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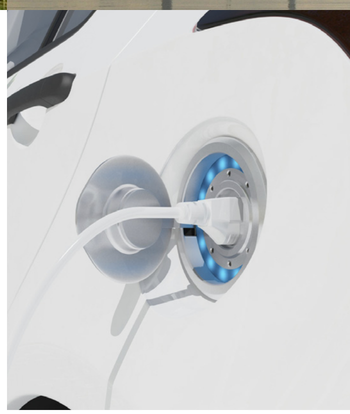

Managing wind power variability and uncertainty through increased power system flexibility

Juha Kiviluoma

VTT SCIENCE 35

Managing wind power variability and uncertainty through increased power system flexibility

Juha Kiviluoma

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Managing wind power variability and uncertainty through increased power system flexibility

Tuulivoimatuotannon vaihteluiden ja epävarmuuden hallinta parantamalla sähköjärjestelmän joustavuutta. **Kiviluoma, Juha.** Espoo 2013. VTT Science 35. 77 p. + app. 88 p.

Abstract

Variability and uncertainty of wind power generation increase the cost of maintaining the short-term energy balance in power systems. As the share of wind power grows, this cost becomes increasingly important. This thesis examines different options to mitigate such cost increases. More detailed analysis is performed on three of these: flexibility of conventional power plants, smart charging of electric vehicles (EVs), and flexibility in heat generation and use. The analysis has been performed with a stochastic unit commitment model (WILMAR) and a generation planning model (Balmorel).

Electric boilers can absorb excess power generation and enable shutdown of combined heat and power (CHP) units during periods of high wind generation and low electricity demand. Heat storages can advance or postpone heat generation and hence affect the operation of electric boilers and CHP units. The availability of heat measures increased the cost optimal share of wind power from 35% to 47% in one of the analysed scenarios.

The analysis of EVs revealed that smart charging would be a more important source of flexibility than vehicle-to-grid (V2G), which contributed 23% to the 227 €/vehicle/year cost savings when smart charging with V2G was compared with immediate charging. Another result was that electric vehicles may actually reduce the overall CO_2 emissions when they enable a higher share of wind power generation.

Most studies about wind power integration have not included heat loads or EVs as means to decrease costs induced by wind power variability and uncertainty. While the impact will vary between power systems, the thesis demonstrates that they may bring substantial benefits. In one case, the cost optimal share of wind-generated electricity increased from 35% to 49% when both of these measures were included.

Keywords wind power, unit commitment, economic dispatch, generation planning, energy balance, electric boiler, heat storage, heat pump, electric vehicle, hydro power, flexibility, variability, uncertainty

Tuulivoimatuotannon vaihteluiden ja epävarmuuden hallinta sähköjärjestelmän joustavuutta parantamalla

Managing wind power variability and uncertainty through increased power system flexibility.
Kiviluoma, Juha. Espoo 2013. VTT Science 35. 77 s. + liitt. 88 s.

Tiivistelmä

Tuulivoimatuotannon vaihtelevuus ja ennusvirheet lisäävät energiatasapainon ylläpitämisen kustannuksia sähköjärjestelmissä. Tuulivoiman osuuden kasvaessa näiden kustannusten suhteellinen merkitys kasvaa. Tämä väitöskirja tutkii eri tapoja lieventää kustannusten nousua lisäämällä järjestelmän joustavuutta. Tarkempi analyysi on tehty kolmelle eri menetelmälle: perinteisten voimalaitosten joustavuuden lisääminen, sähköautojen älykäs lataaminen sekä lämmön tuotannon ja kulutuksen mahdollisuudet joustavuuden lisäämisessä. Analyysit on tehty stokastisella ajojärjestysmallilla (WILMAR) sekä investointimallilla (Balmorel).

Sähkökattilat voivat hyödyntää liiallista sähköntuotantoa ja samalla mahdollistaa sähkön ja lämmön yhteistuotantolaitosten alasajon ajanjaksoina, jolloin tuulivoimatuotanto on suurta ja kulutus vähäistä. Lämpövarastot voivat siirtää lämmöntuotannon ajoitusta ja sitä kautta lisätä sähkökattiloiden sekä sähkön ja lämmön yhteistuotantolaitosten joustavia käyttömahdollisuuksia. Tulokset indikoivat merkittävää potentiaalia suhteellisen pienillä kustannuksilla.

Analyysin mukaan sähköautojen älykäs lataaminen tarjoaa enemmän joustavuutta kuin sähkön syöttö verkkoihin sähköautoista tarvittaessa. Sähkönsyötön osuus älykkään lataamisen kokonaissäästöistä (227 €/auto/vuosi) oli 23 %. Toinen tulos oli, että sähköautot näyttäisivät vähentävän sähköntuotannon päästöjä, koska niiden tuoma joustavuus johtaa entistä suurempaan tuulivoiman osuuteen sähköjärjestelmässä.

Suurin osa tuulivoiman vaihtelevuuden ja ennusvirheiden kustannuksia arvioineista tutkimuksista ei ole huomioinut sähköautojen tai lämmön tuotannon ja kulutuksen mahdollistamaa lisäjoustavuutta. Vaikutukset vaihtelevat järjestelmästä toiseen, mutta väitöskirja osoittaa, että näistä voidaan saada merkittäviä hyötyjä. Yhdessä tutkitussa tapauksessa tuulivoiman kustannustehokas osuus kasvoi 35 %:sta 49 %:iin, kun sekä lämmön kulutuksen että sähköautojen joustavuus huomioitiin.

Avainsanat wind power, unit commitment, economic dispatch, generation planning, energy balance, electric boiler, heat storage, heat pump, electric vehicle, hydro power, flexibility, variability, uncertainty

Preface

This doctor's thesis was carried out at the VTT Technical Research Centre of Finland, presently in the Wind Integration team at the Energy Systems Knowledge Centre. The main source of financing for the thesis was Fortumin Säätiö (Fortum Foundation). Part of the work received financing from Tekes through national IEA Wind collaboration projects and the SGEM research programme. The EU has financed the work through the FP5 project Wind Integration in Liberalised electricity MARkets WILMAR. A year-long research fellowship at the Kennedy School of Government at Harvard University was made possible by a joint grant from the ASLA-Fulbright and Helsinki University of Technology.

I am deeply grateful for the support and joint research efforts of my instructors Dr. Hannele Holttinen and Dr. Peter Meibom. My supervisor, Prof. Peter Lund, has been encouraging and helpful through my PhD studies and has provided valuable comments on the thesis. I have also received comments from Prof. Liisa Haarla and Dr. Ritva Hirvonen, for which the reader should be grateful as they have greatly improved the readability of the thesis. I would like to thank my co-authors for their contributions and for the valuable lessons on how to write journal articles. I am also indebted to my colleagues with whom I had the privilege to work during the course of the thesis. Special thanks to the WILMAR project participants, my colleagues at IEA Wind Task 25, and my friends from the YSSP 2006 at IIASA as well as the Kennedy School during 2007–2008. I am extremely grateful for the opportunity to work with my colleagues at VTT from whom I have learned much during these years.

During the course of the dissertation, two new family members emerged and changed my life. Thanks to Heimo and Lenni for being. My wife Katri is due dual thanks. First, she contributed to my research and this thesis through her immense abilities for critical thinking. Second, thanks for being with me.

Helsinki, June 2013
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Academic dissertation

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List of publications

This thesis is based on the following original publications, which are referred to in the text as I–VIII. The publications are reproduced with kind permission from the publishers.

I Lu Xi, McElroy MB and Kiviluoma J, Global potential for wind-generated electricity. Proc. Nat. Acad. Sci., Vol. 106, No. 27, pp. 10933–10938, 2009.

II Kiviluoma J, Meibom P, Tuohy A, Troy N, Milligan M, Lange B, Gibescu M and O'Malley M, Short Term Energy Balancing With Increasing Levels of Wind Energy. IEEE Trans. Sustain. Energy, Vol. 3, No. 4, pp. 769–776, 2012.

III Meibom P, Kiviluoma J, Barth R, Brand H, Weber C and Larsen HV, Value of electric heat boilers and heat pumps for wind power integration. Wind Energy, Vol. 10, pp. 321–337, 2007.

IV Kiviluoma J and Meibom P, Influence of wind power, plug-in electric vehicles, and heat storages on power system investments. Energy, Vol. 35, No. 3, pp. 1244–1255, 2010.

V Kiviluoma J and Meibom P, Flexibility from district heating to decrease wind power integration costs. In: Proc. of the 12th International Symposium on District Heating and Cooling, pp. 193–198, Tallinn, Estonia, 5–7 Sep. 2010.

VI Kiviluoma J and Meibom P, Coping with wind power variability: how plug-in electric vehicles could help. In: Proc. of the 8th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Farms, pp. 336–340, Bremen, Germany, 14–15 Oct. 2009.

VII Kiviluoma J and Meibom P, Methodology for modelling plug-in electric vehicles in the power system and cost estimates for a system with either *smart* or *dumb* electric vehicles, Energy, Vol. 36, No. 3, pp. 1758–1767, 2011.

VIII Kiviluoma J and Meibom P, Decrease of wind power balancing costs due to smart charging of electric vehicles. In: Proc. of the 10th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Farms, pp. 501–506, Aarhus, Denmark, 25–26 Oct. 2011.

Author's contributions

In Publication I, the author contributed to the understanding of wind energy resources, and participated in the data analysis and writing of the paper. In Publication II, the author was the main writer of the paper and participated in its design. In Publication III, the author participated in the writing and design of the paper and performed most of the analysis of the results. In Publications IV, V, VI, VII and VIII, the author was the main writer and performed most of the data analysis. The design was done together with the co-author, and the co-author performed the Balmorel model runs, while the author performed the WILMAR model runs.

The author has also contributed to the development of the WILMAR planning tool including the module on electric vehicles (Publication VII), the databases containing the input and output data (Kiviluoma and Meibom 2006) and the joint market model of WILMAR (Meibom *et al.* 2006, p. 4). The author has not participated in the writing of the journal or conference publications that document the WILMAR core model.

Contents

List of abbreviations

AA-CAES	Advanced adiabatic compressed air energy storage
AC	Alternative current
CAES	Compressed air energy storage
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CHP	Combined heat and power
CO_2	Carbon dioxide
COP	Co-efficient of performance
DC	Direct current
DR	Demand response
DSM	Demand side management
EV	Electric vehicle
EWIS	European wind integration study
EWITS	Eastern Wind Integration and Transmission Study
FLH	Full load hours
GAMS	General Algebraic Modeling System
GHG	Greenhouse gas
GW	Gigawatt
HVDC	High voltage direct current
JMM	Joint market model
LP	Linear programming
LTM	Long term model
MIP	Mixed integer programming
NTC	Net transfer capacity
O&M	Operation and maintenance
OCGT	Open cycle gas turbine
OTC	Over-the-counter
PHEV	Plug-in hybrid electric vehicle
TCL	Temperature-controlled load
V2G	Vehicle-to-grid
WILMAR	Wind power integration in liberalised electricity markets
WWSIS	Western Wind and Solar Integration Study

1. Introduction

Power generation from wind is variable – even if aggregated generation in a large power system is considered. It is also uncertain, because it is not possible to fully predict wind generation. When the share of wind power in a power system is small, these qualities only have a minor impact on the short-term energy balance of the power system. If the share of wind power grows, the associated variation and uncertainty will start to overshadow the existing variation in and uncertainty of electricity demand and power plant availability (Holttinen *et al.* 2011b). At the same time, maintaining the short-term energy balance in the power system will become more expensive. The research for this thesis focuses on how such cost increases could be mitigated. The analysis concentrates on three options: flexibility from conventional power plants, smart charging electric vehicles, and flexibility from heat generation and heat use.

The research problem is becoming increasingly important because wind power is already an important source of new power generation. The global wind power capacity grew by 38.3 GW in 2010 (GWEC 2011), which corresponds to approximately 80 TWh annually. In comparison, the average annual increase in global electricity generation has been 473 TWh a year from 1990 to 2010 (BP 2011). Meanwhile, the annual installed wind capacity has doubled on average every 3 years between 1991 and 2009 (BTM 2009, GWEC 2011). The growth stagnated in 2010 and fell in 2011–2012, but if wind power manages to get back on the growth track after the current economic turmoil, it could become the largest source of new electricity generation globally. The technical potential for wind-generated electricity is many times greater than the global electricity demand (Jacobson and Archer 2012).

While the market share of wind power is growing, it takes time for power systems to change. Wind power has reached a sizable share of the total electricity generation in only a few balancing areas or synchronous systems, while many others are planning large increases. As part of the planning for a large increase in wind power generation, studies have been conducted to analyse the costs of the variability and prediction errors of wind power as well as the benefits of reduced fuel use due to wind power generation. These studies usually analyse the costs to integrate wind power penetration levels of 5–25% in terms of produced electricity (review in Holttinen *et al.* 2011a, IPCC 2011 Section 8.2.1).

A more flexible power system can integrate variability and uncertainty at lower cost (Chandler 2011). Flexibility is influenced by the types and numbers of power plants in the system, the availability of reservoir hydro power or pumped storage, transmission lines to other power systems, transmission constraints within the system, and availability of demand response including electricity use in transport and heat generation. This thesis attempts to estimate the economic limits for wind power penetration when taking into account relevant options to increase the capabilities of the power system to cope with the increased variation and uncertainty

The important research task of finding cost-effective ways to increase power system flexibility for the short-term energy balance is highly justified. This thesis examines the options mentioned in the above paragraph more closely. Increased flexibility of a power system will not only help wind generation but also enable other forms of power generation to operate more efficiently. The aim of the analysis is therefore operational system costs rather than wind integration costs, which are difficult to isolate from the simultaneous benefits (Milligan *et al.* 2011).

The focus of the analysis is on a future Nordic power system characterised by large-scale reservoir hydro power and district heating systems with combined heat and power generation. Publication III covers the whole Nordic power system as well as Germany. Publications IV–VIII are based on data from Finland only. The latter articles have used a generation planning model to replace retired generating units and to meet the demand increase. Therefore, the resulting power system is not that of Finland but rather a result of the cost assumptions made for the articles together with some data from Finland. The results may apply to other systems as well, but they are then subject to interpretation.

Wind power is not the only new variable form of power generation. Much of the analysis also has relevance to solar power and other variable sources of power (e.g. run-of-river hydro, tidal and wave power). These are not explicitly modelled, as wind has been the dominant new source of variable power.

The models used for the analysis minimise the total system costs. They do not try to maximise the profits of the market participants as assumedly happens in real life. However, the end result should be the same if the markets were perfectly competitive and all the market actors had the same information. However, this is not the case in real life. Therefore, the results can either be interpreted as approximations of what would happen in power markets or they can be seen from the perspective of a central planner who optimises the social surplus.

Some aspects of power system operation have been excluded from the study. For the analysis, the power grid has been simplified into net transfer capacities (NTC) between different regions. This approach ignores real power flows, which will often force restrictions in the actual dispatch of power plants. The inclusion of power flows in the analysis of this study would reveal additional costs, especially at high wind power penetration levels and hence decrease the cost-optimal share of wind power in the system. However, the analysis that compares different ways to integrate wind power is less affected by the omission of power flows.

There are also other grid issues not dealt with in this dissertation, including system stability in case of faults, adequacy of system inertia, small signal stability, dynamic transients and voltage stability. While these are necessary aspects to secure reliable operation of the system, their effect on the first-order economic optimisation of the system is usually limited.

The flexibility of charging and discharging electric vehicles will be dependent on the possible bottlenecks in distribution grids, but it was not possible to include this aspect as distribution grids were not modelled.

Another limitation concerns the costs of future technologies. It was necessary to make a large number of assumptions concerning future costs. A guiding principle behind the assumptions was to try out cost scenarios in which wind power covered a high share of electricity consumption. The assumptions are not predictions of what is going to happen but should be seen as 'what if' scenarios.

A further issue is whether the current market designs provide incentives to ensure sufficient investment in flexibility and capacity adequacy (e.g. Milligan *et al.* 2012). However, this is beyond the scope of the thesis.

The structure of the thesis is the following. Chapter 2 outlines the research issues and the research task more closely and is partially based on Publication II. The literature review in Chapter 3 surveys different possibilities for flexibility. The main tools for the analysis are presented in Chapter 4. These include the generation planning model Balmorel and the unit commitment model WILMAR. These have been used to optimise and analyse the economic operation of power systems with a high penetration of wind power. A closer analysis is performed on some of the flexibility options: the use of conventional power plants, electric vehicles, and heat generation and heat storages (Chapter 5). Chapter 6 discusses the results and Chapter 7 concludes the thesis.

2. Research issues

This chapter provides a background to the main characteristics of wind power that alter the functioning of the power system: variability (Section 2.1) and uncertainty (Section 2.2). Increased variability and forecast errors will impact the mechanisms used to maintain the short-term energy balance (Section 2.3) in an energy system. Wind power will also change investments in other generation (Section 2.4). Lastly, the chapter provides rationale for studying high wind power penetration levels (Section 2.5).

2.1 Variability of wind power generation

The variability in generation from a single wind turbine can be great, but the variability will smooth out considerably as the level of aggregation increases (Holttinen *et al.* 2011b). Wind power generation from a single turbine has quite high variation and includes many hours of zero and full outputs. However, this is not important from the perspective of a power system, as the output from one wind turbine is miniscule in comparison with the average power system size. Under normal operation, the output from a wind power plant with multiple turbines is more stable than the output from a single turbine, as wind gusts are smoothed out over many wind turbines. Furthermore, wind shade from other turbines and non-operational turbines decrease the time with full output. The smoothing continues as the level of aggregation increases. Aggregated wind power generation within a market zone will be smoothed considerably compared with a single wind power plant. The smoothing will be influenced by the number of separate wind power plants, how well the capacity is dispersed between the wind power plants, and how distant the wind power plants are from each other. When multiple market zones are combined, the smoothing will continue as displayed in Figure 1.

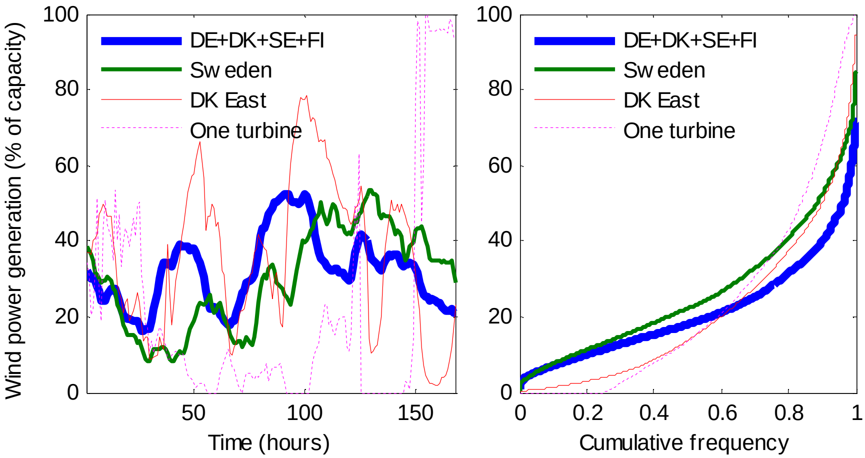

Figure 1. Typical variation in wind power generation on different geographical scales. The left figure displays one week of data from 2010. The right figure shows two years (2010 and 2011) of hourly data sorted by generation level. The aggregated generation for the four countries has been created by calculating a weighted average of the capacity factor for each hour. Germany had a weight of three, and other countries had a weight of one. (Finnish Energy Industries/VTT, Amprion, 50hertz, TenneT, TransnetBW, Energinet.dk, Svenska Kraftnät).

A change in aggregated wind power output can be faster and bigger than a change in demand. It can increase or decrease the rate of change in residual demand (demand net of wind generation), which needs to be met by conventional power plants or by demand-side measures. However, unlike the output from a single wind farm, wind power from a control area does not usually ever generate at full power. If the area is small, there can be weather events when all turbines are facing sustained winds inside the full output range of 12–25 m/s wind speeds, but these are rare. Even during these events, some turbines will not be functional due to repairs or maintenance and thus the output will not be full. Swings in output as well as the maximum output decrease as the area becomes larger, although what really matters is the distance between different wind power sites and how the weather patterns may lie across the area. Wind power variability in different power systems has been described in Holttinen *et al.* (2011b).

Variation in wind power creates costs for the power system. At first, when wind power is a small component of the total electricity generation, the variation creates very small costs. At this point, the variation in demand is much greater. Nearly half of the time, wind power reduces the overall variation and hence the impact remains low (Holttinen *et al.* 2011b).

As the share of wind power of the total generation grows, the variability has three mechanisms that increase power system costs. These are general principles; the actual costs will also depend on the operational practices.

1) When wind power increases the variation in the system, it can cause situations that would not have taken place otherwise. For example, during a low demand event with high wind power generation, it is more likely that a baseload unit has to operate at part load instead of full load. The baseload unit makes room for the wind generation if there is nothing else to back down. In part-load operation, most generation units use more fuel per generated unit of electricity, and part-load operation may increase the need for maintenance. This cost could be avoided if less costly flexibility were available. Meanwhile, the generated wind power decreases the overall cost of operating the system as, despite the decreased efficiency, fuel use is reduced in relation to wind generation. The exception to this is when wind power replaces other non-fuel generation that cannot be used later, such as run-of-river hydro power.
2) The portion of the time that wind power will increase the rate of change in residual demand, which will affect the ramping of conventional power plants. If ramp rates are fast, power plants with faster ramping capability may have to be used in addition to the most economic ones[1]. For example, in a situation in which demand is going up and wind generation is going down, low marginal cost units with a slow ramp up rate are slowly ramping up, but they have to be helped by faster ramping units. These can be ramped back down once the slower units have been fully ramped up, but an extra cost will have been incurred.
3) In the power system planning timescale, more variable residual demand will increase the attractiveness of more flexible power plants over less flexible plants. More flexible plants will have higher investment costs or higher operational costs than less flexible power plants. The former happens if a power plant is made more flexible by increasing start-up and ramping capabilities. The latter takes place if efficiency is reduced in order to gain flexibility (e.g. choosing an engine power plant instead of a combined cycle power plant).

Figure 2 and Figure 3 give an indication of the effect of wind power variability on the power system. The demand curve shows the variability present in the Nordic system in 2011. When large-scale wind power generation is subtracted from the demand, the remaining residual demand shows the new variability in the system. Without wind, the system has variation from winter to summer as well as some daily variation. Wind generation will decrease the average difference between summer and winter, but the variation in the daily timescale will be of a different magnitude.

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[1] An energy-only market does not appreciate the full extent of the ramping capability. It only pays for energy during those periods when ramping is required. There is discussion on whether there should be a separate ramping product in order to assign value to the ramping capability (e.g. Milligan *et al.* 2012).

