, the wind resource is the first to be despatched as soon as all must-run units have been incorporated. Pumped storage, hydro power and wind power have a different commitment and despatch status and are separately taken into account in the optimisation of UC–ED.

Ramp Rate

Ramp rates specify the maximum rate of change [MW/h] of a generation unit's power output. At the start of this research, the generation unit database of TenneT TSO did not comprise ramp rates. The time resolution used for simulation studies thus far was one hour and it was implicitly assumed that units were capable of ramping through their entire operational range within one simulation time-step. When using a 15 min. time step however, this assumption may no longer be valid. Since there are no formal requirements regarding conventional generation unit ramp rates, an estimation had to be made.

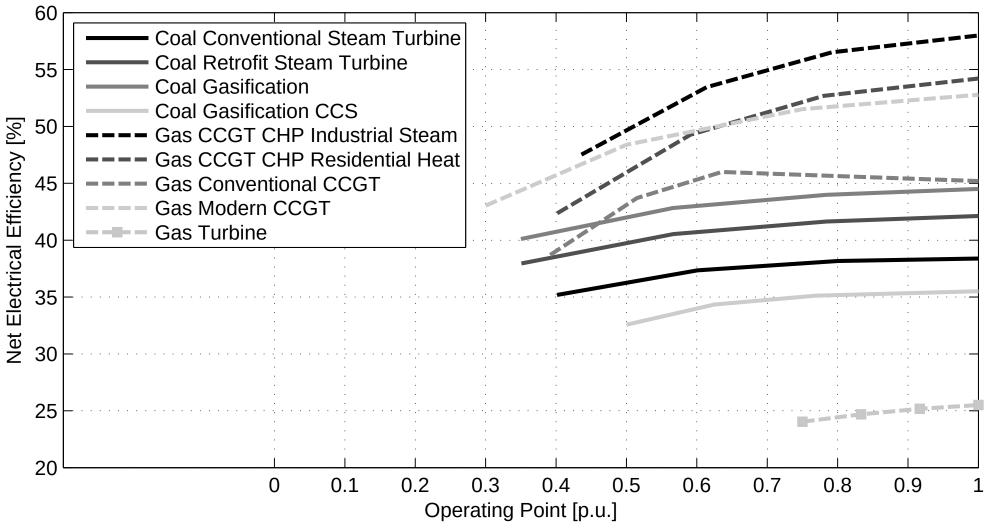

Figure 3.4: Net electrical efficiency curves of fossil generation technologies (illustration).

The technical control possibilities for Dutch generation units have first been assessed on the basis of expert interviews with Dutch utilities. It is found that generation units generally do not ramp up or down at their maximum technical ramp rate but follow a ramp rate set by the operator. A rule of thumb that can be adopted for this is that only 50% of the maximum ramp rate is actually used by utilities [37]. In addition to the expert interviews, the operational requirements formerly applied by SEP [153] are studied as well. These requirements were in force at the time that most of the existing units were built and specified ramp rate requirements ranging from 1.5–3.0% of installed capacity per min. In this research a value of 1.5% per minute is chosen for most units, which is a conservative estimate of the actual technical possibilities of the power generating system in the Netherlands.

Operating Reserves

In this research, all large thermal generation units ($\geq$ 60 MW) are assigned with a contribution to operating reserves, expressed as a percentage of their nominal power. In case these generation units are committed, their despatch is limited by this reserve contribution.

3.4.2 Unit Operating Cost

The operating cost of generation units include fixed and variable operating cost such as start-up, fuel and emission cost. A time dependent formulation of the start-up cost S of the kind

$$S = A + F * (B + C * (1 - e^{DT/T})) \tag{3.1}$$

is available in PowrSym3, where A, B, C and T are constants representing the fixed cost per start [€], the fixed fuel amount per start [GJ], the downtime dependent fuel consumption [GJ] and the time since shutdown [h], respectively, DT is the downtime [h] and F is the fuel

Generation Technology	Fuel	Heat Value GJ/ton	CO_2 ton/MWh	NO_x kg/MWh	SO_2 kg/MWh
Nuclear	U	$5{\cdot}10^5$	0	0	0
Conventional Steam Turbine	Coal	26.3	0.88	1.39	0.70
Retrofit Steam Turbine	Coal	26.3	0.80	1.27	0.64
Gasification Steam Turbine	Coal	26.3	0.76	1.20	0.60
Gasification ST CCS	Coal	26.3	0.17	1.50	0.76
CCGT CHP Industrial Steam	NG	31.7	0.35	0.28	0
CCGT CHP Residential Heat	NG	31.7	0.37	0.30	0
Conventional CCGT	NG	31.7	0.45	0.36	0
Modern CCGT	NG	31.7	0.38	0.31	0
Gas Turbine	NG	31.7	0.64	0.79	0

U = uranium, NG = natural gas

Table 3.3: Energy content and emissions of fossil generation technologies (illustration for optimal operating point).

cost [€/GJ]. However, no data could be obtained from Dutch utilities for an accurate model of this kind. Therefore, start cost are defined as a fixed cost per start only, for which data were available in the database. These could however not be validated.

The fuel consumption of each generation unit is modeled either using heat rates or by specifically modelling the unit's efficiency. Net heat rate levels for up to five power levels can be defined (i.e. $P_{1..5}, H_{1..5}$) for each unit with P_x [MW] and H_x [GJ/MWh] and P_1 being the minimum power output level. Together, the levels form a monotonically increasing piece-wise linear function (incremental heat rate always increases) describing the units efficiency. In Fig. 3.4, the net electrical efficiencies (i.e. excluding heat production) of different power generation technologies are illustrated. This also shows the technical operational range of the power generation units modeled here.

The use of fossil fuels in power generation units gives emissions, the most important of which are carbon dioxide CO_2, sulphur dioxide SO_2 and nitrogen oxides NO_x. The emissions released into the air are in principle defined by the elements involved in the chemical reactions between air and fuel. This is mostly methane (CH_4) for natural gas, and carbon (C), metal compounds and several other compounds involving hydrogen (H), sulphur (S) and nitrogen (N) for coal. Emission levels of CO_2 and SO_2 are connected only to the fuel composition and the operating efficiency of the unit. For NO_x, the emission levels are also significantly dependent upon a range of factors in the thermodynamic processes in the plant [39].

3.4.3 Emissions

Emission levels are defined in the model as fixed coefficients on a fuel energy content base [ton/GJ]. The database contained already validated emission coefficients for CO_2, SO_2 and NO_x emissions, the latter taking into account the impact of de-NO_x-installations possibly present at some plants, now and in the future. SO_2 emissions for natural gas-fired plants are zero. Starting emissions are not taken into account, but these are generally considered to be small. In Table 3.3, typical emission rates of fossil fuels are presented per technology. It can

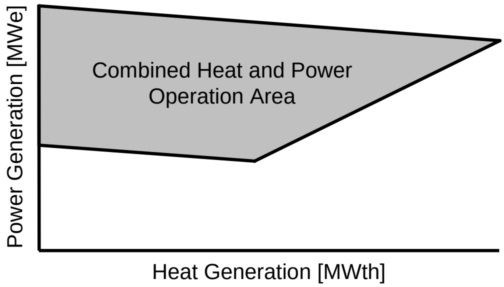

Figure 3.5: Operation area of combined heat and power (CHP) units.

be noted that emission cost [€/ton] are assigned to emissions for each unit. Just like fuel cost, emission cost are an intrinsic part of the unit's operating cost, and thereby an integral part of the optimisation of the UC–ED.

3.4.4 Combined Heat and Power

An important portion of the Dutch generation units produces both steam (high quality heat for industrial applications) or heat (heat for residential areas) and power. The benefits of combined heat and power (CHP) include a very high overall fuel efficiency (electricity plus heat), up to 87% at the best operating point. However, CHP units have additional operating constraints associated with the technical operational area (power P and heat H) and with its operational status due to heat demand.

The operation area of each CHP unit can be described as a set of n linear inequality constraints of the type

$$x_i P + y_i H \geq z_i \tag{3.2}$$

for $i = 1...n$ and has a general form as shown in Fig. 3.5 (x_i and $y_i \leq 0$, $n = 4$), with the optimal operating point in the top-right corner. At high heat production, the flexibility of the unit decreases. The fuel consumption for the heat production by CHP units is included in their overall heat rate levels, which are a part of the optimisation procedure. CHP units are assigned to certain heat areas, which may comprise one or more CHP units, heat boilers and heat buffers. Local demand for heat or steam takes priority in the scheduling of CHP units, with boilers and buffers, if available, standing by for peak-demand situations. For residential heat areas, heat boilers and buffers may offer some operational flexibility for the CHP (i.e. temporal de-commitment based on economics). For industrial heat, CHP has a must-run status considering the steam supply needs. For new CHP units, sets of linear inequality constraints are developed based on the unit's operating efficiency.

3.4.5 Flexible CHP-Units

The operation of combined heat and power units is dominated by the local demand for heat or steam. Introducing possibilities for storing heat allows a de-coupling of the generation of heat and power and thereby brings additional operational flexibility of the CHP units. A higher flexibility of CHP units reduces the amount of must-run capacity in the system and may therefore be an alternative to the development of energy storage for wind power integration. For other systems with a significant share of CHP in the generation mix, such as the Danish, possibilities have been investigated for using heat storage or the use of heat boilers in order to integrate additional amounts of wind energy [104, 111]. In this research, the flexibilisation of CHP-units is considered as a possibility for wind power integration.

A locational scan has been performed with Dutch utilities for the residential heat areas of Amsterdam, the Hague, Leiden, Purmerend, Utrecht, and Rotterdam. It is found that the additional possibilities for a more flexible operation of the CHP-units connected to these areas are scarce since heat boilers and heat buffers are already installed and used there. Heat boilers are also present at all industrial CHP locations but presently operated only in case of an outage of the CHP units. Additional operational flexibility of industrial CHP units would be technically possible but is often considered as unfeasible due to the risks associated with starting and stopping. This consideration is likely to change with the integration of large-scale wind power, since the impacts of wind power on market prices can be significant, especially during periods of low-load. A must-run status of combined CHP, allowing operation only between minimum and maximum output, becomes less profitable with the development of large-scale wind power.

Integration Alternative for Wind Power

For the use of flexible CHP-units as an integration solution for wind power, it is assumed that a total capacity of 1.5 GW of must-run industrial CHP no longer has a must-run status. Instead, these units have an operational flexibility depending on minimum up- and down-times (technical) and start-up cost and efficiency (economical). An efficiency of 95% is assumed for the additional heat boilers introduced for new CHP units. It can be noted that the operation of heat boilers instead of CHP units results in a lower overall energy efficiency. While the revenues for an individual CHP may be low, total cost for generating power and heat separately is still higher. Heat storage is therefore used only as a last resort for the integration of additional wind power, when a trade-off is made between wind power and heat boiler operation versus wasted wind and CHP operation.

3.5 Hydro Power and Energy Storage Models

It is often suggested that wind and hydro power and/or energy storage form a natural combination. Therefore, wind power and (hydro) energy storage are often considered in a back to back configuration [26] or as an hybrid system to provide firm power [87]. Wind power may be used to fill up storage reservoirs during high wind periods, either by pumping up or saving water, and the stored energy may be used for electricity generation during low wind periods. As large-scale wind power will become an important part of a power *system*, however, the cumulative technical capabilities of the rest of this system will determine the technical constraints, if any, for the integration of wind power. Consequently, the technical and economical benefits of energy storage facilities must be assessed on an integral system basis, i.e. by taking into account the whole power system.

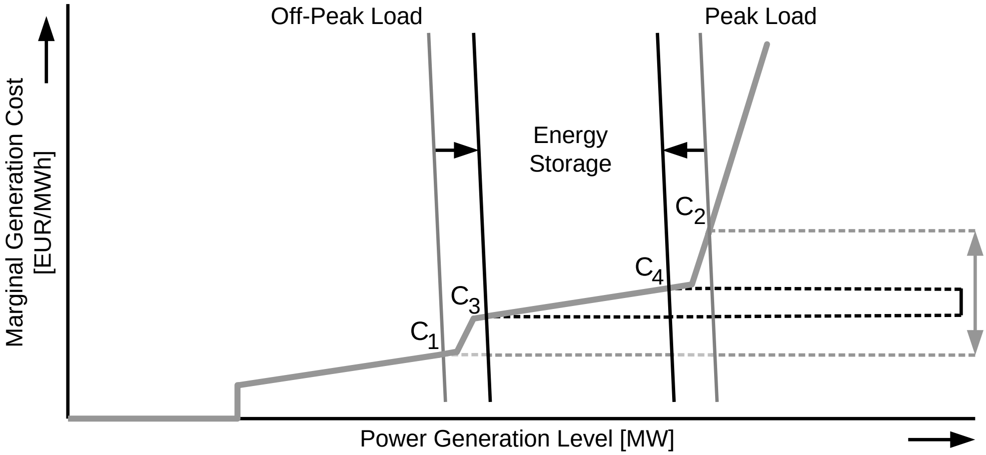

Figure 3.6: Short-term marginal cost curve with peak and off-peak load curves and the impact of energy storage.

3.5.1 Energy Storage and Power System Operation

In principle, all conventional power generation technologies can be regarded as energy storage technologies, in the sense that their primary energy source (coal, gas, oil, water) can be controlled and stored. This means that the fuel of more expensive technologies (i.e. less efficient gas turbines) is only used for power generation during high marginal cost periods (usually peak load), and otherwise saved for later or other use [182]. The difference between energy storage and fuel storage is that energy storage is also capable of taking in power from other technologies for storage. This is, for instance, the main difference between reservoir hydro and pumped hydro. Dependent on the short-term marginal cost (marginal operating cost) in the system, energy storage units are operated either as generating or storing capacity.

The operating principles of energy storage are illustrated in Fig. 3.6. The vertical axis represents the short-term marginal generation cost and the horizontal axis the electricity production level. The electricity demand (load) is a near-vertical line, moving between the peak and off-peak positions shown in the figure. The short-term marginal cost curve (striped grey) shows that the higher the production level, the higher the marginal generation cost is: operational cost is high during peak moments and low during off-peak. On the left, units with a must-run status with corresponding low marginal cost are represented, on the right are the peak load units. Only during peak load, these units are in operation and the marginal generation cost are high (C_2) while off-peak generation cost may be far lower (C_1). The benefits of energy storage in terms of short-term marginal cost benefits are that it levels the costs. In this example, energy storage increases the off-peak cost only slightly from C_1 to C_3 and while it reduces the peak cost much more, from C_2 to C_4. The total benefit of the energy storage unit depends on the marginal cost difference between C_4 and C_3, the turn-around efficiency of the energy storage unit and the energy volumes taken and delivered.

3.5.2 Value-of-Energy Method

In PowrSym3, hydro power and energy storage are optimised by use of the value-of-energy method based on marginal cost. Time-related constraints such as generation cost, operational aspects of thermal generation units and storage reservoir size are major determinants in the despatch of energy storage. The hydro schedule is optimised based on the system marginal cost while taking into account reservoir size limits. In the UC–ED optimisation logic, the system marginal cost is estimated first before energy storage is despatched. The value-of-energy method [9, 62] takes into account all of the aspects mentioned above by placing a monetary value relative to the energy stored in the reservoir. It can be summarised by:

$$V_G = (V_P/\eta) + C_{var} \tag{3.3}$$

$$P_p > 0 \text{ IF } V_P > C_{m,sys} \text{ AND } R \leq R_{max} \tag{3.4}$$

$$P_g > 0 \text{ IF } V_G < C_{m,sys} \text{ AND } R \geq R_{min} \tag{3.5}$$

in which V_P is the pumping and V_G is the generating value of energy [€], η is the net turn-around conversion efficiency, C_{var} represents the variable operation and maintenance cost of the energy storage device [€/MWh], P_p is pumping power [MW], P_g is generating power [MW], $C_{m,sys}$ is the system marginal cost [€/MWh], R is the reservoir level [GWh], R_{min} is the minimum reservoir energy content [GWh] and R_{max} the maximum [GWh]. Thus, energy storage generates if the marginal cost is higher than the generating value of energy and stores if the marginal cost is lower than the pumping value of energy, and remains idle otherwise. PowrSym3 uses load forecasts and wind power predictions for each week to estimate the value of the energy stored in the reservoir during the week (look-ahead logic). In this way, the energy storage reservoir is scheduled such that the total system benefits of energy storage are maximised. The chronology of the method allows the inclusion of low head energy storage devices with the energy conversion efficiency and generation capacity related to reservoir head height.

3.5.3 Hydro Power Models

The absence of combustion processes, fossil fuels or emissions makes it easier to model hydro power units. Three different types of hydro units can be identified: run-of-river hydro, reservoir hydro and pumped hydro. The latter can be modeled such that it represents different energy storage technologies, as is done here.

Run-of-River Hydro

Run-of-river hydro comprises hydro power units with a generating capacity depending on the availability of the primary energy source, water. In case water is available, the unit must produce power or the water must be spilled, resulting in an opportunity loss. Run-of-river hydro usually involves smaller generation units located in water streams. Run-of-river models include specifications for minimum output level [MW], maximum output level and the unit's water inflow. The water inflow is defined as a constant inflow of gross energy on a weekly or an hourly basis and is specified in the input data file.

Reservoir Hydro

Reservoir hydro consists of a unit connected to a hydro reservoir, allowing a de-coupling of water inflow and electricity generation. The reservoir size [GWh] and losses [MWh/h] are defined additional to the minimum and maximum output levels [MWh] and the reservoir inflow, which is modeled as net energy [GWh/week] available for despatch. The minimum power level of the reservoir hydro is used to represent run-of-river elements of this type of hydro power or as an alternative to the explicit modeling of run-of-river hydro units. The operation of reservoir hydro is optimised on a weekly basis (minimum system cost objective).

Pumped Hydro Model

Pumped hydro is capable of storing energy by converting electricity into potential energy. Pumped hydro is modeled as a reservoir hydro unit with a pumping facility between two reservoirs. Using the pumps for storing energy into the upper reservoir increases the head level H_{res} [m] by

$$H_{res} = \sqrt{(R+B)/A} \tag{3.6}$$

where R is the reservoir's energy content [GWh] and A [GWh/m^2] and B [GWh] are constants depending on the physical size of the reservoir. The head level is important especially for pumped hydro units with a small height difference between the reservoirs, since conversion efficiency is partly dependent on the head level in this case. Pumped hydro operation includes the constraint that R must be the same at the beginning and at the end of each week. A ramp rate may be included in the model in order to take into account any technical limitations to the operational flexibility or by setting the minimum time needed for changing from pump to generator operation, if applicable.

It can be noted that the annual optimisation of hydro power, taking into account precipitation forecasts and cascades, is a very complex optimisation problem. At present, PowrSym3 only optimises hydro power operation on a weekly basis using a specified energy inflow. No attempts have been made here to optimise the yearly distribution of weekly available hydro energy.

3.5.4 Energy Storage Alternatives

The pumped hydro model introduced before is applied to modeling different energy storage alternatives, the details of which are presented below. The alternatives include surface pumped accumulation energy storage (PAC), underground PAC (UPAC) and compressed air energy storage (CAES). Furthermore, dedicated interconnection capacity to a hydro-dominated system (NN2) is investigated, since hydro power units elsewhere may provide an alternative for developing such capacity in the Netherlands.

Pumped Accumulation Energy Storage (PAC)

Pumped accumulation storage is modeled based on data and simulation results from earlier case-studies into large-scale surface PAC possibilities in the Netherlands [33, 135]. The design of the PAC applied here is based on the most recent study [168] and consists of two

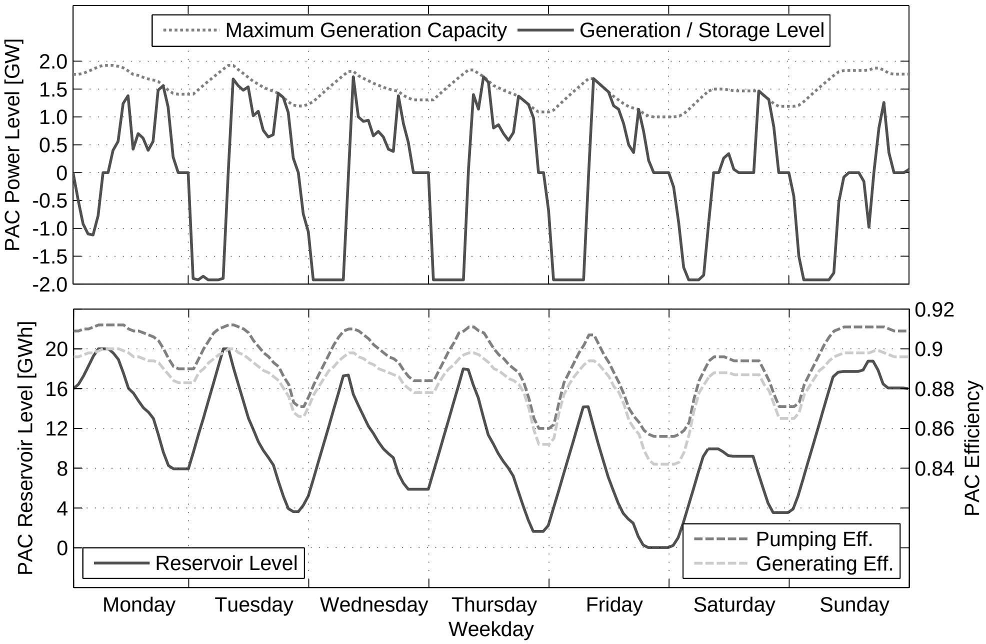

Figure 3.7: Illustrative example of weekly despatch and reservoir level for the PAC.

large reservoirs with a variable head level of 42 to 31 m connected via hydro turbines. Due to the relatively small height difference between both reservoirs, the generating efficiency varies with the head level (pumping efficiency is assumed to be fixed). The relationship between head level and generating efficiency is modeled as a six-point piece-wise linear curve similar to [135], but using a turn-around efficiency varying between 44.9 and 76.5% [168]. The maximum generating capacity [MW] varies linearly with the head height, pumping capacity [MW] is modeled as independent of the reservoir level. Additional technical parameters of the PAC can be found in Table 3.4.

As an example of the relationship between operating efficiencies and reservoir level, Fig. 3.7 shows the despatch of the PAC for one simulated week. The upper graph clearly shows a day-night despatch pattern, storing cheap off-peak electricity (power < 0) and generating electricity during the day. The lower figure shows the reservoir level of PAC during the same week: despatch on a weekly basis results in an 'empty' reservoir on the Friday night, to be filled again using low marginal cost during the weekend. The relationship between generating efficiency, maximum generation level and reservoir head level is clearly visible.

Underground Pumped Accumulation Storage (UPAC)

Underground pumped accumulation storage is modeled similarly to PAC, but with a fixed conversion efficiency [167]. UPAC comprises a surface reservoir and underground a generating and pumping facility and lower reservoir, providing a large, fixed height difference

		PAC	UPAC	CAES	NN2
Generating Capacity	GW	1.3–1.7	1.4	1.5	1.4
Storing Capacity	GW	1.7	1.4	1.5	1.4
Number of Turbines		12	7	5	n.a.
Minimum Generation	MW	n.a.	n.a.	100	n.a.
Ramp Rate	GW/h	13.6	11.2	3.0	2.8
Reservoir Size	GWh	20	16	20	>>
Turn-Around Efficiency	%	45–77	79	181	90
Planned Maintenance Outage Rate	%	2	2	6	2
Forced Outage Rate	%	2	2	4	0
Var. Operating Cost	€/MWh	0.6	0.6	3.5	0
Starting Cost	k€	0	0	180	0

Table 3.4: Technical parameters for the energy storage alternatives.

between the water reservoirs. This results in a fixed turn-around efficiency of 79% [168] and a generation capacity independent of head level. Additional technical parameters of the UPAC can be found in Table 3.4.

Compressed Air Energy Storage (CAES)

CAES effectively is a combined cycle gas turbine (CCGT) with an electrical compressor acting as storage load. Air is compressed into an underground cavern by operating the compressor during periods of low marginal cost and the compressed air is expanded and used for power generation in a CCGT during peak hours. CAES has been modeled in a similar way as the UPAC, but with a round-trip electrical efficiency of 181% and a consumption of natural gas of 4.1 GJ/MWh [168]. This comes down to a total efficiency – (natural gas + compressor energy) / electricity generation – of 60%, which is the best practice for a modern CCGT.

Interconnection to a Hydro-Based System (NN2)

This storage alternative comprises a dedicated interconnection capacity to a hydro-based power system, thereby allowing the use of existing hydro-reservoirs in that system for energy storage. In particular, power may be exported during low marginal cost periods and used in the hydro-based system, thereby storing or saving the energy in the hydro reservoir. This energy can then be imported again to the Netherlands during periods of high marginal cost. This storage option, called NN2, is modeled by a large reservoir hydro unit with two 700 MW interconnectors to it, representing possible additional interconnection capacity from the Netherlands to Norway in this research. Modeling this alternative as a reservoir storage ensures that the Dutch system maintains its annual energy balance during a simulation.

3.6 International Exchange

3.6.1 Areas and Interconnectors

In order to simulate the Netherlands' power system as part of the UCTE-interconnection, models for neighbouring areas and interconnections have been developed and included. Areas are defined by an area name and number, to which generation unit models, load time-series and reserves are assigned. In this research, the Netherlands (NL) is assumed to be a central area with interconnections to Belgium (B), France (F), Germany (D), Norway (NOR) and Great Britain (GB). Interconnectors between the areas are modeled as links, with each link being defined for one direction specifically. An interconnection therefore consists of two separate links, each with a transmission capacity and a loss percentage. Link capacity is fixed for individual weeks and can be adjusted to take into account scheduled maintenance, link losses are assumed to be zero for synchronous interconnectors. Interconnection capacities used here are based on existing interconnection capacities between countries and additional capacity foreseen by the TSO [164].

3.6.2 Possibilities for International Exchange

Inter-area exchanges can be simulated as part of overall system operating cost optimisation under the implicit assumption that all feasible transactions are made. This means the system is optimised for international exchanges up until the moment of operation, taking into account the best available wind power forecast. In reality, however, international markets are commonly closed day-ahead or earlier. For the simulation of day-ahead or other gate closure times ahead of operation, a methodology has been developed to settle international exchange schedules at the different periods before real time. For the settlement of international exchange at gate closure, the best wind power forecast available at gate closure is used. Three gate-closure times are considered: day-ahead, 3 h. ahead and 1 h. ahead. International exchange is scheduled as part of the UC–ED such that all feasible transactions are made, under the assumption that the future wind power output is equal to the best wind power forecast available at gate closure. After gate closure, optimisation of the UC–ED continues within each area until real time, while keeping international exchange levels as settled at gate closure.

The methodology consists of the following steps:

1) Selection of the relevant wind power forecast data from the wind power forecast matrix
2) Creation of a new wind power time series consisting of the selected forecast data
3) First simulation of the UC–ED and calculation of international exchange, with the new wind power time series as input
4) Adapting the original area load files with the international exchange levels as settled in the first simulation run
5) Second simulation of the UC–ED, with all link capacities between areas set to zero, using the actual wind power as input

Taking into account the structure of the wind power forecast matrix, the selected data for a 12–36 h. ahead forecast comprise 24 forecast records for each time step. These are

$$\begin{bmatrix} F_{12+1,\ 48+1} & F_{12+1,\ 48+2} & \cdots & F_{12+1,\ 48+96} \\ F_{36+1,\ 48+1} & F_{36+1,\ 48+2} & \cdots & F_{36+1,\ 48+96} \\ \cdots & \cdots & \cdots & \cdots \\ F_{8700+1,\ 48+1} & F_{8700+1,\ 48+2} & \cdots & F_{8700+1,\ 48+96} \end{bmatrix}$$

resulting in a 364*96 matrix. Similary, the data selected for a 3 h. ahead forecast give a 2912*12 matrix. These data are rearranged and used as the wind power input for the first simulation of the UC–ED. The inter-area exchanges calculated by the UC–ED are exported and saved. For the second simulation run, the scheduled international exchange is matched with the load input file of each area for each 15-min. time-step. Then, a second simulation run is done using the newly created area load files as inputs and assuming no international exchange. Thus, scheduled inter-area exchanges are incorporated by the new load files and cannot be changed after that. System optimisation inside each area continues after international market closure up until the hour of operation.

For the market design with 1 h. ahead gate closure, it is assumed that no wind power forecast errors are present. For this market gate closure, a single simulation run is performed using wind power data as input and assuming that international exchange is always possible. In order to specifically consider wind power in the Dutch power system, it is assumed that wind power in Germany can be predicted very well i.e. there are no wind power forecast errors present at market closure, regardless of the international market gate-closure.

3.7 Summary and Conclusions

In this chapter, the way of optimising unit commitment and economical despatch (UC–ED) in the multi-area, multi-fuel, chronological production costing simulation model PowrSym3 has been presented. The simulation model and database has been used for years by the former Dutch utility SEP and continues to be updated by TenneT TSO. The tool allows for a practical, result-oriented approach of this research. The simulation model and database have been discussed and extended to include models for wind power, ramp rates of conventional generation units, interconnections to neighbouring power systems and energy storage. Furthermore, a methodology is developed for the simulation of the impact of market gate closure times. The database records have been organised into separate classes for the creation of large numbers of internally consistent simulation scenarios. The contributions made to the development of the database of PowrSym3 and to the simulation tool itself make it an up-to-date and highly useful tool for (international) system studies. The tool is especially suited for the investigation of power system operation with large-scale wind power, the consequences of international markets and for evaluating integration solutions for wind power.

CHAPTER 4

Impacts of Wind Power on Unit Commitment and Economic Despatch

4.1 Introduction

In Chapter 3, an existing unit commitment and economic despatch (UC–ED) tool has been presented and extended to include models for wind power, interconnections to neighbouring power systems, and energy storage. In this chapter, a representative model of the Netherlands' and the North-West Europe's generation systems and the interconnections between the different countries is developed. This model is used for a range of system simulations focused on large-scale wind power integration, comprising technical, economic and environmental aspects. The impacts of wind power on system operation is assessed and different solutions for wind power integration, including energy storage, are addressed. From these simulations, 15-min. operational set-points for Dutch generation units can be obtained to be used as input for the dynamic simulations to be performed in Chapter 6.

The chapter is organised as follows. First, the different integration aspects of large-scale wind power is revealed. Simulation parameters are identified to assess the technical, economic and environmental aspects of integrating of large-scale wind power into the Dutch power system. Then, the system to be simulated is specified in detail, comprising load, generation units, and wind power. Representative models of neighbouring countries are included. Transmission capacities are considered between different countries. Then, an overview is presented of all system simulations and the simulation set-up. Different simulations are performed for several wind power penetration levels, taking into account the possibilities of international markets, examining the consequences of forecast accuracy and considering different integration solutions for wind power.

4.2 Simulation Parameters

Since this research is specifically focused on the technical integration of wind power in electrical power systems, different technical limits for the system integration of wind power is identified first. Relevant simulation parameters is identified in order to quantify these limits, if any. After this, the economic and environmental impacts of wind power on power system operation are discussed and simulation parameters for the assessment of these are also identified.

4.2.1 Technical Limits

In the simulation of the chronological UC–ED for the power system as a whole including wind power, the following situations may occur that indicate technical limitations for the system integration of large-scale wind power:

- Minimum load problems
- Insufficient upward power reserves
- Insufficient downward power reserves

Minimum Load Problems

Based on the analysis carried out in Chapter 2 (Fig. 2.12), the first technical limit for wind power integration is expected to concern minimum load problems. This means that technical operating constraints of conventional units (must-run status, minimum power level, minimum up-times) prevent a full integration of available wind power during low load periods. When generation threatens to exceed load, simulation results show increased power exports (if interconnection capacity is available), lower output of base-load generation units and ultimately a spill of the available wind energy. The use of heat boilers is also researched since the use of these could allow a temporary shut-down of combined heat and power (CHP) units.

Insufficient Reserves

As was shown in Chapter 2, Fig. 2.13, significantly larger amounts of power reserves are required to balance wind power variations on a 15-min. time scale on top of the existing load variations. Based on Fig. 2.13, it can be expected that situations with insufficient upward and downward power reserves may occur but only during a limited number of hours (≤ 100) during the year. Furthermore, sufficient upward reserves may at times not be available to balance wind power because of technical operating constraints, unscheduled outages, or large wind power forecast errors.

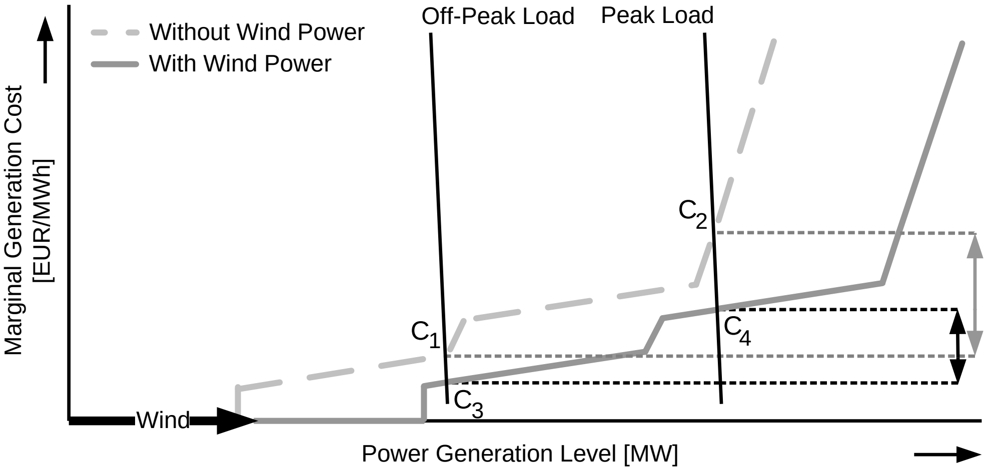

Figure 4.1: Short term marginal cost curve with peak and off-peak load curve and the impact of wind power.

In case of insufficient upward reserves for matching simultaneous load increases and wind power decreases, the simulation results will show violations of spinning reserve requirements and ultimately Energy-Not-Served (ENS). When there is insufficient downward regulation, wind power will be ramped down as a last resort, resulting in a spill of available wind energy. A detailed analysis of the simulation results for the consecutive 15 min. to 15 min. steady-states is necessary to confirm this limit has indeed been reached, since wasted wind energy may also be related to minimum load issues.

Monitoring Variables

The following simulation parameters will be used to monitor the technical integration aspects of wind power:

- Energy-Not-Served (ENS)
- Spinning reserve requirement violations
- Wasted wind energy
- International exchanges

4.2.2 Economic Impacts

Wind power has a number of economic impacts on power system operation, which are all related to the low marginal cost of wind power. Fig. 4.1 is used to illustrate the impacts of wind power on short-term marginal cost in the system. In case wind power is added to an existing system with conventional generation units, wind power shifts the short-term marginal generation cost curve to the right at moments of high wind. As a result, short-term marginal generation cost changes from C_1 to C_3 during off-peak and from C_2 to C_4 during peak moments. Wind power thereby influences the revenues and business cases of other generation technologies, in particular medium-load generation such as CCGT [42] and base-load. This aspect, as well as the optimality (cost, emissions etc.) of the generation mix with increasing wind power penetration levels, falls outside the scope of this thesis, however.

The extent to which wind power indeed lowers the short-term marginal cost curve of the system as a whole, depends on a number of factors. The most important is the technical flexibility of the system wind power is integrated into. Wind power has been reported to reduce spot market prices in some countries with significant wind power penetrations, such as Denmark [132] and Germany [16]. The extent to which this is structural for the whole market depends on the costs of additional power reserves and the decreased operational efficiencies of conventional units, which increase total operating costs. In this research, these aspects are taken into account by the simulation model and are expressed in the total system operating cost.

Monitoring Variables

Based on the above, the economic impacts of wind power are quantified by monitoring

- Total operating cost
- Utilisation factors of conventional generation units

Operating cost [M€/year] will be monitored for the Netherlands specifically. This also applies for the total electricity produced [TWh/y] per conventional generation technology (nuclear, coal, CCGT, CHP, gas turbine, etc.).

4.2.3 Environmental Impacts

The environmental aspects of wind power are an important driving force behind the development of wind power. Electricity generated by wind power replaces fossil-fired conventional generation and thereby saves fuel and CO_2 and other emissions. The simulation model integrally takes into account emission cost [€/ton] during the optimisation of the UC–ED by incorporating these as part of the operation cost (CO_2 content of fuel, operating efficiency). For monitoring the environmental impacts of wind power, emissions (CO_2, but also NO_x and SO_2) will be assessed at the system level for the Netherlands and presented for each conventional generating technology.

4.3 Power System Model Specification

The power system model used here comprises a physical representation of different areas, each representing the generating systems of the Netherlands and its neighbouring areas: Belgium, France, Germany, Norway and Great Britain. Interconnections between these areas are modeled explicitly, transmission constraints within each area are not considered here.

4.3.1 The Netherlands

As was discussed in Chapter 3, at the start of this research, PowrSym3's database contained models for all larger ($\geq$ 60 MW) conventional generation units in the Netherlands. This database is updated to represent the Dutch power system for 2014, the year chosen for investigation. Up to 2014, a large amount of new conventional generating capacity is planned or under development, comprising especially new coal- and gas-fired generation capacity. It is foreseen that some of the older installations will be shut down by that time but market parties have not provided information. The Dutch generating portfolio for 2014 is based on the existing portfolio with the addition of new units specified in [164]. This generation portfolio is assumed for all simulations and no attempts have been made to optimise this portfolio with respect to wind power integration. This is because such an excercise, however useful, is outside the scope of this thesis, which comprises wind power integration from a technical point of view. The interconnection capacity of the Netherlands is based on transmission capacity (net transfer capacities, NTC) forecasts of TenneT TSO for 2014 [164] and ETSO [49].

New Conventional Generation

New coal-fired units (total 5.3 GW) are assumed to have a higher maximum operating efficiency of 44.5% and a efficiency curve shape similar to coal-fired units already present in the database. These new units do not have a must-run status but a minimum up-time and down-time of 16 h. This allows for temporary shut-downs during periods of low prices, for instance during weekends.

New natural gas-fired units (total 3.68 GW) are CCGTs with a maximum operating efficiency of 58% and an efficiency curve shape similar to existing CCGTs. Of the new CCGTs, two units (1.26 GW total) are modeled as industrial CHPs with a must-run status, delivering steam to a separate industrial heat area. The heat load curves of these areas are modeled based on existing curves in the database. The heat areas are equipped with heat boilers assumed only to be used during maintenance of the CHP units, similar to existing CHP unit models.

New Distributed Generation – Excluding Wind Power

New distributed generation (DG) capacity in the Netherlands mostly involves installations, i.e. gas engines, in Dutch greenhouses. These CHP units produce electricity, heat and CO_2 for the greenhouses, with heat boilers as back-up and heat buffers for several days of storage. Due to the availability of a full heat back-up, the generation units are operated against spot market prices and have a very high operational flexibility. A total capacity of 3.0 GW of gas engines have been modeled, with maximum electrical efficiency of 40%, no minimum up-time or down-time and a 10% unavailability. Ramp rates of these DG units are estimated to allow a ramp from minimum to maximum output within 15 min.

Other, existing DG, is modeled as non-despatchable capacity (3.4 GW) and aggregated into a fixed schedule, simulated as must-take power on the basis of natural gas-fired generation. This capacity represents non-despatchable industrial units, waste incineration, and other small DG units. The output of this DG is assumed to be 50% constant and 50% variable with system load and has an efficiency of 19%.

Wind Power

For the Netherlands, a one year data series of 15 min. wind power data for seven wind power penetration levels have been developed in Chapter 2 for respectively 0 GW, 2 GW (225 MW offshore), 4 GW (1 GW offshore), 6 GW (2 GW offshore), 8 GW (4 GW offshore), 10 GW (6 GW offshore) and 12 GW (8 GW offshore). It is assumed that wind power does not replace any conventional capacity. In reality, wind power has a capacity credit [41, 176] and will lead to changes in the total installed generation capacity and the generation mix. These aspects fall outside the scope of this thesis.

4.3.2 Neighbouring Areas

Areas and Interconnectors

In this research, the Netherlands (NL) is assumed to be a central area with interconnections to Belgium (B), France (F), Germany (D), and Great Britain (GB), and Norway (NOR) to a very limited extent. Each country is represented as a single area comprising generation and load, with interconnections to neighbouring areas based on [49, 164]. Only cross-border transmission capacities between countries are taken into account. The power system model with all areas and interconnectors is shown in Fig. 4.2, representing the Netherlands as part of the West European interconnected system. The NODE area (grey) is an empty area used to incorporate the transmission capacity limits foreseen by TenneT TSO for 2014 for the Netherlands with Belgium and Germany. Apart from the separate interconnection capacities which exist between the Netherlands and Belgium (2300 MW) and Germany (5400 MW), a net export/import transmission capacity maximum of 5650 MW is applied between the Netherlands and these countries together (NTC defined by TenneT TSO).

The transmission capacities NL–NOR (NorNed), NL–GB (BritNed) and F–GB (Cross-Channel) are high voltage direct current (DC) sub-marine interconnectors, for which an availability of 98% is assumed, other interconnections have an availability of 100%. Transmission losses are assumed to be 5% of the transmitted power for NorNed, and 4% for BritNed and Cross-Channel.

Area Load

Load data for the areas outside the Netherlands for the year 2014 are developed using UCTE load data for the relevant countries for the year 2007 [171]. This assures that correlations among momentary loads in all countries are automatically taken into account. The load data are processed similarly to the Dutch load data using annual growth rates up until 2014 based on [170, 166]. The growth rates for load in 2014 relative to 2007 are 1.08, 1.08, 1.03 and 1.10 for Belgium, France, Germany and Great Britain, respectively.

Fossil-Fired Generation

Models for conventional generation units in the neighbouring areas of the Netherlands were developed based on installed capacity estimates made in [124, 170]. Generating technology efficiencies and other technical factors were estimated based on an extensive generation unit database made available by TenneT TSO and using the existing models for the Dutch units in the PowrSym3 database. Each generation technology type outside the Netherlands is modeled as an aggregation of units with identical characteristics, with a total generating capacity equaling the capacity foreseen to be installed in 2014.

The most important technical parameters for the fossil-fired generation units are summarised for each technology in Table 4.1, with MR = must-run and EC = economic operation. Nuclear generation units in Belgium, Germany and Great Britain are modeled as having

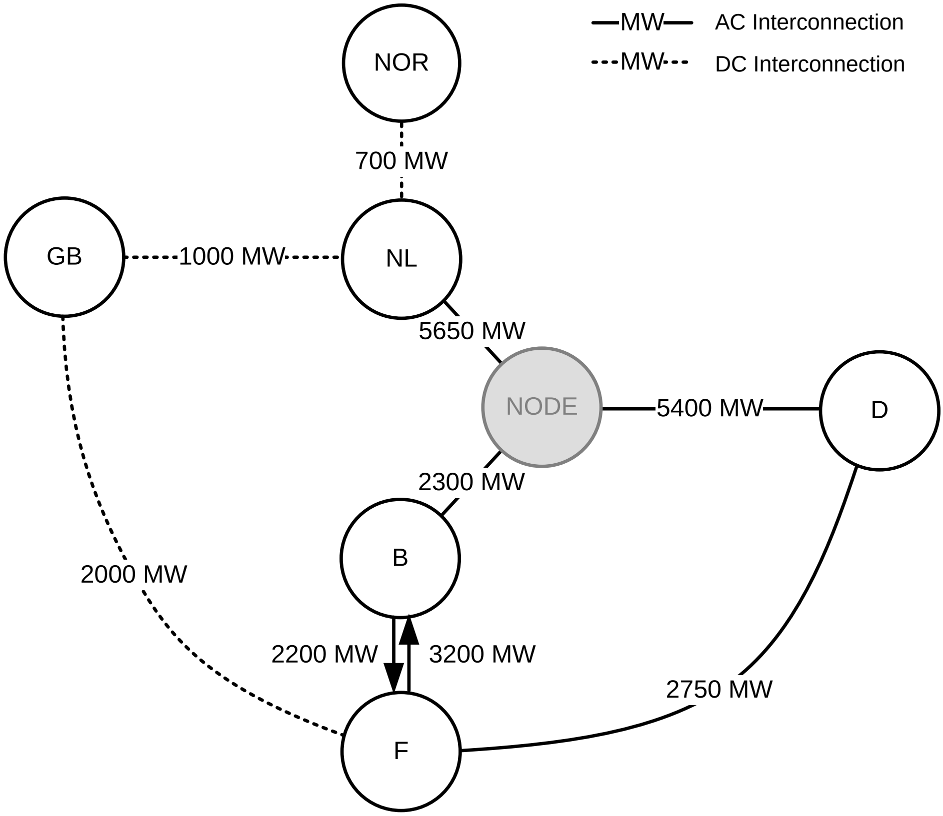

Figure 4.2: Areas and interconnections included in the simulation model.

a technical full-load must-run operational status and no ramp rate. French nuclear units have only a must-run status, which allows part-load operation during moments of low load.

Hydro Power and Pumped Hydro

Total annually available hydro energy in Germany, France and Great Britain are estimated based on yearly statistics from [50]. Since PowrSym3 optimises the UC–ED on a weekly basis, an annual optimisation of hydro energy per week must be done first. For this research, it is assumed that reservoir hydro is operated such that the same amount of energy is available for each week. The UC–ED optimises the hourly distribution of this weekly energy during the week itself. Hydro power has a very high operational flexibility: ramp rates are assumed to be sufficient to allow a full ramp between start and maximum output within 15 min.

Pumped hydro units in Germany, France and Great Britain are modeled with a similar flexibility as hydro power, but without a weekly energy inflow. The UC–ED of pumped hydro in each area is optimised on a weekly basis based on temporal differences in marginal cost in that area. The generating and pumping efficiency are estimated at 90% each. The average

Parameter	Nuclear	Coal	Lignite	CCGT	Oil	GT
Commitment	MR	MR	MR	EC	EC	EC
Despatch	MR / EC	EC	EC	EC	EC	EC
Min. Downtime [h.]	n.a.	n.a.	n.a.	6	4	4
Min. Uptime [h.]	n.a.	n.a.	n.a.	4	4	2
Min. Power Level [%/P_n]	100 / 50	50	50	50	60	60
Ramp Rate [%/P_n/h.]	n.a. / 25	40	40	80	80	160
Max. eff. [%]	n.a.	39	39	51	37	26
Unavailability [%]	20	15	18	14	18	14

MR = Must Run, EC = Economic Optimisation

Table 4.1: Fossil-fired generation models in neighbouring areas.

unavailability of pumped hydro is determined at 2%, due to the absence of thermodynamic processes in these units.

Wind Power

Wind power in neighbouring areas is only taken into account for Germany. This is because Germany already has a large installed capacity of wind power, which is foreseen to increase significantly [51, 170]. Furthermore, wind power outputs in the Netherlands and Germany are strongly correlated and a large interconnection capacity is available between these countries. In a North-West European market, the presence of large-scale wind power in Germany could present additional barriers for wind power in the Netherlands.

In order to correctly incorporate the correlation between wind power in the Netherlands and Germany, 15 min. average wind power data for the German areas EON-Netz, RWE and Vattenfall were obtained from the respective TSOs for the same period as the Dutch meteorological data (June 1, 2004 to May 31st, 2005). Also, day-ahead forecast data were obtained for this period. Wind power and wind power prediction data are scaled to represent the 32 GW of installed capacity foreseen for 2014 (Appendix C). It is found that the correlation between the 15 min. aggregated average wind power data sets for the Netherlands and Germany is 0.73. Thus, interconnection capacity to Germany may not be (fully) available for exports during moments of low load and high wind power, resulting in wasted wind energy. Wind power in Germany is modeled such that it is integrated with a higher priority than Dutch wind power in order to guarantee that wind power in the Netherlands is not integrated into the system at the expense of German wind power.

4.3.3 Power System Overview

Installed generating capacities per technology are based on forecasts made for the relevant countries for 2014 in [124, 164, 170]. The installed capacities are presented per technology and per country in Table 4.2.

An important assumption is that Norway is represented as a pumped hydro unit without inflow, with a generating/pumping capacity equaling the interconnection capacity between the Netherlands and Norway. The hydro power system of Norway has a high operational

Technology	Netherlands [GW]	Belgium [GW]	France [GW]	Germany [GW]	GB [GW]	*Norway [GW]*
Nuclear	0.4	5.9	64.9	14.1	11.9	–
Coal	9.5	2.6	6.0	32.0	30.4	–
Lignite	–	–	–	18.9	–	–
CCGT CHP Ind.	4.0	–	–	–	–	–
BF Gas Ind.	0.9	–	–	–	–	–
CCGT CHP Res.	1.5	–	–	–	–	–
CCGT	7.1	5.0	4.0	15.1	24.4	–
Gas Turbine	0.6	1.5	1.1	4.0	7.0	–
Oil	–	–	9.2	5.3	8.4	–
Reservoir Hydro	–	–	13.6	3.7	1.8	–
Pumped Hydro	–	1.3	4.2	5.5	3.0	*0.7*
RoR Hydro	–	0.1	7.9	–	–	–
Other	6.3	0.4	–	8.2	–	–
Total	30.4	16.8	110.9	106.8	86.9	*0.7*
Wind Power	10.0	–	–	32.0	–	–
Maximum Load	21.0	15.2	80.5	87.1	65.5	–
Demand [TWh/y]	126	97	518	550	367	–

Table 4.2: Generation technologies per country in 2014.

flexibility and is assumed to be available for imports from and exports to the Netherlands at all times. In the simulations performed in this research, the exchange is dependent only on the differences between marginal cost in the Netherlands and the value of the energy contained in the Norwegian reservoir. This simplified representation of Norway removes the need for a full model of the Scandinavian Nordel system, which is a comprehensive task. It is assumed that this model of Norway is sufficient to allow a first-order estimate of the impacts of interconnection capacity with Norway on wind power integration in the Netherlands: a limited amount of transmission capacity is available to a hydro-dominated system with a large storage capacity. This approach is regarded as sufficient for this research, with its focus on the system integration of wind power rather than the economic benefits of interconnection capacity.

4.4 System Simulations

In the system simulations performed here, the UC–ED is optimised on a central basis: it is assumed that electricity markets are very liquid. The objective function is formulated at the system level i.e. no other transmission constraints are taken into account other than those specified between different areas. The UC–ED is calculated using the equal marginal cost method, in which the objective function is the total cost for heat and power generation, including emission cost. Decremental despatch and de-commitment costs are calculated for all units included in the simulation. The simulation program calculates an optimal maintenance schedule for the simulated year beforehand and determines unscheduled outages using the

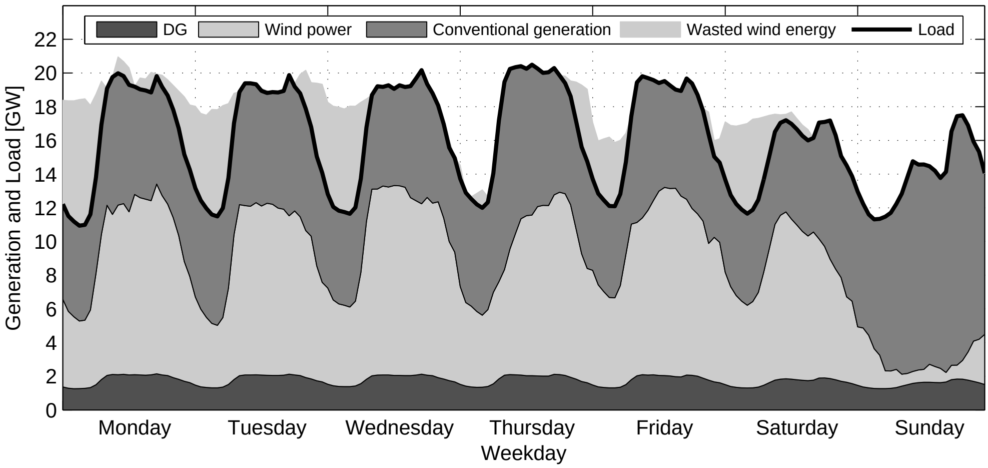

Figure 4.3: Example of a UC–ED for one week in the Netherlands for 12 GW installed wind power capacity and no international exchange.

random Monte Carlo method for all generation units, energy storage units and heat boilers. The commitment and despatch of energy storage and heat boilers is based on the minimisation of the overall operating cost of the system.

As an illustration of the system simulations performed in this research, Fig. 4.3 provides an overview of the UC–ED in the Netherlands during one week for the scenario with 12 GW wind power. The graph shows generation levels for distributed generation, thermal units, integrated wind power, and the amount of wasted wind energy. Total generation by conventional thermal generation units follows the system load, distributed generation, and wind power. In this particular week, wind power is ramped down at moments of high wind power and low load (all nights, except Sunday when there is little wind power available) to prevent minimum load problems. A good example of the use of thermal generation for balancing the combined variations of load and wind power can be seen on early Sunday morning (thermal generation ramps up and wind power is decreasing).

4.4.1 Base Variants

The base simulation variants consider seven levels for wind power capacity installed in the Netherlands, four designs of international markets and three wind power forecast methods. The base variants will be used to quantify the technical, economic and environmental impacts of wind power. For all base variants, it is assumed that wind power is integrated into the system by taking into account wind power in the optimisation of the UC–ED of conventional generation capacity. In case no international exchange market is available, only the Dutch conventional generation units are used.

Wind Power Levels

All base simulations will be carried out for six wind power penetration levels, as developed in Chapter 2 (2–12 GW), and for a 0 MW wind power variant to be used as a reference.

International Exchange

International exchange is modeled and simulated for four market designs:

- No international exchange
- International market gate closure time day ahead
- International market gate closure time 3 h. ahead
- International market gate closure time 1 h. ahead

The base-case for this research is the Netherlands seen as an isolated power system. International exchange with Belgium, France, Germany, Norway and Great Britain is assumed to be zero at all times. This variant serves as a reference to consider the integration of wind power in the Dutch power system using the technical capacities available in the Netherlands only.

The other market designs all comprise international exchange possibilities between the Netherlands and its neighbours, but using different gate closure times. This means that the imports and exports of the Netherlands are optimised using the wind power forecast available at market gate closure. After market gate closure, the international exchange schedules become fixed and are executed as scheduled. For the day ahead (12–36 h.) ahead market closure, wind power forecast errors are significant (Fig. 2.14). This will result in a sub-optimal scheduling of imports and exports from a wind power integration point of view. Forecast errors will have decreased by about 50% if market gate closure is delayed up to 3 h. ahead of operation, and no forecast errors are present for the market design with near real-time operation (1 h. ahead), which allows an optimal scheduling of international exchange considering wind power.

Wind Power Forecasts

The following wind power forecasts are considered as a base-case variants:

- 0 MW wind power forecast (fuel saver approach [55])
- Best available forecast
- Perfect forecast

For the 0 MW wind power forecast, the UC–ED is optimised without incorporating wind power capacity in the planning stage, although actual wind power output is taken into account in the operational stage. This forecast leads to an over-commitment of conventional generating capacity and serves as a worst-case planning situation. The best available forecast comprises an hourly update of the wind power forecast ('rolling forecast'), based on updated wind power forecasts, and a subsequent recalculation of the UC–ED taking these into account. For a perfect forecast, the actual wind power levels are exactly known in all stages of the UC–ED.

It is important to note that that for all wind power forecasts, the real-time wind power output level is assumed to be exactly known and used as an input for economic despatch in the following hours. Furthermore, it is assumed that UC–ED is continuously optimised up until the hour of operation (1 h. ahead). This re-calculation of the UC–ED is in fact much more frequent that presently applied by Dutch PRPs, who usually do this 2–4 times a day. It can also be noted that the central optimisation of the UC–ED such as applied in this research, does not take into account the behaviour of individual market parties or generation clusters on the electricity market (i.e. fuel contracts, individual reserve power considerations). The availability of a better wind power forecast may be very beneficial for the market operating strategy of traders and lead to significant revenues. Here, only the opportunities of wind power forecasts for the maximisation of the system integration of wind power are considered.

4.4.2 Wind Power Integration Solutions

Technical limits may exist for the system integration of wind power in the Dutch power system. After the determination and quantification of these limits, different alternatives will be explored for overcoming these integration limits. For all simulations, conventional generation units are used for balancing wind power. More flexible base-load generation capacity may provide additional technical space for wind power during low-load, high-wind situations. For this alternative, the commitment status of selected industrial CHP units is changed from must-run to economic. The existing heat boilers could in principle take over the generation of steam for the industrial processes at times when the CHP is shut down to allow a further integration of wind power.

The energy storage alternatives included in this research include surface pumped accumulation energy storage (PAC), underground PAC (UPAC), compressed air energy storage (CAES) and creating additional interconnection capacity between the Netherlands and the hydropower-dominated system of Norway (NN2). Models for these alternatives were developed in Chapter 3. It can be noted that no specific attempt has been made here to optimise the design of the energy storage: the energy storage capacities and reservoir sizes applied in [168] have been adopted here.

4.4.3 Simulations Set-Up

The simulations of the UC–ED are carried out for a future year 2014, with a resolution of 15 minutes, for different installed wind power capacities, wind power forecasts, international market designs and balancing solutions. An optimised unit maintenance schedule is calculated ahead of each simulation and unscheduled outages are introduced using the Random Monte Carlo method for all generation units, energy storage units and heat boilers, for every week. UC–ED are centrally optimised (well functioning electricity markets) in order to achieve minimum operating cost at the system level, while all technical constraints are fulfilled. The UC–ED is calculated using an equal marginal cost method, in which the objective function is the total cost for generating both heat and power. A calculation of unit despatch is performed every 15 minutes using the given load profile and an estimation of the wind power production levels.

Power Reserves

Spinning reserves and fast regulating power are provided by the non-despatched capacity of committed generation units. All coal- and gas-fired generation units in the Netherlands sized 60 MW and above are assigned with a spinning reserve contribution of 1% of its rated

WP	NL	24h.	3h.	1h.	PP	0 MW	CHP	ES
0	BF	BF	BF	BF	NL	NL	NL-BF	NL-BF
2	BF	BF	BF	BF	NL	NL	NL-BF	NL-BF
4	BF	BF	BF	BF	NL	NL	NL-BF	NL-BF
6	BF	BF	BF	BF	NL	NL	NL-BF	NL-BF
8	BF	BF	BF	BF	NL	NL	NL-BF	NL-BF
10	BF	BF	BF	BF	NL	NL	NL-BF	NL-BF
12	BF	BF	BF	BF	NL	NL	NL-BF	NL-BF

WP = wind power, NL = isolated Dutch system, 24h. = 24h. ahead international market gate closure, PP = perfect wind power prediction, 0 MW = zero-MW wind power forecast, CHP = flexible CHP-units, ES = energy storage, comprising PAC, UPAC, CAES and NN2, BF = best available wind power forecast

Table 4.3: Overview of the UC–ED simulations.

power. Furthermore, some capacity must be reserved for regulating power. The needed amounts of reserves to guarantee sufficient capacity for load following is determined during the optimisation of the UC–ED based on load and wind power forecasts. For the Netherlands, a spinning reserve of 1600 MW (twice the largest single generator) is assumed, for the other areas except Norway the reserve requirement is set at 2000 MW.

Fuel and Emission Cost

Fuel and emission costs have been determined based on price forecasts stated in [81] for the year 2015. The prices for coal, lignite, gas, oil, uranium and CO_2 used in this research are 2.00 €/GJ, 1.36 €/GJ, 5.00 €/GJ, 10.50 €/GJ, 1.00 €/GJ and 25.00 €/ton respectively. Emission costs are included in the calculation of the marginal operating cost of each thermal generation unit. The sensitivity of the simulation results to these assumptions are very small regarding technical limits for wind power integration, but are considerable for operating cost and emissions. The simulation results for these two are therefore only a first-order estimate.

Overview

In Table 4.3, an overview is shown of all simulations performed in this research. Simulations are performed for different wind power penetrations (seven WP scenarios), international market designs (NL = no international exchange, 24 h. = international market gate closure at 24 h. ahead, 3 h. = idem at 3 h. ahead, 1 h. = idem at 1 h. ahead) and wind power forecasts (BF = best available/rolling forecast, PP = perfect prediction of wind power, 0 MW = 0 MW wind power forecast). Furthermore, solutions for wind power integration are explored (CHP = flexible CHP units, ES = energy storage, consisting of the alternatives PAC, UPAC, CAES and NN2 (NN2 is only simulated for the 1 h. ahead gate closure market design). A total number of 77 simulations ($7 \cdot (4+2+5)$) are carried out for this research.

4.5 Simulation Results

4.5.1 Technical Limits

Possible technical limits for the integration of wind power are minimum load problems and insufficient upward power reserves or downward regulation reserves for balancing load and wind power variations. The simulation results for all base simulation variants (0–12 GW wind power) do not report ENS nor spinning reserve violations in the Netherlands. This applies for all three different wind power forecast modes (0-MW forecast, best available forecast and perfect prediction). From this result, it can be concluded that sufficient upward power reserves and downward regulation are present at all moments during the year in order to balance the aggregated load and wind power and load variations. This was to be expected since the total generation portfolio is rather large compared to the maximum load. The integration of wind power in the Dutch power system does however result in an increase of heat production by boilers at CHP locations (especially residential), wasting of wind energy (especially during low-load periods), and increased exports to neighbouring countries (idem). This indicates that minimum load problems pose a technical limit for the integration of wind power, which is in line with the observations made in Chapter 2.

The simulation results for wasted wind energy and international exchanges vary considerably between the different international market designs, since they are mutually dependent, and to some extent between the different wind power forecast methods investigated here.

Wasted Wind Energy – International Market Design

In Fig. 4.4, wind energy integrated into the Dutch power system is shown for different wind power penetrations and different market designs. Wasted wind energy becomes significant in the range of 6–8 GW installed wind power capacity for the Dutch power system, in the market design without international exchange. The slight change in steepness of the available wind energy curve at 2 and 6 GW installed capacity is due to increased capacity factor of wind power (offshore vs. onshore). The use of international exchange provides significant additional space for the integration of wind power (middle-grey area is additionally integrated wind energy). The light grey area representing wasted wind in a 1 h. ahead market gate closure is very small and not visible in this figure.