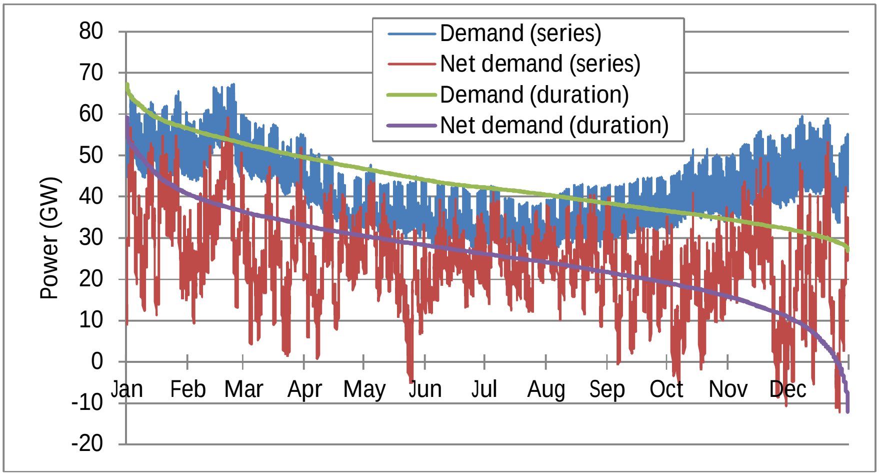

Figure 2. One year of time series for demand (blue) and residual demand (red) for the Nordic countries. The green and purple lines have been sorted in descending order (duration curves). Wind power has been scaled up to cover 40% of the electricity consumption in each country. The data are from 2011. (Finnish energy industries/VTT, Svenska Kraftnät, Energinet.dk, for Norway wind speeds from Rienecker *et al.* 2011 converted to wind generation by the author).

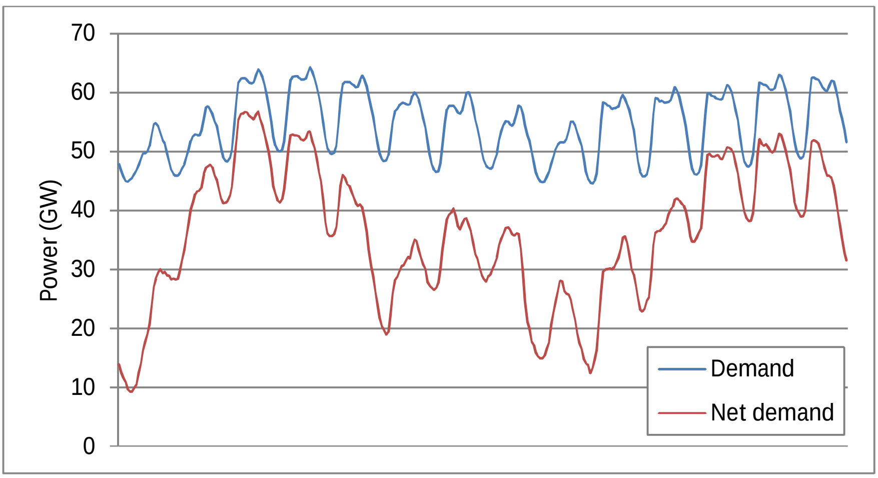

Figure 3. Two weeks of hourly demand (blue) and residual demand (red) for the Nordic countries. Wind power has been scaled up to cover 40% of electricity consumption in each country. The data are from January 2011. (Finnish energy industries/VTT, Svenska Kraftnät, Energinet.dk, for Norway wind speeds from Rienecker *et al.* 2011 converted to wind generation by the author).

The increased variability will increase the benefits of flexibility in new investments. The thesis explores this, especially in Publication IV. On the other hand, variability does not necessarily require many changes to the current practice in the upkeep of the short-term energy balance. The market rules and grid codes can accommodate variability as long as there are power plants and demand-side resources available that can change their behaviour in relation to wind and demand variability. Uncertainty, on the other hand, could have a much bigger impact on market rules and grid codes, as will be explored in the next two sections.

2.2 Uncertainty due to forecast errors

Just like errors in demand forecast, errors in wind power forecasts after the clearing of the day-ahead market have to be corrected with the help of the intra-day market and the balancing market[2]. The markets pool together balancing resources and should therefore find the least cost solutions to correct the sum of all upward and downward errors. However, individual power producers have an incentive to reduce forecast errors as fewer errors mean lower costs over time. In addition to demand and wind power forecast errors, unexpected power plant failures, run-of-river hydro power, solar power, and wave power create forecast errors.

When the wind power forecast error is in the same direction as the demand forecast error, the need for balancing power will increase. Likewise, when the wind power forecast error is in the opposite direction to the demand forecast error, the need for balancing power will decrease – unless the wind power forecast error is greater than the demand forecast error. In this case, the wind power forecast error first changes the sign of the overall system error and then starts to increase the error in the new direction.

Similarly to variation, as wind power penetration increases, the need for correcting forecast errors increases. At the very high levels of penetration, wind power will dominate the intra-day and the regulation power market because demand is more predictable than wind. The accuracy of the wind forecast is quite dependant on the length of the forecast (Figure 4).

[2] The balancing market is called the joint Nordic regulation market in the Nordic power system.

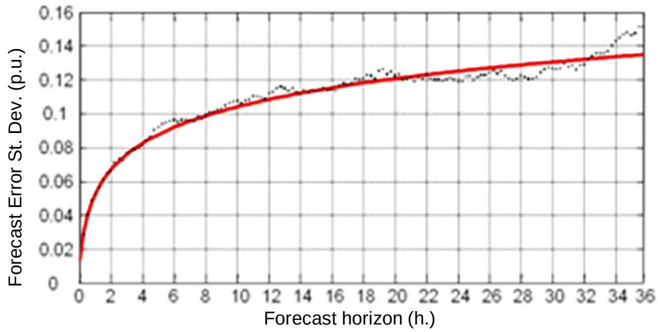

Figure 4. Normalised standard deviation of a wind power forecast error for 12 GW installed capacity versus a forecast horizon (Gibescu *et al.* 2009).

Forecast errors for single wind farms can be quite big. Aggregation of many wind farms over a dispersed area reduces the forecast error, since the correlation of forecast errors typically decreases with distance. The aggregated forecast error of all the wind farms in a power system spanning hundreds of kilometres is therefore much smaller than the forecast errors for individual wind farms (e.g. the st.dev of the forecast error is about half when the region diameter is about 700 km in Giebel 2011). However, the forecast error distributions have thick tails – there are rare occasions when the forecast error is very big (Giebel 2011). These can be challenging for power system operation.

2.3 Power markets and power system operation

In a power system there has to be a balance between demand and generation at all times. The demand for electricity changes according to the needs of the electricity consumers. The balance is maintained mainly by adjusting generation, although some forms of demand can also be adjusted. There are also generation forms that use by-passing energy flows (wind power, run-of-river hydro power and PV). It is usually not worthwhile to adjust these, since it would mean the loss of practically free electricity. An increase in wind power makes it more difficult to maintain the balance, especially if no modifications are made to the way the power system is operated. This thesis explores ways to maintain the balance in a cost-effective manner considering mainly timescales of one hour and higher.

In market-based power systems, the short-term energy balance is achieved through a combination of markets and reserves. As the cases analysed in this thesis are from the Nordic power system, it is used as an example power system in the next paragraphs; other market-based power systems often have similar conventions. The models used in the dissertation try to approximate the Nordic market structure. The operational model (WILMAR) minimises the operational costs of the system, which should lead to the same end result as markets, if the markets are perfectly competitive and all market players have the same information.

The long-term capacity adequacy is maintained through investments in generation capacity while interties, load shedding and demand response may also contribute. The Nordic power market is an energy-only market and hence there are no direct payments for capacity. In an energy-only market, the revenue to justify investments in peak load power plants should come from energy and ancillary service markets through scarcity pricing (Hogan 2005). The generation planning model (Balmorel) used in the thesis minimises the total system costs. The resulting generation portfolio is likely to differ from a portfolio developed by market actors. Investors will consider risks and expected profits.

Starting from investments, Figure 5 shows the timeline of decisions in power system planning and operations, which will be explained below.

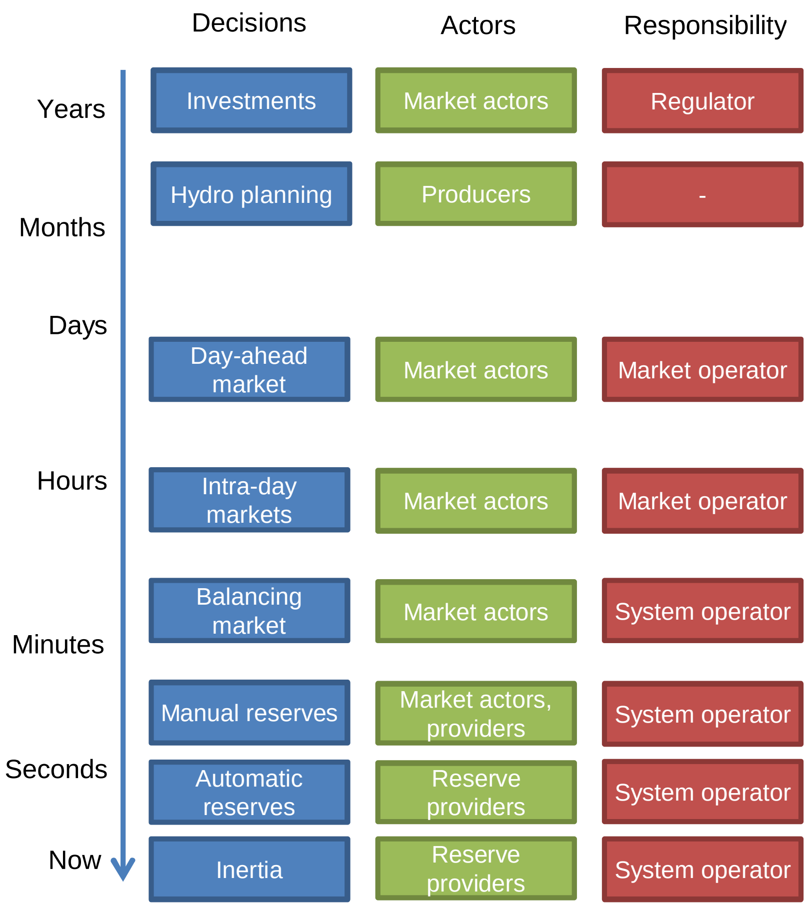

Figure 5. A timeline of decisions affecting generation in power system planning and operations.

The use of reservoir hydro power and other resource-constrained generation forms needs to be planned with a longer term view (from days to years). The value of water in hydro reservoirs is related to the expected revenue from future sales in the hydro plants downstream of the reservoir. The expected sales price depends on the operational costs of generation that hydro generation is likely to replace. The WILMAR model includes a separate model to estimate the water value. In some of the model runs, WILMAR was forced to stay close to the historical water levels because the water value model led to excessive hydro spillage. Balmorel was optimised with a whole year at a time while the end level for the reservoir content was forced.

At the hourly level, the balance between generation and demand was found by using bids made to electricity markets. Hourly electricity markets consist of day-ahead market (ElSpot in Nord Pool ASA), intra-day market (ElBas) as well as over-the-counter (OTC) trades. ElSpot takes place 12–36 hours before the hour of delivery. ElBas closes one hour before delivery, which allows market participants to react to changes that have taken place after ElSpot has closed. The trading volumes in ElBas are small in comparison with ElSpot and hence there is less liquidity. The WILMAR model simulates the ElSpot market solution and approximates the ElBas market together with the Nordic regulation market, as explained in the next paragraph.

During the hour of operation, the electricity demand is not exactly the same as that predicted by the markets before they closed. A further complication is that the demand varies within the hour. Power plants can also fail to generate what they bid due to unavailability of the plant or forecast errors in the energy resource such as wind. The resulting deviation between generation and demand are eliminated by a system consisting of a joint Nordic regulation market, manual reserves and automatic reserves. The Nordic regulation market is the primary source for balancing. The power plant owners make bids to the regulation market before the hour of operation. The Nordic regulation market should not be confused with automatic regulation used in some other power systems.

Frequency deviations within the normal operating range (49.9–50.1 Hz) are first corrected by governor action in power plants in which power plant speed governors sense the frequency and automatically adjust the power output to increase or decrease the frequency. In the Nordic system, this automatic reserve is called the frequency-controlled normal operation reserve, and the responsibility is divided between the different subsystems (Nordel 2007).

If deviations stack up in one direction, the automatic capacity could run out. To avoid this, the system responsible calls power plants from the joint Nordic regulation market to relieve the automatic units. The balancing units have to deliver in 15 minutes.

In addition to the operational reserves, upward disturbance reserves are maintained to ensure a secure system during faults. A frequency-controlled disturbance reserve is automatically activated if the frequency drops below 49.9 Hz and it should be completely activated if the frequency goes down to 49.5 Hz. It consists of power plants and load shedding. In contrast, fast active disturbance reserves are activated manually. They are used to restore the frequency-controlled disturbance reserves. The reserve consists of the transmission system operator's own power plants, contracted power plants, load shedding, the Russian DC link and voluntary bids from the regulation market. The distinction between operational and disturbance reserves is a matter of convention and does not exist in all power systems. Only the capacity procurement for the reserves was included in the WILMAR and Balmorel models.

In the upkeep of the balance as well as the procurement of the reserves it is necessary to take transfer restrictions in the power grid into account. Any foreseeable change in demand or generation cannot be allowed to overload any part of the transmission system. This has to be taken into account by enforcing constraints on the market-based unit dispatch or by using power plants out of the merit order during the operational phase. Only net transfer capacities were used in the model runs for the thesis articles.

2.4 Impact of wind power on generation investments

Thermal power plants, especially intermediate power plants, will have fewer full load hours per year when wind generation replaces thermal generation. At higher wind power penetration levels (tens of per cent of annual energy; depending on the specific power system), the generation from baseload power plants will also be replaced. If the increasing share of wind power is predicted well before it happens, the power generation fleet should change to contain more flexible intermediate and peak load thermal power plants. This is a response to the change in the residual demand duration curve (Figure 2 green and purple lines) as well as increased variability (Figure 2 blue and red lines) and uncertainty. In terms of power plant flexibility, the turn-down ratio is especially important as units that can operate at a low minimum load factor can avoid extra starts and stops (Shortt *et al.* 2013). As peak power plants replace more expensive capacity, the total investment costs in power plants, excluding wind power investments, are reduced.

However, the rise of wind power has been fast and for the most part underpredicted. The result has been more intermediate and/or baseload capacity than would be necessary – at least in the short term (for current capacity adequacy in Europe see ENTSO-E 2012). These stranded investments are a cost factor from the system perspective but have not been analysed in this thesis.

There is also on-going discussion on whether there is sufficient incentive to build enough peak load capacity in the future, partially due to the increasing revenue uncertainty caused by the growing share of variable renewables (Milligan *et al.* 2012). This work assumes that enough capacity is built.

2.5 Rationale for high penetration levels of wind power

The costs of variability and prediction errors per produced wind power MWh rise as the penetration of wind power increases. It therefore becomes more and more relevant to find ways to reduce these costs as the penetration increases. Whereas most studies have analysed penetration levels that could be possible in the short term, some of the studies in this dissertation look at penetration levels up to 60–70% of the produced electricity. There are a couple of reasons for looking at such high penetrations.

First, the competitiveness of wind power relative to conventional power generation could continue to improve and hence very high wind penetration levels are feasible. Although the wind power cost development experienced an upward bump due to high commodity prices and a seller's market for turbines during 2005–2008 (Milborrow 2009), the turbine prices have returned to lower levels. At the same time new turbine models have increased the yield per invested euro. More importantly for the long term, much development is going on and new technologies are being tried out in the turbines. More cost-effective solutions are likely to be found, although it is impossible to predict how much more (a stochastic approach has been taken in Cohen *et al.* 2008). Meanwhile, competing technologies have seen cost increases due to commodity and fuel price rises. The impact of carbon pricing will further increase the cost for some of the competitors.

It is possible that wind or some other form of variable power will emerge as the lowest cost option for generating electricity in a large part of the world. If this is reached, two wind power cost components will determine the optimal wind penetration in the system. First, as more wind power is built, inferior sites will have to be used for power generation. Second, the costs of integrating variable and partly predictable generation increase with penetration. In many regions of the world, wind resources are more than adequate to provide all the energy at a reasonable cost, as demonstrated by the global wind resource assessment made in Publication I. The competitiveness of wind power and the vastness of the resource can lead to very high penetration levels in the future. At these levels, the integration costs become increasingly important.

Second, there have not been many studies looking at higher levels of penetration and there is a need to understand how the costs and benefits will change. There are indications that levels above 50% energy penetration are possible (Burges *et al.* 2008). While each power system is different, in the Irish case it appears that at approximately 40% penetration, the grid would have required a redesign instead of reinforcements (Nedic *et al.* 2008, p. 13). The estimate of the total societal costs for an Irish scenario with 42% of electricity made with renewables was 7% higher than the costs for the base case, which had 16% renewable electricity (Burges *et al.* 2008, p. 74).

Third, the benefits of increased power system flexibility will only be more visible if the penetration is high. Studying low penetration levels would not yield information that was as useful. However, not all scenarios in the dissertation have high penetration. The lower penetration cases improve understanding and often serve as benchmarks for comparisons.

Fourth, climate change mitigation will require radical reductions of greenhouse gases from energy production. Energy efficiency improvements alone will not be enough, especially since global energy consumption is expected to increase (IEA/OECD 2012). The reductions can be achieved either by relying heavily on renewables, nuclear power, carbon capture and storage (CCS), or on a combination of these. CCS will increase the cost of fossil fuel-based electricity considerably, which will make wind power more competitive. Furthermore, CCS technology will only reduce CO_2 emissions of coal- or natural gas-based electricity by 80–90% (IPCC 2005), which may not be enough if GHG emissions need to be reduced by 50–80% by 2050 (compared with 2000) to reach an estimated global average temperature rise of 2.0–2.4 ºC (IPCC AR4 WG1 2007). High reliance on nuclear power will also require flexibility from the system as it is expensive to underutilise high capital cost nuclear power plants. Furthermore, the current nuclear fuel cycle would threaten the known and expected uranium resources (IEA/OECD 2008), if nuclear power is one of the main components of low-carbon energy generation in a world with much greater electricity consumption. Other fuel cycles are still economically unproven. Due to uncertainties in all of the options, it is reasonable to try out ways to cover large portions of electricity and energy demand with variable renewables. Solar energy has by far the largest potential (Vries *et al.* 2007, Trieb *et al.* 2009), but the resource potential of wind power is also several times higher than current consumption (Publication I).

2.6 Summary of the research gaps and dissertation contribution

There is not very much literature on the analysis of the flexibility potential of thermal power plants (Section 3.1). This is a clear research gap, since thermal power plants are the prime source of flexibility for most existing power systems. In section 5.1, the dissertation synthesis therefore extracts results concerning thermal power plant flexibility from the analyses made for the dissertation.

The flexibility off reservoir hydro power is also understudied compared with its potential (Section 3.2). While work was carried out for a better understanding of hydro power flexibility during the dissertation, it also became clear that it is a very complex issue and therefore requires a more concentrated effort to yield robust economic results. Those analyses were therefore left out of the dissertation.

Electricity storage could in theory solve all the problems related to variability and forecast errors of wind power. However, as will be demonstrated in Section 3.3, the economics are quite challenging. Pumped hydro and CAES at some locations could be feasible even today, but site-independent solutions will require considerable technological progress. This area was therefore not analysed further in the dissertation.

Demand response has considerable potential (Section 3.4) to level out fluctuations from large-scale wind power schemes. There is some literature on this topic as will be shown in Section 3.4, but comprehensive approaches to DR and wind power are still missing. Incorporating DR into large-scale energy models is highly challenging, since it can come in so many forms and have various constraints. In the dissertation, electric vehicles, which are a well defined subset of DR, were analysed in detail. The existing research when starting the thesis work had not captured all of the most important economic factors of charging and discharging electric vehicles with a consistent approach (Section 3.5). Deficiencies included assumptions of static market prices, a lack of a cost benefit analysis and missing the impact of electric vehicles on the generation investments. The dissertation developed and used an approach in which a generation planning model was combined with a unit commitment and dispatch model to include these aspects in a single analysis.

There was negligible literature on exploiting heat production and heat use to increase power system flexibility (Section 3.6). The existing literature published before the analysis of the dissertation had not used a power system perspective in estimating the benefits and did not in most cases consider the increased variability of wind power. This was a clear gap and the dissertation has made an early contribution to filling this gap.

Super grids can smooth wind power variability by combining wind generation from a geographically larger area. A few attempts to tackle this question were found, but with some limitations: the lack of a cost analysis, data issues, no transmission constraints, small system size and limitations on available generation options (Section 3.7). A first order estimate was therefore made for this dissertation to take these into account (Kiviluoma and Lu 2010). However, the methodology used was rough and therefore not included in this thesis. A robust methodology would require a huge effort as in the recent work by the NREL (2012) for North America.

The literature on wind power integration from the methodological perspective is surveyed in Section 3.8. It can be concluded from the review that the methodologies developed and used in this study are advanced compared with the literature.

3. Review of power system flexibility

Energy systems have been studied extensively at different levels. Since variability of wind power is a key issue in the analysis of cost-effective ways to increase power system flexibility, this review will focus on articles that have used methodologies that deal with variability. Several energy system models do not have a chronological representation of demand and generation patterns and consequently cannot treat variable generation in a realistic manner (Shortt *et al.* 2013). Studies that have not considered uncertainty can still be relevant to the analysis of flexibility as long as they have considered the chronology of demand and wind power.

As a result of the expected large share of wind power in several power systems, many studies have been made to analyse the effects of high wind power penetrations (reviews in Holttinen *et al.* 2012, IPCC 2011 Section 8.2.1). This review focuses on studies that assess energy penetration greater than 20%, as the dissertation focuses on higher penetrations. Some studies do not reveal the penetration level or are methodologically important to review, and these are hence included.

As the costs due to variability and prediction errors grow, it becomes more economical to use different methods to increase power system flexibility to decrease these costs. This makes the analysis of very large wind power penetrations difficult for two reasons. First, there is no good understanding of the relative merits of different flexibility options. Second, there is a lack of tools to conduct the analysis. These issues stand out in the existing literature.

Some of the options to reduce the costs of wind power variability and prediction errors have received much attention and some very little. Since one dissertation cannot cover all the options in detail, the literature review is used to select options that seem promising and have received little attention.

3.1 Thermal power plants

It is often assumed that large-scale variable electricity generation will require technology that currently does not exist before it can be accommodated in the power system (discussed in Milligan *et al.* 2009). However, most thermal power plants have always adjusted their operations to changes in demand. With wind power in the system they need to adjust operation to changes in the residual demand. Due to the greater variability in the residual demand, conventional power plants will experience more shut-downs, part-load operation and steeper ramps, but it is not clear that new, currently non-existent, technologies are required even at high wind power penetrations. To study this, a power system with thermal power plants as a benchmark can be used with which new flexibility-providing technologies are compared in order to see whether they benefit the system.

The analysis of flexibility from thermal power plants is usually implicitly assumed in wind power integration studies (see Section 3.8). Hence there are few studies that specifically address this issue. This section reviews studies in which the flexibility of thermal power plants is assessed, as they provide more details on the issues of start-ups, part-load operation and steeper ramps.

Troy *et al.* (2010) demonstrate that the impact of wind variability and uncertainty on thermal power plants is dependent on the characteristics of thermal power plants. Part-load efficiencies, in particular, but also minimum down times, start-up costs, and the capability to provide primary reserves mean that inflexible coal units are preferred over combined cycle gas turbines (CCGTs) at high wind penetration levels. However, Troy and O'Malley (2012) show that adding an open cycle gas turbine (OCGT) mode capability to a CCGT plant changes this behaviour and reduces the use of coal units in the Irish power system. In Troy *et al.* (2010) the effect of electricity storage was also evaluated and, similarly, it had a remarkable effect on the utilisation of different plant types. The results indicate that the relations between wind power and thermal power plant types are complex and sensitive to power plant characteristics. They also mean that the development of new kinds of thermal power plants for high wind power penetration systems could yield considerable operational savings as well as reductions in CO_2 emissions.

Corbus *et al.* (2010) studied wind integration in the power system of the Hawaiian Islands from both perspectives: the unit commitment and dispatch as well as dynamic stability. While the system is small and has characteristics not present in larger systems, the study provided an interesting insight. The flexibility of existing conventional generators was put to the test and an upgrade programme was performed. Initial results indicated enhancements in the ramp rates and the possibility of a reduced minimum load factor.

3.2 Reservoir hydro power

There appear to be very few studies that analyse the capabilities of reservoir hydro power for large-scale wind power integration, despite the apparent cost-effectiveness of the technology. Several studies have co-optimised the operation of one wind power plant and one hydro power plant, but this is only interesting if they are behind the same grid connection bottleneck and in some specific market designs (e.g. Zima-Bočkarjova *et al.* 2010). These are not included in this review as the perspective is on optimising the whole power system. One reason for the lack of studies is probably the distinctiveness of hydro power systems.

Even if the actual characteristics differ, there are common features shared by the hydro power plants: reservoir size, plant capacity, design flow and head height. On the contrary, the inflow patterns can have a large variance between hydro power systems. The variance in efficiency is much lower as most hydro power plants reach very high efficiencies. Reservoir hydro power plants are often part of a larger river system with upstream and downstream reservoirs and hydro power plants. The interaction of these creates specific complexities, including time of use constraints and optimal utilisation of reservoir level changes, which are affected by inflows from upstream. Most hydro power systems have constraints regarding minimum and maximum flows that are based on environmental concerns.

While the differences limit the applicability of specific results, it is still interesting to ask how reservoir hydro power affects the economics of integrating variable power generation. While it is certainly an important question for the owners of hydro power assets, the literature only had a few answers to the question. Millham (1985) evaluated the capability of the Columbia-Snake river hydro power system to smooth monthly variations in wind generation during a critical period of low flows. The results suggested that the wind power capacity that could be firmed was clearly lower than the available hydro power capacity. Løvseth (1995) suggests that Norwegian hydro power would be a good match to balance variations in Norwegian wind power, but the analysis is on monthly scale.

Kiviluoma *et al.* (2006) estimated the energy balancing potential of Nordic hydro power based on river system data. The share of run-of-river hydro power was small, less than 10% of the total generation. Most Nordic hydro power capacity has upstream reservoirs and, on average, the reservoirs are large. In Norway, the average reservoir can hold water for nearly a year's worth of generation and is a short distance from the hydro power station. Swedish reservoirs are smaller and the average time lag from the reservoir to the hydro power station is longer. The results imply that there is a large amount of untapped flexibility potential in the Nordic hydro systems, but their value was not quantified in economic terms. However, the constructed data were used to increase the accuracy of the Nordic hydro power modelling in WILMAR.

Kiviluoma and Holttinen (2006) presented results on the energy balancing of large-scale wind power in the Nordic power system with Germany included in the model. The results were somewhat obscured since the modelling of hydro power was too flexible compared with reality. Given this, there were no energy balancing problems even when wind power served 30% of the annual electricity consumption. The modelling approach does not cover all timescales and it does not include security-constrained power flows, so the conclusion is hypothetical. Market prices were strongly affected since the system had very little thermal generation other than nuclear power.

In a more recent development, the tools to analyse hydro and wind power in large systems have received attention. Dennis *et al.* (2011) presented two methods to simplify the modelling of large-scale hydro power in a production cost model PROMOD used in the Western Interconnect of USA. Rinne (2011) has improved the estimation of water value in WILMAR.

3.3 Electricity storage

Electricity storage options to mitigate wind variability have received considerable attention. As there are many different options, it is prudent first to understand their possible benefits and drawbacks for large-scale wind power integration. When the variation in electricity demand is combined with the variation in very large-scale wind power, the resulting residual demand exhibits cycles that have a time range from one to several days. The weather patterns that create the variations in large-scale wind power generation usually take days to pass over a region. This means that electricity storage acting in such an environment could expect roughly 50–250 full cycles per year. The relatively low number of full cycles promotes forms of storage that can achieve a low MWh cost.

The large range (50–250 full cycles) is partly dependent on the cycling efficiency of the storage. Low round-trip efficiency means that only big differences in electricity costs will be worth smoothing. High cost differences occur more seldom than low cost differences. Low-efficiency storage will therefore receive considerably fewer full cycles than high-efficiency storage. Variable operation and maintenance (O&M) costs will also reduce the possible full cycles per year, as variable O&M costs will increase the arbitrage range further.

The cost per MW is another factor, but for most storage types it is not binding. Large-scale energy storage often leads to large power capacity by default. However, notable exceptions include CAES (Compressed Air Energy Storage) and pumped hydro, for which the investment in MW is separate from the investment in MWh. For these technologies, the cost per MW dominates the cost calculation. It is problematic to compare technologies over such distinctions.

The prime electricity storage option is pumped hydro plants. However, their economics are very site dependent and the resource is limited to locations where upper and lower reservoirs are available. The relatively high penetration of variable renewables in the Iberian and Irish power systems has already prompted pumped hydro investments and investment plans.

Denholm *et al.* (2010) articulated further arguments why reliable cost comparisons between storage technologies are not available. Efficiency calculations are often based on different principles. Additionally, most storage technologies are not yet in mass production, and changes in market prices from year to year are high, which makes the comparison even more difficult.

Albeit that the actual investment costs are uncertain, it is still possible to assess the upper limits that the investment costs of different technologies should undercut to be viable. This is done by first calculating the nominal value of the annual sales profit from a set of optimistic assumptions:

$$\left(p_{\mathrm{sale}} - \frac{p_{\mathrm{purchase}}}{\eta}\right) \times c \times t, \text{ where} \qquad (1)$$

p_{sale} is the average selling price (80 €/MWh)

$p_{purchase}$ is the average purchase price (30 €/MWh)
η is the cycle efficiency
c is the number of full cycles per year (250)
t is the length of full discharge in hours (8 h).

The present value of sales is calculated from the nominal values, assuming the lifetime from Table 1 and an 8% interest rate. The present value of sales should be at least the same as the investment cost for storage to be profitable. For pumped hydro and CAES, the target investment cost is expressed in €/kW because that is their main cost component. However, they have an additional cost based on €/kWh of storage (see Table 1). For battery technologies, the target investment cost is in €/kWh of storage, and it is assumed that there is no separate cost to obtain enough charge/discharge capacity. The resulting target costs are presented in Table 1.

Table 1. A target cost below which different storage technologies may become feasible using optimistic assumptions. For pumped hydro and CAES, the target cost (in bold) is in €/kW and for the others it is in €/kWh.

	Target cost				depth of
	€/kW	€/kWh	eff.	lifetime	disch.
Pumped hydro	**1024**	10	0.8	100	1
CAES	**750**	50	0.85	60	1
Flow battery	0	**104**	0.85	40	0.75
Metal-air	0	**9**	0.5	2	1
Regenerative fuel cell	0	**102**	0.75	20	1
Lead acid	0	**53**	0.85	8	0.8
NaS	0	**81**	0.89	10	1
Lithium Ion	0	**78**	0.99	12	0.8

When the target costs are compared with the cost estimates in the literature (Ibrahim *et al.* 2008, Schoenung 2011, Divya and Ostergaard 2009 for batteries, Deane *et al.* 2010 for pumped hydro power), only pumped hydro and CAES appear to be economically feasible. These are scrutinised in the literature review. For other options, technological progress and mass production may reduce costs to a profitable level, but with the current data that would be speculative, and the effort is targeted at pumped hydro and CAES. It should also be noted that further income could be gained from reserve or capacity markets, but in case there is a large-scale implementation of storage, these markets would probably be saturated by electricity storages with low variable costs and the prices would collapse (Publication IV).

A large portion of the electrical storage studies analyse situations in which storage would be connected to the operation of a single wind power plant and their operation co-optimised in relation to the electricity price (c.f. Garcia-Gonzalez *et* *al.* 2008, review of hydro storage in Matevosyan 2008, Costa *et al.* 2008, Faias *et al.* 2008, Bakos 2002, Castronuovo & Lopes 2004, Korpås & Holen 2006; Greenblatt *et al.* 2007, Denholm 2006). This can smoothen the output of single wind power plants, but it is not a cost-effective approach unless there are immediate transmission restrictions and, even then, it is not certain (Denholm and Sioshansi 2009). The outputs of multiple wind power plants at different locations smoothen each other and only the aggregate output of all the wind power in a given region is of concern to the economic operation of the rest of the power system.

If the wind power plant and the electricity storage are in the same grid and there are no transmission constraints, the respective investment decisions are two separate decisions. Even if the two plants have the same ownership, the optimisation of each should be done in relation to the rest of the system and not each other. Only transaction costs in the market place can make it worthwhile in some, usually rare, situations to change the operational strategy due to common ownership. More importantly, there is no rationale, except to save transaction costs, to link the investments of two different plants. The results by Greiner *et al.* (2008) demonstrate this from the operational perspective.

To investigate properly the benefit of storage, a system-wide model is required in which geographically dispersed wind power generation influences the system operation and market prices. This literature review therefore concentrates on studies that have a system perspective.

Black *et al.* (2005) calculated the value of storage in a high wind power penetration system. They found that the value was very dependent on the existing flexibility of the system. The results indicate that only in low flexibility systems might investment in storage be feasible.

Swider (2007) includes endogenous investments in the model and finds that CAES takes a portion of the newly invested capacity by replacing part of the new gas turbine capacity. The applied assumptions lead to investment in CAES even without large wind power penetration. In the highest wind power scenario with just over 20% from wind, wind power increases CAES investments. However, other options than CAES and conventional power plants were not available to increase system flexibility.

Benitez *et al.* (2008) have analysed the benefit of pumped hydro power in Alberta with medium and high wind scenarios. They assume that wind power will replace existing baseload coal condensing generation units of similar energy output. However, it is very unlikely that it would be cost optimal to replace only coal condensing (Publication IV, Swider 2007). The study has assumed that wind power has investment costs while the coal condensing that the wind power replaces does not have any investment costs. In other words, it is assumed that the baseload coal condensing units disappear when wind power is connected to the system and, at the same time, new peak capacity has to be built. In effect, the investment costs of stranded units have been included in the wind power integration cost.

Ummels *et al.* (2008) have made a cost-benefit comparison of CCGT, pumped hydro, underground pumped hydro, CAES and natural gas heat boilers as means to reduce the operational costs of the system at different levels of wind power penetration. Natural gas heat boilers would increase power system flexibility since they would be built in locations with existing inflexible CHP generation. Heat boilers would enable a reduction in CHP electricity generation at times of low residual demand. Their approach suffers from the assumption that pumped hydro or CAES would avoid investments in CCGT only. This decision should be subjected to cost optimisation. Their largest wind power scenario would cover about 27% of the electricity demand. The most profitable flexibility at that wind penetration level comes from natural gas heat boilers. CAES would also have been cost-effective at higher wind penetration levels – at least if heat boilers were not an option. The results also show that electricity storage can increase CO_2 emissions, as it increases the use of baseload units, which often use coal as a fuel.

Lund and Salgi (2009) estimated the operational benefits of CAES in the Danish system with 59% of demand covered by wind power, and they found that in energy arbitrage, CAES would not even be close to profitable. The results from an undocumented analysis showed that electric heaters and electric heat pumps in district heating systems were a much better investment to increase system flexibility.

Thermal electricity storage has also been proposed either as an extension of CAES (AA-CAES) or as a stand-alone concept (Desrues *et al.* 2010). The analysis builds a technical model and does not assess economic aspects.

Göransson and Johnsson (2011) evaluate the possibilities of reducing thermal power plant cycling with storage. While the storage is able to reduce power plant emissions due to cycling, it does not appear to be economical even at a relatively high wind power penetration level.

3.4 Demand response and demand-side management

Demand-side management (DSM) refers to attempts to modify electricity usage patterns through utility programmes. Demand response (DR) is the fast response of dedicated demands if the value of electricity becomes too high. From the perspective of wind power integration and increasing system flexibility, DR offers the most interesting prospects. DR can usually be very fast to react, which means that it can be used for a wide variety of system services starting from spinning reserves all the way to long-term capacity adequacy. Kazerooni and Mutale (2010) have even assessed the value of DR for avoiding transmission investments due to wind power.

Faruqui and Sergici (2010) have surveyed 15 DR experiments in which household electricity customers have received some form of compensation for reducing demand (including time-of-use pricing and critical-peak pricing). The average reduction in loads during peak demand periods varied considerably. Time-of-use pricing resulted in modest reductions of 3–6% while critical-peak pricing had a much higher effect of 13–20%. Enabling technologies, such as programmable, communicating thermostats and always-on gateway systems that controlled multiple end-uses remotely, increased the reductions considerably for both compensation schemes (raising the reduction to 21–36% and 27–44% respectively). Empirical results from on-going DR programmes in the U.S. have achieved levels of 3–

9% of potential reduction in peak demand (Cappers *et al.* 2010). This includes industrial DR as well as household DR. While these results cannot be directly applied to the residual demand variations with large-scale wind power, it is apparent that DR offers considerable potential for increased flexibility. Widergren (2009) also points out that aggregating DR from households will include significant uncertainties in terms of actual delivery. These have to be understood and addressed.

Klobasa (2010) has evaluated that the DR potential in Germany could be more than 30 GW, although a major portion (20 GW) would not be available outside the heating season. The article also explored that the DR would enable the system to cost-effectively balance 48 GW of wind power in the system. The wind power balancing costs were estimated to be about 1 €/MWh lower with DR, which was translated to allow 10–20 €/kW/year activation cost for DR.

Stadler (2008) has analysed possibilities for DSM in the household sector. The analysis concentrates on ventilation systems, refrigeration and water heating. Stadler concludes that storing heat in different applications offers a large potential for integrating variable renewables. However, the results lack an economic component.

Paulus and Borggrefe (2011) analyse the technical and economic potential of DR from energy-intensive industries in Germany. Variable costs from these resources are high, which means that they cannot be used very often for energy balancing. However, they can supplant a considerable amount of investment in peak generation capacity, which will reduce the integration costs of variable generation.

Finn *et al.* (2010) have analysed how domestic hot water heating cylinders could offer DR for price changes anticipated in the electricity market. This was inspected in relation to the anticipated significant wind power penetration in Ireland. While the example demonstrated increased flexibility, especially with well-insulated hot water cylinders, the possible impact of large-scale use of DR was not studied.

Moura and Almeida (2010) analyse how DSM and DR could decrease the peak demand in Portugal. Peak demand situations are especially relevant for wind power in Portugal as wind power generation is usually low at those times. However, the DSM loads in the article were not price sensitive and therefore of limited applicability to wind power integration.

Hamidi *et al.* (2008) present a case using the IEEE standard 30-bus test system. Two wind farms are connected to the system and the effects of multi-tariff rates and DR are investigated. DR is assumed to respond to variations in wind power output. DR appears to offer significant savings in the system operation and increase the value of wind power. However, it is unclear whether wind power forecast errors have been considered or what system services the wind farms are capable of providing.

Short *et al.* (2007) demonstrate the effects of the response by millions of household refrigerators and freezers to frequency signals. These are able to keep the system frequency more stable than a conventional spinning reserve. The effect is especially pronounced with higher shares of wind generation. However, the minute-to-minute variations in wind power generation that they have applied (max change -5.8%) are unrealistically high in comparison with empirical data (c.f. Wan 2005, where max is -2.7%).

Troncoso and Newborough (2010) suggest the use of hydrogen electrolysers to create flexible demand. They use an example of an isolated system for which they aim is to smooth the output from wind so that a thermal power plant can operate almost continually. However, the approach tries to maximise the use of electrolysers and minimise the carbon intensity of electricity generation instead of minimising the system costs.

Understandably, DSM and DR include a very diverse set of possible actions, which further vary between countries. From the system perspective, a specific DSM and DR action should be invested in only when it creates more benefits than costs. As the costs are application specific, it is far easier to analyse the possible benefits of different types of DSM or DR. For example, it would be interesting to calculate the benefit of increasing the amount of DR for several wind power penetration levels. In literature, such analysis seems to be lacking. While such analysis would have matched the intentions of this dissertation well, it was left to future work except for the analysis of electric vehicles.

3.5 Electric vehicles

Electric vehicles can increase the power system flexibility in two ways. First, with smart charging, the charging would occur during hours with low electricity prices, if possible. Second, vehicle-to-grid (V2G) would enable discharging of the batteries to the grid during hours of high prices. An analysis of electric vehicle impacts should consider a charging pattern based on driving profiles, and the effect of electric vehicles on market prices and system costs as well as on CO_2 emissions, and preferably the impact of electric vehicles on generation investments.

There have been several publications about the possible benefits of the participation of electric vehicles in the electricity markets. Kempton and Letendre (1997), Kempton and Tomic (2005), Tomic and Kempton (2007), and Williams (2007) represent calculations of the possible benefits of using electric vehicles and fuel cell vehicles as a new power source in which the authors use power market prices as a reference. Several vehicle setups and electricity markets are analysed. Blumsack *et al.* (2008) assume simple night time charging and use marginal CO_2 emissions based on the current merit order for three regions in the U.S. This static approach does not take into account the pressure to reduce emissions in the future and the possibilities of smart charging to enable further emission reductions. Similarly, Camus *et al.* (2009) assume that off-peak baseload electricity will mainly be used to charge plug-in hybrid electric vehicles (PHEVs).

Hadley (2006) and Hadley and Tsvetkova (2007) use a dispatch model to estimate the cost of charging PHEVs. The generation portfolio is taken from an external estimate and is not influenced by the introduction of flexible demand from PHEVs. The PHEVs are dispatched according to a pre-set schedule, and no vehicle-to-grid (V2G) is considered.

Shortt and O'Malley (2009) consider the effect of electric vehicles on future generation portfolios and use a simplified model to dispatch electric vehicles on top of the demand profile. V2G, or the use of electric vehicles as reserves, was not considered. Short and Denholm (2006) estimated the effect of PHEVs on future generation portfolios, and Denholm and Short (2006) analysed how dispatch might be affected. Costs and benefits were not analysed. Juul and Meibom (2011) are the only ones so far who include endogenous investments in the transport sector as well as in power generation. Investments in PHEVs trigger investments in wind power that more than offset the electricity consumption of PHEVs.

Sioshansi and Denholm (2010) applied a unit commitment model to analyse the impacts of electric vehicles. The method uses measured driving profiles and includes a piecewise approximation of depth of discharge costs. The article indicates the saturation of a spinning reserve market with an increasing share of electric vehicles. The results are in line with the dissertation articles.

Peterson *et al.* (2010b) calculate the costs and benefits of peak shaving with the vehicle batteries. The analysis is based on historical market prices. McCarthy and Yang (2010) simulated the effect of the electricity demand due to electric vehicles on CO_2 emissions. The results were based on the assumption that the emissions of the marginal power plants would be allocated to electric vehicles. Marano and Rizzoni (2008) analyse the effects of PHEVs on the household electricity bill based on end-user rates in combination with household-scale wind power or solar PV generation and thus do not have a systems perspective.

Lund and Kempton (2008) analysed the effect of smart electric vehicles on integrating variable wind power. While the article has results on CO_2 emissions, it does not include costs and benefits. The EnergyPLAN simulation tool included a simplified presentation of electric vehicles.

3.6 Heat storage

Literature on the use of heat storage to mitigate wind variability and prediction errors is sparse. This is surprising as heat storage is one of the least expensive methods to increase power system flexibility. It is clearly a good area for further research and has been one of the main areas in the dissertation.

Early work on heat storage includes Margen's (1986) analysis for both short-term and seasonal thermal energy storage. The analysis concludes that short-term storage is attractive for extending the use of heat boilers intended for base or intermediate heat loads. It can also work economically with a back-pressure CHP unit to increase electricity generation during high prices and decrease it during lower prices. Seasonal use of heat storage was much more sensitive to the fuel price assumptions. While the benefits of increasing power system flexibility were not specifically addressed, the results can be inferred to indicate that heat storage could be useful for integrating large amounts of variable power generation.

Hughes (2010) has analysed the operation of heat storage in residential homes when used in conjunction with resistance heaters powered by wind electricity. While the results are interesting, as they show the dynamics of electric heating with storage in a single household, the study does not have a power system perspective.

Callaway (2009) considers the use of temperature-controlled loads (TCL) for regulation, automatic generation control and load following. The analysis changes the temperature set points of large group of TCLs. Changes can be small and still yield large aggregate changes in short-term demand. The approach takes into account the probabilities in the actual response to set point changes, as not all loads will change behaviour due to a small set-point change. The method is tested to smooth short timescale fluctuations of a single wind farm. While this application is not interesting from the system perspective, the methodology for controlling TLCs appears solid. Callaway also refers to other literature on TCL, but this does not specifically analyse the use of TCL in wind integration.

Warmer *et al.* (2006) have studied the balancing of a market participant with wind power in the portfolio using heat pumps and tap water resistance heaters as flexible demand. The setup was able to reduce the balancing error of the market participant, but the monetary benefits were not reported.

Kennedy *et al.* (2009) analyse the use of the residential building thermal mass for storing heat from a heat pump. They implement a price-dependent temperature control that lets the indoor temperature vary between 18 and 22 ºC while minimising the heating costs. A heating cost reduction of 10% is achieved and the correlation with wind power generation is increased.

Pöyry Energy (2010) includes an analysis of flexibility from heat by treating space heating with electricity as movable demand. The report concludes that heat loads can be an important source of flexibility.

3.7 Super grids and variability

Wind power variation decreases as the area increases (Wan 2005, Ernst *et al.* 1999), since wind power generation is mainly caused by weather patterns that have a limited size. There are currently severe restrictions on the possibility of using the smoothing effect, since power flows over continental-scale power grids are limited due to transmission bottlenecks and administrative barriers. Some studies have therefore been conducted to investigate the reductions in the variability of wind power generation if these barriers were to be transcended.