Fig. 4.5 focuses further on a comparison of the amount of wasted wind energy for different market designs. Only wind power forecast errors in the Netherlands are considered here. In case no interconnection capacity is available for balancing purposes, an estimated amount of 6.2 TWh/y or 15% of available wind energy in the Netherlands cannot be integrated into the system. In case international exchanges can be used for exports at high wind power levels, additional wind power can be integrated, with only 0.05 TWh or 0.1% of available wind energy being wasted for the 1 h. ahead market gate closure.

Interestingly, a day-ahead or 3 h. ahead international market gate closure time results in larger amounts of wasted wind power at smaller wind power capacities. This is the result of the methodology applied for the optimisation of international exchange at market gate closure, which is based on the assumption that all feasible international transactions are being made. In case a significant wind power forecast error is present at the moment that these transactions become fixed, scheduled imports may prevent the integration of unpredicted

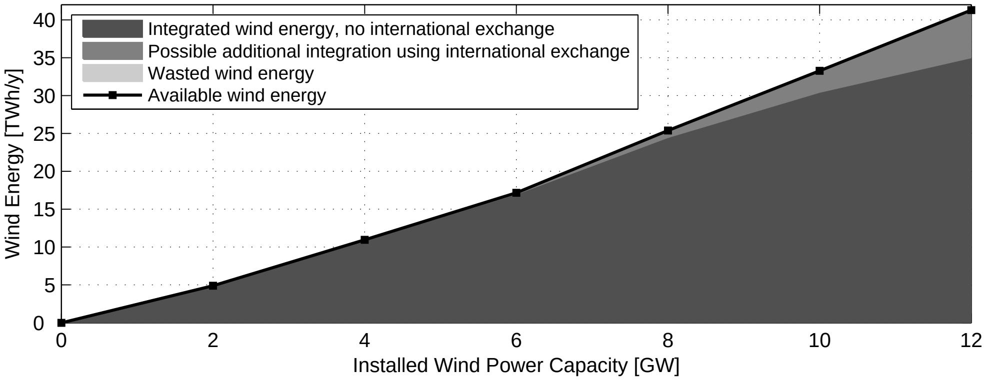

Figure 4.4: Integrated and wasted wind energy in the Netherlands.

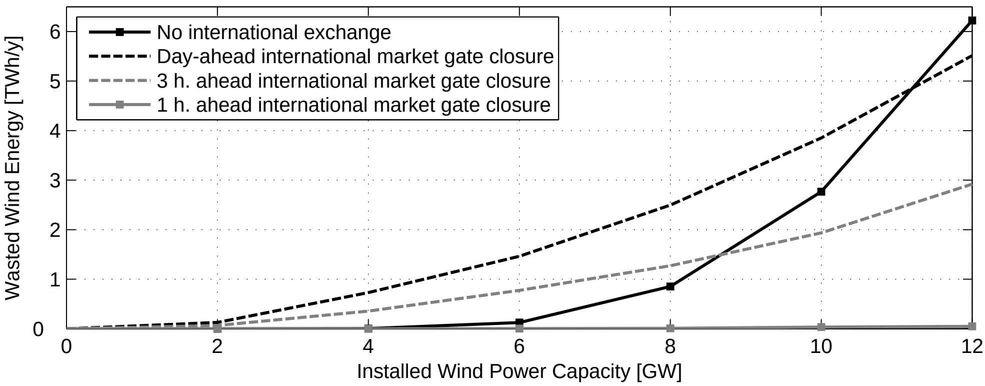

Figure 4.5: Wasted wind energy for different international market designs, best available wind power forecast.

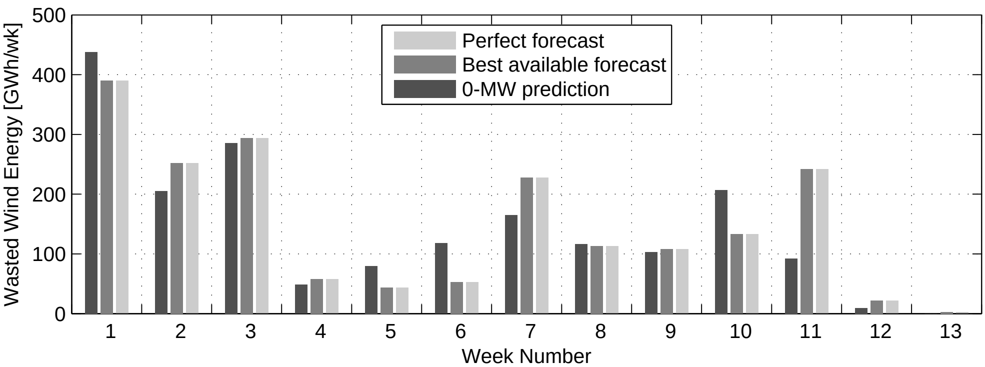

Figure 4.6: Weekly wasted wind energy for different forecast methods, 12 GW wind power, no international exchange.

surpluses of wind power, leading to larger amounts of wasted wind energy. For large wind power penetrations, however, the benefits of international exchange capacity outweigh the disadvantage of forecast errors. Clearly, a more conservative scheduling of international exchanges (imports) will result in less wasted wind energy. This result illustrates the benefits of postponed international market gate closure times for integrating wind power.

In case interconnection capacity is available and the market design allows an adjustment of international exchange up until the moment of operation (1 h. ahead international market gate closure), the potential for additionally integrated wind energy is high. Still, even the most flexible international market design cannot prevent a small amount of wasted wind energy, starting from 8–10 GW installed capacity in the Netherlands (bottom of Fig. 4.5, not visible in Fig. 4.4). The reason for this is that, even though international transmission capacity may be sufficient, this capacity is not always fully available for exports. This applies to Germany in particular. Germany has a significant must-run conventional generation capacity and a large amount of wind power (32 GW in the year 2014) which is highly correlated (0.73) to wind power in the Netherlands. Both factors reduce the possibilities for exports of wind power from the Netherlands, especially during critical periods.

Wasted Wind Energy – Forecast Method

The different types of wind power forecasts only have a minor influence on the amount of wasted wind energy on an annual basis. Fig. 4.6 shows the amount of wasted wind energy for all weeks for 12 GW wind power, with no international exchange possible. Interestingly, some differences are present in the amount of wasted wind between the 0-MW and the best available forecast method. The simulation results show that an over-commitment of conventional generation capacity may be beneficial for wind power integration during some hours of the week. Generally, however, the differences in wasted wind between the 0-MW forecast, the best available wind power forecast and the perfect forecast are small ($<<5\%$ of wasted wind energy). This can be explained by the frequent re-calculation of the UC–ED which is applied to all simulations, which allows the inclusion of the real-time wind power output and of regularly updated wind power forecasts. Since actual wind power levels are accurately known and wind power output generally does not change significantly between 15 min. intervals, the conventional generation units in operation will typically be adequate for the next time-interval as well, explaining the relatively good performance of the 0-MW forecast.

4.5.2 Economic Impacts

Operating Cost

As was illustrated in Fig. 4.1, wind power decreases marginal operating costs in the system. Fig. 4.7 shows the annual savings in operating cost due to wind power, for the Netherlands without international exchange and in case international exchange is possible (1 h. ahead market gate closure time) for the North-West European system as a whole, with the Dutch part as a dotted line. As the figure shows, the operating cost savings by wind power increase with the amount of wind power installed. For the fuel and operating costs assumed here, the overall annual operating cost savings by wind power are estimated to be in the order of 1.5 billion € annually for 12 GW wind power capacity. The slight differences in total cost savings between an isolated Dutch system versus a North-West European system are due to

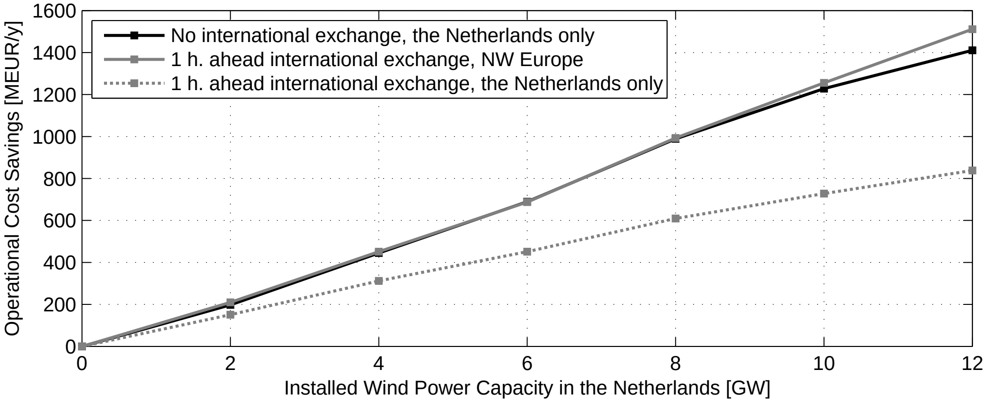

Figure 4.7: Annual operating cost savings by wind power.

a different generation mix that wind power is integrated into. Thus, the base-case with 0 MW wind power is already different with respect to marginal costs. Differences in total cost savings with and without international exchange at high wind power penetrations are due to the wasting of wind in an isolated Dutch system (additional fuel cost and emissions).

In case no international exchange is possible for exports of excess wind power, the relative cost savings gained from wind power start to decrease from 8 GW installed capacity onwards. Limits in the operational flexibility of conventional plants lead to sub-optimal despatch, reduced operating efficiencies and, ultimately, increased wasting of available wind resources. In case the Netherlands is part of an international, North-West European market, the technical integration limits for wind power lay further away. Because more wind power can be integrated in a North-West European system, the operating cost savings are higher than for an isolated Dutch system, where wind power must be wasted. In an international environment, slightly over one half of the total economic benefit of wind power is realised in the Netherlands, the rest is realised in neighbouring areas.

Operating costs are also influenced by wind power forecasts. Savings in operating cost as a result of the use of wind power predictions differ between weeks and are in the order of 0.2% of the total operating cost per year. Application of the best available wind power forecast does however not save operating costs for each operation hour. Over-predictions of wind power may lead to an under-commitment of base-load units: when the wind power falls short compared to the forecast, extra units must be committed at a higher cost. The simulation results show that improvements are possible in the application of wind power forecasts in the tool's optimisation structure. For example, if the tool could choose between the 0-MW and the best available forecast methods throughout every week ('ensemble forecast'), this would result in an additional integration of 1 TWh or 2.4% of available wind energy for 12 GW installed capacity, compared to using the best available forecast only. Summarising, improved wind power forecasts have some benefit for system operation (wasted wind, operating cost) but little influence on the total amount of wasted wind energy. From a technical point of view, a frequent update of the UC–ED using real-time information on wind power together with the application of updated wind power forecasts is sufficient. It can be noted that the

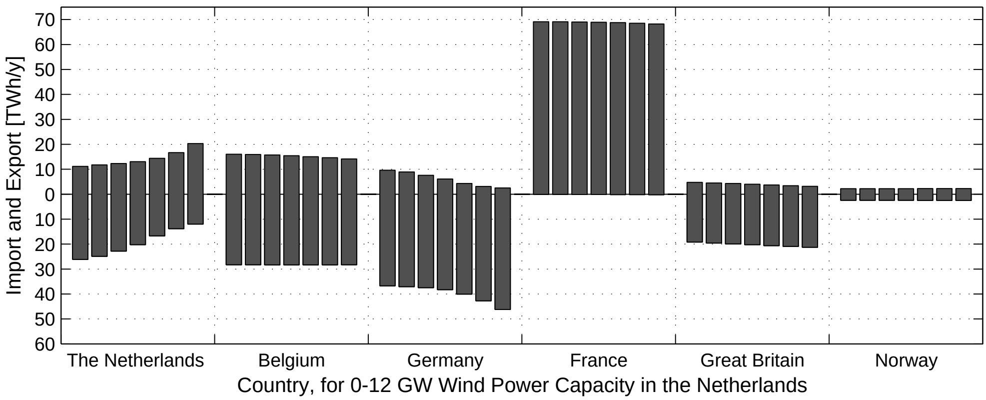

Figure 4.8: International exchange in North-West Europe for 0–12 GW wind power installed capacity in the Netherlands.

benefits of improved wind power forecasts for trading on markets are not considered here. Such benefits may be significant for the individual market parties for the formulation of their market trading strategy [58].

International Exchange

In case international exchange is possible, the integration of wind power in the Netherlands influences in principle the exchanges between all countries. In Fig. 4.8, imports and exports are shown for each country with each bar representing a wind power penetration scenario. Clearly, the Netherlands increases its annual exports and decreases its imports in case more wind power is installed. This influences mainly imports and exports of Germany and Great Britain, and Belgium to a limited extent.

Large interconnection capacities are present between Germany and the Netherlands and Dutch wind power mainly decrease the full-load hours for base-load coal and lignite in Germany, but also some CCGT. Wind power furthermore reduces the exports of base-load coal power from Belgium and to a lesser extent from France during periods of low load (nights and weekends). Germany reduces its imports from France at times of high wind in the Netherlands. Exchanges with Norway stay constant in volume since it is modeled as such, although the moments of exports and imports are increasingly determined by wind power as its installed capacity in the Netherlands increases. These results clearly show the importance of the larger, Germany system for the integration of wind power in the Dutch system.

Generation Output Mix

In Fig.4.9, the change in annual electricity output between different generation technologies is shown for the Netherlands (no international exchange) with increasing wind power capacity. Nuclear, being a full-load must-run technology, is not affected by wind power integration. Wind power does reduce the full-load hour equivalents of coal-fired units, CCGT CHP and CCGT. Importantly, the profits of these units also decrease during the hours that they are in

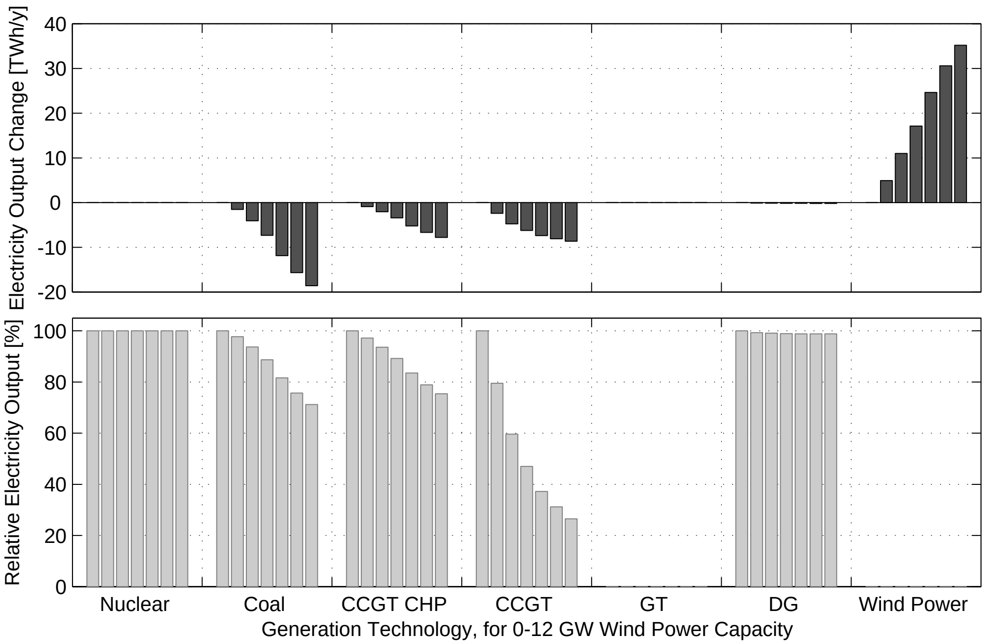

Figure 4.9: Absolute electricity production change and relative output per technology in the Netherlands for different wind power penetration scenarios, no international exchange.

operation, since wind power always replaces the most expensive unit in operation (as far as technically feasible). Because of the large share of coal-fired generation in the Dutch generation park modeled in this research, the electricity generation [TWh/y] of coal is reduced most. Notably, the technical flexibility of coal, CCGT CHP and CCGT does not require additional operating hours of peak-load gas turbines for wind power integration. DG (greenhouse gas engines) decreases its operation hours only very slightly: the must-run part is fixed, and the flexible units produce heat and power during other periods, with the heat being stored.

On a relative scale, the output of CCGT is affected most by the integration of wind power: CCGT operates only during medium- and peak-load hours, during which it is often the marginal technology and therefore the first to be replaced by wind power. Since coal and CCGT CHP have a part-load must-run status, the integration of wind power reduces their output only to a certain extent.

4.5.3 Environmental Impacts

CO_2-Emissions

The simulation results clearly show that wind power leads to a saving of significant amounts of CO_2 emissions. In Fig. 4.10, the annual emission savings are shown for the Netherlands without international exchange, and for the North-West European system as a whole (international exchange is possible in this case), with the Dutch part of that as a dotted line. Emission

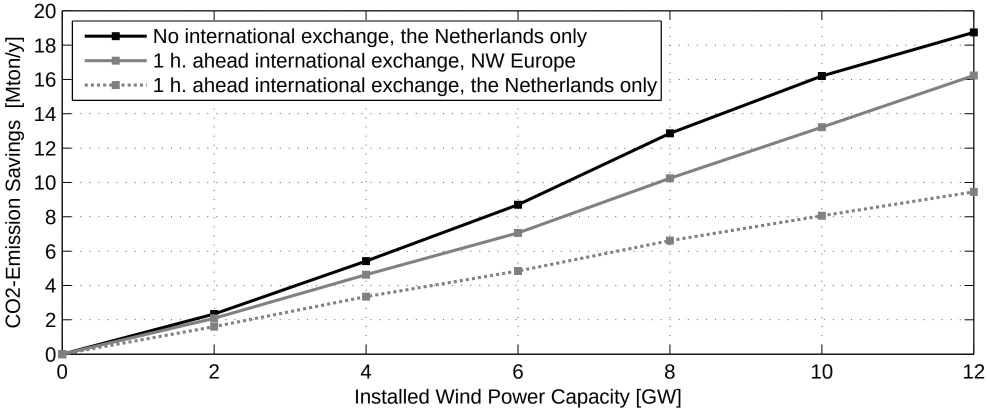

Figure 4.10: CO_2 emission savings by wind power.

savings are estimated to lie around 19 Mton annually for 12 GW wind power, with higher savings for the isolated Dutch system due to the large share of coal in the generation mix. In case international exchange is possible, more expensive, less efficient units (mainly CCGT) have already been pushed out of the market at the 0 MW wind power. Wind power will also replace more expensive CCGT-generation during the day rather than coal-fired units in the isolated Dutch system, resulting in lower emission savings for the cases with international exchange. It can be noted that emission savings also positively impact operating costs, since CO_2 emission savings are part of the total operating cost. The change in steepness of the curves at 2 and 6 GW installed wind power capacity is due to the higher capacity factor of offshore wind power. For the isolated Dutch system, there is a change at 8 GW wind power due to the increasing amounts of wasted wind energy. The results for emission savings for SO_2 and NO_x show similar trends as CO_2. Total annual emissions show an estimated decrease of 11 Mton and 20 kton for SO_2 and NO_x, respectively, for an isolated Dutch system.

4.5.4 Integration Solutions for Wind Power

The integration of wind power in the Dutch power system leads to savings in emissions and operational cost. The technical limit for wind power integration is mainly the minimum-load, leading to increasing amounts of wasted wind energy, while the variability and limited predictability of up to 12 GW wind power can be solved using existing, conventional generation units. In this section, solutions for the integration of wind power in the Dutch power system will be explored. Models for the different solutions were developed in Chapter 3 and consist of pumped accumulation storage (PAC, 1700 MW), underground PAC (UPAC, 1400 MW), compressed air energy storage (CAES, 1500 MW), flexible CHP-units by installing and using heat boilers (CHP, 1500 MW) and an extra interconnection between the Netherlands and Norway (NN2, 1400 MW). It is assumed that energy storage and the additional interconnection capacity to Norway do not replace conventional generation capacity.

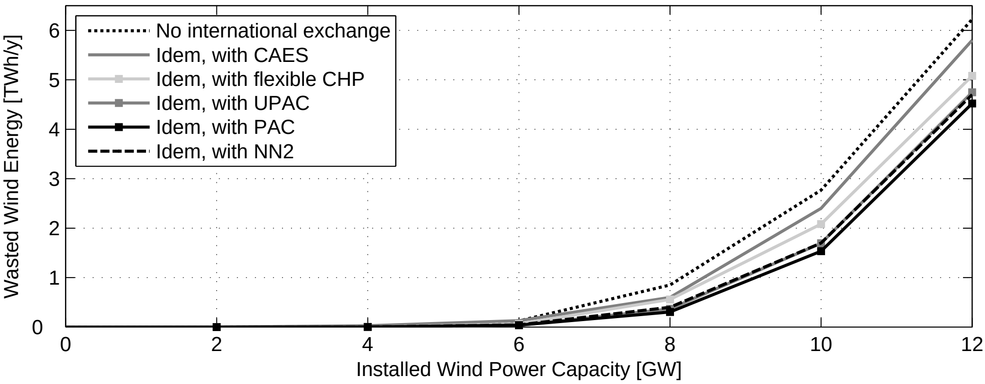

Figure 4.11: Wasted wind with flexible CHP units, energy storage options and extra interconnection to Norway, no international exchange.

Wasted Wind Energy

In Fig. 4.11, the amount of wasted wind energy for all five options can be observed. Clearly, all options considered here reduce the amount of wind wasted in the Netherlands due to minimum-load problems. Energy storage and heat boilers increase the flexibility of the Dutch system and thereby enable larger amounts of wind energy to be integrated. An extra interconnection to Norway creates a virtual energy storage with the same effects. When considering an isolated Dutch system, PAC has the highest potential of all storage options for reducing the amount of wasted wind. An extra interconnector to Norway would provide a similar potential for this, if it could be used as assumed here. However, none of the energy storage options is sufficient to prevent wasted wind energy altogether. In case international exchange is possible with a 1 h. ahead market gate closure, wasted wind energy is reduced much more than using any of the integration options investigated here.

System Operating Cost

The simulation results in Fig. 4.12 show that the operating cost savings by energy storage and boilers are positively correlated with the amount of wind power installed. Energy storage in the Dutch system amounts to savings between € 1 million (PAC) and € 21 million (CAES) annually for 2 GW wind power (currently installed capacity), increasing to € 66 million annually (PAC) for 12 GW installed capacity. The annual economic benefits of heat boilers in the Dutch system are estimated to be € 31 million annually for 12 GW wind power.

Comparing the energy storage options in the Netherlands, it is found that UPAC and PAC allow the highest operating cost savings, followed by CAES and flexible CHP-units. This can be explained by the fact that PAC has the highest maximum pumping capacity, increasing the opportunities for large-scale energy storage at the lowest costs, compared to UPAC, which has a slightly higher efficiency. CAES requires a relatively number of hours of storage for a large number of generation, which reduces possible synergies with large-scale wind power. At high wind power penetration levels, CAES is increasingly pushed out of the market by wind power because of its high operating costs (CAES is based on CCGT-technology). Heat

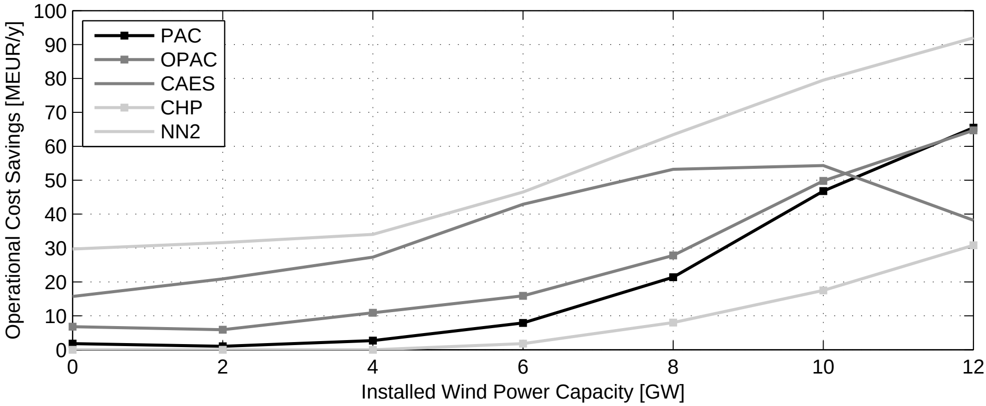

Figure 4.12: Operating cost savings by flexible CHP units, energy storage options and extra interconnection to Norway, no international exchange.

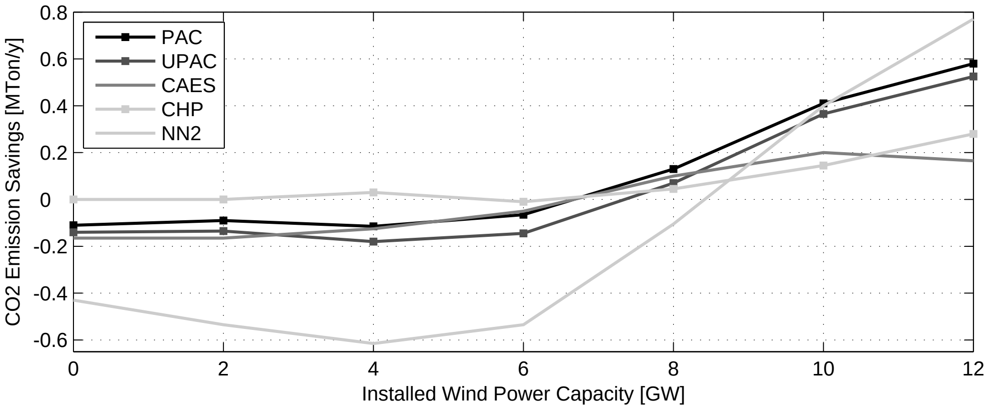

Figure 4.13: CO_2-emission savings by flexible CHP units, energy storage options and extra interconnection to Norway, no international exchange.

boilers are not used until the first minimum-load problems occur at about 6 GW installed wind power since the energy efficiency of the CHP-units can still be used. From 6 GW and upward, the operational cost savings by heat boilers during low-load, high-wind situations increase rapidly. With large-scale wind power, the operational cost savings by increasing the interconnection capacity to Norway are highest (30-92 M€ annually). It can be noted that the possible additional benefits of connecting the Dutch thermal-power system to the hydro-power system of Norway are not considered.

CO_2-Emissions

In Fig. 4.10, it was shown that system CO_2 emission levels are reduced with the integration of large-scale wind power. Fig. 4.13 shows the emission levels of CO_2 for energy storage, flexible CHP-units and extra connection with Norway (NN2) compared to the base-case. Interestingly, the simulation results show that the application of energy storage in the Dutch system increase the system's total CO_2 emissions for wind power levels below 8 GW. Additional emissions with energy storage are highest at low wind power penetrations for NN2 due to its intensive use (very large reservoir capacity) and lie around 0.8 Mton/y.

The additional emission of CO_2 can be explained by two factors. First, it must be understood that energy storage is operated in order to minimise system operating cost, within the technical constraints of the system. For cost optimization, the storage reservoirs are filled when prices are low, to be emptied for generating electricity when prices are high. In the Dutch system, energy storage in fact substitutes peak-load gas-fired production by base-load coal-fired production. Since coal emits about twice as much CO_2 on a MWh basis than gas, the net coal-for-gas substitution by energy storage increases the overall amount of CO_2 emitted by the Dutch system. Second, energy storage brings about conversion losses which must be compensated by additional generation from thermal units, which again increases CO_2 emissions, especially since this is also done by coal-fired units, being the cheapest option. It follows that for the system and assumptions applied in this research, from a CO_2 perspective, energy storage is an environmentally friendly option only for very high wind penetration levels, when energy storage prevents wasted wind. The same is the case for an extra interconnector to Norway operated as assumed here.

Notably, the use of heat boilers not only saves operating costs but also CO_2 emissions. Since the use of heat boilers at CHP-locations specifically tackles the minimum load problem as a result of CHP-unit operating constraints, heat boilers reduces the amount of wasted wind. Since the CO_2 emissions of boilers and wind power are lower than CO_2 emissions of CHP-units, boilers reduce the overall amount of CO_2 emitted by the system as well.

4.5.5 Cost-Benefit Analysis of Integration Solutions

Based on the operational cost savings, a first estimate can be made of the total benefits of heat boilers, energy storage and additional interconnection to Norway in the Dutch system. The total costs for such installations then need to be quantified to enable a cost benefit analysis. In Table 4.4, the parameters of the cost benefit analysis are shown. The possible savings of energy storage by replacing other generation capacity are not taken into account here. As an example, the benefits and overall balance are shown for the largest wind power capacity in the Netherlands investigated in this research. The investment costs and debt interest rates are based on [148] while the investment costs for heat boilers have been obtained from [88]. For the calculation of the annual expenses it has been assumed furthermore that all civil investments for the energy storage options have a technical life-time of 50 years and are depreciated in fifty years, whereas all electro-mechanical installations use a depreciation time of twenty-five years, with a debt interest rate of 7.5% annually (real interest at 0 inflation). The annual revenues and balance are shown for one simulated scenario (12 GW wind power). It has been assumed here that energy storage does not replace investments in other capacity.

In Fig. 4.14, the overall balance (total revenues less total investment costs and operation and maintenance costs) for each option are shown. It can be concluded that only heat boilers have a positive balance for the higher wind power penetrations. The development of PAC and UPAC do not seem to be a cost-efficient solution for wind power integration due to their very large investment costs. From a operational cost savings perspective, the installation and

	PAC	UPAC	CAES	CHP	NN2
Rated capacity [MW]	1667	1400	1500	1500	1400
Reservoir Size [GWh]	20	16	20	-	>>
Time to build [y.]	6	6	3	1	3
Investment cost [M€]	1800	2090	965	60	1500
Interest [M€]	405	470	109	5	169
Activation costs [M€]	2205	2560	1074	65	1669
Debited in 25 years	1103	1280	859	65	834
Debited in 50 years	1103	1280	215	0	834
Debit interest [%]	7.5	7.5	7.5	7.5	7.5
Annuity 25-year part [M€/y.]	99	115	77	6	75
Annuity 50-year part [M€/y.]	85	99	17	0	64
Fixed O&M cost [M€/y.]	10	11	18	0	3
Total Costs [M€/y.]	194	226	112	6	142
Operational cost savings [M€/y.]	66	65	38	31	92
Balance [M€/y.]	-128	-161	-74	+25	-50

Table 4.4: Cost-benefit analysis for flexible CHP units and the energy storage options for 12 GW wind power.

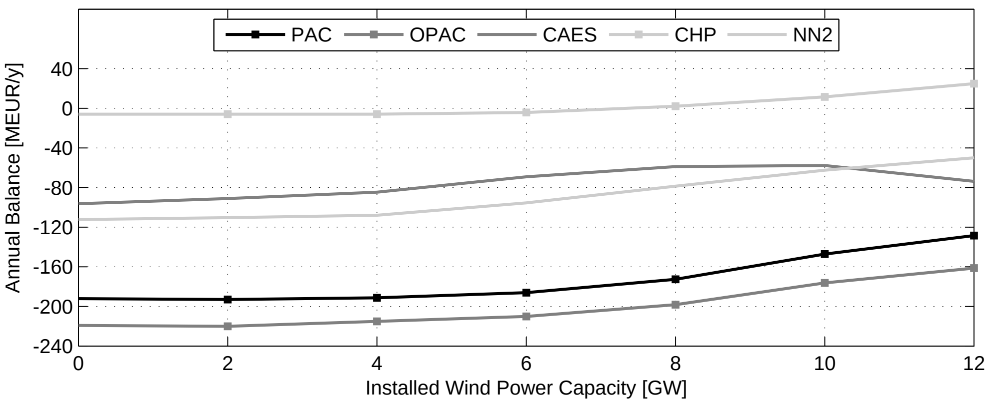

Figure 4.14: Cost-benefit analysis for flexible conventional units and energy storage.

use of heat boilers at CHP locations and a further development of interconnection capacity between the Netherlands and Norway seem to have the highest potential for the integration of large-scale wind power into the Dutch system.