Giebel (2000) investigated Central European-wide wind power generation on an hourly level. Considerable smoothing was demonstrated as well as an estimate for wind power capacity credit. The main limitation of the study is that the model did not include transmission bottlenecks, which is one of the main issues for large-scale integration of wind power (van Hulle 2009). The wind data were based on 28 meteorological sites from Denmark, the UK, Portugal, Spain, the Netherlands, Germany, France, Italy and Greece only. Czisch and Giebel (2000) and Czisch and Ernst (2001) extended the analysed region with ERA-15 data to cover the whole of Europe as well as neighbouring areas.

Czisch and Giebel (2007) presented a paper with cost optimisation for creating an entirely renewable energy system for Europe. Their analysis indicated that it would be cheaper to build a large transmission system to reduce the variability of wind power than to deal with the variability more locally. Their base case with existing technology found a cost-optimal solution with 70% of the electricity coming from wind power and backup from available hydro resources and biomass. Transmission played a big role in smoothing the wind output. When new building of transmission was restricted, the cost of the additional biomass backup required to cope with the increased variation was found to be greater than the cost of transmission. However, only renewable sources of energy were allowed to deal with the variability.

Osborn (2010) presents point-to-point overlays of high voltage direct current (HVDC) lines collecting mainly wind generation from the U.S. Midwest and distributing it to the consumption centres on the East Coast. It is estimated that the overlays would be more economic than reinforcing the AC system.

Rebours *et al.* (2010) stated that the costs of variable generation (presumably additional cost due to variation) were reduced significantly in the scenario with more new transmission lines than in the scenario with fewer new transmission lines. The area under study contained ten western European countries.

Kempton *et al.* (2010) demonstrate the reduction in variability and periods of low-output generation when connecting wind farms along the U.S. East Coast with an HVDC cable.

Kiviluoma and Lu (2010) argue that it is likely to be more economical to tap into good wind resources with a long-distance transmission network than to use poorer wind resource sites closer to consumption. If the cost of high voltage transmission is near the assumed level (600 $/MW/km and 255,000 $/MW for a substation in the scenario with higher transmission costs), the lower cost of wind energy provides enough justification by itself. In addition, there are benefits due to decreased variability, smoother duration curves and less steep system ramp rates.

3.8 System studies with high wind power penetrations

This section takes a look at the existing studies that have analysed high wind power penetration levels (above 20% of electricity). The focus of the review is to analyse what means of flexibility have been taken into account in these studies. The actual results vary between power systems due to differences in the systems and hence are not necessarily comparable with the results in the dissertation.

Purvins *et al.* (2011) review options to manage variability of wind power generation. The article contains examples from literature about the spatial distribution of wind power plants, electricity storage, wind power-induced reserve requirements and the benefit of additional interconnections.

Jonghe *et al.* (2011) present a chronological generation planning model for studying the impacts of variable generation on generation investments. The model is linear and does not include start-up costs. The impact of ramp rate limitations in baseload power plants and pumped hydro on the optimal generation portfolio is examined.

DeCarolis and Keith (2006) analysed the use of five possible wind sites situated very far from a single point of electricity consumption. Wind power generation time series were based on a single up-scaled wind speed ground level measurement, which yields an unrealistically large variation in wind power generation (see Figure 1 of DeCarolis and Keith 2006). The benefits of CAES and hydrogen storage were analysed, but the assumptions reduce the reliability of the results.

The EnergyPLAN model has been used in several high wind power penetration analyses. The model simulates hourly power system operation with aggregated power plants. It uses analytical formulations to simulate the behaviour of power plants, storages and demand-side response (Lund 2011). These can be fast to calculate, but it is unclear how close to optimised solutions the algorithms can get, especially when there are multiple interacting flexibility mechanisms. In Connolly *et al.* (2010), EnergyPLAN is used to estimate a technically optimum wind power penetration level for Ireland, but there are no monetary results. The technical optimum in the article is a theoretical construct, which is not comparable with the more thorough and applied analysis in, e.g., the All Island Grid Study. In Lund and Mathiesen (2009), very large wind penetrations are achieved with power system flexibility from hydrogen generation and biomass CHP plants. However, the results do not reveal the efficiency of these options specifically for integrating variable generation. In another article (Mathiesen & Lund 2009), the same authors compare different ways of facilitating the integration of fluctuating power sources. Their analysis demonstrates that heat storages can have an important impact on power system flexibility. They also show that the use of electrolysers to produce hydrogen for fuel cell vehicles or combined heat and power plants does not appear to be cost competitive with the flexibility mechanisms provided by heat measures and battery electric vehicles.

The All Island Grid Study together with later assignments is the most in-depth analysis of large-scale integration of wind power so far. It includes a search for representative scenarios for power plant portfolios (Doherty 2008, Doherty *et al.* 2006). The approach contains simplified costs for variable generation management and grid expansion as well as a declining capacity factor and capacity value for wind power. The results are based on a large number of optimised power plant portfolios with variations in fuel prices and power plant options. The weakness of the approach is the lack of chronology in the optimisation model. However, it was only used to create portfolios for the later studies that were chronological and included, e.g., start-up costs and power flow constraints.

Meibom *et al.* (2007) analysed the scenarios from Doherty (2008) in the unit commitment model WILMAR. The model has been used in this dissertation and is described later. At the same time, a grid study (Nedic *et al.* 2008) was made in order to analyse the feasibility of challenging situations based on Meibom *et al.* (2007). The scenario with the highest wind power penetration was not feasible due to the extreme situations in which the demand and reserve requirements could not be met (Nedic *et al.* 2008). A system redesign would have been required. The

WILMAR results indicated reasonable operational costs even with high wind power penetrations. This was the case even though sources of flexibility were limited to conventional power plants. Tuohy *et al.* (2009) continued the analysis by looking at the benefits of stochastic unit commitment optimisation as enabled by WILMAR as well as the benefits of more frequent commitments. The inclusion of uncertainty led to more optimal results and better performing schedules. The article also contains a good description of equations used in the WILMAR model.

A study using Balmorel by Karlsson and Meibom (2008) demonstrated that it could be economically optimal to provide a major share of electricity, district heating and transport sector energy requirements from renewable energy if hydrogen were assumed to be the main fuel in the transport sector. The result is naturally dependent on the assumptions about the investment and operational costs for different technologies. Hydrogen acted as a buffer to incorporate fluctuations, especially in wind generation.

The dissertation of Ummels (2009) analysed wind integration with two models: a unit commitment and dispatch model as well as a model for frequency stability. The models were applied for short-term balancing of the Dutch system in the presence of large-scale wind power generation. The analysed periods were worst case situations in the residual demand.

Ummels *et al.* (2008) and Ummels *et al.* (2009) have analysed different options to increase flexibility in the Netherlands with a deterministic unit commitment and economic dispatch model. The results demonstrated a decrease in coal and natural gas. When wind power penetration increased, a particularly cost-effective way to decrease operational costs was the installation of fuel-based heat boilers in CHP units. On the other hand, a new interconnection to Norway resulted in the highest operational cost saving, but it was much more expensive to build than the heat boilers. Other considered options included pumped hydro and compressed air energy storage.

A report by Pöyry Energy (2010) analyses different options to create a low carbon energy system for the UK. It concludes that electrification, especially of space heating, may provide the necessary flexibility to incorporate large amounts of variable power generation. A demand-side response and bulk storage are good for shifting demand within the day, but they are less effective for longer periods. For longer timescales than a couple of days, most of the flexibility is expected to come from generation. The model behind the analysis, Zephyr, is a chronological mixed integer (MIP) model without uncertainty. The portfolios for the scenarios were developed with Zephyr runs using the internal rate of return for each plant to provide information on investment decisions.

There have also been several studies with a big footprint. These have mainly looked at the operational impacts of large-scale wind (and solar) power, the need for additional interconnections, established the contribution of wind energy to resource adequacy and/or analysed the benefits of new market designs. European studies include GreenNet (Kröger-Vodde *et al.* 2009), Tradewind (van Hulle 2009) and EWIS (Winter 2010) while studies in the U.S. include EWITS (NREL and EnerNex 2010) and WWSIS (NREL and GE 2010). The main conclusion related to this dissertation is that long-distance transmission can contribute substantially to the economic integration of wind power and that variability and uncertainty can be greatly reduced when wind generation is collected from a large footprint. WILMAR was applied in GreenNet, Tradewind and EWITS.

4. Methods and models of the thesis

This chapter presents selected methods and models that were used in the dissertation. The exact mathematical formulations and modeling approaches used in the tools employed in this study can be found in the articles and reports shown in the references. Both WILMAR and Balmorel models are freely available, and can be found in internet (http://www.wilmar.risoe.dk and http://www.balmorel.dk). For these reasons, the models are not described in detail here. The main tool was the WILMAR planning tool and it is hence presented in more detail. The author has participated in the development of the WILMAR planning tool (Meibom *et al.* 2006, Kiviluoma and Meibom 2006). Part of the dissertation was the development of an electric vehicle model for WILMAR that includes the necessary data on electric vehicle behaviour. A couple of additional methods were developed to explore different ways to integrate wind power. One developed methodology is for creating synthetic wind power forecast errors. At the time, real stochastic forecasts were not available. The developed method was used but not documented. It is not presented here either, since real forecasts are starting to become available and the Scenario Tree Tool in WILMAR can also create satisfactory forecast scenarios. The data manipulation that led to the time series for electric vehicle behaviour was rather complex and is documented in Publication VII.

4.1 WILMAR model

The WILMAR model is a power system modelling tool that optimises unit commitment and economic dispatch for the next 36 hours. It incorporates stochastic time series for wind power and demand. As a consequence, the forecasts for wind and demand include uncertainty in the form of multiple paths for their evolution during the next 36 hours. This stochasticity is taken into account in the unit commitment optimisation. After the initial unit commitment for the next day, the model takes three-hour steps and recalculates with new forecasts. Only some power plants can be rescheduled, which emulates the functioning of the intra-day and regulation markets. At noon it makes a new unit commitment for the next day and continues solving the intra-day market every three hours.

The model can be solved in deterministic mode in which there is only one prediction for residual demand. The deterministic mode makes the model solve faster, which can be useful as multiple model runs can be time-consuming. The deterministic mode can also be solved with perfect foresight in wind power and demand forecasts. This helps to evaluate the value of such forecasts and the costs associated with forecast errors.

The model can be solved with linear programming (LP) or a MIP solver. The LP version is documented in Barth *et al.* (2006a) and the MIP version in Tuohy *et al.* (2009) as well as Meibom *et al.* (2011). The advantage of MIP is its capability to perform 'lumpy' unit commitment decisions in a more realistic manner. However, this requires unit level power plant data and can be very time-consuming in a big system, especially if run in conjunction with the stochastic forecast data. The LP mode approximates unit commitment decisions by aggregating similar units together and applies an additional variable to keep track of the capacity online. There is still a cost to bring capacity online, but the binary value for the online status of individual units is not present.

WILMAR consists of the Scenario Tree Tool (Barth *et al.* 2006b), Input Database (Kiviluoma and Meibom 2006), Joint Market Model (JMM, Tuohy *et al.* 2009), Long Term Model (LTM, Ravn 2006) and Output Database (Kiviluoma and Meibom 2006). The Scenario Tree Tool creates stochastic scenarios for the wind generation and electricity demand based on Monte-Carlo simulations. For most of the work in this dissertation, the Scenario Tree Tool has been replaced by a forecast replication tool that introduces uncertainty bands around the average forecast based on forecast statistics. The input and output databases are Access databases and contain code and queries to ease the upkeep of assumptions and analysis of results. JMM contains the actual equations for the unit commitment and is written in GAMS. GAMS calls an external solver to solve the LP or MIP problem. IBM ILOG CPLEX has been used as the solver. Figure 6 shows the most important data requirements and the data flow in the WILMAR model.

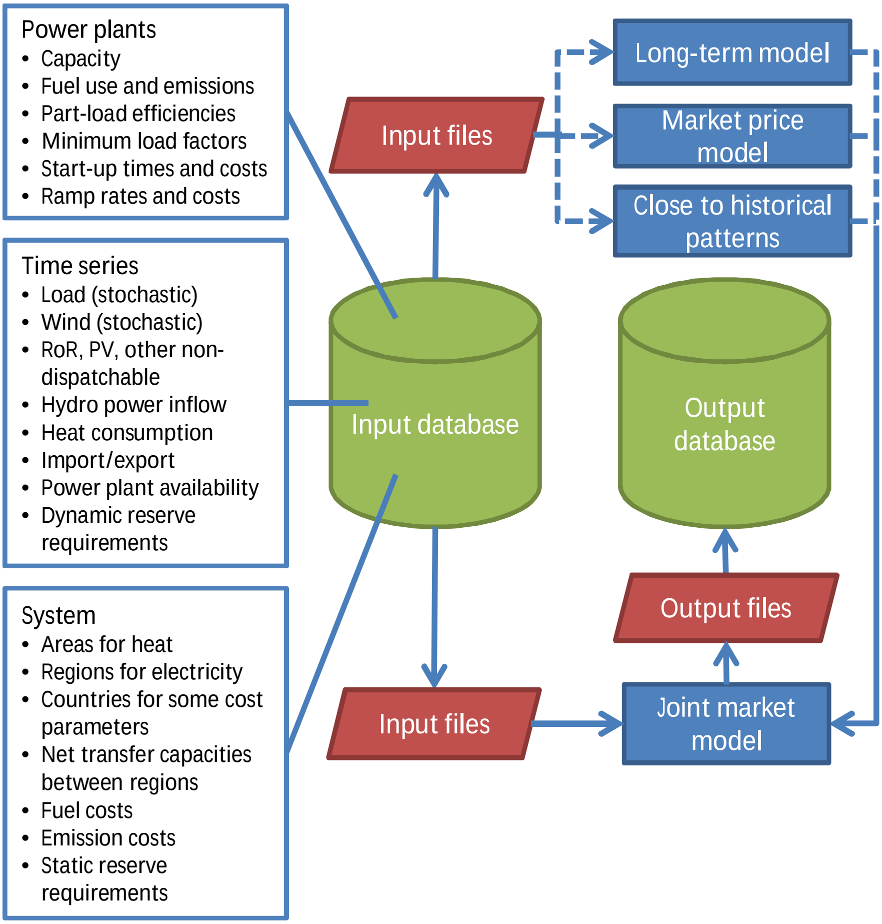

Figure 6. Flow chart for WILMAR.

LTM solves the water value for reservoir hydro power, which is based on the generation reservoir hydro power can expect to replace in the longer term. LTM receives a simplified set of assumptions so that the model can solve a much longer time horizon than JMM. The water value table is transferred from LTM to JMM once a week. LTM did not always perform satisfactorily and in some of the articles it was replaced by a very simple code that penalised the objective function if the reservoir levels deviated too much from the annual historical patterns. Later work replaced JMM with a market price model (Rinne 2011).

WILMAR minimises the following operational costs of the power system: *Fuel use + O&M + start-up + fuel consumption during start-ups + emission costs.*

There are several restrictions on the problem. Heat generation has to equal heat demand separately in each district heating network. The positive spinning reserve from power plants and storage has to be larger than the demand for spinning reserve and the same applies to negative spinning reserve. A non-spinning reserve, which can also be provided if power plants are currently offline but capable of starting up fast enough, has to be larger than the demand for this reserve. This reserve is procured dynamically: if there is a chance that the residual demand may increase considerably, more spinning reserve will be required.

For each unit, down regulation minus up regulation plus negative spinning reserve has to be smaller than the generation bid to the day-ahead market. Wind power can shed generation or act as a downward reserve, restricted to the predicted output.

The fuel consumption of power plants increases linearly with power output, and for most power plants there is also some fuel consumption not dependant on the output. This creates a difference in the efficiencies for partial and full load. Extraction-type combined heat and power plants (CHP) have more equations, as described in Barth *et al.* (2006a).

The model was originally made for the Nordic power system and Germany. At the time unit aggregation was used, as the number of power plants would have made the model impossible to solve. For part of studies in this dissertation, power plant data have been updated to unit level for Finland.

WILMAR was originally developed in an EU project in 2002–2006 and it has been applied to several studies since, where it has also been developed further. A recent study was conducted for the Irish power system in which the model was verified against a Plexos model, and this showed high consistency for the Irish system (Meibom *et al.* 2007, p. 26). In this dissertation, WILMAR has been applied to a portfolio based on Balmorel results as well as to the Nordic power system together with the German power system.

4.2 Model for plug-in electric vehicles

In the dissertation, WILMAR was upgraded to include a model for electric vehicles. The electric vehicle model treats the electric vehicles as electricity storage that is not always connected to the power grid and, while gone, spend some of their stored electricity. Each vehicle type has its own general electricity storage pool in each model region. It would be more correct to have separate storage for each vehicle, but the problem would not be possible to solve with thousands of vehicles, and some simplification had to be made. The model is documented in Publication VII.

The model includes a relation between the vehicle departure and arrival times. Figure 7 shows an example pattern of electric vehicles that arrive at 7 pm in the network. Some of them had left in the morning and some during the afternoon. This influenced the calculated consumption of electricity during the trip, since the distribution of trip lengths varies throughout the day. Furthermore, there can be system benefits if the batteries do not need to be completely full on departure.

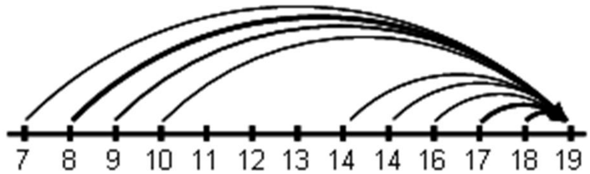

Figure 7. Electric vehicles arriving at 7pm have multiple departure times from the grid (Publication VII).

4.3 Balmorel model

The Balmorel model is a linear optimisation model of a power system, including district heating systems. It calculates investments in storage, production and transmission capacity and the operation of the units in the system while satisfying the demand for power and district heating in every time period. Investments and operation will be optimal under the input data assumptions covering, e.g., fuel prices, CO_2 emission permit prices, electricity and district heating demand, technology costs and technical characteristics. The original model was developed by Balmorel Project (2001) led by H. Ravn and has been extended in several projects, e.g. Jensen and Meibom (2008), Karlsson and Meibom (2008), and Publication VII. Balmorel has a very similar structure to WILMAR in Figure 6.

The optimisation period in the model is one year divided into time periods. The yearly optimisation period implies that an investment is carried out if it reduces system costs, including the annualised investment cost of the unit.

The geographical resolution is countries divided into regions that are in turn subdivided into areas. Each country is divided into several regions to represent its main transmission grid constraints. Each region has time series of electricity demand and wind power production. The transmission grid within a region is only represented as an average transmission and distribution loss. Areas are used to represent district heating grids, with each area having a time series of heat demand. There is no exchange of heat between areas.

The hourly heat demand has to be fulfilled with the heat generation units, including heat storages. The loading of heat storages adds to the heat demand. Loss during the heat storage process is not considered. The dynamic aspects of district heating networks are not taken into account. The district heating network is a small storage unit in itself with complicated properties, and the buildings are another.

5. Results

This chapter presents the main findings of the different analyses made. The focus is on those results that help in understanding the benefits of increasing power system flexibility for the integration of variable power generation. First, the results on conventional power plants and reservoir hydro power are presented. The next flexibility option is different heat measures in Section 5.2. The results on electric vehicles are presented in Section 5.3.

5.1 Conventional power plants and hydro power

The main tool to compensate for wind power variability and prediction errors in the power system is conventional power plants including reservoir hydro power. This is not likely to change even if other options become available in the future. It is therefore important to understand the limitations of the operational properties of the power plants. For thermal power plants, minimum load factors, efficiencies in part load operation, and the wear and tear costs of cycling are especially important. Cold, warm and hot starts are also likely to increase and these have complicated cost structures. These properties are important in the current power plant fleet as well as for new investments.

The combined output of spatially distributed wind power plants changes rather slowly in comparison with possible ramp rates that can be managed by the conventional power plant fleet. However, the magnitude of the ramp rate increases with wind power penetration (Holttinen *et al.* 2011b). If wind power generates half of the load, the absolute ramp rates of wind power on an hourly timescale are higher than the ramp rates in the demand. In the Nordic system, the largest one hour demand change in 2011 was 5.7 GW upwards and 3.5 GW downwards. The largest change in the residual demand, which combines the demand and upscaled wind power generation with 60% energy penetration, has a ramp of 7.7 GW upwards and 6.2 GW downwards. The downward ramp in the residual demand is easier to deal with since wind power generation can be limited if necessary.

A 7.7 GW change in the Nordic power system requires approximately 10–11% of the total capacity (> 70 GW, ENTSO-E 2011) to participate in the ramp up during the hour. This ramp would require about 130 MW per minute. Only large hydro power plants or gas turbines could come close to managing that, but this is not necessary since multiple units can ramp up simultaneously. Almost all units can ramp from minimum generation to maximum generation during one hour if they are warm (Kumar *et al.* 2012), expect nuclear units, which may have more severe technical or regulatory restrictions (NEA 2012). In practice this kind of ramp up would see some units ramping up more slowly than others. Managing the ramping up event requires co-ordination that can be achieved through market mechanisms. However, day-ahead and intraday markets with hourly resolution will not be accurate enough for this purpose (Ela and O'Malley 2012). Hence, the coordination would benefit from markets with a higher time resolution, e.g. 5, 10 or 15 minutes.

5.1.1 Use of conventional power plants

Power plants have quite different properties when it comes to minimum load factors, efficiency at part-load operation, wear and tear of cycling, and the expense of starting up and shutting down. Since wind power variability and prediction errors will increase cycling of conventional power plants, these matters become more important in systems with a large amount of wind power. The results here are derived from Publication IV, in which the generation planning model (Balmorel) was applied to a future system based on the hourly load and wind time series from Finland.

Figure 8 demonstrates the effect of increasing wind penetration on the cycling of conventional units (the wind power investment cost was varied between 900, 800 and 700 €/kW[3]). The cycling is calculated by summing absolute changes in the power plant output over the year and divided by the installed capacity and by two (whole cycle includes up and down ramps). Interestingly, the increase in the cycling occurs mostly in mid-merit and baseload power plants. However, the results are from the Balmorel model runs (Publication IV), which did not include start-up costs or part-load efficiencies.

[3] The investment cost is low from the current perspective. At the time of the analysis, it was assumed that wind power investment costs would continue to decrease towards the study year of 2035. However, it now appears that progress in wind turbine manufacturing in the last few years has improved the yield rather than lowered the investment costs.

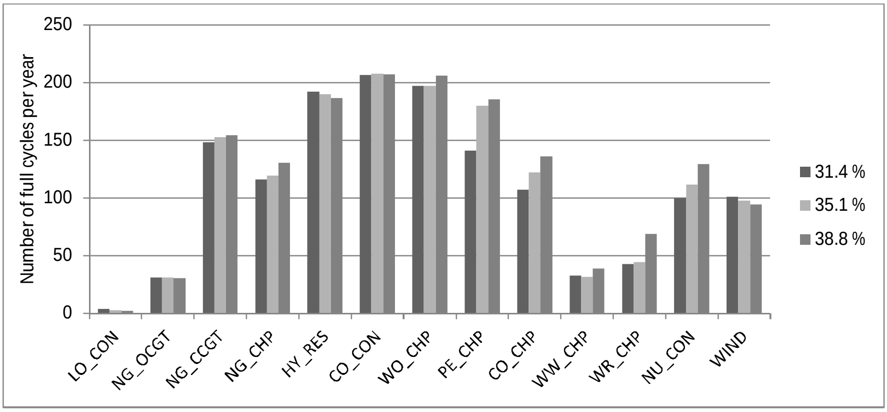

Figure 8. Cycling of conventional units with increasing wind power penetration (from 31.4% to 38.8% of annual consumption). LO = Light Oil, NG = Natural Gas, HY = Hydro, CO = Coal, WO = Wood, PE = Peat, WW = Industrial Wood Waste, WR = Forest Residues, NU = Nuclear, CON = Condensing, OCGT= Open Cycle Gas Turbine, CCGT = Combined Cycle Gas Turbine, CHP = Combined Heat and Power.