Reflection

Above, a straightforward cost-benefit analysis has been carried for investments for making CHP units more flexible, for developing energy storage options and for an extra interconnection to Norway. The results obtained here suggest that the development of energy storage in the Netherlands, although providing additional opportunities for wind power integration, is not a very attractive solution for this. The benefits of energy storage increase with the amount of wind power installed, but are dependent on the differences between peak and off-peak marginal cost. Because of that, fuel prices, emission prices, international exchange possibilities, electricity demand (level, profile) and the generation portfolio all influence the business-case for energy storage. Therefore, the economic benefits of energy storage must be assessed using a wide range of scenarios for these aspects, while taking into account that the energy storage options may reduce the need for investments in conventional generation. Also, the development of of additional interconnection capacity between the Netherlands and Norway may have additional benefits because of possible synergies between the two generation systems. These aspects fall outside of the scope of this research.

Although it specifically addresses one cause for minimum load issues, the use of heat boilers at the selected industrial CHP locations alone is not sufficient for the prevention of wasting available wind resources altogether. Therefore, this solution should be expanded to other CHP-locations as well. Furthermore, more research is needed into the optimisation of the generation mix in order to remove the minimum load problem, in particular making other base-load units more flexible. Demand-side management would also be a possibility to solve this issue. Above all, however, the results illustrate the importance of international exchanges for wind power integration.

4.6 Summary and Conclusions

The UC–ED model developed in Chapter 3 is applied in this chapter to the Netherlands as part of the North-West European interconnected system. Representative models have been developed of the Netherlands' power system, the neighbouring areas and the interconnections between these. Annual simulations have been performed for a range of wind power penetrations of 0–12 GW in the Netherlands, market designs (isolated system – flexible use of interconnections) and wind power forecasts. Technical limits to the system integration of wind power in the Dutch system have been identified and the economic and environmental impacts of wind power on system operation quantified. Furthermore, the opportunities of energy storage and heat boilers for the integration of wind power in the Dutch system have been explored. Pumped accumulation storage (PAC), underground PAC (UPAC), compressed air energy storage (CAES), the use of heat boilers at selected combined heat and power (CHP) locations and increased interconnection capacity with Norway (NN2) may provide additional technical space for wind power integration.

The simulation results indicate that for the Dutch thermal generation system, ramp rate problems due to the aggregated variations of load and wind power are rare. This can be explained by the existing commitment constraints imposed on base-load coal units (must-run status) and combined heat and power units due to heat demand, resulting in a high operating reserve levels. The high reserve levels provide sufficient ramping capacity for balancing wind power variability in addition to existing load variations. For the optimization of system operation with large-scale wind power, it can be noted that accurate, actualisations of wind power output and a continuous re-calculation of UC–ED are essential.

Although the additional variations introduced by wind power can be integrated, limits for wind power integration increasingly occur during high wind and low load periods. Depending on the international market design, significant wind power opportunity may have to be wasted to prevent minimum load problems. Wind power integration benefits from postponed gate closure times of international markets, as international exchange may be optimised further when improved wind power predictions become available. The limited predictability of wind power, although important for the scheduling of international exchange, is shown to have only a limited influence on wasted wind and operating costs in an isolated Dutch power system.

Wind power has a number of consequences for power system operation. The simulation results show that wind power reduces total system operating costs, mainly by saving fuel and emission costs. Wind power reduces the number of full-load hours of base-load coal-fired generation and CCGT with and without CHP-function. This has particular impacts on the revenues of these conventional generation units (operating hours, marginal cost, etc.). By replacing fossil-fired generation, wind power significantly reduces the total exhaust of emissions (CO_2, SO_2, NO_x). In case possibilities for international exchange exist, wind power significantly reduces imports and increases exports of the area it is integrated into. In the case study performed here, it is shown that the presence of large-scale wind power in Germany limits the use of exports for wind power integration in the Netherlands during some periods. Still, international exchange is shown to be key for wind power integration.

It can be concluded that energy storage, which has been often suggested as a logical partner for wind energy, is not the most attractive solution for the integration of large-scale wind power in the system investigated here. This is because significant amounts of available wind power continue to be wasted at high wind power penetrations in an isolated power system. An interesting result is that energy storage is shown to increase overall emissions of CO_2 for the system as a whole at lower wind power penetrations. This can be explained by the use of energy storage for substituting clean, peak-load gas generation for base-load coal generation and the conversion losses inherent to operating storage. Heat boilers always provide CO_2 emission savings with increasing amounts with wind power installed capacity.

The cost benefit analysis performed here shows that neither PAC nor UPAC are likely to have a positive balance, even at very high wind power penetrations, which is mainly due to the very large investment costs associated with these options. CAES may be an option for higher wind power penetrations, although its benefits for wind power integration are limited. NN2 has the largest potential for wind power integration and for operational cost savings due to its very large reservoir size and low conversion losses. Considering this alternative for wind power integration only however results in a negative balance. For the Dutch power system, the use of heat boilers at CHP locations and the development of additional interconnection capacity with Norway seem to have the highest potential for efficiently creating additional technical space for wind power integration. Possibilities for international exchange should be regarded as a promising alternative for the development of energy storage in the Netherlands.

CHAPTER 5

Power System Dynamic Model

5.1 Introduction

Apart from the impacts on unit commitment and economic despatch, wind power also has, as a generation technology of growing significance, increasing impacts on the behaviour of power systems. These impacts are mainly due to two reasons: wind turbines often use generator types different from conventional ones and wind turbines have a an uncontrollable primary energy source: the wind. The effects of wind power on system frequency are related to the changing rotating mass of synchronously coupled generators and keeping the power balance between generation and load. An important aspect which determines the impact of wind power on power system operation is the market design for wind power. The responsibility for securing additional resources needed for balancing wind power may lie with the transmission system operator (TSO) or may be assigned to the associated market party. In the latter case, wind power is exposed to the market mechanism.

In this chapter, a dynamic simulation model is developed specifically for the assessment of the performance of secondary control with wind power in liberalised environments. The model allows for evaluating market design impacts on power system operation, taking into account essential system parameters such as inertia and primary response, secondary control mechanisms and operational strategies of individual market parties. The dynamic model is designed such that optimised unit commitment and economic despatch (UC–ED) schedules are imported and used as a starting point for the dynamic simulations. This ensures that realistic sets of conventional generation units are used in the dynamic simulations.

The chapter is organised as follows. First, a literature overview is provided and the contribution of this thesis with respect to existing dynamic models for power–frequency control is stated. Then, the modeling approach and structure are presented and the core of the dynamic model is described. The modeling approach is built upon the hypothesis the power system's frequency response can be computed without considering voltage aspects (i.e. constant power load). This approach is validated through simulations of the New England test system with a dedicated power system simulation tool. After this, relevant technical concepts are introduced and the power system model is developed and validated for the Dutch power system as part of the UCTE interconnection.

5.2 Literature Overview and Contribution of this Thesis

5.2.1 Literature Overview on Power-Frequency Control and Wind Power

A lot of research is available on the consequences of different generator types used in wind turbines. Because wind turbines often have a-synchronous generators (Section 2.4.3), the mechanical properties of wind turbines (rotor speed and mechanical power) are rather decoupled from the electrical properties (active power output). Therefore, wind turbines have a different behaviour than conventional generation in response to system disturbances [155]. Although fixed speed wind turbines provide inertial response similar to conventional synchronous generators [101], the presently far more common, variable speed, doubly-fed induction generator (DFIG) concepts are usually not equipped to do so, although this is technically possible [17, 116, 120, 144]. The impacts of wind power on power system inertia is particularly important in smaller, isolated systems with a relatively small rotating inertia as a starting point, such as the Irish [43, 119]. This might be a limiting factor for the penetration level of wind power in such systems [145].

A second and generally more challenging aspect influencing frequency stability, is the variability of wind power. Wind power introduces additional power fluctuations to the system which may coincide with existing power variations of load and generation, requiring additional power reserves. This regards secondary and longer-term reserves especially [37, 44, 70]. Because the wind speed variations can be predicted only to a limited extent, additional reserves are needed as well to compensate for this uncertainty [44]. Wind power also influences the UC–ED of conventional generation units (Chapter 4). Therefore, different or less conventional generation capacity is available for power–frequency control. Thus, wind power has a direct and an indirect effect on frequency stability it the sense that a different generation mix leads to a different dynamic behaviour of the system.

A third aspect which influences power–frequency control is the design of the liberalised market with respect to wind power [69]. The responsibility for integrating wind into system operation lies with the transmission system operator (TSO) or with the individual market parties having wind power as part of their portfolio. In the latter case especially, wind power challenges the planning and operation of the market party's individual generation portfolio and influences the market bidding strategy [52, 154]. These aspects also influence the extent to which conventional generation is available for power–frequency control. It can be noted that TSOs increasingly require wind power to supply system services, including speed-droop control, just like conventional generation. The technical capabilities of wind power plants to supply such services have been shown in [98, 172].

Models in Literature

Different models have been developed for the investigation of the dynamic interaction between wind power and system behaviour. Reference [101] applies a single-bus power system model for the assessment of the impact of wind power on the primary frequency response in an isolated system. The approach is based based on a mechanical power system modeling approach first introduced in [134], which is similar to the models that can be found in [5, 27, 34]. Unfortunately, these models do not comprise operational aspects extending over the range of 20–60 s and are used only for the assessment of primary control. The impacts of large-scale wind power on system frequency are also investigated in [96] but using a test system rather than an actual power system and without considering geographical spreading of wind power. In [32], a methodology for redesigning frequency control is proposed, which incorporates some market aspects and a central bidding process for secondary reserves. Reference [129] presents a case-study for the assessment of power reserves for wind power using a steady-state simulation method based on existing load flow simulation models. It can be noted that a steady-state approach is not suitable for the assessment of frequency stability, as attempted in this research.

None of the models discussed above fully comprise the long-term dynamic aspects of power system operation with large-scale wind power, nor do they include the market aspects relevant to secondary control in liberalised markets, in particular the responsibility for balancing wind power. Research focused on market design or bidding strategies such as [6, 12, 13, 52] does not comprise the technical aspects of system stability. Furthermore, existing models disregard the impacts of UC–ED optimisation with wind power on the plant mix available for balancing in real-time. Considering the wide range of technical and market-related modeling aspects, a dedicated general approach must be developed in order to incorporate all these.

5.2.2 Contribution of this Thesis

The contribution of this chapter is twofold. First, an accurate dynamic power system model is developed for the simulation of power–frequency control in the presence of wind power, taking into account a liberalised trading environment. Parameters for the dynamic model, which include system inertia, speed droops and frequency-dependent load damping are validated for the Dutch control zone as a part of the UCTE interconnection. The dynamic model contains realistic dynamic representations of generation units and generation control schemes presently applied both by the TSO and by individual market parties. Since classical dynamic models for power-frequency control do not comprise market aspects such as market parties' operational strategies and bidding mechanisms for secondary control, the model developed here can be regarded as novel.

The second contribution of this chapter lies in the fact that the model structure developed here is designed such that it can be used to simulate selected cases following from optimised UC–ED schedules. The dynamic model comprises the same generation units as implemented in the UC–ED tool. By importing the cases, only generation units scheduled for operation are available for power balancing and reserves. Since wind power is an integral part of the UC–ED optimisation, the dynamic model is provided with realistic sets of generation unit operating points before starting the simulation of the control performance. This methodology ensures that the dynamic performance of the system reflects the generation mix resulting from UC–ED. The availability of a full year optimal UC-ED-schedule in which realistic wind power data are incorporated, provides a very large number of possible cases for dynamic simulation. This makes the method highly flexible and very accurate, since worst cases can be identified from the UC–ED first and then simulated using the dynamic model.

5.3 Power–Frequency Control Model

5.3.1 Modeling Approach

The modeling approach applied here results from the specific focus of this research on frequency stability. Models of frequency control that neglect transmission network or voltage aspects have been developed in [5, 134]. The mechanical modeling approach (single-bus power system representation) allows the inclusion of longer-term aspects such as secondary control and energy-based control, such as done in [150]. Such an approach is based on two assumptions, namely that inter-machine and inter-area oscillations are absent and that impacts of network-related aspects on frequency response can be disregarded. The first assumption comes down to the application of a uniform system frequency and aggregated moment of inertia. The second involves a lossless network that serves active power loads only: loads are assumed to be constant power and only frequency-dependent. Below, a short background for these assumptions is given and the possible impacts on the simulation results are given.

Uniform System Frequency and Aggregated Moment of Inertia

Frequency is directly related to the rotating speed of synchronously connected generators. During normal operation, slight differences in rotating speeds are present due to the ever-changing equilibrium between generation and load and the control actions which are performed continuously. Large, interconnected systems may also experience frequency oscillations between different areas. These inter-area frequency oscillations caused by the delays in the controls and are specifically related to the geographical size and the loading of the transmission system. In the UCTE interconnection, but also in the North American systems, Wide Area Monitoring Systems (WAMS) are applied to investigate these oscillations. WAMS data are also used for the development of system simulation models and the assessment of damping solutions [22, 61]. For such non-uniform frequency studies, a simulation tool must be used that is fully based on differential equations, explaining the use of for instance PSS™NETOMAC [24] for such exercises.

This research considers the Dutch system in particular, as part of the Western-European region of the UCTE system. This part of the UCTE interconnection is rather meshed with relatively short transmission lines, resulting in low reactances between generators and large synchronising torques. The Netherlands can be considered as part of a coherent North-Western European area [22]. For this research, it is therefore assumed that the system is absolutely stiff i.e. that inter-area oscillations between the Dutch zone and rest of the area will not appear. When also inter-area oscillations are assumed to be absent on a system-wide basis, all generators operate in synchronism with a single system frequency. Since the rotating speed of generators is directly proportional to frequency, all rotating masses in the system can be aggregated to a single moment of inertia.

Frequency Independent of Voltage

Under normal operating conditions, frequency and voltage can largely be regarded as independent parameters. In short-term stability studies (ms to s time-range), voltage aspects are normally neglected [99]. The voltage dependency of consumption [134] and the impedances of transmission lines may however lead to different levels of consumption and losses, which may have a significant impact on system frequency. Therefore, the assumption to regard frequency as independent of the voltage must be validated. This will be done in Section 5.4.

5.3.2 Mechanical Power System Model

Power Balance

Using the assumptions given above, a mechanical modeling approach is used, looking at the power system as a large, single rotating mass. In case of an imbalance between the torques acting on this rotating mass, the net torque causing acceleration or deceleration is

$$T_a = T_m - T_e \tag{5.1}$$

with T_m as mechanical torque and T_e as electromagnetic torque [99]. In case $T_m \neq T_e$, the mass will experience an angular deceleration or acceleration $d\omega/dt$ determined by the equation of motion / Newton's Second Law for rotational motion

$$T_a = J\frac{d\omega}{dt} \tag{5.2}$$

with J as the mass' rotational inertia. Applying

$$P = \omega T \tag{5.3}$$

gives the relationship between the mechanical power P_m, the electrical power P_e and the acceleration

$$\frac{d\omega}{dt} = \frac{P_m - P_e}{J\omega} \tag{5.4}$$

Moment of Inertia

The power system's moment of inertia or mechanical starting time is proportional to the amount of rotating mass in the system. The moment of inertia determines the rate-of-change of the frequency immediately after a disturbance: the larger system inertia is, the less is the frequency rate-of-change following a power imbalance [99]. Replacing $d\omega/dt$ with the frequency rate-of-change df/dt, P_m with the mechanical power input of all generators P_G, P_e with the electrical power output of all generators, equal to system load including losses P_L, allows rewriting Eq. 5.4 to give the relationship between generation, load and frequency change in a power system

$$\frac{df}{dt} = \frac{P_G - P_L}{M} \tag{5.5}$$

where M represents the aggregated moment of inertia of all operating generators at rated power [MWs/Hz] in the system [99]

$$M = \frac{\sum_{x=1}^{n} 2H_x P_{r,x}}{f_0} \tag{5.6}$$

in which f_0 is the rated frequency [Hz], $P_{r,x}$ is the rated power of each synchronously coupled generation unit in the system [MW] and H_x is the inertia constant of each generation unit [s]. From equation 5.5 it follows, that a large M decreases df/dt following a power imbalance, resulting in system frequency being less vulnerable to power imbalances.

Power–Frequency Characteristic

The power–frequency characteristic β of a power system determines the overall dynamic response of generation and load in response to a power imbalance [99]. β consists of a load self-regulation part D and the aggregated primary response of all generators in the system contributing to primary control. In case load exceeds generation, system frequency starts to decrease (and vice versa). This generally results in motors running slower and using less power, consequently decreasing demand. This load damping reaction D [MW/Hz] can be calculated from

$$D = \frac{\Delta P_L}{\Delta f} \tag{5.7}$$

in which P_L equals the load [MW] and Δf the frequency deviation from the rated value [Hz].

Although load damping helps to re-install the system power balance, it is not sufficiently strong to prevent large excursions of system frequency. In order to prevent these, selected generators in the system are equipped with power-frequency control mechanisms. These are designed to quickly stabilise system frequency after an imbalance: generators increase their production in case system frequency falls below the rated value (and vice versa). The generation response depends on the chosen speed droop R, which is the generation output change [MW] per frequency deviation [Hz], and the delay following a frequency deviation. The primary response of an individual generation unit i ΔP_{G_i} [MW] to a frequency deviation is calculated from

$$-\frac{1}{R_i} = \frac{\Delta P_{G_i}}{\Delta f} \tag{5.8}$$

in which Δf is the change in frequency. The power-frequency characteristic β, then, is the overall dynamic response of system load and of all n generators contributing to primary control

$$\beta = \Sigma_{i=1}^{n}(\frac{1}{R_i}) + D \tag{5.9}$$

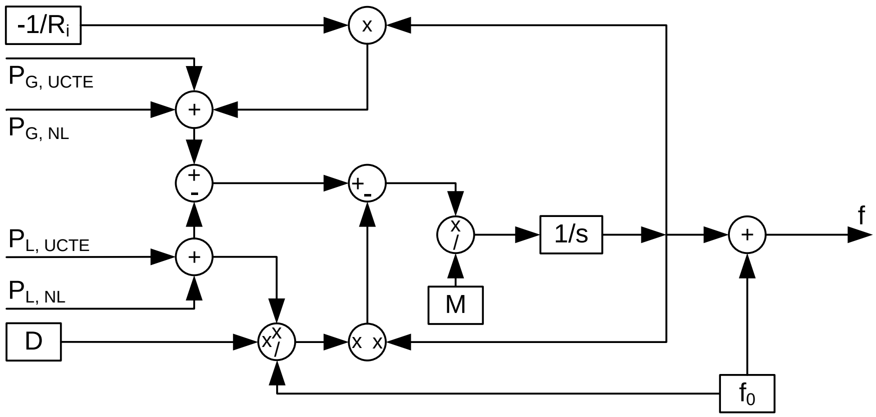

Figure 5.1: Overview of the dynamic model as used in this research.

The system frequency response Δf [Hz] to any power imbalance ΔP [MW] is determined by

$$\Delta f = \frac{\Delta P}{\beta} \tag{5.10}$$

The mechanical model as presented here is introduced into the simulation tool MATLAB/ SIMULINK. Simulink is a well established and highly flexible tool with a user-friendly interface, which allows an orderly and surveyable development of the dynamic model. Furthermore, this tool allows the inclusion of longer-term aspects relevant for this research, such as secondary control. It is flexible enough to allow the modeling of different market designs for wind power and capable of using external data as input for the dynamic simulations. Fig. 5.1 provides a schematic overview of the model, where $P_{G,NL}$, $P_{L,NL}$, $P_{G,UCTE}$ and $P_{L,UCTE}$ represent the total generation and load of the Netherlands and the rest of the UCTE-system, respectively. The generator droop of individual generators $-1/R_i$ are implemented at the generation unit level in the Netherlands and for an aggregated generation unit for the rest of the UCTE-system. The model set-up is validated by comparing the simulation results to manual calculations for different parameter settings (moment of inertia of the system, generator droops) and power imbalances, as done in [99].

5.4 Validation of the Modeling Approach

The use of the mechanical approach itself must be validated as a representation of an electrical power system. This can only be done by comparing the simulation results of the mechanical model to those obtained by an established power system simulation tool. Successive system simulations are carried out while omitting certain electrical aspects in order to validate the extent to which electrical aspects can indeed be neglected when investigating long-term frequency stability.

For the analysis, a validated, multi-bus, multi-generator, multi-load test system is modeled using the mechanical approach in Simulink, and then compared to a full electrical and

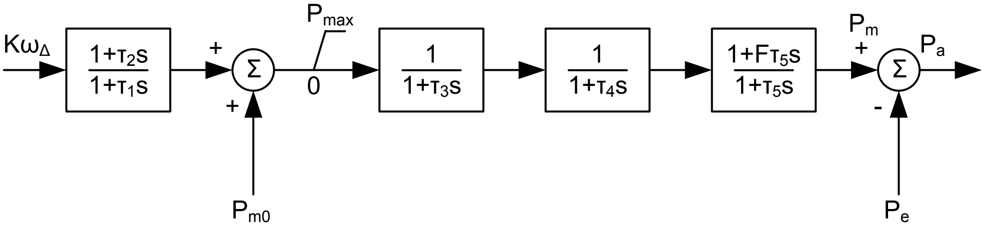

Figure 5.2: General purpose governor block diagram [4].

Technology	T_1 [s]	T_2 [s]	T_3 [s]	T_4 [s]	T_5 [s]	F [pu]
Coal	0.100	0.000	0.200	0.100	8.720	0.300
Natural Gas	0.080	0.000	0.150	0.050	10.000	0.280

Table 5.1: Data for general purpose governor block diagram.

mechanical representation modeled in a validated power system simulation tool. In the validation, the primary control and load damping response of the modeled power system are examined in response to a generation unit outage using both simulation tools. The system's frequency response is monitored and compared. The validation of the mechanical approach for primary control (up to about 30 s) is sufficient to validate it also for the longer time-ranges that are the focus of this research (15 min.).

Simulation Tool for Validation

Due to its flexibility and proven accuracy, the simulation tool PSS™SINCAL is selected for validation of the mechanical model. SINCAL is a widely used network analysis and planning tool built in NETOMAC. This tool can include all electrical and mechanical aspects of power systems.

New England Test System

The system model used for the validation is the New England test system, which is often used in power systems research, especially for transient stability studies. It consists of 10 generators, 18 loads and 39 buses. The data for this test system are provided in [8, 137] and shown in Appendix D. Most relevant for this exercise are the specifications of the generators' inertia constant H, rated generation power P_r and speed droop R. The latter two are not specified and therefore had to be chosen for this research.

The additional data for generator rated power and generation technology were estimated by using parameters of units F18 and F21 specified in [4]. Speed droop was estimated based on the generation technology. The additional data included in the test system are given in Table 5.2. Furthermore, a general purpose governor model (Fig. 5.2) was used for each generator in the New England test system, with data for coal-fired units based on unit F21 and for gas-fired units on unit F18 (Table 5.1). Using the data specified in Appendix D,

Generator	Fuel	Base [MW]	Droop [MW/Hz]
G10	Natural Gas	250	125.0
G02	Natural Gas	600	250.0
G03	Coal	700	233.3
G04	Coal	700	233.3
G05	Natural Gas	600	250.0
G06	Coal	700	233.3
G07	Natural Gas	600	250.0
G08	Natural Gas	600	250.0
G09	Coal	1000	333.3
G01	Coal	1000	–
Total		7050	2158.3

Table 5.2: Additional generator data used for the New England system.

Table D.1, Table 5.2 and Eq. 5.6, the aggregated moment of inertia M for the New England Test System was determined at 2609.0 MWs/Hz.

5.4.1 Simulations

First, the response of the New England test system to an outage of generator G10 will be examined. The outage will result in an immediate change of frequency, which depends on the system's moment of inertia and the output level of the outaged generator. Frequency will eventually settle at a value deviating from the rated value (60 Hz), which depends on primary control reaction and load damping. The responses of both models (SINCAL and Simulink) are first validated with respect to each other and then compared when taking into account different electrical aspects in SINCAL. The following simulations are made:

1) Steady-state calculation of the load flow in the New England test system in SINCAL
2) Dynamic simulation of the frequency after outage of generator G10 in the New England test system model in SINCAL, with constant power load and a single bus representation
3) Dynamic simulation of the frequency after the same outage in the same system, using the swing equations in Simulink
4) Dynamic simulation of the same outage using SINCAL with full representation of the New England test system and constant impedance load
5) Dynamic simulation of the same outage using SINCAL with full representation of the New England test system and constant power load

The load flow is performed for ensuring the correct representation of the New England test system in SINCAL. The common assumption is applied that the load is independent of the voltage (constant PQ) to examine the load flow results validated for this system in [75]. The load flow is used to provide the initial states for the dynamic simulations performed in SINCAL, which must equal those in Simulink. In the second simulation in SINCAL, voltage-related aspects (lines, transformers, generator voltage droop) are removed from the model, effectively creating a constant power load, single-bus representation of the New England test system. The simulation results of SINCAL are compared to the third simulation which is

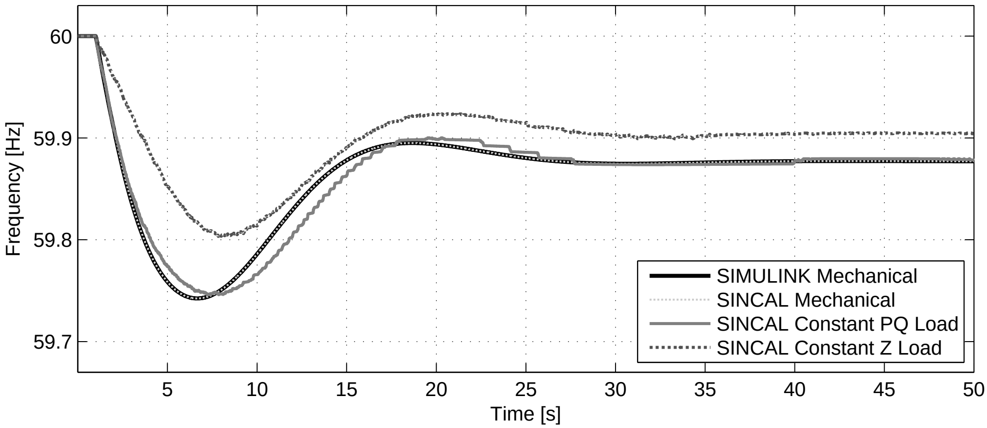

Figure 5.3: System frequency after generator outage in the New England system.

done in Simulink. The fourth simulation evaluates the extent to which the simulation results for a mechanically modeled New England test system differ from a full, electrical representation of the same system with a constant impedance load (load proportional to the square of the voltage). In the fifth simulation, the load is modeled as voltage-independent (constant PQ). The simulations for load as either constant PQ or constant Z represent a reasonable range for the possible load response (models for different load types are discussed in [7]).

In the dynamic simulations, it is assumed that at t = 0 s frequency is stable at 60 Hz and all generators and loads have the values specified in Appendix D, Table D.1. At t = 1 s generator G10 is outaged, which reduces the total generation level from 6140.8 to 5890.8 MW, the moment of inertia from 2609.0 to 2469.0 MWs/Hz and the generators' aggregated droop from 2158.3 to 2033.3 MW/Hz. From t = 1 s the frequency starts to decrease with a rate of change dependent on M and on the instantaneous power imbalance (250 MW) coming from the outage of generator G10. Generators with a speed droop characteristic then respond to the frequency drop by increasing their generation levels; load damping is assumed to be 0 for all simulations. Soon, the power balance is re-established and frequency stabilises at a value below 60 Hz. At t = 50 s the simulation is terminated. It can be noted that system frequency in SINCAL is approximated by observing the speeds of all generators and using the system's centre of inertia (COI) [99], the averaged rotating speed weighed according to the generators' rated powers.

5.4.2 Validation Results

In Fig. 5.3, the simulation results for the validation of the modeling approach are shown; for the single-bus model in Simulink (black); the single-bus model in SINCAL (dotted light grey); the full system representation in SINCAL (grey); and the same representation but with load modeled as constant power (dotted dark grey). The simulation of the single bus representation of the New England test system in Simulink and in SINCAL deliver more or less identical simulation results, with the frequency dropping at the same rate of change and stabilising at 59.877 Hz around t = 30 s. This means that the New England test system is represented correctly in both tools and therefore that the dynamic modeling approach developed in Simulink is applied correctly.

Simulation of the New England test system model in SINCAL with a constant impedance load yields a frequency stabilising at 59.904 Hz, a difference of 0.027 Hz compared to the single-bus approach. The reduced change in frequency is caused by the reduction in load, due to the voltage decrease after the generation outage. Using a constant PQ load, the frequency stabilises also at 59.877 Hz and the frequency shows a very similar response to the Simulink single-bus representation. This proves that neglecting the transmission network in Simulink does not change the primary response of the system to a power imbalance. It can be noted that the inclusion of network-aspects results in a slight delay of the frequency response to the outage, amounting to 1–2 s for the outage considered here.

Conclusion

From the simulation results it can be concluded that the modeling approach used and applied in Simulink is valid for the simulation of frequency stability. A single-bus test system representation in SINCAL leads to identical simulation results for the same generator outage. Voltage related system aspects such as transmission lines, transformers and losses do not have a significant impact on the frequency response of the model in SINCAL. In case a constant impedance load is assumed, a local voltage decrease due to the outage of generator G10 results in lower consumption of active power, which partly compensates the power imbalance and results in a less severe decrease in frequency. Application of constant PQ loads ignores this effect and leads to simulation results that are very similar to the single-bus representation. Since inclusion of voltage-dependent load models results in a smaller frequency deviation, the single-bus modeling approach applied in this thesis can be considered as conservative from the perspective of frequency variation.

5.5 Validation of the Model and Full Model Development

Below, the power system dynamic model described in the previous paragraphs will be extended to include longer term aspects such as secondary control, energy program responsibility and a power imbalance market. The full model comprises the following elements:

- An aggregated moment of inertia, representative for the UCTE interconnected system
- A power–frequency characteristic of the UCTE interconnected system
- Secondary control as performed by the Dutch system operator
- Energy program responsibility
- Short-term operational aspects of Dutch generation units

First, a two area model with one single moment of inertia is set up and validated for the Dutch power system as part of the UCTE interconnection. Secondary control is included in the model as well, with the transmission system operator (TSO) as being responsible for the overall power balance, and the market parties responsible for their individual energy exchanges with the system. Dynamic models are developed for the same conventional generation units as those of the Dutch area in the UC–ED model.

5.5.1 Validation of the UCTE-Interconnection Model

In Section 5.3.2, a mechanical model has been developed for the simulation of the power system's frequency response to a power imbalance. The approach most importantly involves the following parameters: the system's moment of inertia M (Eq. 5.6) and a power-frequency characteristic β (Eq. 5.9), consisting of load damping D (Eq. 5.7) and the primary reaction of the generation units (Eq. 5.8).