Increasing wind power generation will decrease the operating hours of fuel-based conventional power plants (Figure 9), which leads to lower profitability of the base- and intermediate load power plants. These will find it more difficult to recuperate capital costs and in the long term change the power plant structure towards plants with lower capital costs and higher fuel costs. This can be seen in Figure 9, in which the capacity of natural gas-based plants increases and the capacity of the mid-merit and baseload plants decreases with increasing wind power penetration. The decrease was especially pronounced for coal-based generation. Nuclear and reservoir hydro generation were not open for new investments. Forest residue and wood waste-based CHP were resource limited. Peat-based CHP generation was based on existing units.

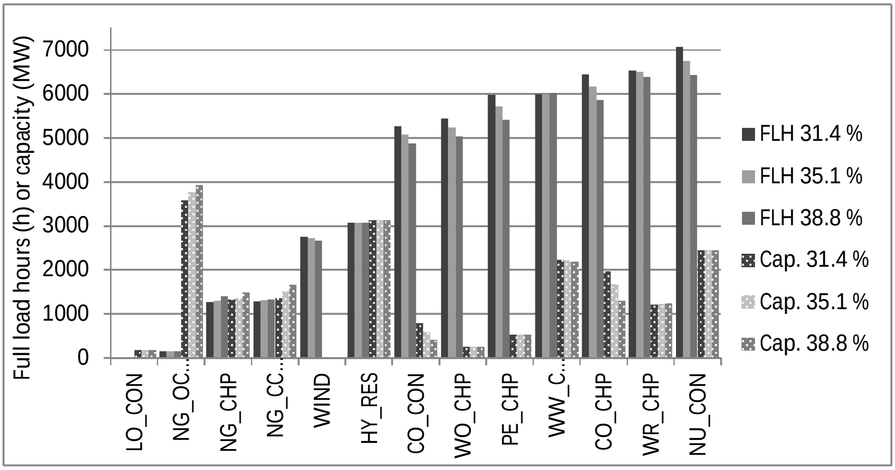

Figure 9. Full load hours (FLH) and installed capacities (Cap.) of conventional units with increasing wind power penetration (from 31.4% to 38.8% of annual consumption). The capacity for wind power was removed as it did not fit in the figure (12.9–16.5 GW). LO = Light Oil, NG = Natural Gas, HY = Hydro, CO = Coal, WO = Wood, PE = Peat, WW = Industrial Wood Waste, WR = Forest Residues, NU = Nuclear, CON = Condensing, OCGT= Open Cycle Gas Turbine, CCGT = Combined Cycle Gas Turbine, CHP = Combined Heat and Power.

In the scenarios in which new nuclear power was allowed (not shown in the figures above), reduced wind power costs led to decreased investments in nuclear capacity. However, nuclear power had already replaced all coal-based generation, so coal could not be reduced further with decreasing wind power cost. Investments in wind power correlated positively with investments in gas turbines, but their use remained low in all scenarios. They were only used during periods of high demand and low wind power generation. The results are highly dependent on the chosen parameters and would have exhibited different behaviour if, for instance, lower natural gas prices had been assumed.

Publication IV also explores a larger set of scenarios, which include different flexibility measures in addition to the wind power investment cost. Figure 10 demonstrates that the availability of different flexibility measures can increase the competitiveness of wind power more than the investment cost of wind power at higher penetration levels. Furthermore, it shows that heat measures were more important than electric vehicles. It is also apparent that the availability of relatively low cost nuclear power (2.625 M€/MW) as an investment option would replace a large portion of wind power generation. Other electricity sources were not as competitive, but this is naturally sensitive to the parameters assumed.

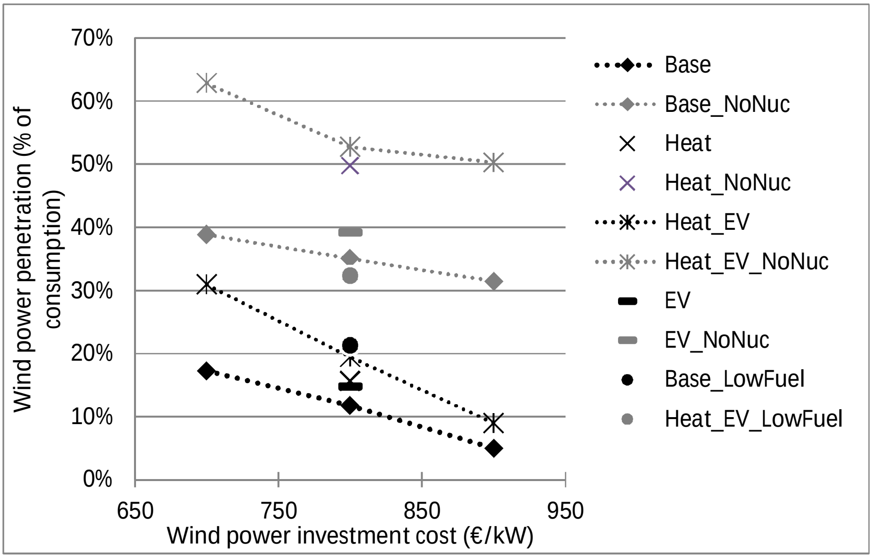

Figure 10. Resulting wind power penetration from the Balmorel generation planning model with different assumptions about wind power investment costs in 2035 (x-axis) and the availability of electric vehicles (EV), heat measures (Heat) and nuclear power (NoNuc) as well as two scenarios with lower fuel prices (LowFuel) for gas and coal.

In the scenarios of Figure 10, the cost of electricity varied between 33 and 43 €/MWh (old power plants were assumed to have been fully amortised and the value of heat was 10 € per produced MWh). The cost refers to the average cost for produced electricity including annualised investment costs. The cheapest scenarios were those with low fuel costs and low wind power costs and the most expensive were those in which the construction of new nuclear plants was not allowed, in addition, flexibility was not available and wind power costs were higher.

Figure 10 also demonstrates that flexibility from heat measures had a greater impact on the cost optimal share of wind power than electric vehicles, especially in the scenarios without new nuclear power plants. It was assumed that about half of the personal vehicles in Finland used electricity as fuel, while heat pumps and electric boiler investments were applicable to below 30% of the district heating loads and heat storage investments were available for all district heating loads (Publication V).

5.1.2 Capabilities of reservoir hydro power

Limitations on the regulation of hydro power with reservoirs originate from the degree of automation and from the reservoir and river system properties (Kiviluoma *et al.* 2006). Reservoirs that are enlargements of the existing river bed can usually produce only a couple of hours at full capacity before the reservoir is at its minimum. This is often good enough to provide daily peak demand power, but periods of low wind power generation can last longer. For hydro power plants with large reservoirs, this is clearly not a problem, since they can easily provide full power through the low wind power generation periods. New units in these locations would increase capacity and hence they could offer rather cheap additional flexibility for integrating wind power, but this can be restricted by flow limitations in the rivers. Another option at locations with two reservoirs at different heights would be to include pumping capability.

Kiviluoma *et al.* (2006) estimated the energy balancing potential of Nordic hydro power based on river system data. The share of run-of-river hydro power was small, less than 10% of the total generation. Most Nordic hydro power capacity has upstream reservoirs and, on average, the reservoirs are large. In Norway, the average reservoir can hold water for about 0.7 years' worth of generation and is a short distance from the hydro power station (estimate for the time lag was close to zero in central and northern Norway and about 2 hours in southern Norway). Swedish reservoirs are smaller (on average 0.45 years' worth of generation) and the average time lag from the reservoir to the hydro power station is longer (estimated as 2–3 hours). The results imply that there is a high amount of untapped flexibility potential in the Nordic hydro systems, but their value was not quantified in economic terms. However, the constructed data were used to increase the accuracy of the Nordic hydro power modelling in WILMAR throughout this dissertation.

5.2 Heat storages with heat pumps or electric boilers

Storage of electricity on a large scale is still not economically feasible nor always technically practical, except for pumped hydro in some locations. On the other hand, converting electrical energy into other energy forms that can be stored and used for other purposes than electricity can be relatively cheap. This section examines the possibility of converting electricity into heat or cold and using heat storages as a buffer between periods of cheap electricity and demand for heat.

Electricity can be converted to heat directly in resistance coils, which warm up water. The efficiency is close to 100%. Electricity can also be converted into heat with heat pumps, which use the high exergy of electricity to prime heat from an ambient source to a higher temperature. Depending on the required temperature lift, the co-efficient of performance (COP) of a heat pump may typically vary between 2 and 5. When the heat use is space heating and the heat source is outside air, the COP will decrease to one at cold temperature. When the heat source is ground water or sea water, the temperature lift remains reasonable throughout the year. This was assumed in the dissertation, which analysed only large-scale district heating systems in which sea water can be an economic option for the heat source.

The dissertation includes three articles that contain analyses on heat measures. The first article (Publication III) analysed the operational benefits of electric boilers and heat pumps in three district heating areas with the WILMAR model. The value of wind power was increased with the heat measures, since the additional electricity consumption increased power prices (2.0% wind power value increase due to electric boilers and 2.6% increase due to heat pumps). This took place, especially, during low power prices, which were the result of high wind power generation. Fuel use in heat boilers and CHP plants was reduced and caused overall system benefits especially in those district heating systems that used fuel oil for heating. The analysis in the article covered 25 days in February and the results are therefore tentative.

The second article (Publication IV) used the generation planning model Balmorel. The model was used to analyse a future power system in 2035 based on Finnish data for time series and the remaining power plants. Scenarios with heat measures were compared with scenarios in which heat measures were not allowed as investments. The impact of heat measures was significant for the integration of wind generation. The main results from Publication IV are presented next.

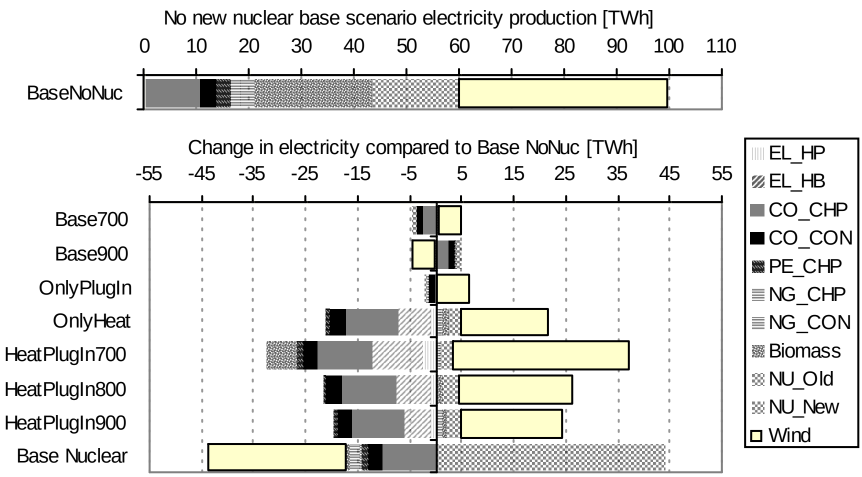

Figure 11. Electricity generation in the scenarios without new nuclear power. The upper figure shows the generation mix in the base scenario without new nuclear power. Changes in the generation mix are then shown in the lower figure. Heat pumps (EL_HP) and electric boilers (EL_HB) will increase electricity consumption and are therefore negative changes in the graphs. Hydropower is not shown, as electricity generation from hydro power does not change between scenarios. CO = Coal, PE = Peat, NG = Natural gas, NU = Nuclear, CHP = Combined heat and power, CON = Condensing.

In the scenarios in which new nuclear power was not allowed (Figure 11), heat measures increased the cost optimal share of wind generation from 35% to 47%. In the scenarios in which new nuclear power was allowed, there was an increase in wind generation from 12% to 15%. It was more difficult to replace relatively inexpensive nuclear generation (2.625 M€/MW) than coal generation, which was already replaced by the nuclear generation. The results are highly sensitive to the assumed cost parameters for heat measures, wind, nuclear and other generation units (assumed costs in Table 3 of Publication IV). As a comparison, the reduction of wind power investment cost from 800 €/kW to 700 €/kW increased the wind power share from the base of 35% to 39% in the no nuclear scenarios and from 12% to 17% in the nuclear scenarios.

In operational terms, electric boilers were especially important to cope with the high wind-low demand situations (Figure 12). Heat pumps were not nearly as important, since they require a high number of full load hours in order to be profitable and do not match the variable wind power generation as well. However, during low wind-high demand situations, heat pumps reduced electricity consumption, which brought useful flexibility to the power system.

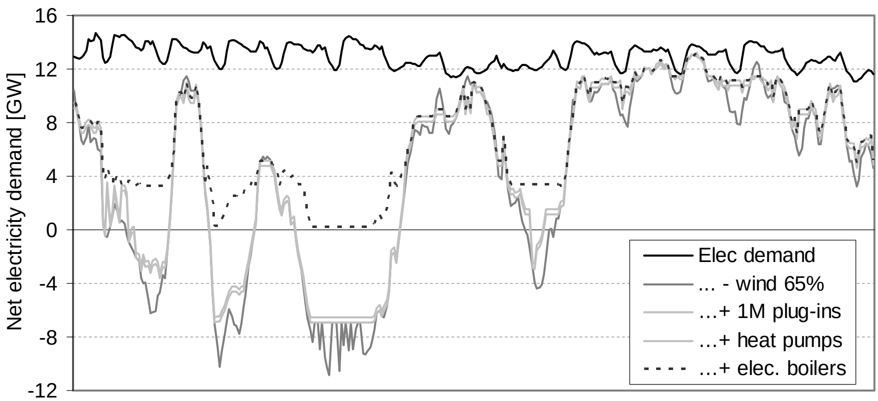

Figure 12. Changes in net electricity demand when flexibility mechanisms are overlaid on top of each other (Publication VII). The x-axis holds two weeks in March from the 'HeatPlug NoNuc 700' scenario. This scenario (heat measures available, no new nuclear power allowed and wind power at 700 €/kW) had the greatest wind power penetration, and the selected weeks included both a very high and a very low wind power generation event.

The heat measures included heat storages as an investment option. The impact of this was examined more closely in a third paper (Publication V). The results imply that if the share of variable generation becomes large, heat storages will become very beneficial for district heating networks. Heat storages create operational benefits, which justify the investments in heat storages, by moving demand from more expensive sources of heat to less expensive ones by shifting demand in time. The heat storages create additional flexibility by allowing CHP units to shut down during events with relatively low residual demand and hence remove must-run electricity generation (Figure 13). Heat storages also helped heat pumps to displace generation from CHP units because it allowed the shut-down of heat pumps during high residual demand situations and hence decreased electricity consumption.

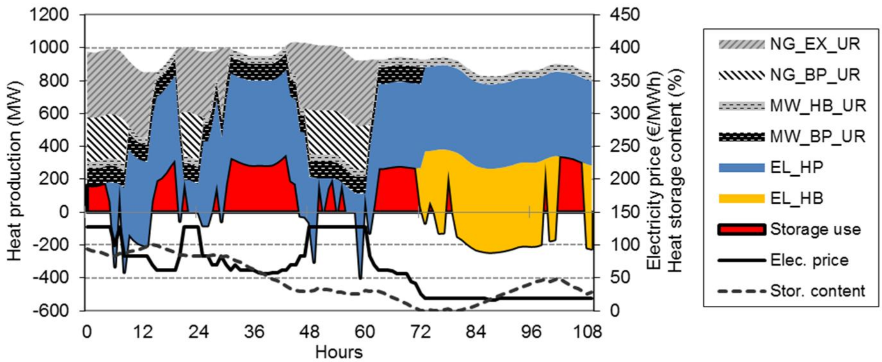

Figure 13. Example of 4.5 days of heat generation in January for the 'Urban' district heating system (Publication V). The negative heat generation values are due to the loading of the heat storage. The electricity price (solid line) and heat storage content (dashed line) are on the right y-axis. NG_EX_UR is natural gas extraction CHP, NG_BP_UR is natural gas backpressure CHP, MW_HB_UR is a municipal waste heat boiler, EL_HP is a sea water heat pump, EL_HB is an electric resistance boiler, and storage refers to the heat storage in the district heating system.

In the winter, the charging of heat storages was mostly based on the use of electric boilers. They create large amounts of heat in a relatively short time during periods of low power prices. In summer, heat storages were charged by turning on wood waste and forest residue CHP units or heat pumps. During spring and autumn, CHP units operate more often, since the heat load is greater, but the heat storage still helps to shut them down for periods of a few hours.

5.3 Electric vehicles

Personal vehicles are idle most of the time (WSP LP Consultants 2006). For electric vehicles, this means that there can be a considerable time window for charging their batteries. Typical daily driving distances (52 km in Publication VII) at 0.2 kWh/km imply a charging need of three hours on a 220 V/16 A one-phase household plug. The possible flexibility in electricity demand could benefit the integration of variable generation. Vehicle-to-grid could offer additional flexibility during hours of high power prices or by relieving more expensive forms of rarely used reserves.

The dissertation includes four articles that address electric vehicles. In the first article (Publication IV), Balmorel is used to analyse the power generation investment impacts of electric vehicles and heat measures for the year 2035 using time series from Finland. The Balmorel version in use had a model for charging and discharging the batteries in electric vehicles but it did not include investments in the transport sector. It was therefore assumed that approximately 25% of the personal vehicle fleet was based on full electric vehicles and 25% on PHEVs.

The impact of electric vehicles on generation investments was interesting. The assumed one million electric vehicles (half of the vehicle fleet) increased electricity consumption by 4.0 TWh. In the scenarios in which no new nuclear power was allowed, wind power generation increased by 6.2 TWh (from 35% to 39% of the annual energy). The smart charging electric vehicles enabled wind power to displace mainly coal condensing generation due to the increased flexibility of the system. In the scenarios in which new nuclear power was allowed, wind increased by 4.0 TWh (from 12% to 15% of the annual energy) while existing nuclear power increased by 2.0 TWh to reach 19.7 TWh. At the same time, new nuclear generation was reduced by 1.5 TWh down to 41.1 TWh. These results mean that electric vehicles may actually reduce overall CO_2 emissions (2–3 Mt CO_2 in the analysed scenarios for one million electric vehicles compared with 90 gCO_2/km gasoline vehicles).

The Balmorel runs also provided power plant portfolios for the WILMAR runs in Publication VII. This was the first time when a generation planning model was combined with an operational model in order to analyse the benefits of smart charging electric vehicles more comprehensively. The article presents a robust methodology for analysing the impact of electric vehicles in a unit commitment time frame. According to the results, smart charging electric vehicles reduced power system costs by 227 €/vehicle/year. Part of the benefits come from less expensive operations and part comes from smaller investments and fixed costs. The scenario setup indicated that the benefit was divided between spinning reserve procurement (17%), capability to change output after day-ahead unit commitment (47%), and day-ahead planning of charging and discharging (36%). V2G was enabled with a round-trip efficiency of 85% and 10 €/MWh wear and tear costs. In a scenario in which V2G was not allowed, the system benefit was reduced by 53 €/vehicle/year. When V2G was available in half of the one million electric vehicles, the system benefit was only reduced by 6.7 €/vehicle/year.

The third article on electric vehicles (Publication VI) gave an estimate of how the size of the electric vehicle fleet influences the system benefits of smart charging electric vehicles compared with electric vehicles that start charging immediately after plugging in. The more smart charging electric vehicles there are, the smaller the system benefits per vehicle. However, it should be considered that increasing the penetration of variable and uncertain generation will increase the need for flexibility and therefore better maintain the benefits of smart charging. The article remained inconclusive about this hypothesis. The use of a generation planning model to set up the power plant portfolios would have improved the results.

Lastly, Publication VIII analysed the impact of electric vehicles on wind power, focusing on balancing cost reductions due to electric vehicles. The average wind power balancing cost decreased from 2.4 €/MWh ('No EVs' scenario) and from 2.7 €/MWh ('Dumb' electric vehicles scenario) down to 1.6 €/MWh in the 'Smart' electric vehicles scenario. In the 'Dumb' scenario, charging started immediately as the vehicles were plugged in. In the 'Smart' scenario, charging was optimised when the operational costs for the power system were minimised. However, the revenue for wind power from other power markets decreased at the same time and the net result was almost zero. In the 'Smart' scenario, electric vehicles were allowed to discharge to the grid when the benefit exceeded the discharging costs. When this V2G was disabled, the balancing costs increased back to 2.2 €/MWh. When half of the electric vehicles had V2G disabled, the balancing cost was 1.8 €/MWh. Interestingly, the introduction of electric vehicles increased the overall balancing activity, since conventional power plants changed their schedules with the help of electric vehicles in order to increase average efficiency and reduce start-up costs.

6. Discussion

This dissertation investigates wind power integration through the exploration of the economic possibilities of increasing power system flexibility with conventional power plants, electric vehicles and heat loads.

Analysing flexibility from heat loads is difficult due to the complexities in the systems that use heat. The results presented in the thesis are based on a simplified description of heat loads, heat pumps, electric boilers and heat storage. The reliability of the results may be improved by comparing them against real systems. The results concerning the heat load are mainly valid for district heating systems, with their main applicability to northern latitudes. Local heating and cooling systems are more common. Local systems will have higher investment costs before their flexibility can be increased (Estanqueiro *et al.* 2012). Nonetheless, they can be operated along similar principles and may thus offer substantial flexibility even without district heating networks.

The dissertation includes the development of comprehensive methodology for analysing the impact of electric vehicles on the power system economics. The driving patterns were based on real data from the Finnish National Road Administration. The stochastic unit commitment model was able to optimise the charging and discharging of electric vehicles within the driving pattern constraints. A power generation planning model was combined with an operational model. Even so, not all possible revenue streams were covered: distribution grid benefits were not included and revenues from reserves only partially. To further improve the model, the literature review indicates that inclusion of depth-of-charging-based variable costs would be important at least for some battery chemistries (Peterson *et al.* 2010a) as well as more realistic behaviour of battery storage pools. Instead of one storage pool for each vehicle type, there should be a separate pool for each hour of leaving vehicles, as also suggested in the discussion in Publication VII.

Some of the assumptions used in the beginning of the dissertation may have been too optimistic. The cost of wear and tear of the battery due to V2G use was assumed at 10 €/MWh. The latest research indicates an estimate of up to 50 €/MWh based on data from Peterson *et al.* (2010a) and Millner (2010). The estimated benefits of V2G (53 €/vehicle/year) would be lowered by the higher wear and tear costs. Clear improvements in battery cost and/or cycling durability are necessary to achieve the assumptions used in this study.

The investment costs of wind power, which ranged between 700 and 900 €/kW in the analysis, have not yet been achieved. The investment costs are currently around 1500 €/kW (Milborrow 2012), but at the same time the average yield and capacity factor have increased. As a consequence, the wind power production costs (€/MWh) have decreased. As the target of the analysis is 20 years ahead, the cost assumptions, and in particular the wind production cost, may still be realistic. Higher capacity factors of wind power in the future may change the variability of wind power generation and more research would be needed to quantify these impacts.

Reservoir hydro power consisting of several reservoirs and power plants within a river system is highly complex to optimise. A model such as WILMAR aggregates river systems, which yields generation from the hydro assets that is too flexible. Work is on-going to improve the river system representation in the WILMAR model. More restrictive use of hydro power is likely to increase the value of other forms of flexibility.

A simplified modelling approach to the power grid was used here due to the necessity to reduce the research task and the size of the optimisation problem. The preclusion of grid issues is a limitation, as high levels of wind power generation could considerably increase the costs to mitigate the problems that arise. This should be evaluated separately.

The power system is characterized through a range of factors such as the power plant mix, plant flexibility and ramping capabilities, capacity and strength of the electric network, and in particular the high voltage grid, interconnections between power systems, operational rules and regulations, shape and profile of the electricity demand, wind power generation patterns, etc. (Chandler 2011, p. 37–39). Understandably, the number of combinations to characterize the power system is so vast that a uniform and generalized picture on wind power integration is difficult to accomplish, if not impossible. Hence, this thesis has been restricted by a geographical scope of Finland and the Nordic countries. Thus, while the results and conclusions should have relevance to wind integration in many regions, they are not necessarily universally applicable. The following paragraphs consider the impact of power system flexibility on the applicability of the results.

The Nordic power system as a whole is very flexible, due to the high share of reservoir hydro power with large water reservoirs, in particular in Norway and Sweden. The Finnish power system per se, though the share of hydropower of all electricity varies from 11 to 19% (Official Statistics of Finland 2012), is not that flexible due to the dominance of backpressure-type CHP with fixed ratios between heat and power and nuclear power with regulatory and technical restrictions on ramping (NEA 2012). From a wind power integration point of view, a flexible power system would inherently allow more variable generation capacity than a rigid one.

Chandler (2011) has calculated rough estimates for the potential of variable generation in present power systems. While the Nordic countries scored 48% in this index, on the lower end of the scale Japan obtained just 19%, where the percentage describes how much variable generation of total could be possibly integrated into the present power system. Flexibility is subject to diminishing returns and thus flexibility is more valuable in a power system with less of it (Holttinen et al. 2012). Therefore, the value of the flexibility options estimated in the dissertation is likely to be higher in more rigid power systems. However, the relative importance of different flexibility options will tend to vary between power systems subject to different conditions and having different configurations.

7. Conclusions

The main finding of this dissertation is that high levels of wind power generation (30–60% of the annual energy) are possible without dedicated electricity storage through other flexibility-increasing methods. The analysed scenarios assume continued fossil fuel scarcity, costs from CO_2 emissions and decreasing wind power costs. The results demonstrate the relative impact of wind power investment costs and available flexibility measures on the cost optimal share of wind power. Reducing the wind power investment cost from 900 €/kW to 700 €/kW increased wind power penetration by 7–12 percentage points when flexibility from the heating sector and electric vehicles were not available. When these flexibility measures were available, the penetration increased by 9–21 percentage points when the investment cost was reduced from 900 €/kW to 700 €/kW. As a simplified transmission system description was used, the results may underestimate the true power system costs of wind power.

Many past studies have not optimised the power plant portfolio to match the new situation created by the increasing share of variable generation. Instead, wind generation is just added to an existing power system or it is assumed to support increasing electricity demand, which is often depicted by a flat block. The dissertation highlights the importance of the generation planning approach for the studies on future systems with tens of per cent of annual energy from wind power. The resulting power plant portfolio can be surprising, for example, the availability of the flexibility measures enabled portfolios in which wind and nuclear power together generated up to 77% of the annual energy.

The results indicate a large and economic flexibility potential from the heat measures – e.g. in one of the analysed settings they increased the cost optimal share of wind power from 35% to 47%. The mechanisms that increase flexibility include electric boilers, heat storages and heat pumps. Electric boilers can convert excess power generation into heat and therefore enable the shutdown of CHP units during periods of high wind generation and low electricity demand. The economic consequences for CHP were not assessed. Heat storages can advance or postpone heat generation and hence affect the operation of electric boilers and CHP units. The interactions can be complex, for example, during periods of relatively high wind power generation heat storages were not usually charged with heat from electric boilers. Instead heat storages were discharged in order to shut down combined heat and power plants.

Electric vehicles have received much more attention as means to increase power system flexibility than the heating sector. The results in the dissertation indicate that electric vehicles will not be as important as the heating sector – the availability of electric vehicles increased the share of wind power from 35% to 39% in a comparable scenario. Furthermore, the electric vehicle batteries are dimensioned for road trips while heat storages in district heating systems are relatively low cost and therefore additional investments can be justified by power system benefits alone – as demonstrated by the analysed scenarios.

Electric vehicles can still constitute an important source of flexibility if they charge and discharge smartly, e.g. smart charging electric vehicles constituting half of the personal vehicles if Finland were able to increase the cost optimal share of wind power by 3–4 percentage points in the analysed scenarios. The results also indicate that smart charging is more important than V2G, which contributed 23% to the 227 €/vehicle/year cost savings when smart charging with V2G was compared with immediate charging. Another result was that electric vehicles may actually reduce the overall CO_2 emissions when they enable a higher share of wind power generation (a reduction of 2–3 Mt CO_2 in the analysed scenarios for one million electric vehicles compared with 90 gCO_2/km petrol vehicles).

In wind power integration studies, conventional power plants are often assumed to take care of the increased flexibility needs. Power plants do this by cycling more and operating more at part-loads. For lower wind penetration levels, this is possibly the only form of flexibility that is economic in addition to non-technical means (e.g. changes in rules and regulations).

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PUBLICATION I

Global potential for wind-generated electricity

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Global potential for wind-generated electricity

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The potential of wind power as a global source of electricity is assessed by using winds derived through assimilation of data from a variety of meteorological sources. The analysis indicates that a network of land-based 2.5-megawatt (MW) turbines restricted to nonforested, ice-free, nonurban areas operating at as little as 20% of their rated capacity could supply >40 times current worldwide consumption of electricity, >5 times total global use of energy in all forms. Resources in the contiguous United States, specifically in the central plain states, could accommodate as much as 16 times total current demand for electricity in the United States. Estimates are given also for quantities of electricity that could be obtained by using a network of 3.6-MW turbines deployed in ocean waters with depths <200 m within 50 nautical miles (92.6 km) of closest coastlines.

Wind power accounted for 42% of all new electrical capacity added to the United States electrical system in 2008 although wind continues to account for a relatively small fraction of the total electricity-generating capacity [25.4 gigawatts (GW) of a total of 1,075 GW] (ref. 1; www.awea.org/pubs/documents/Outlook_2009.pdf). The Global Wind Energy Council projected the possibility of a 17-fold increase in wind-powered generation of electricity globally by 2030 (ref. 2; www.gwec.net/fileadmin/documents/Publications/GWEO_2008_final.pdf). Short et al. (3), using the National Renewable Energy Laboratory's WinDs model, concluded that wind could account for as much as 25% of U.S. electricity by 2050 (corresponding to an installed wind capacity of ≈300 GW).

Archer and Jacobson (4) estimated that 20% of the global total wind power potential could account for as much as 123 petawatt-hours (PWh) of electricity annually [corresponding to annually averaged power production of 14 terawatts (TW)] equal to 7 times the total current global consumption of electricity (comparable to present global use of energy in all forms). Their study was based on an analysis of data for the year 2000 from 7,753 surface meteorological stations complemented by data from 446 stations for which vertical soundings were available. They restricted their attention to power that could be generated by using a network of 1.5-megawatt (MW) turbines tapping wind resources from regions with annually averaged wind speeds in excess of 6.9 m/s (wind class 3 or better) at an elevation of 80 m. The meteorological stations used in their analysis were heavily concentrated in the United States, Europe, and Southeastern Asia. Results inferred for other regions of the world are subject as a consequence to considerable uncertainty.

The present study is based on a simulation of global wind fields from version 5 of the Goddard Earth Observing System Data Assimilation System (GEOS-5 DAS). Winds included in this compilation were obtained by retrospective analysis of global meteorological data using a state-of-the-art weather/climate model incorporating inputs from a wide variety of observational sources (5), including not only surface and sounding measurements as used by Archer and Jacobson (4) but also results from a diverse suite of measurements and observations from a combination of aircraft, balloons, ships, buoys, dropsondes and satellites, in short the gamut of observational data used to provide the world with the best possible meteorological forecasts enhanced by application of these data in a retrospective analysis. The GEOS-5 wind field is currently available for the period 2004 to the present (March 20, 2009) with plans to extend the analysis 30 years back in time. The GEOS-5 assimilation was adopted in the present analysis to take advantage of the relatively high spatial resolution available with this product as compared with the lower spatial resolutions available with alternative products such as ERA-40, NECP II, and JRA-25. It is used here in a detailed study of the potential for globally distributed wind-generated electricity in 2006.

We begin with a description of the methodology adopted for the present study. The land-based turbines envisaged here are assumed to have a rated capacity of 2.5 MW with somewhat larger turbines, 3.6 MW, deployed offshore, reflecting the greater cost of construction and the economic incentive to deploy larger turbines to capture the higher wind speeds available in these regions. In siting turbines over land, we specifically excluded densely populated regions and areas occupied by forests and environments distinguished by permanent snow and ice cover (notably Greenland and Antarctica). Turbines located offshore were restricted to water depths <200 m and to distances within 92.6 km (50 nautical miles) of shore.

These constraints are then discussed, and results from the global analysis are presented followed by a more detailed discussion of results for the United States.

Methodology

The GEOS-5 analysis uses a terrain-following coordinate system incorporating 72 vertical layers extending from the surface to a pressure level of 0.01 hPa (an altitude of ≈78.2 km) (5). Individual volume elements are defined by their horizontal boundaries (latitude and longitude) and the pressures at their top and bottom. The horizontal resolution of the simulation is 2/3° longitude by 1/2° latitude (equivalent to ≈66.7 km × 50.0 km at midlatitudes). The model provides 3D pressure fields at both layer centers and layer edges in addition to wind speeds (meridional and zonal) and temperatures at the midpoint of individual layers with a time resolution of 6 h. The 3 lowest layers are centered at approximate altitudes of 71, 201, and 332 m. The 6-h data for the 3 lowest layers are used in the present analysis by using an interpolation scheme indicated as follows to estimate temperatures, pressures, and wind speeds at 100 m, the hub height for the 2.5- and 3.6-MW turbines considered here.

Knowing pressures at the lower and upper edges of individual layers together with temperatures and pressures at the midpoints of the layers, altitudes corresponding to the midpoints of the layers are calculated based on an iterative application of the barometric law by assuming a linear variation of temperature between the midpoints of individual layers. The barometric law was also used to calculate the pressure at 100 m. Wind speeds and temperatures at 100 m were computed by using a cubic spline fit to data at the midpoints of the 3 lowest layers.

The kinetic energy of the wind intercepted by the blades of a turbine per unit time (P) depends on the density of the air (ρ), the area swept by the rotor blades (πr^2), and the cube of the wind speed (V^3) reduced by an efficiency or power factor (f_p) according to the formula (6):

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$$P = \frac{1}{2}\rho \pi r^2 f_p V^3 \qquad [1]$$

The efficiency with which kinetic energy intercepted at any given wind speed is converted to electricity by the turbine depends on details of the turbine design specified by what is referred to as the turbine power curve. Typically, conversion to electricity varies as the cube of the wind speed at low wind speeds, asymptoting to a constant value for moderate to higher wind speeds, dropping to 0 at the highest wind speeds when the blades of the turbine are normally feathered to prevent damage. For the present purpose, we chose to use power curves and technical parameters for 2.5- and 3.6-MW turbines marketed by General Electric (GE) (http://gepower.com/businesses/ge_wind_energy/en/index.htm).

These power curves assume an air density of 1.225 kg/m^3 under conditions corresponding to an air temperature of 15 °C at a pressure of 1 atmosphere (7). To account for the differences in air density at the rotor elevations as compared with this standard, wind speeds in the published power/wind speed curves were adjusted according to the formula

$$V_{corrected} = \left(\frac{P \cdot T}{1.225R}\right)^{1/3} \cdot V_{original}, \qquad [2]$$

where P and T identify the air pressures and temperatures at the hub height and R denotes the atmospheric gas constant, 287.05 N·m/(kg·K) for dry air.

Optimal spacing of turbines in an individual wind farm involves a tradeoff among a number of factors, including the costs of individual turbines, costs for site development, and costs for laying power cables, in addition to expenses anticipated for routine operations and maintenance (O&M). Turbines must be spaced to minimize interference in airflow caused by interactions among individual turbines. This process requires a compromise between the objective to maximize the power generated per turbine and the competing incentive to maximize the number of turbines sited per unit area (8). Restricting overall power loss to <20% requires a downstream spacing of >7 rotor diameters with cross-wind spacing of >4 diameters (9, 10). Applying this constraint to the 2.5-MW GE turbines (rotor diameter 100 m, r = 50 m) requires an interturbine areal spacing of 0.28 km^2. Similar restrictions apply to the spacing of offshore turbines (rotor diameter 111 m, r = 55.5 m). For present purposes we assume an area for individual offshore turbines of 5 × 10 rotor diameters corresponding to an occupation area per turbine of 0.616 km^2. The greater spacing for offshore turbines was selected to ensure that the overall power loss should be limited to 10% compensating for the presumed higher cost of installation and greater O&M expense for turbines operating in the more hostile marine environment (8, 9). Subject to these constraints, we propose to calculate the electricity that could be generated potentially every 6 h on the scale of the individual grid elements defined by the GEOS database (≈66.7 km × 50.0 km) subject to the additional spatial limitations identified below.

In addition to providing an estimate for the maximum potential power generation, we propose to evaluate also the power yield expressed as a fraction of the rated power potential of the installed turbines, i.e., to account for the anticipated variability of the wind over the course of a year. This quantity is referred to as the capacity factor (CF), defined by the relation

$$CF = \frac{P_{real}}{P_{rated}} \times 100\%, \qquad [3]$$

where P_{real} denotes the power actually realized (neglecting potential interference between neighboring turbines), and P_{rated} refers to the power that could have been realized had conditions permitted the turbine to operate at maximum efficiency for

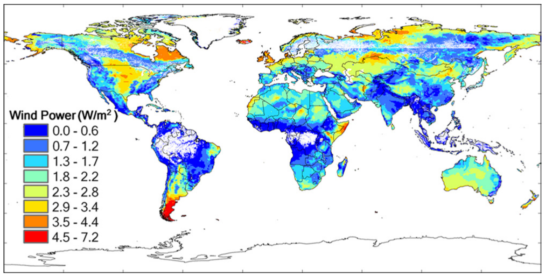

Fig. 1. Global distribution of annual average onshore wind power potential (W/m^2) for 2006 accounting for spatial limitations on placement without limitations on potential realizable capacity factors.

100% of the time. We assume in this context that downtime for maintenance accounts for loss of only a small fraction of the total potential power that could be generated by the installed turbines reflecting the fact that maintenance is normally scheduled for periods of relatively low wind conditions (11). We restrict attention in this analysis to regions with capacity factors >20%.

Geographic Constraints

The Moderate-Resolution Imaging Spectroradiometer (MODIS) provides a useful record of the spatial distribution of different types of land cover for 2001, with a horizontal resolution of ≈1 km × 1 km. This record will be used to exclude from our analysis areas classified as forested, areas occupied by permanent snow or ice, areas covered by water, and areas identified as either developed or urban.

Wind speeds are generally lower over forested areas, reflecting additional surface roughness. Consequently, turbines would have to be raised to a higher level in these environments to provide an acceptable economic return. Although it might be reasonable for

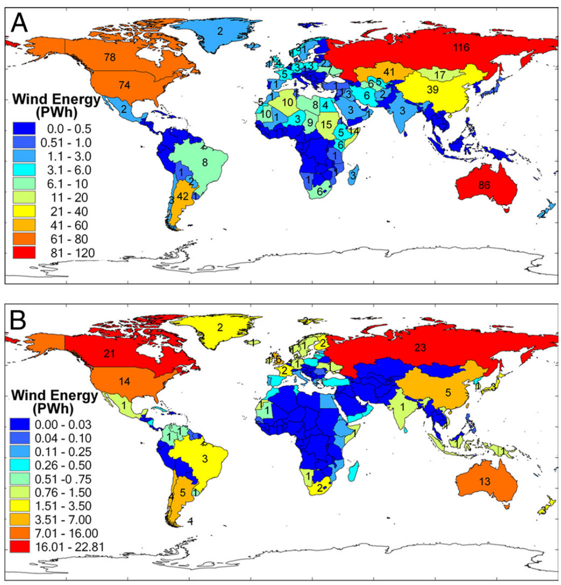

Fig. 2. Annual wind energy potential country by country, restricted to installations with capacity factors >20% with siting limited. (*A*) Onshore. (*B*) Offshore.

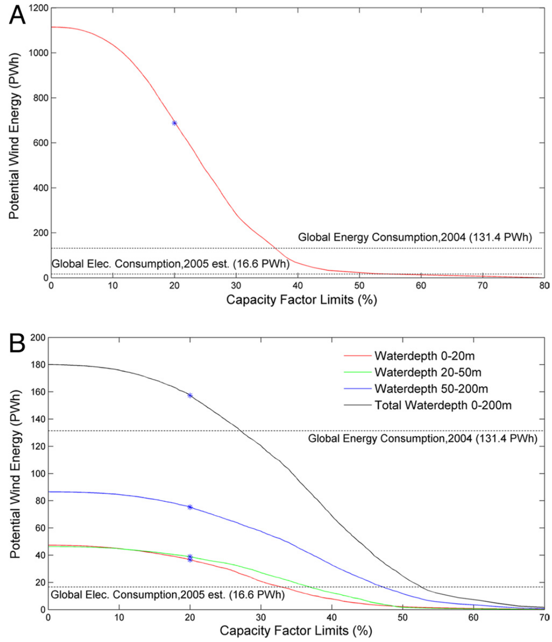

Fig. 3. Annual wind energy potential as a function of assumed limits on capacity factors. Results corresponding to the capacity factor limit of 20% assumed in this study are indicated by *. (*A*) Global onshore. (*B*) Global offshore.

some regions and some forest types, we elected for these reasons to exclude forested areas in the present analysis.

The exclusion of water-covered areas is more problematic. Wind speeds are generally higher over water as compared with land. However, it is more expensive to site turbines in aquatic as compared with terrestrial environments. Public pressures in opposition to the former are also generally more intense, at least in the U.S.

Topographic relief data for both land and ocean areas were derived from the Global Digital Elevation Model (GTOPO30) of the Earth Resources Observation and Science Data Center of the U.S. Geological Survey. The spatial resolution of this data source for offshore environments (bottom topography) is ≈1 km × 1 km (12). A number of factors conspire to limit the development of offshore wind farms. Aesthetic considerations, for example, have limited development of wind resources in the near-shore environment in the U.S. although objections to near-shore development in Europe appear to have been less influential. There is a need to also accommodate requirements for shipping, fishing, and wildlife reserves and to minimize potential interference with radio and radar installations. Accounting for these limitations, Musial and Butterfield (13) and Musial (14), in a study of offshore wind power potential for the contiguous U.S., chose to exclude development of wind farms within 5 nautical miles (nm) (9.3 km) of shore and restrict development to 33% of the available area between 5 and 20 nm (9.3–37 km) offshore, expanding the potential area available to 67% between 20 and 50 nm (37–92.6 km).

For purposes of this study, following Dvorak et al. (15), we consider 3 possible regimes for offshore development of wind power defined by water depths of 0–20, 20–50, and 50–200 m. Somewhat arbitrarily, we limit potential deployment of wind farms to distances within 50 nm (92.6 km) of the nearest shoreline, assuming that 100% of the area occupied by these waters is available for development.

Table 1. Annual wind energy potential, CO_2 emissions, and current electricity consumption for the top 10 CO_2-emitting countries

Country	CO_2 emission, million tonnes	Electricity consumption, TWh	Potential wind energy, TWh	
			Onshore	Offshore
U.S.	5,956.98	3,815.9	74,000	14,000
China	5,607.09	2,398.5	39,000	4,600
Russia	1,696.00	779.6	120,000	23,000
Japan	1,230.36	974.1	570	2,700
India	1,165.72	488.8	2,900	1,100
Germany	844.17	545.7	3,200	940
Canada	631.26	540.5	78,000	21,000
U.K.	577.17	348.6	4,400	6,200
S. Korea	499.63	352.2	130	990
Italy	466.64	307.5	250	160

CO_2 emission and electricity consumption are for 2005; data are from the Energy Information Administration (http://tonto.eia.doe.gov/country/index.cfm).

Wind Power Potential Worldwide

Approximately 1% of the total solar energy absorbed by the Earth is converted to kinetic energy in the atmosphere, dissipated ultimately by friction at the Earth's surface (16, 17). If we assume that this energy is dissipated uniformly over the entire surface area of the Earth (it is not), this would imply an average power source for the land area of the Earth of ≈3.4×10^{14} W equivalent to an annual supply of energy equal to 10,200 quad [10,800 exajoules (EJ)], ≈22 times total current global annual consumption of commercial energy. Doing the same calculation for the lower 48 states of the U.S. would indicate a potential power source of 1.76×10^{13} W corresponding to an annual yield of 527 quad (555 EJ), some 5.3 times greater than the total current annual consumption of commercial energy in all forms in the U.S. Wind energy is not, however, uniformly distributed over the Earth and regional patterns of dissipation depend not only on the wind source available in the free troposphere but also on the frictional properties of the underlying surface.

We focus here on the potential energy that could be intercepted and converted to electricity by a globally distributed array of wind turbines, the distribution and properties of which were described above. Accounting for land areas we judge to be inappropriate for their placement (forested and urban regions and areas covered either by water or by permanent ice), the potential power source is estimated at 2,350 quad (2,470 EJ). The distribution of potential power for this more realistic case is illustrated in Fig. 1. We restricted attention in this analysis to turbines that could function with capacity factors at or >20%.

Results for the potential electricity that could be generated using wind on a country-by-country basis are summarized in Fig. 2 for onshore (*A*) and offshore (*B*) environments. Placement of the turbines onshore and offshore was restricted as discussed earlier. Table 1 presents a summary of results for the 10 countries identified as the largest national emitters of CO_2. The data included here refer to national reporting of CO_2 emissions and electricity consumption for these countries in 2005. An updated version of the table would indicate that China is now the world's largest emitter of CO_2, having surpassed the U.S. in the early months of 2006. Wind power potential for the world as a whole and the contiguous U.S. is summarized in Table 2.