System Inertia

The power system's inertia consists of the aggregated inertia constants H of individual, synchronously coupled machines, typically lying in the range of 2–7 s [4, 60, 99, 120]. Because system inertia comprises a very large number of separate masses, system inertia is typically assessed by using system frequency observations immediately after a significant disturbance [29, 79, 93].

For the estimation of system inertia of the UCTE-interconnection as a whole, including the Dutch area, frequency deviation measurements at a sample rate of 4 s were obtained from the Dutch TSO for 87 significant instantaneous power imbalances in the UCTE-interconnection from 1/10/2004–11/12/2006. These events involve power imbalances and frequency deviations between 1–2.6 GW and 20–110 mHz, respectively. df/dt is approximated using the $\Delta f/\Delta t$ immediately after the power imbalance. M is estimated using Eq. 5.5 to obtain an estimation of M, as illustrated by the dotted line in Fig. 5.4.

Load Damping and Primary Response

As with system inertia, load parameters may be possible to assess with some accuracy for smaller, isolated systems [133], but it is generally more difficult for larger, interconnected systems such as the UCTE interconnection. This is because it is practically impossible to verify the primary and secondary control settings for each generator, which allows a differentiation between the generation response and the load response. A typical value for C in Eq. 5.7 is 1 (a 1% change in frequency implies a 1% change in load) [76, 99] and this value is applied by UCTE as well [169].

Primary reserves for immediate power balancing in the UCTE interconnected system are divided between different control zones, each of which is responsible for a fixed amount [MW]. In case of a certain power imbalance, all control zones contribute by their individual share of the total, which presently comprises 3000 MW. In order to guarantee such a contribution, a generation speed droop as well as a response time may be laid down in the grid connection requirements of individual countries or control zones. Typical values are a droop of 10% (10% change in frequency implies a 100% change in generation) and a full primary control response within 30 s [169]. A frequency measurement inaccuracy of up to 10 mHz is allowed in the Netherlands [130]. It can be noted that this also prevents very fast changes in generation output around the rated frequency (50 Hz for UCTE).

By investigating the Δf for the same events as used for the estimation of system inertia, Eq. 5.10 delivers an estimation of β, the aggregation of load damping and primary response. A comprehensive investigation conducted in 1997 [183] estimated a range for β of 2–5·10^4 MW/Hz. In the following, the UCTE data will be used to approximate β.

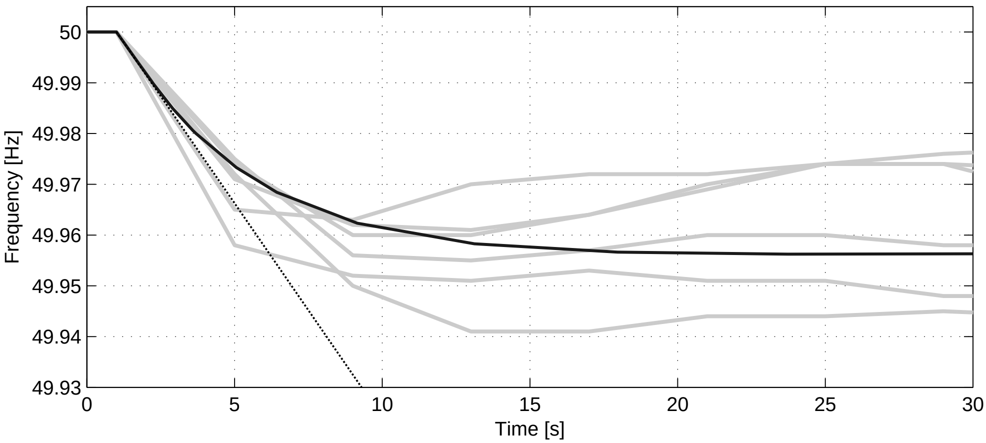

Figure 5.4: Validation of system inertia and power–frequency characteristic (in black) using data of UCTE (representative selection out of total of 87 events, in grey).

Validation Results

Data analysis of all available events shows that M lies within a range of $1.2{\cdot}10^5$ and $4.8{\cdot}10^5$ MWs/Hz, with a mean of $2.6{\cdot}10^5$ MWs/Hz and a standard deviation of $1.1{\cdot}10^5$ MWs/Hz. Correlations between M and the time of day, the type of day or the season were found to be insignificant. For this research, M is approximated at $2{\cdot}10^5$ MWs/Hz since it is a rather conservative estimate within the range found in the analysis. Using Eq. 5.6 and estimating $P_{r,UCTE}$ at $5.0{\cdot}10^5$ MW, H_{UCTE} would be estimated at 10 s. This relatively high value compared to the references given above may be explained by the contribution to system inertia of rotating motors in the system, and a possible voltage response of loads located close to the outaged generation unit, resulting in less severe initial drop of frequency.

The power–frequency characteristic was found to lie between $1.2{\cdot}10^4$ and $4.7{\cdot}10^4$ MW/Hz, with a mean of $2.6{\cdot}10^4$ MW/Hz and a standard deviation of $7.3{\cdot}10^3$ MW/Hz. Correlations between β and the time of day, the weekday and the season were found to be insignificant. It is in fact likely that there exists a function between β and the time of day (plant mix) but this could not be concluded based on the available data. For the simulations, β of UCTE is assumed to be $2.6{\cdot}10^4$ MW/Hz for all simulations, regardless of the load level (i.e. time of day). Assuming a primary control dead band of 10 mHz, the resulting primary response of the system model to an outage of 1144 MW is shown in Fig. 5.4, together with a small number of representative data recordings used for the validation.

5.5.2 Secondary Control

Area Control Error

Secondary control has the objective of returning the system frequency to its rated value and the area exchanges at their scheduled values [83, 74]. Before the liberalisation of the electricity sector, mostly a central generation co-ordinating organisation was responsible for providing secondary control using automatic generation control (AGC). Classical AGC realises generation changes by sending secondary control signals to selected generation units. In liberalised markets however, generation is no longer owned nor despatched by a central operator [149, 151]. The secondary control loop is performed by market parties based on economic considerations rather than direct control by a central operator: secondary reserves are generally made available nowadays by market parties through a dedicated reserve power or imbalance market, which is usually organised by the TSO or an independent system operator (ISO). In case a deviation of frequency and/or inter-area exchanges arise, a bid is called and the TSO sends a secondary control signal to the market party associated with the bid. The price (and penalties) associated with the bid provides the market party with an incentive to adjust its generation or load level.

For multi-area interconnected systems, such as investigated here, secondary control is governed by the Area Control Error (ACE) [MW]. The ACE for a certain area comprises the unscheduled power exchanges over the area's interconnectors plus a term proportional to system frequency deviation

$$ACE = \beta * \Delta f + \Sigma \Delta P_{tie} \tag{5.11}$$

where β is the power–frequency characteristic of the zone under consideration, Δf [Hz] is the frequency deviation from rated frequency and ΔP_{tie} [MW] equals the interchange flow deviation from the scheduled value.

The system modeled for this research consists of two areas: the Dutch control zone and the rest of the UCTE-system. For a correct modeling of the ACE using Eq. 5.11, a certain setting of β for each area must be determined. It can be noted, that UCTE specifies a minimum power-frequency characteristic β for the Dutch control zone of 736 MW/Hz. From the frequency deviation measurements used above, it is found that β for the Netherlands varies between 667 and 2000 MW/Hz. For the calculation of ACE, in practice, the Dutch TSO TenneT applies a constant value of 900 MW/Hz and this value will be used in the model.

Processed Area Control Error

Instead of directly sending out secondary control signals based on the ACE, TSOs use signals based on a processed area control error (PACE). These PACE-signals are then sent to the party responsible for the generation capacity to be made available to the TSO, a separate signal for upward and for downward secondary reserves. Typically, the ACE first feeds into an integrator with gain [10, 32] in order to obtain the secondary control signal. The PACE-logic has the objective of minimising the ACE while neglecting insignificant transients in system frequency, which would result in unnecessary, fast changes in secondary control demands [28]. Due to its principle objective, secondary control in fact responds rather slowly to power imbalances. A secondary response must however be sufficiently strong in case ACE suddenly increases, such as after a generator outage.

For this research, the secondary control logic used by TenneT TSO for the calculation of the PACE was obtained and implemented in the model. Due to confidentiality reasons, the details of the actual integrator and gain control applied by TenneT cannot be disclosed here. TenneT TSO observes the development of ACE within the last 20 s (t_{-20} to t) in order to allow for a quick minimisation of the ACE after a significant power imbalance. In case

$$[ACE \geq 300MW] \; AND \; [ACE_{t-20} - ACE_t \geq 150MW] \tag{5.12}$$

holds, the PACE-logic is by-passed and the secondary control signal is set such that all available downward regulating power available is called. This results in a maximum demand for secondary control in order to quickly bring ACE within bounds again ($\leq$ 300 MW). A similar logic is applied for negative ACE.

Power Reserve Bidding Ladder

The bids for secondary reserves received from market parties are arranged by the TSO in a price order, creating a power reserve bidding ladder. A separate ladder is created for upward and for downward reserves. A bid ladder model is developed, with each bid defined as a vector b

$$b = (id, PTU, size, rr, p) \tag{5.13}$$

in which id is the market party identifier, PTU is the program time unit for which the bid is applicable, $size$ is the size of the bid [MW], rr is the ramp-rate [% of size/min.] and p is price of the activated part of the bid [EUR/MWh].

During real-time operation, the TSO applies the PACE to the bidding ladder in order to select the bids necessary for power balancing. The PACE is re-calculated and applied to the bidding ladder every 4 s, possibly requiring the call of additional bids. The market party associated with the next activated bid then receives a signal ΔP [MW] from the TSO, with a desired rate-of-change [MW/min.] constrained by the ramp-rate specified in the bid. In the Netherlands, rr must equal at least 7% of size/min., allowing a full activation of the bid within 15 min. In case PACE drops and the bid is no longer necessary, the bid is reduced accordingly. Because of the ramp rates specified in the bids, secondary control may change slower than system frequency and positive and negative bids can be active simultaneously. It is the responsibility of the market party associated with the bids called to adjust its generation operating points and/or load schedules accordingly. This responsibility is part of energy program responsibility that every party in the system has.

5.5.3 Energy Program Responsibility

A system of balance or energy program (e-program) responsibility has been developed in order to guarantee an orderly organised market and to allow for a continuous balance between generation and load. In this system, balance responsible parties or in the Netherlands, program responsible parties (PRPs), have been made responsible for keeping their own energy balance: generation is supposed to be delivered to the power system only if there is a load to match it. Therefore any customer (generator or load) connected to the system must be associated with a PRP. A PRP must maintain its energy balance [MWh] for each settlement period, which is the program time-unit (PTU, 15 min. in the Netherlands but generally an hour). Below, the system of program responsibility as organised in the Netherlands is discussed.

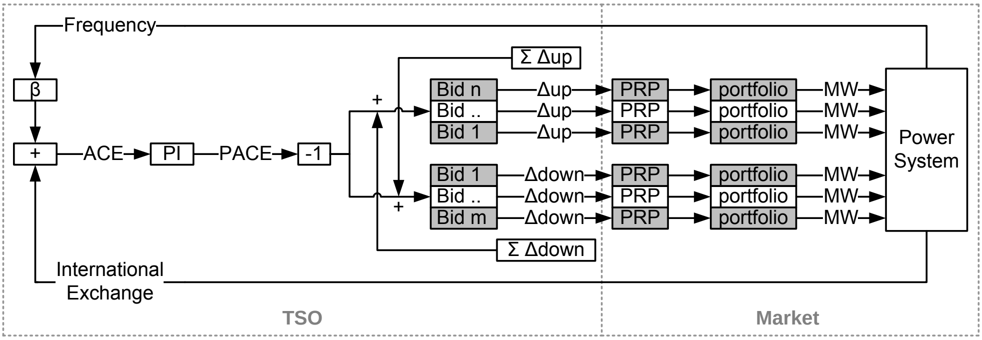

Figure 5.5: Schematic overview of the secondary control loop at the system level as modeled in this research.

Program Responsibility in the Netherlands

Program responsibility requires PRPs to provide e-programs to the TSO for each PTU and to act accordingly. In principle, the e-programs mention MWh-values only for the exchange of each PRP with the rest of the system system for each PTU. On the day preceding operation (12–36 h. ahead of operation), the TSO receives all e-programs from the PRPs. The e-programs are checked for consistency (i.e. the sum of all net transactions between PRPs adds up to scheduled international exchange for each PTU) and then approved. The TSO itself is the PRP for the compensation of network losses and for matching all real-time e-program deviations [162]. Actual power deviations from the program resulting in an ACE are balanced by the TSO by activating bids for secondary reserve. The PRPs contributing to this system balancing are rewarded by the imbalance market price for secondary reserves. The balancing costs are largely transfered afterward to the PRPs which caused the imbalance [14].

The secondary control loop at the Dutch control zone level, as modeled for this research, is presented in Fig. 5.5, including the bidding ladder and the involvement of the PRPs. It can be noted that the Dutch system of program responsibility is organised such that a physical link is absent between the secondary control signals sent out by TenneT TSO and the generation unit operating set-points. So-called imbalance pricing mechanisms encourage actions by PRPs to minimise e-program deviations and to follow secondary control orders. Below, models are developed for the power and energy balance of the individual PRPs.

Modeling of the Power Balance of a PRP

While a power imbalance is picked up by the TSO and secondary control is activated, the imbalance will also be noticed by the PRP responsible for it: generation and/or load levels of its portfolio do not match the scheduled value. Thus, also the PRP causing the imbalance takes measures in order to minimise its imbalance and possible imbalance costs in case the deviation is not corrected within the current PTU. The actual power imbalance $P_{imb,t}$ [MW] of each PRP in the Netherlands is modeled in this research by

$$P_{imb,t} = \Delta P_{G,t} - \Delta P_{L,t} - P_{2nd,up,t} + P_{2nd,down,t} \tag{5.14}$$

where $\Delta P_{G,t}$ [MW] and $\Delta L, t$ [MW] equal the generation and load deviations from values scheduled by the PRP as an average value during the PTU, and $P_{2nd,up,t}$ [MW] and $P_{2nd,down,t}$ [MW] equal the secondary control signals received from the TSO for the activation of upward and downward secondary reserves, with t expressed in [s].

Modeling of the Energy Balance of a PRP

Energy program responsibility as established in the Netherlands in fact only relates to a physical energy balance between the system and the PRP within a PTU: the total energy exchange [MWh] within a PTU must equal the value laid down in the e-program [MWh/15 min.]. Similarly, imbalance costs are settled not on a [MW] but on a [MWh] basis. Therefore, the operation objective of a PRP is to minimise its energy imbalance for each PTU $E_{imb,PTU}$ [MWh], with

$$E_{imb,PTU} = \frac{1}{3600} \int_{t_0}^{t, t \leq t_{PTU}} P_{imb,t} dt. \tag{5.15}$$

In this research, Eq. 5.15 is applied in the dynamic model to assess the physical position of PRPs relative to their e-program. Taking into account the physical position of the TSO and the actual market prices, it is possible to adjust the e-program deviation such that imbalance costs are minimised. The less time before t = t_{PTU}, the larger the power over- or undershoot must be in order to counterbalance earlier power deviations and arrive at the scheduled MWh-value. So, for the counterbalancing of power deviations, PRPs continuously adjust operation set-points of selected units under secondary control within their portfolio. This is especially important when a short PTU is installed, for example 15 min. such as in the Netherlands.

Imbalance Pricing

Imbalance pricing provides an incentive for PRPs to execute their programs as planned, while at the same time it provides an incentive for PRPs to respond to the secondary control signal received from the TSO. The uncertainty of the system imbalance price, which depends on the actual bid prices and the amount of real-time imbalance, presents a market risk for PRPs and therefore encourages them to balance their e-program deviations using their own portfolio. In this research, a perfect functioning of the imbalance market is assumed i.e. no PRP applies strategic imbalancing for profit maximisation.

In the Netherlands, PRPs receive the same imbalance price for an active participation in secondary control (a response to a ΔP-signal from the TSO) or a passive contribution (an e-program deviation with the opposite sign to the system imbalance, for each PTU separately). Because participation in secondary control is taken into account in calculating $P_{imb,t}$ and $E_{imb,PTU}$, both the PRP's imbalance and the system imbalance are, in principle, returned to zero. The short-term operational objectives of the TSO and of PRPs are however conflicting to a certain extent, in the sense that PRPs focus on e-program deviations, a [MWh/PTU]-value, while the TSO focuses on ACE, a [MW] value.

Modeling of Imbalance Control by PRPs

For imbalance minimisation at the PRP-level, an imbalance control is developed in this research based on interviews with Dutch PRPs. Although no detailed information could be obtained on the formulation of the actual controls, it was found that Dutch PRPs apply a continuous control signal which is largely based on the actual e-program deviation. PRPs consider imbalance control as a reactive process, because of the short duration of a PTU in the Netherlands. This means that only feedback loops are applied.

The controller developed in this research reacts on the momentary program deviation $E_{imb,t}$ and the actual power imbalance $P_{imb,t}$. The value for the $E_{imb,t}$ is reset to zero at the end of each PTU. The integral of the $P_{imb,t}$ is used since a controller based solely on the actual energy imbalance would result in an abrupt change of the control signal at each PTU-crossing. An additional benefit is that imbalance control is continued over different PTUs after a significant power imbalance which cannot be managed within one PTU (i.e. ramp rate limitations). The secondary control signal used by the PRP, $2nd_{PRP,t}$ [MW] is

$$2nd_{PRP,t} = -c_1 E_{imb,t} - \frac{c_2}{3600}\int_{t_0}^{t} P_{imb,t} dt + P_{2nd,up,t} - P_{2nd,down,t} \tag{5.16}$$

assuming that all secondary control requested by the TSO is directly transfered to the PRP's units under secondary control and with c_1 and c_2 set to 10 [h^{-1}] and 3.6 [h^{-1}], respectively. The values of c_1 and c_2 have been determined such that $2nd_{PRP}$ accumulates fast enough to allow for $E_{imb,t}$ to return to zero after a power imbalance, but without an overshoot due to the ramp rate limitations of the units under secondary control. It can be noted that this controller could not be optimised further, since no data were available for doing so. It has been assumed that the secondary control signal is the same for all PRPs and for all simulations. The secondary control signal is transferred to the operating set-points of selected generation units, which will then change their output correspondingly.

Overview of the PRP-Model

In this research, each PRP is modeled with a portfolio consisting of conventional generation units, wind power, distributed generation, and load. In the short-term, the operation of the generation unit portfolio as a whole is governed by the minimisation of e-program deviations. A schematic illustration of the modeling of a PRP is shown in Fig. 5.6, with in this case only a single unit n selected for secondary control.

5.5.4 Dynamic Generation Unit Models

Dynamic models are developed for all large ($\geq$ 60 MW) conventional generation units in the Netherlands. These large units are typically used for primary and secondary control. Especially primary control involves a relatively fast output change. The maximum ramp-rates used in the secondary control are equal to those applied in the UC–ED. Shorter-term variations within the 15 min. range are not included for load, distributed generation units and wind power. For these, linear interpolation between the 15 min. set-points obtained from UC–ED is applied.

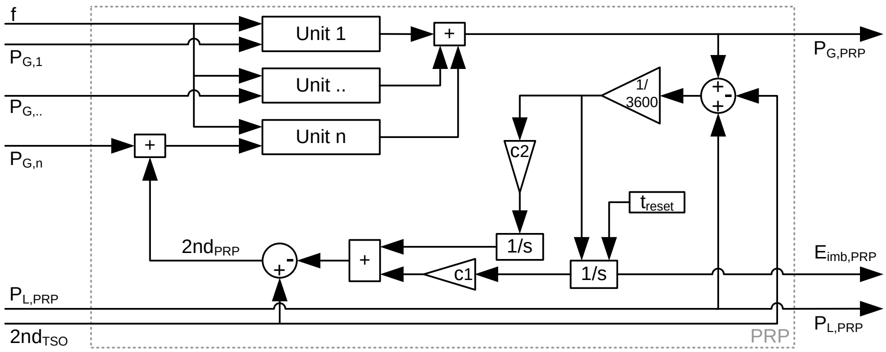

Figure 5.6: Schematic overview of the modeling of a program responsible party (PRP).

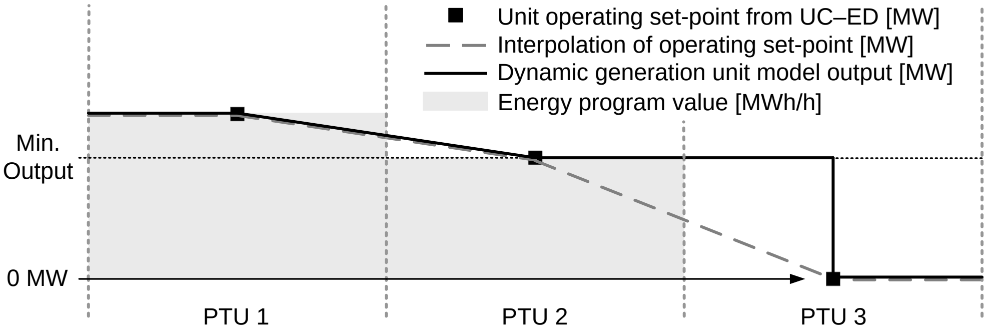

Figure 5.7: Example of the interpolation in the dynamic model of steady-state generation unit output set-points from the UC–ED during decommitment.

Modeling Approach

In this research, it is chosen to apply two separate models for the long-term and the short-term dynamics. In the long-term simulations with a time-step of 15 min, the unit commitment and economic despatch (UC–ED) of generation units is optimised, taking into account the relevant long-term operating constraints. The short-term simulations specifically focus on primary and secondary control. The model uses selected sequences of steady-state generation unit operating set-points from the UC–ED optimisation as a starting point. A linear interpolation is applied between the generation unit operating set-points to obtain continuous operating set-points, which are used in the dynamic simulations.

Fig. 5.7 shows the interpolation process for the decommitment of a unit. The unit is taken out of operation in PTU 3. Since generation units have a technical minimum power output level, in the dynamic model, the unit continues to operate at this point until the interpolated input signal reaches zero. At this moment, the dynamic model of the generation unit will switch to a zero output as well (identical for unit start-up). It can be noted that the interpolation of the UC–ED operating points causes some e-program deviations, in Fig. 5.7 during PTU 3. The power imbalance and resulting e-program deviation are picked up by the secondary control of the associated PRP and subsequently minimised using other units within the PRP's portfolio. The simulation procedure using the UC–ED model first for long-term simulations and then the dynamic model will be discussed in more detail in Chapter 6.

Since most of the long-term operational aspects (i.e. minimum uptimes and downtimes, ramp-rates) are already included in the UC–ED, using short-term models comprising operational aspects up to 15 min. is sufficient here, especially for primary and secondary control. For the development of short-term generation unit models, literature research has been done and expert interviews with the largest six Dutch PRPs have been held on operating aspects of generation units.

Conventional Generation Unit Models

In the short-term models for conventional generation, a differentiation is made between the initial (< 30 s) and the longer-term response (≤ 15 min.). The initial response of a thermal unit to an active power-related disturbance is associated with primary control and depends on the speed droop settings (Eq. 5.8) and the governor characteristics. In the longer-term range of importance for secondary control, the response of generation units is in principle limited only by the long-term thermodynamical aspects, in particular boiler dynamics. Several models exist and were validated for the time-range up to 15 min., including general boiler models [30, 38], models for coal-fired and oil-fired units [31, 53], for gas-fired units [108, 186] and for large, high-temperature boiler units [78]. For the initial response on frequency deviations, only models for gas turbines and combined cycle gas turbines could be found in literature [90]. For this research, block diagrams for a range of Dutch units constructed before 1990 could be obtained from historical testing reports [84, 85].

Several interviews with Dutch PRPs revealed that very little information is available on the dynamic performance of Dutch generation units. Most generation unit data are already contained in the unit database of TenneT TSO and no specific short-term models of generation units are used at or are available from Dutch PRPs. Primary control settings are most often those which were once installed. Generation unit ramping for secondary control is in practice limited by the chosen ramp rate control settings, rather than by the technical limits or short-term time constants, which are generally not known. Dutch PRPs generally show little interest in models describing the short-term dynamic behaviour of their generation units.

Short-Term Models of the Dutch Generation Units

In this research, short-term models of Dutch generation units were developed on the basis of the testing reports which were available [84, 85]. These reports present block-diagram models for the governors, turbines and short-term boiler dynamics of a large number of generation units in the Netherlands. These models include power-frequency droop settings, time constants for the governor, turbine and boilers, and the minimum and maximum power levels. For other units, generic models available from literature are used and the time constants are estimated based on generation unit technology, unit size and operational requirements applicable at the time of the installation of the unit [153]. It was unfortunately not possible to validate any of the models against actual unit data. Since output data from the optimisation of UC–ED at a time-step of 15 min. are used as an input for the dynamic simulations, ramp rate limitations are included for this time-range. Combining these limitations with the

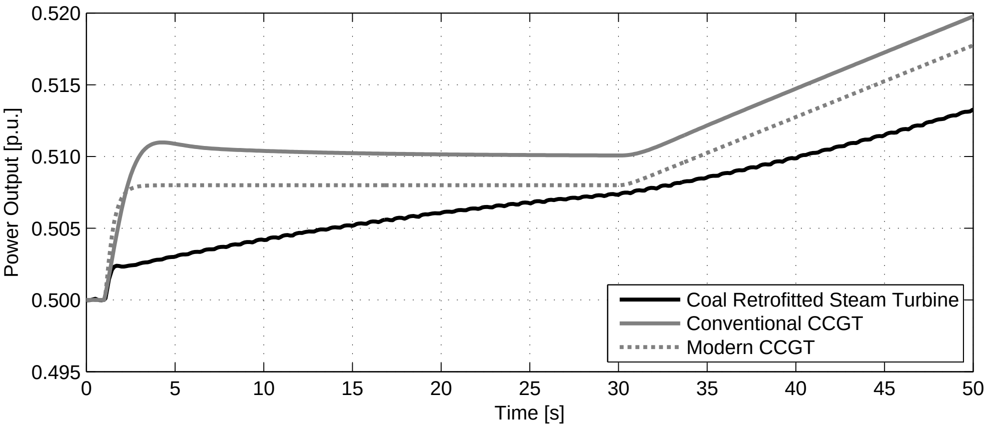

Figure 5.8: Responses of three generation units to a frequency step of -50 mHz at t = 1 s and an operating point step of 0.1 p.u. at t = 30 s

shorter-term dynamic models is assumed to provide a reasonable estimation of the dynamic performance of the Dutch conventional generation units.

The dynamic models of Dutch PRPs' generation units use system frequency and an operating set-point as inputs. Droop settings for all unit testing reports are found to be in the range of 5–12%. For new generation units or existing units for which data are not available, a 10% droop is assumed. The dynamic representation of smaller units that were explicitly modeled in the UC–ED, include no primary or secondary control response and operate according to the imported and interpolated set-point signal. The units are modeled with the governor and longer-term dynamics found in the testing reports, if applicable. Output rates-of-change are limited by the ramp-rate estimate chosen for the UC–ED. The primary response is not subjected to the ramp rate constraint since this output change is due to fast changes in the valve positions rather than boiler time-constants. To illustrate this difference between the primary responses and the ramp rate limitations, the responses of three Dutch generation units to a frequency step and to an operating point step are shown in Fig. 5.8. The operational set-point of the units is limited by the same minimum and maximum power applied for the UC–ED. Detailed representations of over 90 generation units are implemented in the dynamic simulation tool.

5.6 Summary and Conclusions

In this chapter, a dynamic simulation model has been developed for the assessment of the control performance in liberalised environments. The model is focused on the Netherlands as part of the UCTE interconnection but the methodology used here has a general applicability. A swing equation modeling approach is adopted based on two assumptions. The first assumption is that speed differences between individual generators and inter-area frequency oscillations are not relevant here. The second is that voltage-related aspects (transmission system, reactive power, and voltage dependency of loads) can be disregarded for studying power-frequency control. The modeling approach is validated by comparing a mechanical representation of the New England test system in Simulink with a full representation in the power system simulation tool SINCAL. A primary response to a generator outage was simulated to validate the modeling approach. The simulation was repeated in SINCAL while subsequently considering different electro-technical aspects of the model representation in this tool. It was concluded that a mechanical swing equation approach is valid for this research. From a frequency point of view, it is in fact a conservative approach since inclusion of voltage-dependent aspects of the load in practice leads to reduced frequency deviations after a power imbalance.

The dynamic model developed in this chapter incorporates system aspects such as inertia and primary control. The model is validated against frequency data of teh UCTE-interconnection of the primary response of the system following significant disturbances. The validation allows an estimation of the system's moment of inertia and the power-frequency characteristic. The model is extended to include secondary control mechanisms at the level of the TSO and balancing control mechanisms of individual market parties. The model is designed such that UC–ED schedules can be used as a starting point for the dynamic simulations. The modeling procedure is based on the import of operating set-points of Dutch generation units from the UC–ED and a linear interpolation of these set-points during the dynamic simulations. This methodology ensures that only realistic sets of generation units are used for power balancing in the dynamic simulations. Since long-term operational aspects are already included in the optimisation of the UC–ED, short-term dynamic models of generation units consider only aspects relevant for primary and secondary control. Short-term models for Dutch generation units have been developed based on historical unit testing reports, expert interviews with Dutch utilities and literature research. The dynamic model has been validated for the Dutch control zone as part of the UCTE interconnection and set up to include different PRPs' portfolios, comprising conventional generation units, distributed generation, load and wind power.

CHAPTER 6

Impacts of Wind Power on Short-Term Power System Operation

6.1 Introduction

The variability and limited predictability of wind power increasingly challenge the real-time balancing of generation and load in electrical power systems and require additional secondary reserves. The way these reserves are provided and operated is no longer straightforward in market environments, and it is even more complicated if wind power is integrated into these markets and subject to program responsibility. In order to assess the performance of the operation, a dynamic model of the power system has been developed. The model comprises automatic control mechanisms of the generators and the actions of the Transmission System Operator (TSO) and the market parties, taking into account the market design adopted for wind power integration.

In this chapter, the previously presented dynamic simulation model is applied to assess frequency stability in the presence of large-scale wind power. Furthermore, the dynamic performance of the system is analysed for different wind power penetrations and market designs. The possible use of wind power and pumped hydro energy storage as short-term balancing solutions are also simulated. The Netherlands is used as a case-study, with estimations for the generation portfolios of six Dutch PRPs in the year 2014.

This chapter is organised as follows. First, the main two market designs for wind power, i.e. with or without program responsibility for wind power, are presented and discussed. The relevant simulation parameters for the technical integration of wind power in the system are identified, with a focus on frequency stability and short-term power system behaviour. After this, the power system model is specified in detail, considering the Dutch market parties and their generation portfolios, power reserves and secondary control. An estimate is made of the rest of the UCTE-system. The system simulations to be performed are discussed, including the simulation procedure, identification of worst cases, different market designs for wind power and short-term balancing strategies. The simulation results are presented using the simulation parameters identified earlier. The chapter ends with the conclusions on the simulation results, indicating the impacts of wind power on short-term power system operation.