The results in Table 1 indicate that large-scale development of wind power in China could allow for close to an 18-fold increase in electricity supply relative to consumption reported for 2005. The bulk of this wind power, 89%, could be derived from onshore installations. The potential for wind power in the U.S. is even greater, 23 times larger than current electricity consumption, the bulk of which, 84%, could be supplied onshore. Results

Table 2. Annual wind energy potential onshore and offshore for the world and the contiguous U.S.

Areas	Worldwide, PWh		Contiguous U.S., PWh	
	No CF limitation	20% CF limitation	No CF limitation	20% CF limitation
Onshore	1,100	690	84	62
Offshore 0–20 m	47	42	1.9	1.2
Offshore 20–50 m	46	40	2.6	2.1
Offshore 50–200 m	87	75	2.4	2.2
Total	1,300	840	91	68

Analysis assumes loss of 20% and 10% of potential power for onshore and offshore, respectively, caused by interturbine interference. Analysis assumes offshore siting distance within 50 nm (92.6 km) of the nearest shoreline.

for the contiguous U.S. will be discussed in more detail in the next section. If the top 10 CO_2 emitting countries were ordered in terms of wind power potential, Russia would rank number 1, followed by Canada with the U.S. in the third position. There is an important difference to be emphasized, however, between wind power potential in the abstract and the fraction of the resource that is likely to be developed when subjected to realistic economic constraints. Much of the potential for wind power in Russia and Canada is located at large distances from population centers. Given the inevitably greater expense of establishing wind farms in remote locations and potential public opposition to such initiatives, it would appear unlikely that these resources will be developed in the near term. Despite these limitations, it is clear that wind power could make a significant contribution to the demand for electricity for the majority of the countries listed in Table 1, in particular for the 4 largest CO_2 emitters, China, the U.S., Russia, and Japan. It should be noted, however, the resource for Japan is largely confined to the offshore area, 82% of the national total. To fully exploit these global resources will require inevitably significant investment in transmission systems capable of delivering this power to regions of high load demand.

The electricity that could be generated potentially on a global basis by using wind, displayed as a function of an assumed capacity factor cutoff on installed turbines, is presented in Fig. 3 for onshore (*A*) and offshore (*B*) environments. The results in Fig. 3*A* suggest that total current global consumption of electricity could be supplied by wind while restricting installation of land-based turbines to regions characterized by most favorable wind conditions, regions where the turbines might be expected to function with capacity factors >53%. If the cutoff capacity factor were lowered to 36%, the energy content of electricity generated by using wind with land-based turbines globally would be equivalent to total current global consumption of energy in all forms. Cutoff capacity factors needed to accommodate similar

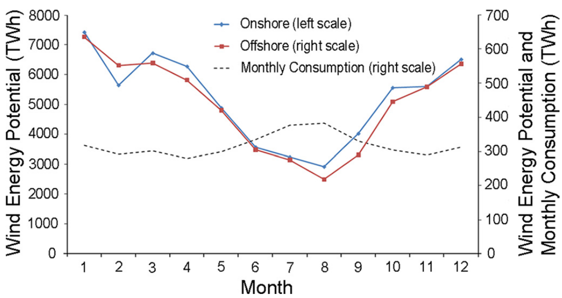

Fig. 4. Monthly wind energy potential for the contiguous U.S. in 2006 with monthly electricity consumption for the entire U.S.

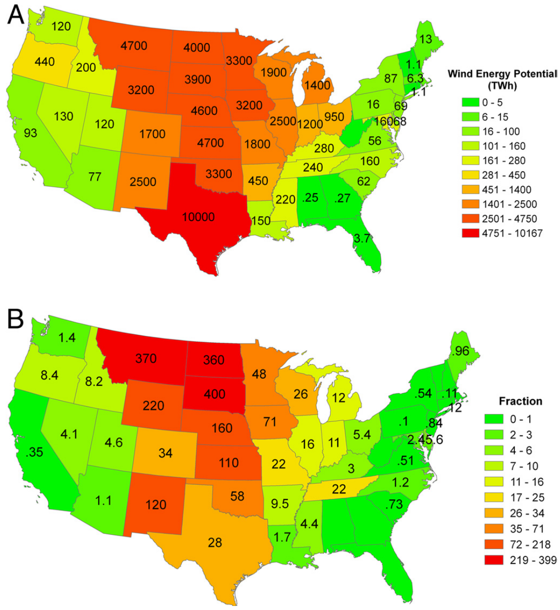

Fig. 5. Annual onshore wind energy potential on a state-by-state basis for the contiguous U.S. expressed in TWh (*A*) and as a ratio with respect to retail sales in the states (2006) (*B*). For example, the potential source for North Dakota exceeds current total electricity retail sales in that state by a factor of 360. Data source for total electricity retail sales was www.eia.doe.gov.

objectives with offshore resources would need to be reduced as indicated in Fig. 3*B*. To place these considerations in context, we would note that capacity factors realized by turbines installed in the U.S. in 2004 and 2005 have averaged close to 36% (18).

Wind Power Potential for the United States

An estimate of the electricity that could be generated for the contiguous U.S. on a monthly basis (subject to the siting and capacity limitations noted above) is illustrated for both onshore and offshore environments in Fig. 4. Results presented here were computed by using wind data for 2006. Not surprisingly, the wind power potential for both environments is greatest in winter, peaking in January, lowest in summer, with a minimum in August. Onshore potential for January, according to the results presented in Fig. 4, exceeds that for August by a factor of 2.5: the corresponding ratio computed for offshore locations is slightly larger, 2.9.

Fig. 4 includes also monthly data for consumption of electricity in the U.S. during 2006. Demand for electricity exhibits a bimodal variation over the course of a year with peaks in summer and winter, minima in spring and fall. Demand is greatest in summer during the air-conditioning season. Summer demand exceeds the minimum in spring/fall demand typically by between 25% and 35% on a U.S. national basis depending on whether summers are unusually warm or relatively mild. The correlation between the monthly averages of wind power production and electricity consumption is negative. Very large wind power penetration can produce excess electricity during large parts of the year. This situation could allow options for the conversion of electricity to other energy forms. Plug-in hybrid electric vehicles, for example, could take advantage of short-term excesses in electricity system, while energy-rich chemical species such as H_2 could provide a means for longer-term storage.

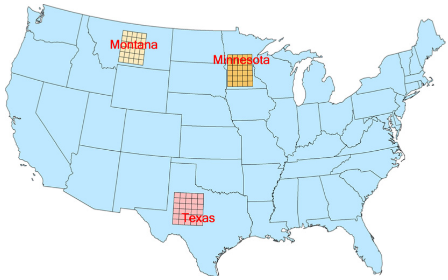

Fig. 6. Locations of regions in Montana, Minnesota, and Texas selected to explore the spatial correlation of wind resources.

Potential wind-generated electricity available from onshore facilities on an annually averaged state-by-state basis is presented in Fig. 5*A*. Note the high concentration of the resource in the central plains region extending northward from Texas to the Dakotas, westward to Montana and Wyoming, and eastward to Minnesota and Iowa. The resource in this region, as illustrated in Fig. 5*B*, is significantly greater than current local demand. Important exploitation of this resource will require, however, significant extension of the existing power transmission grid. Expansion and upgrading of the grid will be required in any event to meet anticipated future growth in electricity demand. It will be important in planning for this expansion to recognize from the outset the need to accommodate contributions of power from regions rich in potential renewable resources, not only wind but also solar. The additional costs need not, however, be prohibitive (ref. 18; www.nrel.gov/docs/fy08osti/41869.pdf). The Electric Reliability Council of Texas, the operator responsible for the bulk of electricity transmission in Texas, estimates the extra cost for transmission of up to 4.6 GW of wind-generated electricity at ≈\$180 per kW, ≈10% of the capital cost for installation of the wind power-generating equipment (ref. 19; www.ercot.com/news/presentations/2006/ ATTCH_A_CREZ_Analysis_Report.pdf.).

An important issue relating to the integration of electricity derived from wind into a grid incorporating contributions from a variety of sources relates to the challenge of matching supply with load demand, incorporating a contribution to supply that is intrinsically variable both in time and space and subject to prediction errors. This challenge can be mitigated to some extent if the variations of wind sources contributing to an integrated transmission grid from different regions are largely uncorrelated. An anomalously high contribution from one region can be compensated in this case by an anomalously low contribution from another. To investigate the significance of this potential compensation, we examined the covariance of wind resources from 3 specific regions, one in Montana, the second in Minnesota, and the third in Texas, as indicated in Fig. 6. Analysis of 6-h averaged potential wind-generated supplies of electricity from the 3 regions over the 4 seasons, winter, spring, summer, and fall, yielded the results summarized in Table 3. Contributions from the 3 regions are essentially uncorrelated during the winter months (October through March) with *r* values of <0.07. Correlation coefficients (*r* values), however, are relatively high in summer (July through September) with values ranging from 0.28 (Montana versus Texas) to 0.37 (Montana versus Minnesota) with intermediate values in spring. The analysis suggests that wind power could make a relatively reliable contribution to anticipated base load demand in winter. It may be more difficult to incorporate wind power resources into projections of base load demand for other seasons, particularly for summer.

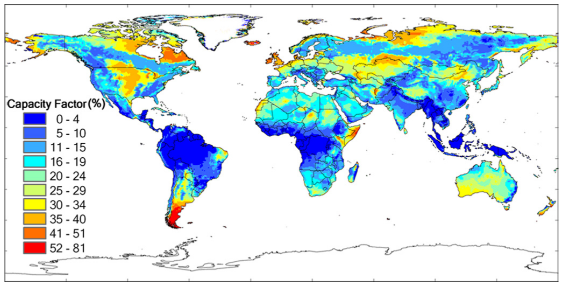

Fig. 7. Global distribution of onshore capacity factor (%) for winds at 100 m with exclusion of permanent snow/ice-covered areas such as Antarctic and Greenland.

Concluding Remarks

The GEOS-5 winds used here were obtained through assimilation of meteorological data from a variety of sources, in combination with results from an atmospheric general circulation model. Transport in the boundary layer was treated by using 2 different formalisms, one applied under conditions when the boundary layer was stable, the other under conditions when the boundary layer was either unstable or capped by clouds. The variation of wind speed with altitude was calculated in the present study by using a cubic spline fit to the 3 lowest layers (central heights of 71, 201, and 332 m) of the GEOS-5 output to estimate wind speeds at the rotor heights of the turbines considered here (100 m). Wind speeds so calculated were used in deriving all of the results presented above.

The rotors of the turbines modeled in this study are of sufficient size that as the blades rotate they traverse significant portions of the 2 lowest layers of the GEOS-5-simulated atmosphere. Use of wind speed for a single level (100 m) must be consequently subject to some uncertainty. To assess this uncertainty we explored results derived with an alternate approach. The power intercepted by the blades of the rotors passing through the separate layers was calculated initially on the basis of the reported average wind speeds for the involved layers. Adopting a typical value of ≈135 m for the height of the boundary between the first 2 layers, given a rotor diameter of 100 m as appropriate for the assumed onshore turbines, it follows that 99% of the area swept out by the rotors would intercept air from the first layer, with only 1% encountered in the second layer. The power intercepted by the rotors may be calculated in this case by averaging appropriately the power intercepted in the 2 layers. Implementing this approach yielded results that differed typically slightly lower, by <15% for the onshore results presented above, by <7% for the offshore results.

The GEOS-5 data had a spatial resolution of ≈66.7 km × 50.0 km. It is clear that wind speeds can vary significantly over distances much smaller than the resolution of the present model in response to changes in topography and land cover (affected in both cases by variations in surface roughness). In general, we expect the electricity yield computed with a low-resolution model to underestimate

Table 3. Correlations of wind power potential between selected regions of Montana (MT), Minnesota (MN), and Texas (TX) in different seasons for 2006

	Correlation coefficient, *r*			
Region	Jan.–March	April–June	July–Sept.	Oct.–Dec.
MN–MT	0.027	0.11	0.37	−0.15
MN–TX	0.069	0.29	0.29	−0.060
MT–TX	0.065	0.26	0.28	−0.0024

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rather than overestimate what would be calculated by using a higher-resolution model. The GEOS-5 data are expected to provide a useful representation of winds on a synoptic scale as required for example to describe the transport between adjacent grid elements. They would not be expected to account for subgrid scale variations in wind speeds even though the latter might be expected, at least under some circumstances, to make a significant contribution to the potentially available wind power. To test this hypothesis we explored the implications of a high-resolution wind atlas available for an altitude of 100 m for Minnesota (20). Wind speeds indicated by the high-resolution database are higher than the wind speeds indicated by GEOS-5, supporting our hypothesis. The close association of wind speed with surface land classification implied by the high-resolution Minnesota wind atlas suggests that land classification data could provide a useful basis for at least a preliminary downscaling of the relatively coarse spatial resolution of the potential wind resources in the present study.

We elected in this study to exclude forested, urban, permanently ice covered, and inland water regions. Given the relatively coarse spatial resolution of the GEOS-5 database, it is possible that this approach may have failed to identify localized environments where wind resources may be unusually favorable and where investments in wind power could provide an acceptable economic return. To explore this possibility, we developed a global land-based map of the efficiencies with which turbines with rotors centered at 100 m might be capable of converting wind energy to electricity. We included all land areas with the exception of regions identified as permanently ice-covered (notably Greenland and Antarctica). Results, stated in terms of relevant capacity factors, are presented in Fig. 7. Regions with particularly favorable capacity factors, even though forested, urban, or occupied by extensive bodies of inland waters, might be considered as potential additional targets for development.

It is apparent, for example, that the low-resolution GEOS-5 record underestimates the wind resource available in Spain and Portugal (a consequence most likely of the complex terrains present in these regions). Sweden is another example where wind resources indicated with an available high-resolution wind atlas (21) are significantly higher than those implied by GEOS-5. The discrepancy in this case may be attributed to the extensive forest cover of the region and the a priori decision to neglect such regions in the present global study. Assessment of the potential of mountainous or hilly regions is also problematic. On average, wind speeds in these regions may be relatively low. Particularly favorable conditions may exist, however, on mountain ridges or in passes through mountainous regions. The Appalachian mountain range in the U.S. offers a case in point. In general the low-resolution results tend to slightly overestimate wind resources in regions of flat terrain, while underestimating the potential for regions defined by more complex topography.

The analysis in this article suggests that a network of land-based 2.5-MW turbines operating at as little as 20% of rated capacity, confined to nonforested, ice-free regions would be more than sufficient to account for total current and anticipated future global demand for electricity. The potential for the contiguous U.S. could amount to >16 times current consumption. Important additional sources of electricity could be obtained by deploying wind farms in near-shore shallow water environments.

An extensive deployment of wind farms may be considered as introducing an additional source of atmospheric friction. For example, if the entire current demand for electricity in the U.S. were to be supplied by wind, the sink for kinetic energy associated with the related turbines would amount to ≈6% of the sink caused by surface friction over the entire contiguous U.S. land area, 11% for the region identified as most favorable for wind farm development [the region indicated in red in Fig. 5*A* defined by wind resources >280 terawatt hours (TWh)]. The potential impact of major wind electricity development on the circulation of the atmosphere has been investigated in a number of recent studies (22, 23). Those studies suggest that high levels of wind development as contemplated here could result in significant changes in atmospheric circulation even in regions remote from locations where the turbines are deployed. They indicate that global dissipation of kinetic energy is regulated largely by physical processes controlling the source rather than the sink. An increase in friction caused by the presence of the turbines is likely to be compensated by a decrease in frictional dissipation elsewhere. Global average surface temperatures are not expected to change significantly although temperatures at higher latitudes may be expected to decrease to a modest extent because of a reduction in the efficiency of meridional heat transport (offsetting the additional warming anticipated for this environment caused by the build-up of greenhouse gases). In ramping up exploitation of wind resources in the future it will be important to consider the changes in wind resources that might result from the deployment of a large number of turbines, in addition to changes that might arise as a result of human-induced climate change, to more reliably predict the economic return expected from a specific deployment of turbines.

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PUBLICATION II

Short-term energy balancing with increasing levels of wind energy

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Short-Term Energy Balancing With Increasing Levels of Wind Energy

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***Abstract*—Increasing levels of wind energy are adding to the uncertainty and variability inherent in electricity grids and are consequently driving changes. Here, some of the possible evolutions in optimal short-term energy balancing to better deal with wind energy uncertainty are investigated. The focus is mainly on managing reserves through changes in scheduling, in particular market structure (more regular and higher resolution scheduling), reserve procurement (dynamic as opposed to static), and improved operational planning (stochastic as opposed to deterministic). Infrastructure changes including flexible plant, increased demand side participation, more interconnection, transmission, larger balancing areas, and critically improved forecasting can also be significant and are dealt with in the discussion. The evolutions are tightly coupled, their impact is system-dependent and so no "best" set is identifiable but experience of system operators will be critical to future developments.**

***Index Terms*—Energy balancing, market design, power system operations, reserve allocation, scheduling, unit commitment, wind power.**

I. Introduction

INCREASING levels of wind energy, which is variable, difficult to predict accurately, and increasingly connected via power electronic converters, are changing how electricity grids are planned, designed, and operated [1]. For example, the spatially distributed, asynchronous nature of wind energy is driving upgrades in the transmission system, with deployment of high voltage direct current transmission (HVDC) becoming increasingly popular to connect areas with good wind resources to areas with large loads. Systems with high wind penetration are also experiencing dramatic changes to the operating regimes of conventional generators, which must now operate more flexibly in order to accommodate variable wind power. The displacement of conventional generation also impacts power system dynamics as the voltage support and frequency response previously supplied by these units are also displaced [2], [3].

The increased variability and uncertainty that comes with increased wind energy penetrations exists across multiple time scales and makes energy balancing more challenging. Long-term energy balancing is complicated by the fact that the capacity value of wind for a given system can vary significantly from year to year [4]. Optimal short-term (minutes to day ahead) energy balancing for systems with high wind penetration, which is the focus here, requires high-quality wind forecasts and advanced scheduling methodologies. These advances from the traditional scheduling approach include: dynamic reserve targets, higher resolution scheduling periods, more frequent scheduling, and the use of stochastic optimization techniques. The performance of these approaches is heavily influenced by infrastructural and portfolio changes in the power system. In particular, a more flexible portfolio, more demand side participation, increased interconnection, transmission, larger balancing areas, and improved wind forecasting [5].

The remainder of the paper is arranged as follows: Section II briefly summarizes how short-term energy balancing is currently achieved through the scheduling process and how large-scale wind energy penetration may impact this process. Section III describes advancements to the traditional scheduling methodology that are being implemented in industry and/or proposed in the literature. Section IV discusses longer term infrastructural developments in the power system that will impact short-term energy balancing with increasing levels of wind energy. Section V concludes.

II. Short-Term Energy Balancing and Wind Energy

The primary objective of optimal short-term energy balancing is to minimize costs while maintaining the balance between supply and demand at, or above, a desired reliability level. The problem can be studied by modeling unit commitment (UC), which determines the commitment schedule of units, in combination with economic dispatch (ED), which determines the dispatch level of those units in real time. UC tools commit units, typically day-ahead, based on the demand forecast and requirement for reserves and are subject to both unit constraints (e.g., minimum generation) and system constraints (e.g., transmission capacity). Reserves, with various activation times, ensure sufficient generation is available to

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meet forecast errors, contingencies, and variations over shorter time resolutions than the resolution of the UC and dispatch (typically one hour down to 5 min). Therefore, committed units need to be able to manage primary, secondary, and tertiary frequency control as well as meet the ramp requirements over all time frames. As wind energy increases, the most impacted reserve categories are regulating reserves and load following reserves together with supplemental/replacement reserves (see [6] for discussion on reserve terminology). Regulating reserve corrects random movements in a time frame faster than the dispatch interval, while the latter two correct the cumulative forecast error in the minutes-to-hours time frame and are jointly termed "tertiary reserves." Given that relatively slow moving aggregated wind generation does not change quickly enough to be considered a contingency event, contingency reserves have been shown to be unaffected by increasing wind penetration and hence are not discussed here [7].

The convention has been to commit generating units once per day well ahead of the hours of actual operation [8]. The rationale for the day-ahead UC is due to the temporal nature of the constraints on some of these units. A decision to commit or decommit a unit must respect the unit's startup and shutdown times as well as minimum up and down times, which for a large coal or nuclear unit can be lengthy, and so such decisions need to be made well in advance. If necessary, the system operator may recommit units intraday to allow for significant changes in demand or contingencies. Intraday markets perform a similar function where they exist.

Demand follows daily, weekly, and seasonal patterns and as such demand forecasts are relatively accurate. Consequently, UC optimization approaches have traditionally been deterministic, with uncertainty in demand and power generation being accounted for by provision of reserves. Wind power forecasts by contrast are relatively inaccurate, particularly in the day-ahead time-scale, as error increases strongly with time horizon. This can be seen in Fig. 1 which illustrates wind power forecast error at various time horizons on the 2020 Dutch system. This study used an atmospheric model to generate wind speed forecasts. In the short-term (1–6 hours ahead), information from online wind or wind power measurements have to be used in addition to the numerical weather prediction model data to reach a good performance [9]. Large wind power forecast errors increase system costs and reduce reliability as reserves must be deployed and units redispatched.

At low penetrations of wind power, additional reserves can be scheduled to cover the additional uncertainty due to wind power. However, as the wind power penetration grows, it becomes increasingly inefficient to rely on existing methods for reserve quantification and scheduling. Section III explores evolutions to scheduling that are being studied and in some cases applied in industry.

III. Scheduling Evolutions for Short-Term Energy Balancing

Table I summarizes the evolutions in the scheduling methodology that are currently being deployed and/or proposed for short-term energy balancing with high levels of wind energy. Different methods, which can account for the uncertainty of

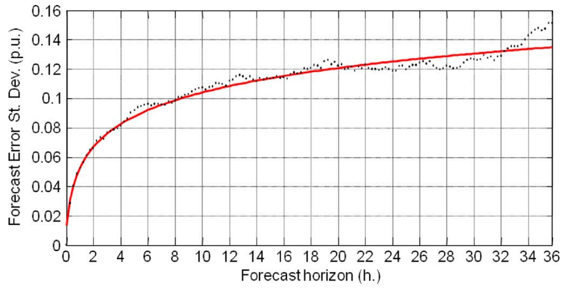

Fig. 1. Normalized standard deviation of wind power forecast error for 12 GW installed capacity versus forecast horizon (source: Netherlands, AVDE tool with data from the atmospheric model HIRLAM [10]). Solid line is a curve fitting.

wind power output, are presented in the first column, while the top row categorizes these methods in terms of when they are undertaken, i.e., once per day or more regularly. The different methods can be complimentary. For example, more regular and higher resolution commitment and dispatch can be done in place of, or as part of dynamic reserve procurement. In reality, combinations of these different strategies will be employed.