6.2 Market Designs for Wind Power

6.2.1 Organisation of Markets

With the liberalisation of energy markets in Europe, generation unit despatch has become decoupled from system operation. Market parties are free nowadays to make arrangements for trading electrical energy, which is done on different electricity markets. The largest energy volume is traded in the period before day-ahead: energy derivatives are traded for longer time periods in the future so that market parties can settle their physical positions (i.e. scheduling of generation unit maintenance, long-term base-load contracts etc.). Until one day ahead of operation, trading can be done on the spot market, which may be a national or an international market. Spot market trading allows for a more accurate scheduling of units since updated demand forecasts are available. This optimisation continues during intra-day, by trading on adjustment markets and by offering generation capacity to the TSO as power reserves. The actual demand to be covered by a market party's generation units during each program time unit (PTU) is the sum of the loads of its customers plus the power exchanges settled for this period with other market parties.

After closure of the day-ahead spot market, market parties submit their scheduled exchanges with other parties to the TSO. Market parties may have the possibility to continue trading on an intra-day adjustment market and adjust their schedules accordingly. At the moment of (intra-day) market gate closure, the control over the power system is passed to an imbalance settlement administrator, usually the TSO [67]. This is necessary because, even though generation and load are scheduled to match, this does not guarantee a physical power balance in real-time. Therefore, on top of the automated primary actions, the TSO manages secondary reserves (regulating power, available within 15 minutes) and tertiary reserves (reserve power, available after 15 minutes) in order to maintain the balance in the system in real-time. Secondary and tertiary reserves are generally made available by market parties according to the submitted bids for operating reserves to the TSO. The balancing costs encountered by the TSO are mostly passed on to market parties who deviated from their programs. The volumes called by the TSO may be settled against the price of the bid or the price of the highest bid that is called for [48, 56, 162]. In the Netherlands, PRPs receive the same

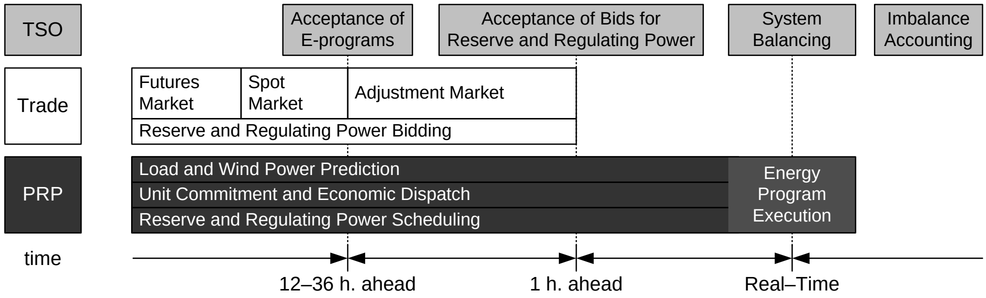

Figure 6.1: Organisation of markets and program responsibility in the Netherlands.

imbalance price for active contributions (response to secondary control signal of the TSO) as for passive contributions (voluntary or unintended actions). The market design of Nordel has specific incentives to eliminate self-regulation of PRPs [126], for instance, programs may be updated even during the hour of execution. An overview of the organisation of markets and the system of program responsibility in the Netherlands is shown in Fig. 6.1.

6.2.2 Program Responsibility for Wind Power

In case wind power is subject to program responsibility, such as being the case in the UK, Spain [52] and the Netherlands, integrating the variability and limited predictability of wind power is the responsibility of the PRPs with wind power in their portfolio. Consequently, the TSO does not use real-time wind power data or wind power forecasts. E-programs submitted to the TSO comprise the MWh-values for the net exchange of a PRP with the system (including wind power) for each PTU. Any deviations from the e-program must be managed by the PRP within the PTU in order to satisfy the e-program. Otherwise, an imbalance price has to be paid to the TSO for having the energy program deviation. This encourages PRPs to make optimal trade-offs for wind power integration, taking into account the characteristics of their own generation and load, wind power forecasts, imbalance prices, etc. In this way, wind power becomes part of the overall operational strategy of the PRPs. The integration costs of wind power are then part of the PRPs' operating costs, which are passed on to the customer.

PRPs have several possibilities to manage e-program deviations, whether or not resulting from wind power:

- Despatch and control of generation/load in the PRP's own portfolio
- Arrangements on the day-ahead spot market
- Arrangements on the adjustment market
- Bidding strategy in the reserve and regulating power market
- Paying the price of the imbalance market

PRPs can make arrangements for balancing power within their own portfolio by scheduling these during the UC–ED planning phase. During operation, the unused capacity is available for balancing wind power variations and prediction errors. Also, some parts of the load portfolio (i.e. demand-side management) may be available for power balancing as well. As discussed in Section 5.2.1, wind turbines may be equipped to provide control capabilities, although wind power production opportunity is lost in case this is applied [98, 172]. The need for reserves for wind power decreases with the geographical spread of wind power within the PRPs' portfolios, although this applies only to a limited extent in the Netherlands. As the time of operation draws nearer, wind power prediction errors decrease and more accurate wind power predictions can be used to continue trade on the intra-day adjustment market, which is especially valuable for wind power integration [12, 69]. Certainly, PRPs must find an optimum between prices on the spot-market and adjustment market, wind power balancing costs, lost production opportunity of their own generation units, and costs incurred on the imbalance market.

6.2.3 Prioritisation of Wind Power

In case wind power is assigned as prioritised generation (a.o. Germany and Denmark), wind power is partly or fully exempted from program responsibility. The TSO may be set responsible for forecasting wind power, buying the electricity generated by wind power, nominating it in the market and compensating its variability and limited predictability. Usually, the forecast wind power is nominated by the TSO and assigned to the PRPs, which cover part of their load with the assigned wind power. In case wind power generates more than nominated, the TSO sells the excess energy to the market, and on the other hand buys any deficits. By doing so, the TSO incurs the costs for integrating wind power into the system, effectively socialising these costs.

Comprehensive economic studies concerning the imbalance cost of wind power show that with increasing wind power penetrations, the imbalance costs increase as well. At wind power penetration levels of up to 10% of annual electricity demand [TWh], the integration costs associated with wind power are estimated to be 1–4 €/MWh; at higher penetration levels up to 30%, this cost estimate is 2–5 €/MWh [6, 35, 70]. Although these cost estimates are modest compared to average electricity market prices, these costs are certainly significant. The prioritisation of wind power not only keeps wind power integration costs away from wind park owners and operators, it also shields wind power from market risks.

6.2.4 Comparison of Market Designs for Wind Power

The variability and limited predictability of wind power is a specific disadvantage for PRPs with wind power in their portfolio. The capabilities of the other generation units (minimum uptimes and downtimes, ramp-rates, efficiency curves) largely determine the technical and economic integration of wind power into the operational strategy of each PRP. In order to minimise their individual risks, PRPs are inclined to balance the wind power within their portfolio by operating reserves individually. The total amount of reserves held by all PRPs together is however likely to be larger than if a system-wide coordination of reserves would be used, such as when wind power deviations are handled by the TSO. In order to minimise this inefficiency, some market designs include incentives to promote the management of imbalances on markets rather than by individual PRPs [126].

In case wind power is integrated on a cross-border level (i.e. the Dutch power system as part of a larger control zone within the UCTE-interconnection), wind power is integrated into a larger system. Provided sufficient transmission capacity is available, more conventional generation capacity is available for integrating the wind power. Also, the total variability and limited predictability of wind power may decrease with the larger geography of the system, reducing the total amount of reserves needed for wind power integration. These notions not only hold for wind power specifically, but for system balancing in general (compare e.g. the coordination of primary reserves in the UCTE-system). For a relatively small country, such as the Netherlands, the variations and forecast errors of wind power are highly correllated (Chapter 2) and international exchange allows the integration of larger amounts of wind power (Chapter 4). An international market design allowing the adjustment of exchange schedules close to real-time is the most beneficial for wind power integration. In order to investigate the impacts of market designs on the system integration of wind power, it is however decided to focus on the Dutch system without scheduled international exchange. This conservative assumption makes that wind power 'stresses' the system much more than it would in an international setting, enabling the comparison of market designs for wind power specifically. Both market designs investigated here concern wind power being subject to program responsibility and as prioritised generation. These market designs concern the short-term range, in which the real-time deviations from scheduled values of wind power are balanced either by the associated PRP or by the TSO.

6.3 Power System Model

6.3.1 Simulation Parameters

The dynamic simulation model is focused on the shorter-term technical impacts of wind power on power system operation. Relevant simulation parameters will be identified in order to quantify these impacts. The simulation parameters to be monitored will be discussed shortly below.

Power Balance

The simulation parameters used for assessment of the power balance are:

- Frequency: active power balance in the system
- Area control error (ACE): power-frequency balance
- Processed ACE (PACE): need for secondary reserves by the TSO

The central parameter for the active power balance is the system frequency. The frequency should stay within certain bounds to ensure reliable operation of the system. The dynamic power system model presented in the previous chapter allows the assessment of power-frequency stability, comprising not only system frequency but also deviations from scheduled power exchanges between zones. It is the objective of the TSO to maintain a stable frequency (50 Hz in the UCTE-system) and simultaneously to minimise the ACE. For this, the TSO calls off bids for reserve and regulating power, the amount of which is determined by the PACE. It is assumed that power variations should be balanced within the control area in which they occur in less than 15 min. as is required by UCTE [169]. This means a full recovery of ACE within 15 min. and returns PACE to zero as well.

Energy Balance

The simulation parameters used for assessment of the energy balance are:

- Power balancing reserves activated by the PRPs

Generation Technology	PRP1 [GW]	PRP2 [GW]	PRP3 [GW]	PRP4 [GW]	PRP5 [GW]	PRP6 [GW]
Nuclear		0.2				0.2
Coal	1.4	2.2	1.9	0.8	2.1	1.0
CCGT CHP Industrial Steam		0.9		2.3	0.3	0.6
Blast Furnace Gas Industrial			0.9			
CCGT CHP Residential Heat			1.1		0.4	
CCGT	4.4	1.3	0.6			8.5
Gas Turbine		0.5	0.0		0.0	0.0
DG	1.3	1.3	1.3	0.6	1.3	0.6
Total	7.0	6.4	5.9	3.7	4.1	3.3

Table 6.1: Conventional generation portfolios of PRPs.

- Energy program deviations of the PRPs

In order to minimise program deviations, PRPs may make available power balancing reserves in their own portfolio. The amount of reserves for each PRP is part of its UC–ED optimisation strategy. It is assumed that during the dynamic simulations, the PRPs can decide autonomously to activate their reserves. Therefore, program deviations depend on the actual power imbalance of the PRP and the corrective actions it takes to minimise the deviations which may result from it.

6.3.2 The Netherlands' Control Zone

Portfolios of PRPs

For a representation of the Dutch power system, the generation unit models presented in Section 5.5.4 are clustered into six PRPs. The PRPs are distinguished according to the scheme of Table 6.1, where the generation capacity is split for each technology between the different PRPs. The generation portfolios are estimations based on public data [163, 164]. The PRPs serve a demand profile which is the aggregation of all set-points of the generators within the portfolio of the PRP determined by the UC–ED optimisation. Distributed generation outside the optimisation of UC–ED is spread amongst the PRPs as 20% of this capacity for PRPs 1–3 and 5, and 10% for PRPs 4 and 6.

For wind power, it is assumed that each PRP has a wind power portfolio with a similar (limited) geographical spread within the Netherlands. Therefore, each PRP can make use of the geographical spread of wind power, decreasing the operating risks associated with it. At the same time, this means that all PRPs experience similar wind power variations at the same moment in time, so that the benefits of counter-balancing wind power between PRPs are insignificant. Since PRPs are not favoured or disadvantaged by the geographical concentration of the wind power in their generation portfolio, a clear comparison between the market designs for wind power can be made. The wind power capacity is distributed between the PRPs in the same way as for DG.

Secondary Control and Power Balancing Reserves of PRPs

For the dynamic simulations, it is assumed that Dutch PRPs fully respond to the secondary control signal of the TSO. It can be noted that this is in accordance with the operational strategy of Dutch PRPs, especially since most PRPs have contracts with TenneT TSO for bidding in on secondary regulation. During the simulations, the delta-signals for upward and downward regulating power received from the TSO are combined with the autonomous balance control signal of the PRP (Section 5.5.3). The aggregated control signal is then added to the operating set-points of selected generation units within the PRPs portfolio.

The generation units used for secondary control by each PRP are selected based on lowest marginal operating cost, with the exception of nuclear units. For most of the PRPs modeled here this comes down to the use of base-load (coal-fired, CHP) generation units within the generation portfolio during the day and during the night. This is in accordance with the present operation practices of Dutch PRPs. Benefits of this operating strategy is that these units have a rather flat efficiency curve, are always available for reserves unless outaged and that this allows the despatch of natural gas-fired, medium- and peak-load generation units at their best operating points. It can be noted that in the Netherlands, the ramp-rates of coal-fired generation units are sufficient to provide secondary reserve. For the simulations, it is assumed that no reserves additional to the 1600 MW total minimum included in UC–ED are taken into account by Dutch PRPs.

Secondary Control by TSO TenneT

TenneT TSO uses system frequency and unscheduled international exchange as inputs (together forming the ACE) and uses the PACE-logic for sending out the secondary control signals to Dutch PRPs (delta-signals for upward and downward regulation). The secondary control logic applied by TenneT TSO includes a bidding ladder which is limited to 1000 MW of upward and downward regulating power (available within 15 min.) and reserve power (call time $>$ 15 min.). The bids for secondary and longer-term reserves received from Dutch PRPs are arranged in order to marginal cost and this order is assumed to not change between different PTUs.

6.3.3 Rest of the UCTE-System

The rest of the UCTE-system is modeled as an aggregation of generation and load according to the approach developed in Section 5.3.2. Scheduled international exchange with the Netherlands, in case possible and optimised as part of UC–ED, is modeled as a difference in load in UCTE. The moment of inertia of the UCTE interconnection is assumed to be constant at $2{\cdot}10^5$ MWs/Hz and its β at $2.6{\cdot}10^4$ MW/Hz. A dead-band of 10 mHz for primary control is applied. International exchange between the Dutch area and the rest of the UCTE-interconnection is treated only by the Dutch ACE and the secondary control actions taken in the Netherlands. It is assumed that no disturbances occur outside the Dutch area and that there is no secondary reaction from UCTE to assist the Netherlands.

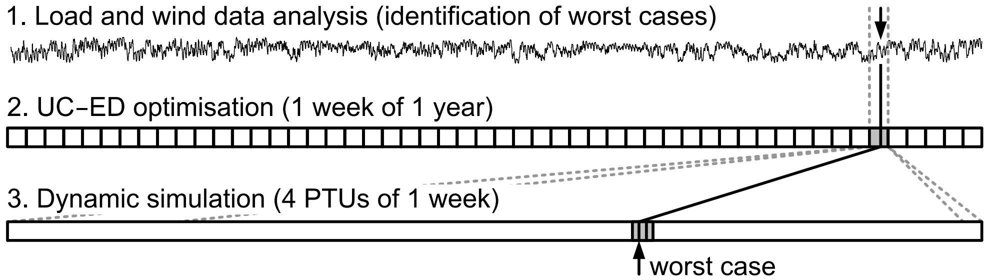

Figure 6.2: Simulation procedure: wind power data analysis, UC–ED optimisation and dynamic simulation of four subsequent PTUs.

6.4 System Simulations

6.4.1 Simulation Procedure

The procedure for the dynamic simulations in fact consists of three consecutive steps, which are illustrated in Fig. 6.2:

1) Identification of wind power worst cases;
2) Optimisation of UC–ED for selected weeks;
3) Dynamic simulation of selected PTUs.

Aggregated load and wind power data, as developed in Chapter 2, have been used to develop duration curves for load-less-wind power and load-less-wind power variations. Here, the same data are used to identify 'worst' combinations of high-wind and low-load and the largest variations of load-less-wind power. The consecutive time-periods during which these worst-cases occur, are the most interesting cases to simulate and is the subject of investigation in this chapter. The weeks during which these worst-cases occur, are selected first, after which the UC–ED is optimised for the Dutch power system only for an entire year using a 15-min. time-step. This is done to ensure that longer-term aspects such as minimum uptimes and downtimes and ramp-rates are taken into account in the dynamic simulations, and that the generation units in operation form a realistic combination of units. It is assumed that the UC–ED is re-calculated and optimised up to the hour ahead of operation, taking into account the best available wind power forecast. The continuous re-calculation of the UC–ED implies that in the dynamic simulations, e-program deviations of Dutch PRPs resulting from wind power forecast errors are small.

After the optimisation of the UC–ED, the operating set-points for all generation units are obtained for a one-hour period (i.e. four consecutive PTUs) containing a certain worst-case and brought into the dynamic model. In order to obtain continuous operating signals, linear interpolation of the 15 min. set-points is applied as shown in Chapter 5, Fig. 5.7. The same is done for the load and the wind power set-points. The dynamic model is then initialised around the operating points of the first PTU of the hour under investigation and then run for four consecutive PTUs. The simulation parameters identified earlier in this chapter are monitored and reported.

6.4.2 Wind Power Worst Cases

The worst cases are selected situations from one PTU to the next with large power variations and low-load, high-wind combinations. The former require additional ramping actions from conventional generation units. Even though the simulation results of the UC–ED did not report any ramping problems, unit ramping is likely to have an impact on short-term power system operation (frequency, ACE). The low-load, high-wind periods may result in less conventional capacity being available for primary and secondary control actions. Therefore, also outages of a large generation unit are simulated and analysed for the worst cases identified below. It is assumed that the Netherlands balances its own wind power i.e. all ramping actions required for balancing the Dutch load and wind power are performed by Dutch conventional generation units.

Aggregated Load and Wind Power Variations

For identifying the worst case for variability, the largest aggregated variation of load and wind power within 15 min. is selected from the data developed in Chapter 2. Since it is assumed that wind power can always be ramped down, only the maximum simultaneous load increase and wind power decrease is considered here. For an installed capacity of 12 GW wind power, the worst case variation of the system load and wind power data developed in Chapter 2 is +4421 MW/15 min. This worst case consists of a combination of a load increase (+171 MW) and a wind power decrease (-4250 MW, falling from 10105 MW to 5855 MW within 15 min.). However, it was found that the variation of wind power during the actual simulation of UC–ED is only 1275 MW. The reason for this is that a significant amount of wind energy ccould not be integrated anyhow (wasted wind energy), so that the actual wind power level is only 7130 MW instead of the available 10105 MW. The wind power level then drops to 5855 MW, resulting in a total power variation of load less wind power of only +1446 MW/15 min instead of +4421 MW/15 min.

In order to find the worst case actually uccuring during UC–ED, the simulation results of UC–ED are analysed. The largest upward variation of load-less-wind power occurring during the UC–ED is found to be +1890 MW/15 min. for 12 GW wind power. In this case, also wasting of wind energy occurs: the variation of foreseen wind power is -3020 MW/15 min (from 6862 to 3842 MW/15 min.), while the wind power variation in UC–ED is -1527 MW/15 min.

For the simulation of the worst case, three different wind power penetration levels are considered: 0 GW (reference), 6 GW and 12 GW. The largest upward load-less-wind power variation from the perspective of the UC–ED is simulated for each penetration level. For 12 GW wind power, the worst case is as described above. For 6 GW wind power, this case involves a wind power drop from 2210 MW to 1332 MW. With the load variation in that period (+363 MW), this implies an aggregated variation of load-less-wind power of +1241 MW. It can be noted that during the simulation, UC–ED results in a number of conventional generation units being brought on-line at their minimum power level. As a worst case, it is furthermore assumed that a 600 MW coal-fired unit is outaged during the dynamic simulation. These events will result in sudden changes in the power balance in the system and will therefore be visible when monitoring frequency and ACE. To illustrate this, the power imbalance and e-program deviations are monitored of the PRPs that bring units on-line or take these off-line during the simulation.

Low-Load, High-Wind Situation

During low-load, high-wind periods, conventional generation units have to be taken out of operation in order to allow for the integration of wind power. During such periods, less conventional generation capacity is available for providing primary and secondary reserves. As a result of this, a generation unit outage may result in a larger excursion of frequency and/or the ACE during such situations. The worst case selected here comprises a generation unit outage during a high wind (11266 MW available), low load (10467 MW) situation. In order to prevent minimum load problems, conventional generation units are shut-down for as far as technically possible, and otherwise ramped down to their operational minimum. Must-run nuclear and coal units at minimum load still supply a total of 4316 MW, while must-run CHP-units and distributed generation supply a further 5204 MW, resulting in a total of 9520 MW of generation other than wind power. As a result, a very large amount of wind power (10319 MW) must be wasted in order to avoid minimum load problems. Only 947 MW of wind power can be integrated at this moment, which is very low.

The high level of must-take generation and the absence of possibilities for international exchange are not optimal for wind power integration during this low-load situation. When the maximum flexibility of industrial CHP-units would be assumed, this would allow the shut-down of these units and the integration of a further 3 GW of wind power. Would international exchange be possible, then this would likely not result in a different commitment of conventional generation units in the Netherlands but only in exports of excess wind power. With both assumptions, still the same coal-fired generation capacity would be available for power balancing in the Netherlands as without these assumptions. Therefore, even though not optimal for wind power integration, this case still represents a reasonable worst case for investigating frequency stability with wind power.

For this simulation, it is assumed that the conventional generation unit supplying most power at this moment in time is tripped in the dynamic simulation at t = 100 s. An industrial CHP-unit is at this moment operating at a level of 550 MW and is part of the portfolio of PRP4. It is assumed that shortly after the occurrence of the outage, PRP4 re-dispatches the power to be supplied by the outaged unit between the conventional generation units within its portfolio available for secondary control. In this case, this mainly concerns two coal-fired generation units of 800 MW each, operating at minimum load (385 MW) at the moment of the outage.

6.4.3 Market Designs for Wind Power

The market designs for wind power discussed and compared in Section 6.2 can be analysed as well using the dynamic simulation tool. For this case, deviations in wind power (i.e. due to forecast errors) are introduced during the simulation and the results between the different market designs are compared. For these simulations, the maximum load-less-wind power variation case for 6 GW wind power is used. At the beginning of the simulation, no deviations from the scheduled wind power are expected. Between t = 450 s and t = 1350 s (halfway PTU 1 and PTU 2), a wind power deviation is initiated going from 0% to 6% of the predicted value, which is in line with the forecast error present 15 min. ahead of operation (Chapter 2, Fig. 2.14). As a worst case, it is assumed that a positive forecast error is present, leading to a wind power decrease between PTUs 1 and 2 on top of the existing large variation.

In case wind power is subject to program responsibility, balancing the forecast errors of wind power is done by the PRPs. It is assumed that all PRPs experience a similar forecast error since their wind turbines and parks have the same geographical spread and the PRPs are likely to use similar weather forecast data. For PRPs 1, 2, 3, and 5, a 6% forecast error leads to a power deviation of -16 MW; for PRPs 4 and 6, this forecast error leads to a power deviations -8 MW. After t = 1350 s, it is assumed that the forecast error increases further by the same amounts for each consecutive 900 s until the end of the simulation.

In case wind power is prioritised, the TSO is responsible for forecasting wind power and scheduling it into the market. It is assumed that wind power is assigned to the PRPs in the same distribution as under program responsibility. PRPs do not take into account wind power deviations in the calculation of their power imbalances and e-program deviations. Wind power deviations result in an ACE and subsequent PACE, leading to secondary control signals sent out by the TSO.

6.4.4 Short-Term Balancing Solutions

For the dynamic simulations discussed above, existing conventional generation units are used for balancing wind power. In principle, wind power plants could also be considered to perform short-term regulating actions. Furthermore, pumped hydro energy storage could be added to the system and used to obtain fast regulating power.

Regulation by Wind Power Plants

Wind power plants have the potential to supply very fast upward and downward power reserves, provided that wind is available and not fully used in case of upward regulation [98, 172]. Wind power may then be used for primary and secondary control, although some wind energy must be wasted in these cases (opportunity loss). In this simulation, the same conventional generation unit outage of PRP4 as discussed in Section 6.4.2 is simulated for the 12 GW wind power scenario. It is assumed that all PRPs use their wind power plants for secondary control and the performance of wind power plants is compared to conventional units.

For PRP4, it is assumed that it has 200 MW of fast regulating reserve available by applying pitch control on wind turbines in operation (delta control). This capacity is assumed to be capable of a ramp from zero to full power within 30 s, including a 2 s activation time. Other reserves provided by wind power are assumed to comprise shut-down or ramped down wind parks. Bringing these on-line requires yawing the turbines into the wind and starting these up. It is assumed that the additional reserve capacity by wind parks is gradually made available within 5 minutes following the outage. At this moment, PRP4 can make available an additional 500 MW from otherwise wasted wind energy. As a conservative assumption, the other PRPs with a similar wind power opportunity available, do not apply these reserves.

Regulation by Pumped Hydro Energy Storage

Pumped hydro storage is technically capable of fast ramping by adjusting its generation or pumping power. Compared to wind power plants, the availability of this capacity for power-frequency control does not depend on the wind. For this simulation, it is assumed that a

WP [GW]	Variation Outage	LL–HW Outage	Variation Market Design	LL-HW WPP	Variation PAC
0	PRPs				
6	PRPs		PRPs,TSO		
12	PRPs	PRPs		PRPs	PRPs

WP = Wind Power level, PRPs = wind power balanced by PRPs, TSO = idem by TSO,
LL–HW = Low-Load, High-Wind situation, WPP = regulating Wind Power Plant,
PAC = fast-ramping Pumped Accumulation energy storage

Table 6.2: Overview of the dynamic simulations.

pumped hydro accumulation storage unit (PAC) is part of the portfolio of PRP1. The presence of PAC in the Dutch power system results in a different UC–ED, since the PAC can be used to balance wind power and thereby allows a more gradual operation of the UC–ED of conventional generation units. For a clear comparison of results, it is assumed that PRP1 bids in the same amount of secondary reserves to the TSO as is done without PAC. Certainly, PRP1 may in reality change its bidding strategy with PAC as part of its portfolio. PRP1 applies PAC both for providing secondary control to the TSO and for balancing its own portfolio.

6.4.5 Overview

In Table 6.2, an overview is shown of all dynamic simulations performed here. Simulations are done for different wind power penetrations (WP), worst cases (Variation = large power variation situation, LL–HW = low-load, high-wind situation), market designs for wind power (PRPs = wind power balancing performed by PRPs / e-program responsibility, TSO = wind power balancing performed by TSO / prioritisation), and balancing solutions for wind power (WPP = regulating wind power plants, PAC = use of PAC for fast-ramping). In total, eight combinations of a UC–ED and dynamic simulation are carried out for this research. A simulation input file consisting of the unit operational set-points obtained from UC–ED is generated, following the procedure described in Section 6.4.1.

6.5 Simulation Results

The simulation results comprise system frequency, ACE, and PACE and the e-program deviations of selected PRPs. As an illustration, Fig. 6.3 shows a combination of the simulation results for the largest power variation on a 15-min. timescale in case of 0 GW wind power. Variations in frequency and ACE are the result of a unit outage at t = 1350 s and of the operational actions undertaken by the PRPs and the TSO. PACE is the summed secondary control signal sent to the PRPs for secondary control. During unit commitment, different generation units have been scheduled for shut-down or start-up. Dommitment or de-commitment decisions result in instantaneous power imbalances due to the minimum output levels of these units.

In order to illustrate the simulation results, Fig. 6.3 presents a dynamic simulation of four consecutive PTUs. In the upper graph is also plotted a one-hour, 4 s time series of UCTE-

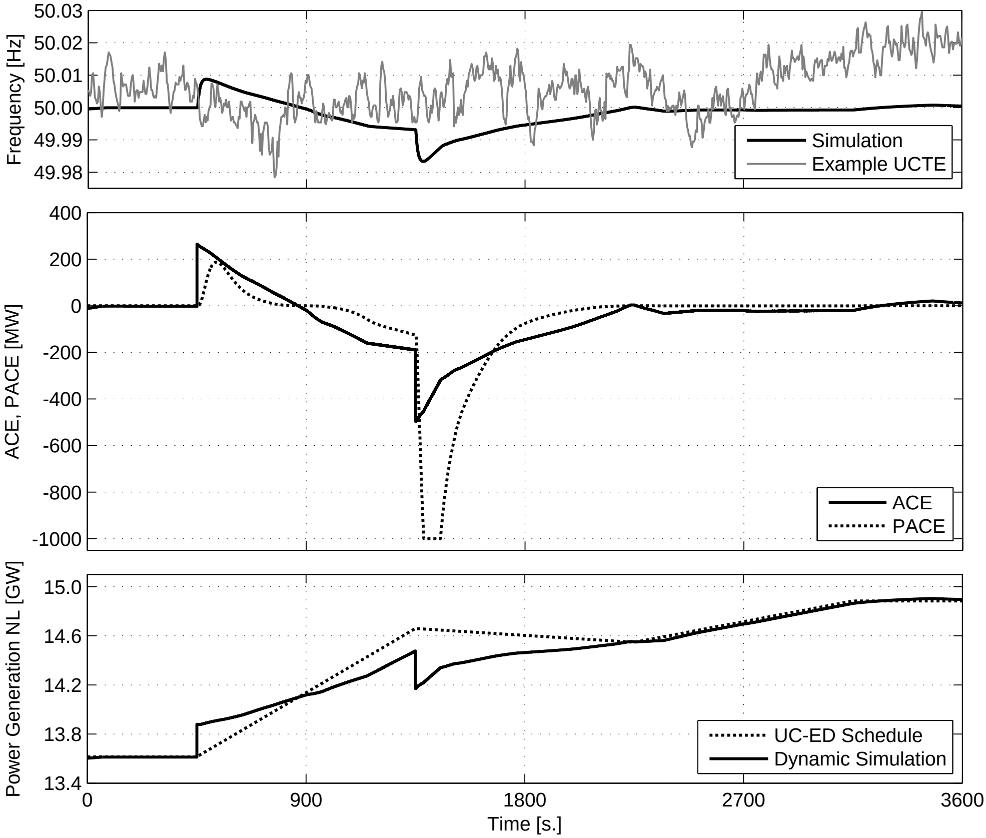

Figure 6.3: Frequency, ACE, PACE, scheduled power production and actual power production in the Netherlands during 4 PTUs, 0 GW wind power.

frequency, as an example of frequency during normal operation in the UCTE-system. The frequency in the UCTE system often jumps 10-20 mHz per 4 s but it stays well within the range of 49.95–50.05 Hz. It can be noted that the frequency is often much further away from 50 Hz.

At t = 450 s (halfway the first PTU in Fig. 6.3), generation units are started up as scheduled by the UC–ED to follow the increase of the load. Due to the commitment of generation units, operation limits in the dynamic models and control actions, power deviations occur. As a result of these, frequency starts to deviate from its rated value and an ACE is introduced. In order to return the ACE to zero, the TSO activates secondary reserves by sending delta signals to selected PRPs (PACE). Simultaneously, the PRPs associated with the power deviations will also activate balancing reserves to minimise the e-program deviations resulting from their power imbalances. The PRP responsible for the unit commitment at t = 450 s decreases its generation level after the commitment in order to minimise its e-program deviation (not shown here). After the unit outage at t = 1350 s, the PRP experiencing this outage increases the generation of the remaining units in order to return to its e-program.

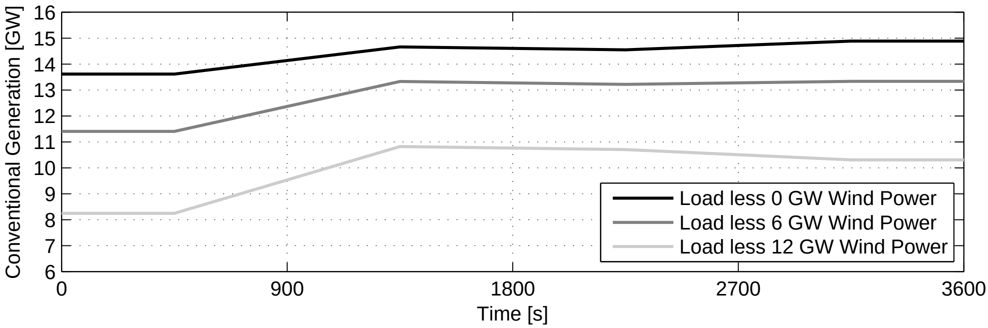

Figure 6.4: Scheduled conventional generation output for following the worst-case power variation of load and 0, 6 and 12 GW wind power.

The combination of the behaviour of individual PRPs and the TSO leads to the generation levels shown in the lower graph of Fig. 6.3, with system load increasing considerably between t = 450 s and t = 1350 s. Eventually, secondary control actions by the TSO through the PRPs from t = 1350 s and onwards and balancing control actions by the PRPs return the power deviations and system frequency to zero.

6.5.1 Wind Power Worst Cases

Load and Wind Power Variations

The simulation of the maximum load and wind power variations uses the conventional generation set-points from the optimisation of the UC–ED as starting point. Conventional generation is scheduled such that the total variations can be followed. In Fig. 6.4, the scheduled total generation of the conventional units is shown for 0, 6 and 12 GW wind power with the maximum variation occurring between t = 450 s to t = 1350 s. Clearly, the required ramping of conventional generation for balancing the maximum power variation of load-less-wind power increases with the installed wind power capacity. This means that more generation units are scheduled for a start-up and used for ramping between t = 450 s to t = 1350 s.

The simulation results for the worst case power variations of system load and wind power are shown in Fig. 6.5 and comprise system frequency (upper graph), ACE (middle) and PACE (below). PACE is limited to the size of the bidding ladder, $-1000 \leq \text{PACE} \leq 1000$. As a result of the larger power variations to be balanced by conventional generation, larger generation capacities are involved for following load and wind power for higher wind power penetration levels. Clearly, the deviations of frequency, ACE and PACE are larger at the higher penetration levels due to more generation unit start-ups at t = 450 s. Between t = 450 s and t = 1350 s, the conventional generation units are scheduled to ramp up (Fig. 6.4) but the ACE still drops significantly during this period. For 0 GW wind power, the ACE and PACE stay within a 250 MW range, although the activated secondary reserves do not return the ACE to zero. For 6 and 12 GW wind power, the ACE becomes so large that the PACE reaches its maximum (around t = 1050 s and t = 900 s, respectively) and all available secondary reserves are activated. Also, the frequency drops below 49.99 Hz which results in the activation of primary

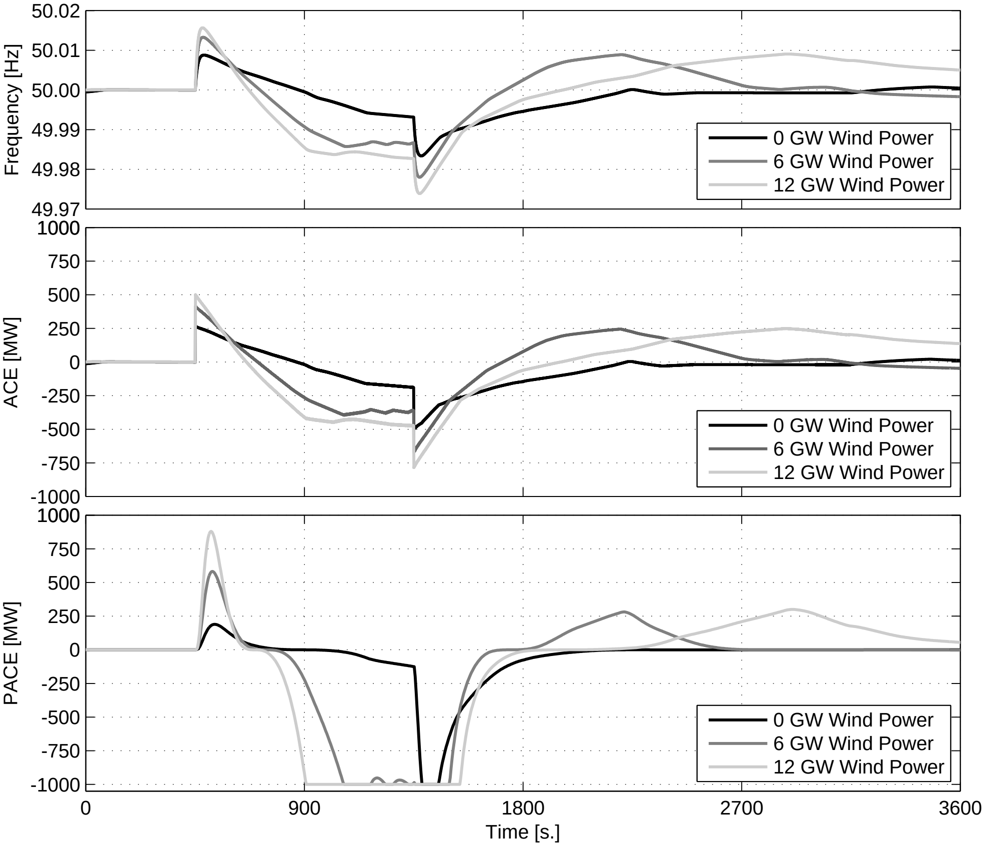

Figure 6.5: ACE and PACE during the worst case of load-less-wind power variation for 0, 6 and 12 GW wind power.

reserves. Primary and secondary reserves stabilise the frequency and the ACE but secondary reserves are insufficient to decrease the ACE. Limits for ramping exist for the 6 and 12 GW wind power scenarios since the conventional generation capacity is already scheduled in the UC–ED for following the power variations of load and wind (Fig. 6.4).

At t = 1350 s a generation unit outage is simulated and the ACE drops further. For 0 GW wind power, the outage results in the PACE increasing to -1000 MW, calling all available secondary reserves on the bidding ladder. The PACE-logic is by-passed after the outage (250 MW, minimum operation level of the outaged unit) at t = 1350 s since the ACE is below -300 MW and a power imbalance $\geq$ 150 MW occurs. Also, the frequency drops below 49.99 Hz and primary reserves are activated. As a result of the activation of additional secondary reserves, frequency and ACE are brought back within 15 min. after the outage. For 6 and 12 GW wind power, the PACE is already at its maximum before the outage due to the large ACE. Secondary reserves only start to decrease the ACE after t = 1350 s, when the large variation of load and wind power ends and conventional generation capacity is available for ramping. Some overshoots of ACE and PACE occur after t = 1800 s due to the ramp-rate limited de-activation of the secondary reserves, but frequency deviations and the ACE are eventually returning to zero. Notably, PACE is sooner at its maximum for the 6 and 12 GW wind power penetration levels (lower graph of Fig. 6.5). Because more secondary reserves have been activated, the ACE returns to zero somewhat faster than for load variations only (middle graph of Fig. 6.5, after t = 1350 s).

From the simulations, it follows that frequency, ACE and PACE are influenced by the additional commitment decisions of conventional generation, rather than directly by wind power variations. The instantaneous frequency deviations as a result of unit commitment may in reality be lower than simulated here, since it is unlikely that start-ups and shut-downs of different units occur exactly at the same moment. The additional start-ups of conventional units, together with their ramping capabilities, are sufficient to incorporate the variations of load and wind power. The frequency variations as a result of wind power integration are in the order of an additional 10 mHz on top of the 10 mHz as a result of existing load variations (upper graph in Fig. 6.5. In any case, these frequency deviations are within the range of frequency deviations occurring during normal operation in the UCTE-interconnection (Fig. 6.3). Furthermore, it is found that the secondary reserves available to the TSO and the secondary reserves applied by PRPs are sufficient to return the ACE to zero within 15 min. after a significant power imbalance, as required by UCTE.

Low-Load, High-Wind Situation

In Fig. 6.6, the simulation results for a low-load, high-wind situation with a conventional generation unit outage are shown. The results comprise system frequency, ACE and PACE and the power imbalance and the development of the energy program deviation of PRP4, the PRP associated with the outaged unit (550 MW power imbalance). The outage at t = 100 s results in a frequency deviation of 20 mHz and a primary response of conventional generation units in the whole system. The frequency and the ACE for the Netherlands resulting from the outage subsequently trigger secondary control at the national level (PACE drops to -1000 MW, resulting in the calling of all available secondary reserves), as well as balancing control actions by PRP4. PRP4 is able to significantly reduce its imbalance and the development of its e-program deviation is limited within half an hour (actual program deviation is reset to zero at the beginning of each PTU), although some imbalance remains. ACE is returned within bounds within 15 min. (PACE = 0 at t = 900 s) and returned to zero within 1250 s after the event.

From the simulation results it can be concluded that, even during high-wind, low-load periods, the performance of secondary control is still adequate. This is because significant amounts of conventional generation units must remain on-line due to the technical requirements and are therefore available for secondary control during these periods. Similarly, PRP4 has sufficient conventional generation on-line within its portfolio to re-distribute the load initially covered by the outaged unit between its remaining units.

6.5.2 Market Design for Wind Power

The simulation results for both market designs for wind power balancing, energy program responsibility and prioritisation, are shown in Fig. 6.7. The figure comprises system fre-

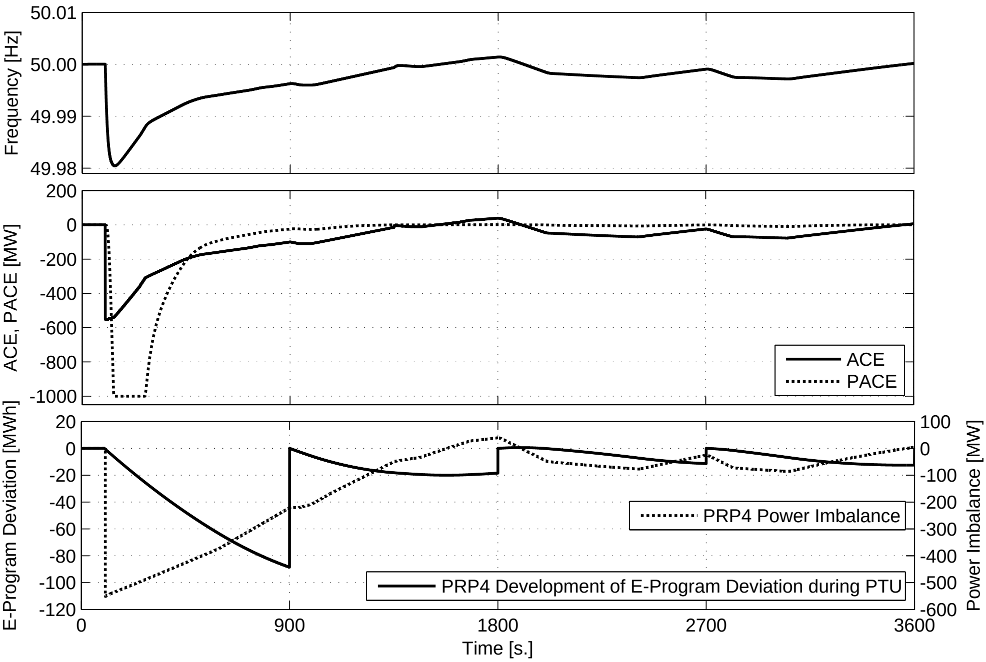

Figure 6.6: Frequency, ACE, and PACE and the associated PRP's power imbalance and e-program deviation development, with a generation unit outage at t = 100 s.

quency, ACE and the power balance and e-program deviation of PRP4, which has the outage generation unit in his portfolio. In this simulation, the same maximum power variation and generation outage at t = 1350 s are considered as simulated for 6 GW wind power in Section 6.5.1 but now with a wind power forecast error, increasing from 0 to 6% between t = 450 s and t = 3150 s. It is assumed that the UC–ED set-points are the same for both market designs (i.e. a perfect market in both cases). In case wind power is subject to program responsibility, the wind power forecast error is balanced by the PRPs, each balancing its own wind power. In case wind power is prioritised, the wind power forecast error results in an ACE and the TSO consequently sends out a PACE-signal. For both market designs, reserves are activated in order to balance the unscheduled shortfall or surplus of wind power, but the activation is done either by the PRPs (balancing reserves when wind power is subject to program responsibility) or by the TSO (secondary reserves in case wind power is prioritised).

The amount and distribution of the activated secondary reserves differs between both market designs (ACE and PACE in Fig. 6.7). The TSO only applies the ACE for power balancing, while PRPs use real-time wind power measurements. This results in a larger ACE in case wind power is prioritised, since the additional secondary reserves for wind power are activated through the ACE only. At t = 3150 s, ACE differs by about 80 MW: the aggregated wind power forecast error at the system level. For both market designs, the performance of secondary control is sufficient to return the frequency to its rated value after the power imbalance. The impact of the market design for wind power is most visible with the PRPs

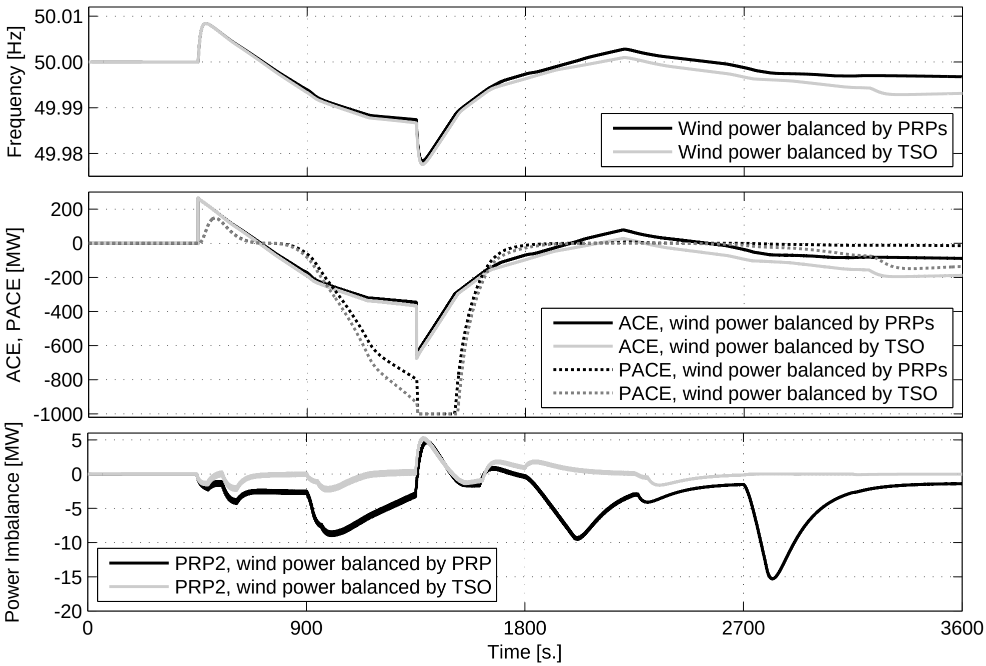

Figure 6.7: Frequency, ACE and PACE and the power imbalance for PRP2 for both market designs for 6 GW wind power.

(PRP2 in Fig. 6.7). In case wind power is prioritised (grey line), the PRP is able to keep its power imbalance (and consequently its e-program deviation) very close to zero.

From the above, it can be concluded that wind power forecast errors do not seem to have a significant impact on power-frequency control in power systems. Optimisation of UC–ED including wind power results in sufficient conventional generation capacity for providing the technical flexibility needed to compensate for wind power forecast errors during the dynamic simulation. The market design for wind power is shown to be important for individual PRPs with wind power in their portfolios, since wind power challenges the continuous minimisation of energy program deviations by the PRPs.

6.5.3 Short-Term Balancing Solutions

Regulation by Wind Power Plants

Fig. 6.8 shows the simulation results for the application of wind power plants for power-frequency regulation and the development of the energy program deviation during each PTU of PRP4. In this simulation, wind power plants are applied for power-frequency control during the same high-wind, low-load period as simulated above, the results of which are also shown in Fig. 6.8 for comparison of results. It is important to note that in the high-wind, low-load situation as simulated here, significant amounts of available wind energy cannot be integrated. Even though the application of wind power plants for regulation allows some

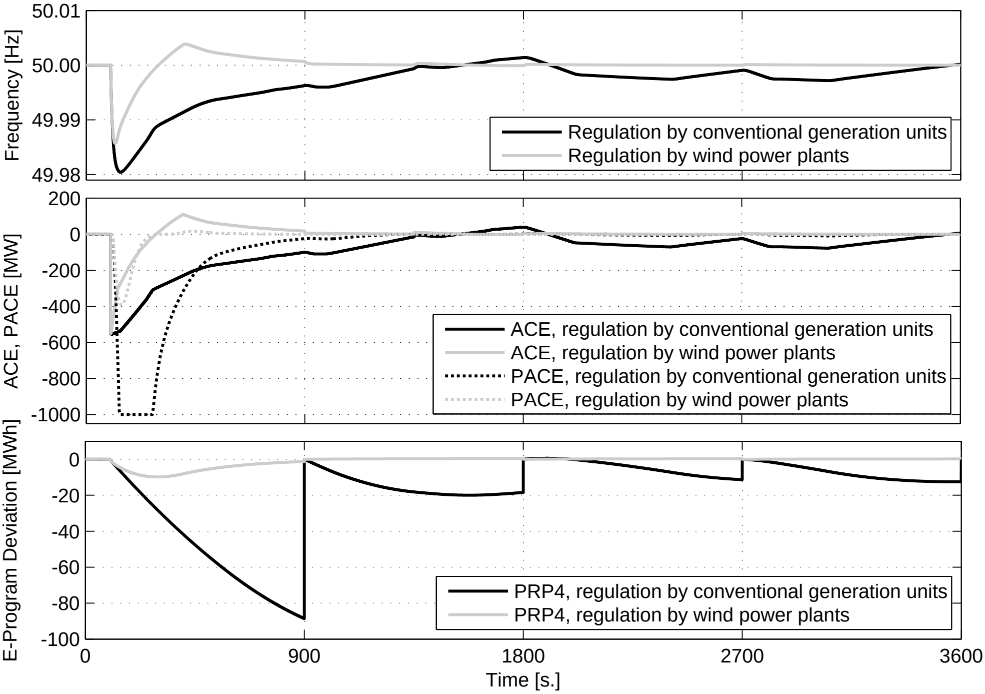

Figure 6.8: Frequency, ACE, PACE and e-program deviation development with and without wind power plants providing regulation for the high-wind, low-load situation with 12 GW wind power.

additional use of wind power, the amount of wasted energy is not significantly reduced. The use of wind power plants for regulation does provide the opportunity to run conventional generation units at a more stable (but still low) operating point, since power-frequency control is provided by wind power plants.

As the simulation results show, an important advantage of using wind power plants for regulation is their very fast ramping capabilities, which improve the performance of secondary control. The ramp rates of wind power plants are far higher than those of conventional units and allow PRPs to follow their energy program very accurately. In fact, the response of secondary control is so fast compared to the setting of PACE that an overshoot of the frequency and the ACE occurs around t = 400 s, which may be undesirable. This could be solved by changing the settings of the gain of the PACE to take into account units with a high ramp-rate. It can be concluded that power-frequency control can be improved by applying wind power plants for regulation, instead of using conventional units only.

Regulation by Pumped Hydro Energy Storage

In Fig. 6.9, the simulation results for the use of pumped hydro accumulation (PAC) energy storage for regulation are shown. The previously investigated wind power variation worst-

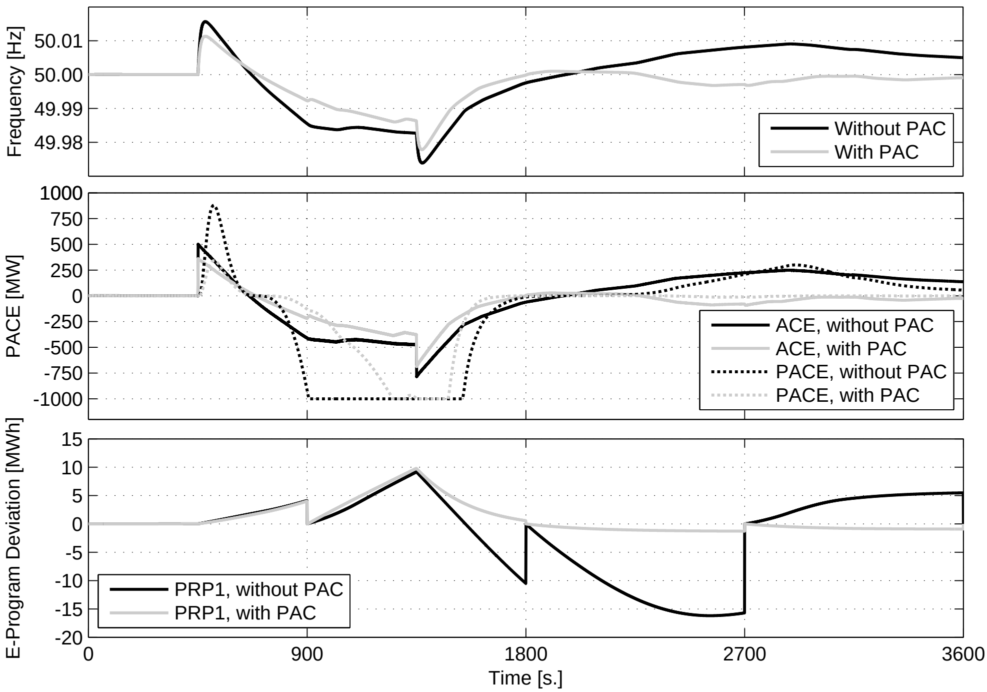

Figure 6.9: Frequency, ACE, PACE and e-program deviation development of PRP1 with and without using the PAC for regulation for the maximum load and wind power variation with 12 GW wind power.

case with 12 GW wind power is used again, but now with the inclusion of PAC in the optimisation of the UC–ED and using the PAC for regulation in the dynamic simulation, instead of conventional generation units. The simulation results of the simulation with and without PAC are shown in Fig. 6.9 for comparison. PRP1 applies the PAC for balancing its portfolio and for providing secondary control to the TSO.

The simulation results indicate that the fast ramping capabilities of the PAC provide similar benefits for power-frequency control as wind power plants. As Fig. 6.9 shows, the application of PAC improves the ramping of secondary control at the system level and the balancing control for PRP1, since PRP1 applies this unit for providing reserves to the TSO and to itself. Another improvement of the PAC is that it makes the UC–ED more efficient due to its fast ramp rate. In fact, PAC reduces the amount of conventional generating capacity that is committed and de-committed. PAC has particular benefits for PRP1 since it allows it to minimise its e-program deviations very well by fast ramping. Another possible benefit is that PRP1 may increase its revenues from providing secondary reserves to the TSO by a different bidding strategy. Notably, the large capacity of PAC and its low marginal operation costs could push large amounts of thermal generation capacity out of the imbalance market. This notion also applies for wind power, but only during periods in which significant amounts of wind power are wasted and the opportunity losses for using wind power for balancing are zero.

6.6 Summary and Conclusions

In this chapter, the dynamic simulation model developed in Chapter 5 is applied to assess frequency stability in the presence of large-scale wind power. The dynamic performance of the system is compared for different wind power penetrations and market designs for wind power.It is assumed that the Netherlands balances wind power independently of the neighbouring areas. Furthermore, the use of wind power plants and pumped hydro energy storage for power-frequency balancing is simulated, using the Netherlands as a case-study.

From the simulation set-up and the results, it is concluded that the power variations due to wind power require a more dynamic operation of conventional generation units. The additional power variations introduced by wind power can be handled by frequently re-calculating the UC–ED using updated wind power forecasts. The dynamic simulations show that the integration of wind power during power system operation may require additional secondary reserves, mainly due to the commitment and de-commitment of conventional generation units and due to wind power forecast errors. The additional commitment and de-commitment decisions necessary for incorporating the variability of wind power are found to have an impact of power system frequency and the ACE, rather than wind power's variability itself.

The performance of existing secondary control mechanism of the TSO is found to be sufficient to return ACE to within bounds within one PTU (15 min.) for all wind power worst cases investigated here. The same applies for the use of balancing control by the PRPs to minimise energy program deviations. The simulations show that sufficient secondary reserves can be made available regardless of wind power situation or the market design for balancing wind power (energy program responsibility or prioritisation). Importantly, also during high-wind, low-load periods, the performance of secondary control is found to be adequate. Although technical operating constraints of conventional generation on the one hand result in a lot of wasted wind power during low-load, high-wind periods, these constraints on the other hand ensure that sufficient conventional generation capacity is available for secondary control during such situations. The performance of secondary control and balancing may be improved by using wind power plants or pumped hydro energy storage facilities. Their fast ramping capabilities provide opportunities for individual PRPs and for the TSO for power balancing, and may be alternatives for using only conventional generation units.

Finally, some observations can be made based on the worst cases examined here. The first has to do with the wasted wind occurring during high-wind, low load situations. The wasted wind energy in fact reduces the total variability of wind power that is integrated into the system. In case additional generation units could be de-committed during high wind, low-load situations, the generation system would at times also have to balance larger wind power variations. Then again, such a generation system would also be better equipped to do that. The second observation is that conventional generation unit outages during high-wind, low-load situations are unlikely to have a large impact on power system operation. This is because conventional units are likely to operate at their minimum power level during these periods, reducing the maximum power imbalance resulting from an outage. The technical operating constraints of these units thereby ensure that sufficient upward power reserves are available during these situations. A third observation is that the balance control objectives of the TSO (secondary reserves) and the PRPs (balancing reserves) are not fully aligned. Strategic behaviour of PRPs for minimising their program deviation [MWh] may temporarily increase the ACE [MW], triggering additional secondary reserves at the system level.

CHAPTER 7

Conclusions and Recommendations

7.1 Conclusions

7.1.1 Power System Integration of Wind Power

The present day need for electricity is largely covered by coal-fired, gas-fired, hydro and nuclear power plants. Although generally reliable, affordable and proven, the disadvantages of the use of fossil fuels and uranium are that these resources are finite and unequally distributed between states, which may lead to political conflicts. Furthermore, the burning of fossil fuels for power generation results in the emission of greenhouse gases, in particular CO_2. So along with the increasing electricity demand worldwide, there is a growing need for sustainable power generation technologies, such as wind power.

In the past decade, wind power has become a generation technology of significance in a number of countries, and its growth is foreseen to continue. When integrating significant amounts of wind power in power systems, technical challenges arise due to the uncontrollability of the primary energy source, the wind. While power system operation requires a continuous power balance between generation and load, the variability and limited predictability of wind power introduces additional uncertainty into power system operation. The question arises, to what extent the power system can accommodate wind power while maintaining a reliable electricity supply.

This research has been focused on the impacts of large-scale wind power on power system operation, in particular on power balancing. With power system frequency as the central parameter for the active power balance between generation and load, this thesis has investigated in fact the frequency stability with large-scale wind power at different time-scales. In the long-term time-scale (time resolution 15 min.), unit commitment and economic despatch (UC–ED) are simulated. The simulation results are used in a second, dynamic model exploring long-term frequency stability (time resolution 4 s). The research includes an exploration of measures to mitigate the possible negative consequences of wind power on power system operation. The following steps have been taken:

1) Investigation of the variability and limited predictability of large-scale wind power, both on the short-term (s. to min.) and long-term (h. to weeks) time-scales (Chapter 2);
2) Further development of an existing UC–ED model to simulate long-term power system operation with wind power (Chapter 3 and 4);
3) Development of a new dynamic power system model to simulate short-term power system operation with wind power (Chapter 5 and 6);
4) Application of both models to explore solutions that facilitate the system integration of large-scale wind power (Chapter 4 and 6).

The focus project has been on the technical aspects of power systems design and power system operation, but also takes into account economical and market aspects and to some extent environmental aspects. The developed methodology is illustrated using a foreseen future setup of the Dutch power system in 2014. International exchanges and trading on international and national markets are included. This research considers wind power penetrations up to 12 GW (4 GW onshore, 8 GW offshore), supplying up to a third of the electricity demand of the Netherlands estimated for 2014.

7.1.2 Impacts of Wind Power on Long-Term Power System Operation

Technical Integration Limits

The wind power and load data for the Dutch system have been used for a preliminary assessment of the possible impacts of wind power on power system operation. From this, load-less-wind power curves (power levels) and load-less-wind power variation curves (ramping levels) have been developed. From these curves it is observed that wind power reduces the demand for conventional generation, especially for base-load and medium-load generation. The aggregated power variations of system load and wind power lie mostly within the variability range of system load itself and conventional generation is capable of matching these variations. Wind power does however increase the occurrence and size of the maximum variations occurring a few hours during the year and care has to be taken that the conventional generation can manage these situations. Minimum load issues during high wind, low load periods are likely to present the first technical integration limit for wind power.

The simulation results for unit commitment and economic despatch (UC–ED) confirm the above observations. It is concluded that the variability of load and wind power can be technically accommodated by the conventional generation units of the simulated system. Ramp rate problems as a result of the aggregated variations of load and wind power are found to be absent. It can be noted that the technical constraints imposed on base-load coal and combined heat and power (CHP) units do not allow their de-commitment and thereby guarantee that sufficient power reserves are available at all times. The limited predictability of wind power requires a more frequent re-calculation of UC–ED (i.e. rolling UC–ED). The present quality of the updated wind power forecasts are found to be adequate for the optimisation of UC–ED. A frequent re-calculation of UC–ED also allows for the scheduling of additional power reserves close to the moment of operation, if necessary.

Impacts of Wind Power on UC–ED

The simulation results show that wind power reduces total system operating costs in the UC–ED of conventional units, mainly by saving fuel and emission costs. A first estimation of these benefits shows that the operating cost savings lie in the range of € 1.5 billion annually, and CO_2-emission savings around 19 Mton for 12 GW wind power installed in the Netherlands. These benefits are dependent on fuel prices, the conventional generation mix, electricity consumption, the yearly wind regime, the international market design, interconnection capacity, etc. but are considerable in any case. It is shown that wind power reduces the number of full-load hours of especially base-load generation units (coal, combined heat and power) and of medium-load CCGT. For high wind power penetrations, the presence of large capacities of must-run base-load generation results in large amounts of wasted wind in the Netherlands, especially during low load periods.

In case international exchange is taken into account in the optimisation of UC–ED, the amounts of wasted wind are very much reduced. It is found that wind power significantly increases the exports and/or reduces the imports of the area it is integrated into, in this case the Netherlands. International exchange provides a very large potential for wind power integration in the Netherlands, especially at high penetration levels. However, limits may exist to the use of interconnections for wind power integration in case neighbouring systems also comprise significant amounts of wind power. In the case study performed here, it is shown that the presence of large-scale wind power in Germany may limit exports from the Netherlands during low-load, high-wind periods. Despite the high geographical correlation of wind power output in Western Europe, international exchange still provides a large potential for the integration of additional wind power in the Netherlands.

7.1.3 Impacts of Wind Power on Short-Term Power System Operation

Frequency Deviations

From the simulation results, it can be concluded that the variability and limited predictability of large-scale wind power do not reduce frequency stability. The variations of large-scale wind power occur in the time-ranges of minutes and upward and thereby do not impact frequency stability directly. The most important impact of wind power variability is the more dynamic operation required from conventional generation units. Since these units are committed and decommitted at a certain minimum power levels, such events lead to power imbalances and thereby frequency deviations. These frequency deviations are however well within the normal frequency range in UCTE and insignificant from a frequency stability point of view. Taking into account the large system inertia of the UCTE-system, there are no indications that the system integration of wind power would be limited by frequency-related aspects. It can furthermore be noted that modern, variable speed wind turbines are technically capable of contributing to power system inertia and to some extent to power-frequency control.

Secondary Control

In this research, it is found that the additional power variations introduced by wind power can be adequately handled provided that wind power is integrated into the optimisation of UC–ED of the program responsible parties (PRPs). The performance of existing automatic generation control (AGC)-mechanisms of both the TSO and PRPs is found to be sufficient to return the area control error (ACE) to within bounds within one 15 min., as required by UCTE. This conclusion holds for large combined variations of system load and wind power, for high-wind, low-load situations and for conventional generation unit outages. Additional secondary reserves will be required during real-time operation to incorporate the additional power imbalances, due to the commitment and de-commitment of conventional generation units and because of wind power forecast errors. Since existing base-load generation units remain in operation due to technical operating constraints, sufficient conventional generation capacity is available for the provision of upward reserves at all times. It is found that the use of wind power plants or pumped accumulation energy storage for regulation may improve the performance of secondary control due to their very high ramp rates, reducing the need for conventional units for providing this.

7.1.4 System Integration Solutions

International Exchange and Postponed Gate-Closure of Markets

In case international exchange is possible using the available interconnection capacity, minimum load problems and wasted wind power in the Netherlands are very much reduced since excess wind power may be exported to neighbouring areas. The simulation results show that wind power also benefits from postponed gate-closure times of international markets, since international exchange can be based on improved wind power forecasts. For the Netherlands, flexible international exchange and markets largely eliminate the need for other integration solutions for wind power.

Energy Storage and More Flexible Base-Load Generation

Energy storage is often suggested as a logical complement for power systems with large-scale wind power. From this research, however, it can be concluded that energy storage facilities are not the most efficient solution for the integration of large-scale wind power in the Netherlands. With regard to an isolated Dutch power system, significant amounts of available wind energy continue to be wasted even if large-scale energy storage solutions are implemented. A cost–benefit analysis furthermore shows that pumped hydro solutions in the Netherlands are unlikely to have a positive outcome, even at very high wind power penetrations. This is mainly due to the very large investment costs associated with these options. It must be noted however that business cases for energy storage depend on the differences in marginal costs between peak and off-peak, which are dependent on a wide range of factors.

An important simulation result is that energy storage increases the emission of CO_2 of the system as a whole, especially at low wind power penetrations. This is because energy storage allows storing power from cheap coal-fired plants for substitution of expensive, but relatively clean peak-load natural gas-fired units. Furthermore, energy storage brings about significant conversion losses, which must be produced as well. In fact, energy storage partly annuls CO_2 emission savings by wind power, unless very large amounts of wind power are installed.

It can be concluded that a more flexible operation of base-load generation technologies, in the Netherlands in particular the use of heat boilers at industrial CHP-locations, provides a cost-efficient solution for wind power integration. During periods of high-wind and low-load, the CHP-units may be decommitted, allowing the integration of additional wind power. This also prevents the operation of the CHP-units at a loss during low-load, high-wind periods. The development of additional interconnection capacity, for instance with Norway creates the largest additional technical space for wind power integration. A business case for this option largely depends on the synergies between the Netherlands' and Norwegian generation systems and cannot be made only for wind power integration.

7.2 Recommendations for Further Research

7.2.1 UC–ED Model Extension

The Netherlands is strongly interconnected to its neighbours in the UCTE-interconnection, to Norway and in the future also to Great Britain. Strong interconnections are very important for the further development of international electricity markets. As a result of the international trade in electricity between countries, generation planning and operation are becoming international rather than national affairs. Consequently, the system integration of wind power should no longer be investigated only for 'isolated' power systems. Even though national studies will continue to provide highly useful insights into power system operation with wind power, a national scope is likely to underestimate the technical possibilities for wind power integration in the power system.

In this research, important steps have been taken toward an international power system model for wind power integration studies. The UC–ED model should be extended further to include other European countries and especially the Scandinavian Nordel system. The Nordel system has a large impact on the marginal prices of the North-West European electricity markets and connection to the Scandinavian hydro reservoirs can be foreseen to play an important role for wind power integration in the future. In order to perform international studies it will be needed to include the transmission bottlenecks within countries or areas in a more profound way. All areas must be optimised simultaneously while subject to transmission constraints between or within areas. This way, inter-area exchanges are an integral result of the system optimisation with wind power, which is essential for a correct estimation of technical limits for wind power integration. Furthermore, a more unit-specific (rather than technology-specific) modeling approach should be applied to the generation systems outside the Netherlands.

7.2.2 Power Transmission and Load Flows

In further research, the extended UC–ED model should be used as an input for detailed load flow studies in order to determine the transmission limits for wind power integration. Instead of assuming a selected set of worst cases on beforehand, it is recommended to determine the worst-cases based on a large set of generation, wind power and load combinations following from UC–ED schedules. This UC–ED-based load flow analysis mirrors the operation of international electricity markets with an implicit auction of transmission capacity and the power flows resulting from the international transactions. Investigation of the worst cases derived from this analysis makes sure that the correct worst cases are captured and investigated: these cases are difficult to determine on beforehand for power systems with large-scale wind power.

7.2.3 International Trade and Markets

In this research, it has been shown that large amounts of wind power can be technically integrated into the power system. It has also been shown that international exchange is an important enabling factor for this. The extent to which interconnection capacity is indeed available for exchanges during moments of low-load and high-wind power, depends on the extent to which an international market is available to facilitate this. This market is governed by technical aspects (i.e. the technical characteristics of conventional generation units) but also on the organisation of the market itself (gate-closure times, auctioning of transmission capacities, market design for wind power, etc.). Additional research is necessary into the development of suitable international market designs to allow an efficient system integration of wind power.

7.2.4 Large-Scale Renewables and Energy Demand

At present, renewables such as wind power, geothermal and solar altogether supply less than 1% of energy demand worldwide [80]. With a substantially larger penetration, the variability and periodic unavailability of renewables presents a formidable challenge for existing energy systems in general, and for power systems in particular. The methodologies developed here for the power system integration of wind power are in principle applicable for a wide range of renewables, since most renewables have a limited controllability of their respective energy sources. Future research in the integration of renewables in existing energy systems should revolve around three questions: 1) How large are the differences in time and in size between the energy demand and the energy supply? 2) How do increased amounts of renewables influence these differences? 3) How can the differences between demand and supply be narrowed in the best possible way? The electricity system must be regarded as an integral part of a much larger energy supply system. The development of integrated solutions will require substantial research efforts.

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APPENDIX A

Wind Speed Measurement Locations

The 10-minute wind speed averages are measured in units of 0.1 m/s at 10 m sensor height for 18 locations (6 inland, 6 coastal, 6 offshore). These data are obtained for the period between May 31, 2004 and June 1, 2005. The locations of the relevant KNMI[1] wind speed measurement stations are listed in Table A.1. using local coordinates (Dutch coordinate system or Rijksdriekhoeks-coördinatenstelsel).

The 15-minute wind speed day-ahead forecasts are measured in units of 0.1 m/s at 10 m height for 7 locations (1 inland, 1 coastal, 5 offshore). The data are obtained for the same period for a forecast lead time of 12-144 hours ahead. Locations of numerical weather prediction stations are listed in Table A.2. Locations of all measurements stations are shown in Fig. A.1.

[1]Royal Dutch Meteorological Institute

Location	inland/coastal/offshore	X [m]	Y [m]
De Bilt	inland	140827	456835
Europlatform	offshore	10044	447580
F3	offshore	111995	763069
Gilze Rijen	inland	123731	397594
Hoek van Holland	coastal	65550	445050
Huibertgat	offshore	222037	621279
K13	offshore	10240	583356
Lauwersoog	coastal	209000	603125
Leeuwarden	inland	178970	581970
L.E. Goeree	offshore	36662	437913
Lelystad	inland	164125	497125
M. Noordwijk	offshore	80512	476658
Marknesse	inland	188850	523975
Stavoren	coastal	154725	545250
Texelhors	coastal	110125	556875
Vlissingen	coastal	30475	385125
Woensdrecht	inland	2820	384700
IJmuiden	coastal	98450	497450

Table A.1: KNMI 10-minute wind speed measurement locations (local coordinates) [185].

location	inland/coastal/offshore	X [m]	Y [m]
Cabauw	inland	123350	442580
Europlatform	offshore	10044	447580
EWTW1	coastal	131500	540250
F3	offshore	111995	763069
FINO	offshore	150100	635100
K13	offshore	10240	583356
NSW	offshore	89651	514267

Table A.2: Numerical weather prediction locations (local coordinates).

Figure A.1: Inland, coastal and offshore wind speed measurement and numerical weather prediction locations.

APPENDIX B

Wind Power Locations

Province	X [m]	Y [m]	Wind Power Scenario [GW] 2	4	6	8	10	12
Drenthe	204900	529750	10	50	100	100	100	100
Flevoland NE	172256	525694	300	450	600	600	600	600
Flevoland SW	163550	494771	340	500	550	550	550	550
Fryslân	167514	570971	150	200	300	300	300	300
Gelderland	176352	451416	12	50	100	100	100	100
Groningen	249610	601562	150	400	500	500	500	500
Limburg	201420	364190	10	50	100	100	100	100
Noord-Brabant	96752	406977	40	100	150	150	150	150
Noord-Holland	125986	528069	280	400	500	500	500	500
Overijssel	211800	512200	10	50	100	100	100	100
Utrecht	130289	458206	10	10	50	100	100	100
Zeeland	47490	387127	210	300	400	400	400	400
Zuid-Holland	70878	433166	250	400	400	400	400	400
Total			1772	3000	4000	4000	4000	4000

Table B.1: Onshore wind power capacities and locations (local coordinates).

Estimation of onshore wind power is based on present totals per province [189] and the location of onshore wind parks is determined by the weighed average of existing locations for each province. Locations and capacities of offshore wind park sites in Table B.2 are estimated based on [125], [189] and are exactly known for wind parks OWEZ and Q7.

Developer	Wind Park	X	Y	Wind Power Scenario [GW]					
		[m]	[m]	2	4	6	8	10	12
Airtricity	Breeveertien	52449	507423			350	350	350	350
E-Connection	Brown Ridge	24052	519080				270	270	270
Evelop	Bruine Bank	38123	515308				220	220	550
WEOM	Den Haag II	19244	461803			350	500	500	500
WEOM	Den Haag III	12412	464541					250	700
Raedthuys	Den Helder 3	71833	544381					450	450
Airtricity	Den Helder I	45396	547222				200	500	500
Airtricity	Den Helder II	40576	542001				100	500	500
WEOM	Den Helder Noord	71388	552880					400	800
Evelop	Helder	64201	547175				200	200	200
Evelop	Horizon	42922	518153						270
WEOM	Katwijk	57900	474771		350	350	350	350	350
Evelop	Noord Hinder	7007	461081				400	400	400
WEOM	OWEZ	89651	514267	105	105	105	105	105	105
Evelop	Q7	76244	511804	120	120	120	120	120	120
E-Connection	Q4-WP	61328	496025				100	100	100
Evelop	Riffgrond	196529	637927					200	500
E-Connection	Rijnveld Oost	49317	480077				110	110	110
Raedthuys	Scheveningen 5a	27172	479113				250	250	250
Raedthuys	Scheveningen 5b	22971	480485						250
Evelop	Scheveningen Buiten	43172	468099			300	300	300	300
Airtricity	West Rijn	35157	475917		275	275	275	275	275
WEOM	IJmuiden	74677	506653		150	150	150	150	150
Total				225	1000	2000	4000	6000	8000

Table B.2: Offshore wind park capacities and locations (local coordinates).

Figure B.1: Selected locations for onshore and offshore wind power.

APPENDIX C

German Wind Power Data

German wind power and forecast data obtained for this research comprise the following:

- E.ON: 15 min. averaged wind power data from June 1st, 2004 to May 31st, 2005 for installed capacity of 6427–7088 MW (May 18th, 2004 and June 13th, 2005), 15 min. averaged, hourly updated day-ahead forecasts from September 1st, 2004 to May 31st, 2005
- RWE: 15 min. averaged wind power data from June 1st, 2004 to May 31st, 2005 for unknown installed capacity (maximum output 2702 MW)
- Vattenfall Europe: 15 min. averaged wind power data from June 1st, 2004 to May 31st, 2005 for installed capacity of 5678–6400 MW (June 30st and May 31st, 15 min. averaged, hourly updated day-ahead forecasts from June 1st, 2004 to May 31st, 2005

The wind power and forecast data comprise the same period as the Netherlands' wind speed data series used in Chapter 2 in order to take automatically capture existing correllations between wind power output in both countries. Correlations between forecast and realised wind power were found to be 0.95 on average for the E.On Netz data and 0.90 for the Vattenfall Europe data, where it can be noted that the graphical area of the E.On Netz area is significantly larger. For the 2014 wind power forecast it is assumed that the total forecast correllation is 0.95. Based on statistics obtained from [51], German installed wind power capacity mid 2004 and mid 2005 comprised an estimated total of 15.600 and 17.500 MW, respectively. The wind power data above represent approximately 95% of installed capacity (with the E.ON area representing 40%, Vattenfall Europe 36% and RWE 19%), the wind forecast data represent about 40–76%.

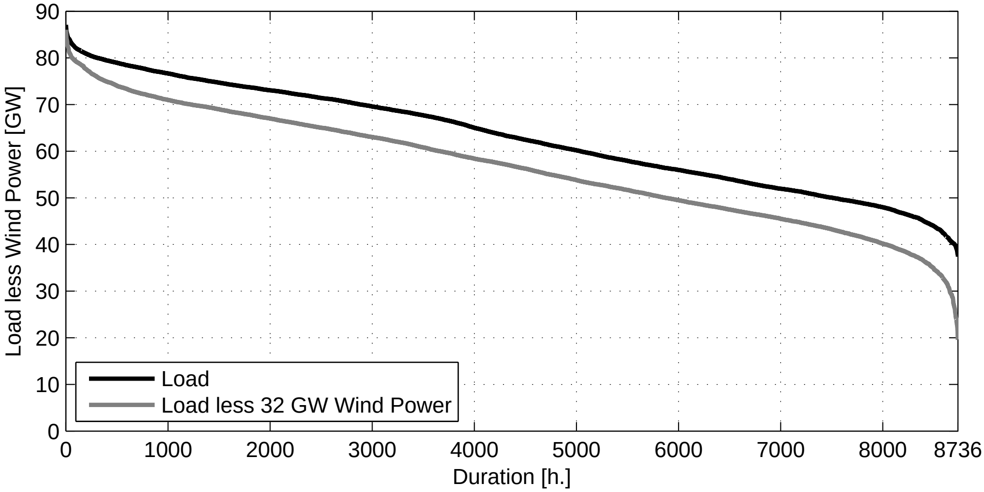

Figure C.1: Load and load-less-wind power duration curve for Germany in 2014.

In 2014, installed wind power capacity in Germany is foreseen to be 32.000 MW [171]. For the development of time series for wind power and wind power forecasts in 2014, the time series are scaled assuming wind power capacity is distributed similarly to the present distribution between the three areas. This estimation does not incorporate the larger geographical spread of wind power in Germany due to offshore wind parks, nor the higher capacity factors of these installations. The estimated load and load-less-wind power duration curves for Germany are shown in Fig. C.1.

APPENDIX D

Validation Test System Data

The data in this appendix are adopted from [8], [137] except for the last column of Table D.1 which is added for model validation purposes in this thesis only. Additional data used for this research are specified in Table 5.2, page 101. Bus 31 is assigned as the slack bus, generator G02 as the slack generator.

Table D.1: Bus data of the New England 39 bus test system.

Bus -	Volts [pu]	Load [MW]	Load [MVAr]	Gen. [MW]	Gen. Name
1	-	0	0	0	
2	-	0	0	0	
3	-	322.0	2.4	0	
4	-	500.0	184.0	0	
5	-	0	0	0	
6	-	0	0	0	
7	-	233.8	84.0	0	
8	-	522.0	176.0	0	
9	-	0	0	0	
10	-	0	0	0	
11	-	0	0	0	
12	-	7.5	88.0	0	

Continued on next page

Table D.1 – continued from previous page

Bus -	Volts [pu]	Load [MW]	Load [MVAr]	Gen. [MW]	Gen. Name
13	-	0	0	0	
14	-	0	0	0	
15	-	320.0	153.0	0	
16	-	329.0	32.3	0	
17	-	0	0	0	
18	-	158.0	30.0	0	
19	-	0	0	0	
20	-	628.0	103.0	0	
21	-	274.0	115.0	0	
22	-	0	0	0	
23	-	247.5	84.6	0	
24	-	308.6	-92.2	0	
25	-	224.0	47.2	0	
26	-	139.0	17.0	0	
27	-	281.0	75.5	0	
28	-	206.0	27.6	0	
29	-	283.5	26.9	0	
30	1.0475	0	0	250.0	G10
31	*0.982*	*9.2*	*4.6*	*520.8*	*G02*
32	0.9831	0	0	650.0	G03
33	0.9972	0	0	632.0	G04
34	1.0123	0	0	508.0	G05
35	1.0493	0	0	650.0	G06
36	1.0635	0	0	560.0	G07
37	1.0278	0	0	540.0	G08
38	1.0265	0	0	830.0	G09
39	1.03	1104.0	250.0	1000.0	G01
Total		6097.1	1408.9	6140.8	

Table D.2: Line data of the New England 39 bus test system.

Line Bus	Data Bus	Resistance [pu]	Reactance [pu]	Susceptance [pu]	Transformer Magnitude	Tap Angle
1	2	0.0035	0.0411	0.6987	0	0
1	39	0.0010	0.0250	0.7500	0	0
2	3	0.0013	0.0151	0.2572	0	0
2	25	0.0070	0.0086	0.1460	0	0
3	4	0.0013	0.0213	0.2214	0	0
3	18	0.0011	0.0133	0.2138	0	0

Continued on next page

Table D.2 – continued from previous page

Line Bus	Data Bus	Resistance [pu]	Reactance [pu]	Susceptance [pu]	Transformer Magnitude	Tap Angle
4	5	0.0008	0.0128	0.1342	0	0
4	14	0.0008	0.0129	0.1382	0	0
5	6	0.0002	0.0026	0.0434	0	0
5	8	0.0008	0.0112	0.1476	0	0
6	7	0.0006	0.0092	0.1130	0	0
6	11	0.0007	0.0082	0.1389	0	0
7	8	0.0004	0.0046	0.0780	0	0
8	9	0.0023	0.0363	0.3804	0	0
9	39	0.0010	0.0250	1.2000	0	0
10	11	0.0004	0.0043	0.0729	0	0
10	13	0.0004	0.0043	0.0729	0	0
13	14	0.0009	0.0101	0.1723	0	0
14	15	0.0018	0.0217	0.3660	0	0
15	16	0.0009	0.0094	0.1710	0	0
16	17	0.0007	0.0089	0.1342	0	0
16	19	0.0016	0.0195	0.3040	0	0
16	21	0.0008	0.0135	0.2548	0	0
16	24	0.0003	0.0059	0.0680	0	0
17	18	0.0007	0.0082	0.1319	0	0
17	27	0.0013	0.0173	0.3216	0	0
21	22	0.0008	0.0140	0.2565	0	0
22	23	0.0006	0.0096	0.1846	0	0
23	24	0.0022	0.0350	0.3610	0	0
25	26	0.0032	0.0323	0.5130	0	0
26	27	0.0014	0.0147	0.2396	0	0
26	28	0.0043	0.0474	0.7802	0	0
26	29	0.0057	0.0625	1.0290	0	0
28	29	0.0014	0.0151	0.2490	0	0
2	30	0.0000	0.0181	0.0000	1.025	0
6	31	0.0000	0.0250	0.0000	1.070	0
10	32	0.0000	0.0200	0.0000	1.070	0
12	11	0.0016	0.0435	0.0000	1.006	0
12	13	0.0016	0.0435	0.0000	1.006	0
19	20	0.0007	0.0138	0.0000	1.060	0
19	33	0.0007	0.0142	0.0000	1.070	0
20	34	0.0009	0.0180	0.0000	1.009	0
22	35	0.0000	0.0143	0.0000	1.025	0
23	36	0.0005	0.0272	0.0000	1.000	0
25	37	0.0006	0.0232	0.0000	1.025	0
29	38	0.0008	0.0156	0.0000	1.025	0

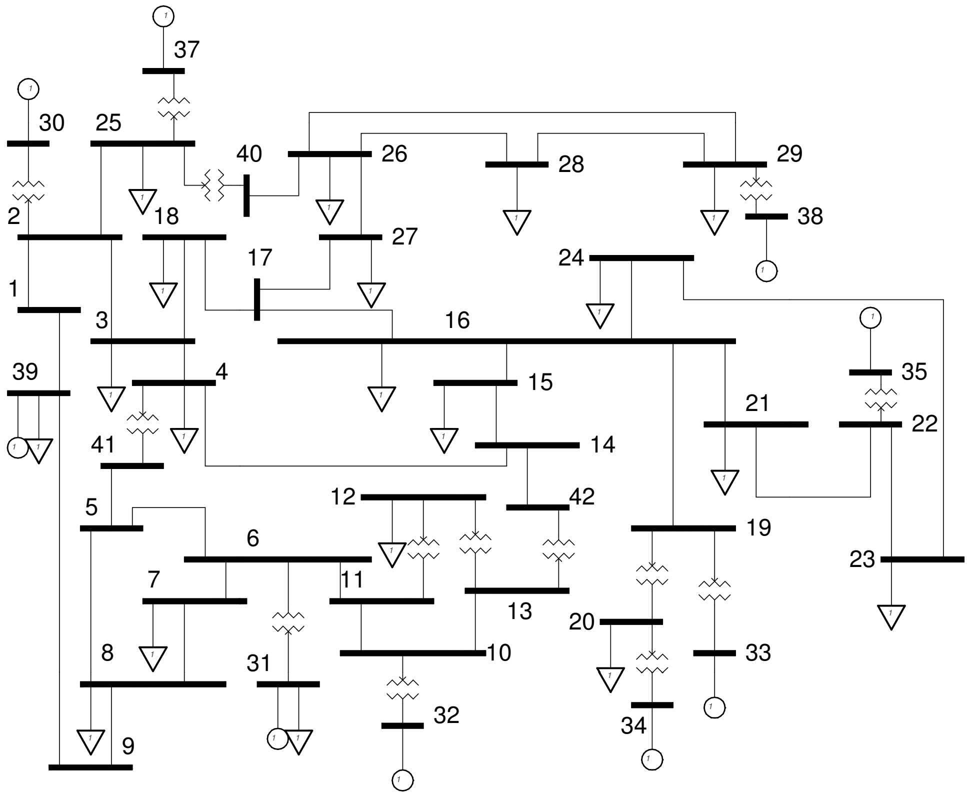

Figure D.1: Single line diagram of the New England 39 bus test system

APPENDIX E

Nomenclature

List of Abbreviations

ACE	Area Control Error
AGC	Automatic Generation Control
ARP	Access Responsible Party
B	Belgium
BF	Blast Furnace gas
BRP	Balance Responsible Party
CAES	Compressed Air Energy Storage
CCGT	Combined Cycle Gas Turbine
CCS	Carbondioxide Capture and Sequestration
CHP	Combined Heat and Power
CO_2	Carbondioxide
COI	Centre of Inertia
D	Germany
EC	Economic Optimisation
ENS	Energy-Not-Served
F	France
GB	Great Britain
GT	Gas Turbine
HIRLAM	HIgh-Resolution Limited Area Model
HVDC	High Voltage Direct Current

ISO	Independent System Operator
LOLP	Loss-Of-Load Probability
MLE	Maximum Likelihood Estimator
MR	Must Run
NG	Natural Gas
NL	The Netherlands
NN2	NorNed 2, submarine transmission cable between the Netherlands and Norway
NOR	Norway
NO_x	Nitrogen oxides
NTC	Net Transfer Capacity
NWP	Numerical Weather Prediction
O&M	Operation and Maintenance
PAC	Pumped ACcumulation energy storage
PACE	Processed ACE
PP	Perfect wind power Prediction
PRP	Program Responsible Party
PSD	Power Spectrum Density
PTU	Program Time Unit
RES	Renewable Energy Sources
RoR	Run-of-River
SO_2	Sulfurdioxide
ST	Steam Turbine
TSO	Transmission System Operator
UCTE	Union for the Coordination of Transmission of Electricity, association of transmission system operators in continental Europe
UC–ED	Unit Commitment and Economic Dispatch
UPAC	Underground Pumped ACcumulation energy storage
U	Uranium
WAMS	Wide Area Measurement System

List of Symbols

$2nd_{PRP,t}$	secondary control signal
a	inverse of characteristic distance [km^{-1}]
A	area [m^2]
A_r	swept turbine rotor area [m^2]
A_T	area per turbine location [m^2]
ACE_t	ACE at moment t [MW]
c_p	power coefficient of the wind turbine
$C_{1..8}$	cost level [€]
C_{var}	variable operation and maintenance cost [€/MWh]
$C_{m,sys}$	system marginal cost [€]
cov	covariance, correlation of wind speed variations between locations
D	distance or load damping reaction [MW/Hz]

D_{ave}	average distance scale [m]
D_{decay}	characteristic distance of the decay of correllation [m]
D_{min}	minimum distance [m]
D_{max}	maximum distance [m]
DT	downtime [h]
$E_{imb,PTU}$	energy program deviation [MWh]
f	frequency [Hz]
f_0	nominal frequency [Hz]
F	fuel cost [€/GJ]
d	change
g	graviational acceleration [m/s^2]
H	heat [GJ] or inertia constant of generators [s]
H_res	reservoir head level [m]
H_x	heat rate level or inverse of efficiency x [GJ/MWh]
id	market party identifier
J	rotational inertia of a mass [kgm^2]
K	Charnock's constant for surface roughness at sea
L_{esti}	Obukhov (or stability) length
L	length scale [m]
L_T	length scale per turbine location [m]
M	moment of inertia [MWs/Hz]
N	number of wind turbines
P	power [MW]
p	price [€/MWh]
$P_{2nd,dn,t}$	downward regulating power [MW]
$P_{2nd,up,t}$	upward regulating power [MW]
P_g	generating power [MW]
P_G	power generation [MW]
$P_{imb,t}$	power imbalance [MW]
P_L	load, power consumption [MW]
P_p	pumping power [MW]
P_r	rated power of generators [MW]
P_t	power at time t [MW]
P_{tie}	power over tie-lines [MW]
P_{wt}	wind turbine output power [W]
R	reservoir energy content [GWh]
R_{max}	maximum reservoir energy content[GWh]
R_{min}	minimum reservoir energy content [GWh]
S	start-up cost [€]
rr	ramping rate [MW/h]
t	time [s]
T	torque [Nm]
T_a	accellerating torque [Nm]
T_e	electrical torque [Nm]
T_m	mechanical torque [Nm]
u_*	friction velocity [m/s]

v	wind speed [m/s]
v_t	blade tip speed [m/s]
V_G	generating value of energy [€/MWh]
V_P	pumping value of energy [€/MWh]
$w(x,t)$	log wind speed at location x and time t
$z_1(x_1, y_1)$	location with parameters x_1 and y_1
z_h	location hub height [m]
z_s	location sensor height [m]
$\mathcal{N}(0,\sigma)$	zero-mean, normally-distributed term of standard deviation σ
β	power-frequency characteristic
$\gamma(t)$	zero-mean, normally-distributed noise term
Δ	deviation
$\epsilon(x,t)$	zero-mean random process variable for intra-day wind speed variations
η	net turn-around conversion efficiency
θ	blade pitch angle [$^\circ$]
κ	Von Kármán constant
λ	tip speed ratio between the turbine blade tip speed
$\mu(x,t)$	mean wind speed pattern at location x and time t [m/s]
$\mu(z_h)$	mean wind speed at wind turbine hub-height [m/s]
π	ratio of a circle's circumference to its diameter
ρ	density of air
σ_F	width of Gaussian filter F
$\sigma(z_h)$	standard deviation at hub height
$\sigma(z_s)$	standard deviation at sensor height
Σ	sum
$\phi(t)$	first-order auto-regressive moving average (ARMA) process
ω	rotational speed

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- IEA Wind Task 25, September 19, 2007, Oslo, Norway
- Dutch Wind Workshops, October 27, 2008, Delft University Wind Energy Research Institute (DUWIND)

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Curriculum Vitae

Bart Christiaan Ummels was born on July 27 1979, in IJsselstein, the Netherlands. He attended secondary school at the Adelbert College in Wassenaar, the Netherlands, where he graduated in 1997 (Gymnasium β, cum laude). He studied Integrated Engineering at the University of Reading, England for one year before studying Aerospace Engineering at Delft University of Technology, the Netherlands, until 1999. Between 1999 and 2004, he studied Systems Engineering, Policy and Management at Delft University of Technology. During his studies, he joined Eltra (now Energinet.dk), Transmission System Operator of Denmark, and KEMA T&D Consulting, the Netherlands for internships on the system integration of wind power and on power system operation. He obtained the M.Sc. degree with an annotation in sustainable technological development in November 2004, with a thesis on power system operation and sustainability. From 2004 to 2008, he has worked towards a Ph.D. degree in Electrical Engineering on power system operation with large-scale wind power. During his Ph.D, he has been involved in wind power integration studies for Dutch TSO TenneT. He has done a number of research projects on energy storage, wind power integration and long-term generation planning for the Dutch Ministry of Economic Affairs and the Transition Platform Sustainable Electricity Supply. In November 2008, he joined Siemens Wind Power in the Hague and Brande, Denmark as a technical project manager for the development of offshore wind parks. Furthermore, he lectures on sustainable energy and on wind power for the Stichting Post Hoger Onderwijs Energiekunde (PHOE) and writes and translates informative texts on wind power integration. Bart Ummels is married and has two daughters.

Our society revolves around electricity. Most electricity is produced from fossil fuels, such as coal and natural gas. The disadvantages are that their supply is finite and unevenly distributed across the earth. Conventional power stations also emit greenhouse gases. Therefore, sustainable alternatives must be developed, such as wind power. The disadvantages of wind are that it may or may not blow and that it is unpredictable. The generation of electricity must however always equal the consumption. This makes the integration of wind power in the electricity system more difficult.

This Ph.D.-thesis investigates the integration of wind power into the existing power system. Simulation models are developed and used to explore the operation of power systems with a lot of wind power. The simulations provide a picture of the reliability, cost and emission of CO_2 of the generation of electricity, with and without wind power. The research also takes into account electricity exchange on international markets. Possible solutions for integrating wind power, such as flexible power plants and energy storage, are investigated as well.