A. Scheduling Frequency

A more frequent UC, ED, and reserve procurement achieves two things: portion of the procured reserves can be released later and less expensive reserves can be used more often. Increased frequency enables the use of more up-to-date forecasts and real system information. By using updated information, the reserves carried on the system can be reduced as the operating period gets closer, as illustrated by Fig. 2. In general, repeating UC and reserve procurement in the intraday would still require that a 24-hour or longer UC is carried out to accommodate slower starting units and to ensure availability of capacity; however, these schedules should then be updated whenever new information is available. In addition, this approach allows commitment decisions for quicker starting units to be made closer to real time, delaying commitment decisions until more accurate forecasts are available. In effect, fewer units need to be scheduled for startup, which reduces the procurement costs.

The rationale for more frequent scheduling was proposed by Schlueter *et al.* in 1985 [12], although it was designed for storm events and has not been cited in recent literature. Tuohy *et al.* [13] show that increasing the frequency of commitment from 6 hours to 3 hours can bring tangible benefits in terms of cost and reliability in the Irish system; however, modeling limitations prevented any benefits of decreasing the planning period further from being quantified. Similarly, [14] demonstrates benefits when moving from day-ahead to 3-hour ahead gate closure in the UC.

More regular UC and ED may also cause some additional costs. Operational costs for some power plants may increase due to shorter preparation time. This increases the importance of accurate modeling of certain unit constraints, for example, startup times of units, which may be longer than the time between commitments [15].

While research demonstrates benefits for more regular scheduling, in power exchanges the liquidity of the intraday market

TABLE I
EVOLUTIONS FOR SHORT-TERM ENERGY BALANCING WITH INCREASING WIND ENERGY PENETRATIONS

	Explanation	Scheduling frequency: Once per day	Scheduling frequency: More regular scheduling
Dynamic reserve procurement	A reserve requirement that is based on dynamic forecast error estimates at different time horizons.	Wind power increases tertiary reserve significantly, but the impact will be more limited when the forecast uncertainty is accounted for dynamically.	The combined impact of more regular UC and dynamic reserve procurement would help to keep tertiary reserve requirement relatively low most of the time.
Stochastic UC	Optimization of UC decisions over several scenarios for possible outcomes of wind and demand.	Improves the reliability and yields more optimal UC.	Reduces tertiary reserve procurement and improves UC optimality further.
Scheduling resolution	Scheduling period is shortened e.g. from hourly to five minutes	Ramps within the scheduling period will be smaller, which reduces regulating reserves. Scheduling accuracy will be improved.	

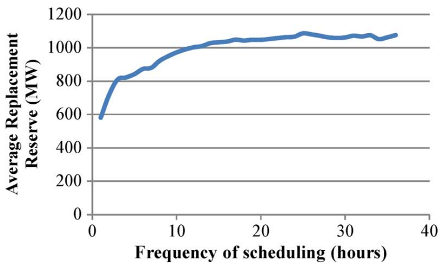

Fig. 2. Example of the trade-off between the reserve requirements and the frequency of commitment [11]. Replacement reserve is similar to the tertiary reserve defined here.

has been low—at least in Europe [16]. This hinders the realization of possible benefits from more regular scheduling. One reason is that generators may expect higher profits in the balancing market and, therefore, do not bid intraday [17]. They may also be hindered by bilateral contracts. Hence, intraday has been an expensive method to balance forecast errors. This leads to self-balancing, which is suboptimal, or to the use of balancing markets, which is on average more expensive due to the shorter response time. The liquidity problem of intraday markets is something that most modeling studies do not capture, as they assume that all available power plants will bid into the intraday market. Therefore, the results from these models may overestimate the benefits of more regular scheduling. It remains to be seen whether the liquidity will be sufficiently improved as increasing uncertainty induces more intraday trading. Another option is to modify current market structures in order to promote liquidity (e.g., auctions instead of continuous trading or bundling of day-ahead and intraday markets into one real-time market), but new market structures will have problems of their own.

Intraday markets are operational at least in Belgium, Germany, U.K., France, Italy, the Nordic system, Spain, Portugal, Poland, Romania, the Netherlands, and the North American ISOs. It is also planned to be a feature of the common European internal energy market, which is to start in 2014 [18].

B. Dynamic Reserve Procurement

Meteorological conditions govern the probable range of wind power output and wind power forecast errors also tend to vary with these conditions [19]. As a simple example, if the predicted wind power output is low, downward error cannot be large. Therefore, a static reserve level is not appropriate. Rather, dynamic reserve constraints which are functions of the wind forecast error and/or the short-term variability of wind power output should be implemented, where the reserve requirement is based on the present level of wind power output, and the expected uncertainty and short-term variability of wind. Taking dynamic reserve allocation as a starting point, the influence of wind power on different operating reserve categories has been detailed in [20].

Regulating reserve is used to correct fast changes in energy imbalance under normal operating conditions. The increase in the required regulating reserves depends primarily on the capacity of the wind generation fleet. Fluctuations in wind farm outputs are uncorrelated in such a short time scale and, therefore, the combined seconds to minutes fluctuation of a large portfolio of wind farms is small [21]. In situations with very high levels of wind generation where the regulating power plants are being displaced, wind power plants need to provide the regulation. The alternative is that wind power plants will have to be curtailed in order to accommodate the minimum generation levels of the regulating power plant.

The longer time frame reserves (several minutes to hours) are strongly influenced also by the geographic spread of the wind power plants. A wide geographic dispersion results in less correlation between turbine outputs and hence less reserves are needed [21].

A simple implementation of a wind forecast is based on the current output level of wind power plants ("persistence forecast") as in [22]. This can be used as the input for an algorithm to calculate the short-term reserve target (e.g., minutes to an hour ahead). Hence, a dynamic reserve requirement can provide cost savings by decreasing spinning reserves compared to a static reserve target [23].

As the time horizon increases, forecast errors become more important. Hence, the required tertiary reserve is highly dependent on the time horizon. Fig. 2 shows the average replacement reserve that is needed as the time horizon for forecast updates increases for the 2020 Irish system with 6000 MW of installed wind capacity [11]. This is based on the 90th percentile of forecast error, which was found to correspond to the required 8 hours loss of load expectation [11]. As can be seen, the average amount of required reserve increases when rescheduling is done less often, particularly in the first 1-10 hours of the forecast.

In power systems with a long lead time for unit commitment (e.g., day-ahead), dynamic reserve procurement can dramatically decrease the need for tertiary reserves. Dynamic reserves have been implemented in recent wind integration studies (e.g., [11], [24], and [25]). In many power systems, tertiary reserves are procured from a real-time balancing market. However, markets do not inherently ensure that the bid stack contains enough capacity to give a high level of reliability if the forecast error happens to be large [8].

Holttinen *et al.* [1] compare the results from several wind integration studies, where it is shown that the methods and assumptions used to calculate the reserve requirements create important differences between results. Also Milligan *et al.* [6] discusses how different wind integration studies have analyzed future reserve needs. They also clarify the different reserve definitions across power systems and how they might relate to the increasing share of wind power. The methods to estimate reserve requirements varied widely, including forecast error statistics with and without the consideration of wind power output level [26], time-step Monte Carlo simulations [27], and risk-based methods [7] which convolute probabilities of wind power, demand, and unit availability. In the risk-based methods, the probability of violating reserve requirement could be constant throughout the year [28]. It could also aim at maintaining a certain probability level over a longer period (e.g., a year), but not force the same probability in each situation as the cost can vary. The latter approach could potentially provide more robust commitments. In [29], [30], and [13] dynamic reserve procurement is combined with a more frequent scheduling.

C. Scheduling Resolution

Power systems with a significant amount of wind power could benefit from higher resolution scheduling (e.g., 5 min instead of one hour). This has been recently implemented in several power systems [31] and in many cases wind power has been at least a partial motivator. Ramps within the shorter dispatch interval will be smaller, which enables a reduction of regulation reserves acting within the scheduling interval [32]. For example, [33] discusses a proposal for an energy imbalance market in the Western Interconnection of the U.S. and compares different market resolutions. In all different scenarios examined 10-min dispatch interval with a 10-min gate closure decreased the requirement for regulation reserves by about 70% compared to hourly dispatch interval with a 40-min gate closure. The impact of moving from a hourly dispatch interval to a half-hourly dispatch interval with the same 40-min gate closure was close to 20%. The method calculated the dynamic reserve requirement using variability within the dispatch interval along with the uncertainty. Other reserves were not impacted, since they were assumed to depend on one-hour forecasts.

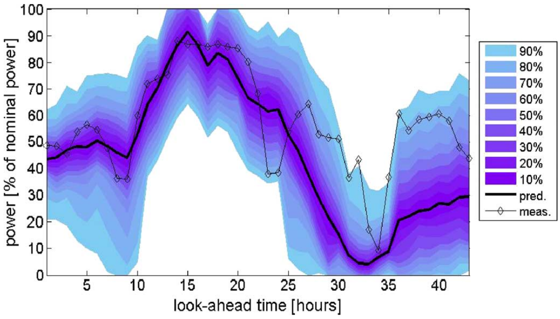

Fig. 3. Probability weighted forecasts [37].

Another reason to increase scheduling resolution is that with higher ramps, the hourly dispatch may change too much from one dispatch interval to the next. For example, if a large system is experiencing a steep ramp in the net demand and the marginal units happen to be in a smaller system connected with an intertie, the intertie could experience a complete reversal over a short period of time. Higher scheduling resolution could lead to more manageable, gradual changes.

Larger net demand ramps due to both wind generation [34] and higher market resolution will cause higher MW/min ramps to be visible in the UC and ED models. Therefore, it becomes more important to model ramping limitations accurately. Aggregated wind data from Texas, which displays wind generation ramps in 1-min resolution is available in [35]. Ela and O'Malley [36] have developed a model that combines UC, ED, and automatic generation control (AGC) in order to analyze the impact of wind power on the short-term energy balance, considering also the time scale of seconds. According to the test system results, decreasing the dispatch interval helps to decrease control performance standard violations caused by ramping limits and wind power uncertainty.

D. Stochastic UC

Uncertainty can be directly represented in the UC formulation by using a stochastic approach. In one formulation of this method, the UC optimizes the expected cost, subject to constraints, with the expected net demand (demand minus wind generation) given by a distribution of possibilities (Fig. 3). In this way, the additional reserves may be implicitly carried [29], because the solver will try and meet as much of the distribution as is optimal considering, for example, the value of lost load. If the whole distribution is included, then the stochastic unit commitment approach inherently has a dynamic reserve constraint built in as the distribution of forecasts is an input that is changing with the underlying meteorological conditions.

In practice, not all of the stochastic information can be included in UC models. In standard approaches to UC, the distribution is represented by "scenario trees" with branches corresponding to different possible outcomes. Each additional branch included in the optimization will increase the computation time. Fig. 3 is an example of a distribution that considers only the forecast quantiles. A more robust representation would include both a sufficient number of branches for possible output levels, as well as stochastic information about the ramp steepness and ramp timings. If ramp uncertainty is not included in the stochastic scenarios, then ramping capability may have to be provided by a separate ramping reserve constraint, or as an addition to existing reserve categories. Midwest ISO is planning to incorporate a ramping constraint into their market clearing tools, which will incentivize market participants to provide ramping services when needed [38], [39].

There are several alternative formulations and approaches that can be taken to stochastic UC. These are primarily being investigated in research models and not in the commercial models that are used by the power industry at large. Some of the models reviewed below do not use actual wind forecasts, or even their statistical properties, as input data and, therefore, their results should be treated with caution although their UC methodologies can be valuable. Restrepo *et al.* [28] examines the effect that including a probability distribution of net demand in a deterministic UC will have on the day-ahead UC, assuming a prediction error which remains constant throughout the day. The probability distribution is rendered into an equivalent mixed-integer form. It is shown, as expected, that the amount of wind curtailed can get quite high. Ruiz *et al.* [40] combine stochastic programming methods with increased reserve to examine the impact of wind on the day-ahead UC. It is shown that using stochastic methods combined with an appropriate amount of reserve reduces wind curtailment and increases the robustness of the day-ahead solutions. Wu *et al.* [41] and Wang *et al.* [42] describe a security constrained stochastic UC model which models uncertainty of wind power in the day-ahead time frame. In [42] an algorithm for calculating a day-ahead UC schedule is presented, taking network constraints into account and being robust towards wind power forecasts errors. Bouffard and Galiana [43] propose a short-term forward electricity market-clearing problem with stochastic security capable of accounting for wind power generation. This algorithm was shown to reduce costs and allow greater wind penetrations compared with a deterministic solution. A simple example from a small system was used to illustrate the benefits of their approach. Pappala *et al.* [44] present a self-adaptive particle swarm algorithm to solve a stochastic UC problem. It is again shown that stochastic methods can increase the amount of wind energy that can be integrated while maintaining power system reliability. Wang *et al.* [45] have included an economic dispatch simulation in a stochastic day-ahead UC model. Both models were run in hourly resolution with no intraday rescheduling or power flow constraints. The authors evaluated different strategies to apply wind power forecasts and reserve requirements and it was found that stochastic UC with additional static reserve requirement gives the least cost results. Constantinescu *et al.* [30] combine a numerical weather prediction model using ensembles with a stochastic UC. Meibom *et al.* [46] present a stochastic UC model that allows UC schedules for power plants to be dependent on wind power production and demand forecasts, as long as units' startup times are respected. The stochastic unit commitment model is unique in its combination of a scenario generation methodology, treatment of reserves, and frequent scheduling and dispatch driven by updated forecasts. Sturt and Strbac [29] have a similar approach, but without transmission constraints, which decreases computation time. The analysis compares different scenario trees and their impact on the system cost and computation time. Larger trees yield benefits, but at a considerable computational cost.

Stochastic UC solution times can be excessive, especially in large systems. The solve time may be increased by an order of 10 or more compared to a deterministic UC. Furthermore, when evaluating impacts of wind power, larger footprints need to be included in the modeled area in order to more accurately represent the interconnected systems that are prevalent around the world and to take spatial smoothing into account. To reduce the problem size, aggregation of units into unit groups, in combination with relaxed mixed integer programming (LP), has been proposed for larger footprints (see [47]). Decomposition schemes in combination with parallel computing facilities also offer promise in handling larger problems sizes [48]. Further work remains to reduce computation times by using more efficient, but still adequate, model formulations and as well as parallel computing facilities.

Stochastic UC may yield lower costs and better performance than a deterministic optimization but the studies so far are not conclusive. However, the stochastic approaches do tend to reduce curtailments which would indicate that as wind penetration rises they will prove advantageous.

While it is possible to integrate uncertainty into optimization models, it will also be important to convey similar information to control rooms, but in a simplified form [49]. Simplification should display expected generation as well as what risks the forecast contains for system security. One such approach would be to use up-to-date system information to select the most applicable scenario from a set of scenarios produced by an earlier run of stochastic scheduling tool. This would reduce the amount of displayed information and would also take into account the slower running cycle of the stochastic tool.

IV. Discussion

The effectiveness of the scheduling evolutions described in the section above will be dependent on the characteristics of the particular system. As the power system evolves over the coming years there are longer term infrastructural changes that will have a substantial influence on the evolution of short-term energy balancing with increasing wind energy penetration.

Market signals related to the pricing of reserve and other frequency-related ancillary services may result in a very flexible generation portfolio where the necessity to forecast out multiple hours may be removed as all units can start at very short notice. In this case, the rationale for a day-ahead UC may be unnecessary. Additionally, a system with a highly flexible plant portfolio, which can respond rapidly to forecast errors, may not see as much benefit from the robust solutions produced by stochastic unit commitment as an inflexible system would. Some power plant manufacturers have already reacted by developing combined cycle units that are capable of more flexible operation (e.g., Siemens SGT5-8000H, GE FlexEfficiency 50) or reciprocating engines [50]. It is also possible to retrofit old units for more flexible operation [51].

Electrification of the two other major end-uses of energy, transport and heat, could also provide balancing opportunities.

Smart charging of electric vehicles could be especially useful for providing contingency reserves and in reducing the impact of wind power forecast errors. However, it is energy-restricted and hence likely to offer only limited resources over periods lasting several hours. On the other hand, converting and storing electrical energy as heat holds large potential in energy terms. With a heat storage, excess wind power generation can be later used for heating or cooling, either in space heating or in industrial applications [52]–[55]. More conventional demand response (see [56]), which might involve shutting down noncritical applications in the case of very high energy or reserve market prices, would be especially useful when large wind forecast errors arise due to unusual weather events. Sioshansi [57] demonstrates that price elastic demand can reduce the monetary impact of wind power forecast errors considerably.

There are also plans for interconnection to reservoir hydro dominated systems to access flexibility. Examples include the planned interconnections between the Nordic system and continental Europe as well as the U.K. [58]; in North America, new interconnections are planned between the MidWest ISO and Manitoba Hydro, BC Hydro and Western Electricity Council, Hydro Quebec and New York ISO, as well as ISO New England.

The construction of more transmission and the development of larger balancing areas[1] will decrease costs from variability and uncertainty. Several studies have found benefits in larger balancing areas [59]–[61]. There are multiple reasons for this. In a larger system, wind power ramps will be less steep per unit, while ramping capability will increase monotonically. Reserves can be provided with fewer and on average more efficient units than before. In addition, forecast errors will be reduced somewhat per unit, thus reducing the need for additional reserves [1].

The most direct infrastructure change that will impact on the effectiveness of the scheduling evolutions for short-term energy balancing is better wind forecasts. A survey of Jones [62], based on an international questionnaire to system operators, found that wind power forecasts are vitally important for successful integration of variable generation. Furthermore, 30% of respondents believed that probabilistic forecasts are of "high" importance and a further 40% believed they are of "modest" importance in control rooms.

Quantitative analysis is required to determine the best way of achieving optimal short-term energy balancing in evolving grids and to help inform future developments. This is highly complex due to several possible trade-offs and hence current literature is only beginning to address the issue. For example Tuohy and O'Malley [63] illustrated the trade-off between better forecasting and the benefits of storage. Similarly the study in [14] shows that in the Netherlands international exchange is a better solution than storage for short-term energy balancing with high wind penetrations. These studies coupled with significant learning potential as power system operators gain experience of managing large levels of uncertainty due to wind plants will determine future trends.

[1]Area where the system operator is responsible to maintain physical balance in relation to adjacent areas and hence play its role in interconnection wide frequency control. A tight cooperation between balancing areas could achieve similar results.

V. Conclusion

Short-term energy balancing to manage the variability and uncertainty of wind power is evolving. Scheduling evolutions including scheduling frequency, dynamic reserve procurement, higher scheduling resolution, and stochastic UC are being proposed and some are being implemented. Frequent scheduling takes advantage of new data closer to real-time and helps to reduce exposure to uncertainty. With more frequent scheduling, the procured reserves can be released later and less expensive reserves can be used more often. Dynamically scheduling reserves reduces the quantity of reserve procurement. Scheduling at higher resolution can reduce the need for reserve, while stochastic scheduling produces solutions which may inherently carry required reserves and are robust against forecast uncertainty. Each of these scheduling evolutions impact on how system operations and decision making can be organized to better manage reserve requirements. Infrastructure developments including increased system flexibility, increased demand side management, interconnection, transmission, larger balancing areas, and improved wind forecasting will also improve short-term energy balancing performance. The scheduling evolutions discussed here are tightly coupled and complimentary to the infrastructure developments, and the overall best solution is system dependent and will be determined by further research and experience.

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Research Article

Value of Electric Heat Boilers and Heat Pumps for Wind Power Integration

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Key words:
wind power;
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stochastic
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The paper analyses the economic value of using electric heat boilers and heat pumps as wind power integration measures relieving the link between the heat and power production in combined heat and power plants. Both measures have different technical and economic characteristics, making a comparison of the value of these measures relevant. A stochastic, fundamental bottom-up model, taking the stochastic nature of wind power production explicitly into account when making dispatch decisions, is used to analyse the technical and economical performance of these measures in a North European power system covering Denmark, Finland, Germany, Norway and Sweden. Introduction of heat pumps or electric boilers is beneficial for the integration of wind power, because the curtailment of wind power production is reduced, the price of regulating power is reduced and the number of hours with very low power prices is reduced, making the wind power production more valuable. The system benefits of heat pumps and electric boilers are connected to replacing heat production on fuel oil heat boilers and combined heat and power (CHP) plants using various fuels with heat production using electricity and thereby saving fuel. The benefits of the measures depend highly on the underlying structure of heat production. The integration measures are economical, especially in systems where the marginal heat production costs before the introduction of the heat measures are high, e.g. heat production on heat boilers using fuel oil.

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Introduction

Problem Overview

A basic property of power systems is that power production must continuously be equal to power consumption including transmission and distribution losses. Wind power production varies with the wind speed and is only partly predictable. Large power plants have start-up times of several hours as well as minimum up times and minimum down times of several hours. The decisions about which power plants to run in a certain operation hour (unit commitment decisions) therefore need to be taken several hours in advance based on forecasts of the wind power production, load and availability of power plants in the operation hour. In the actual oper-

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ation hour, power plants outages and deviations between the load and wind power forecasts, and realised load and wind power are covered by up- or down-regulation of fast-responding power plants or flexible load.

In the Nordic power system, unit commitment and dispatch of power plants are partly determined by trade on the day-ahead market (called Elspot) on the Nordic power pool, Nord Pool. The market is cleared at 12:00 for the following day. To handle the demand for regulation power, i.e. reserve power with an activation time of maximum 15 min, the Nordic transmission system operators (TSOs) operate a regulating power market in each operation hour. Flexible producers and consumers can submit regulating power bids to this market up to 1 h before the actual operation hour. When a regulation need arises in the operation hour, the regulation bids are invoked with the cheapest first. Producers and consumers are required to pay balancing costs when deviations between the amounts sold and bought on the day-ahead market and the actual production and consumption in a given operation hour arise. For a given operation hour, the balancing costs are proportional to the difference between the day-ahead power price and the price on the regulating power market. This also applies for newly installed wind power capacity in Denmark, and it is assumed to apply for all wind power production in this paper.

The Danish power system is characterised by a large share of production from combined heat and power plants and wind power, and the share of wind power is expected to increase in the coming years. The electricity production from combined heat and power (CHP) plants is to some extent driven by the heat demand in the district heating grids connected to the CHP plants. In situations combining a large heat demand, low electricity demand and large wind power production, e.g. a cold winter night with high wind speeds, the electricity demand will be covered by electricity production from heat demand driven CHP plants, wind power production and minimum production on large power plants required for system stability reasons. This production is bid cheaply into the power market, because it has either low marginal costs (wind power) or has to be produced due to coverage of heat demand or due to system stability constraints, and therefore causes the electricity prices to decrease, e.g. the Elspot price at Nord Pool for Western Denmark was zero during 29 h in 2006. The amount of heat demand-driven power production in CHP plants can be relieved by introducing heat storages, heat pumps and electric heat boilers in connection with the CHP plants. Thereby the duration of zero price periods in Western Denmark can be reduced, and thus the value of the wind power production can be increased.

Furthermore, the flexibility introduced in the power system by these measures can be used to provide regulating power asked for by the TSOs, when differences between planned and actual power production arise. As the demand for regulating power will increase with the increasing share of variable and only partly predictable wind power production, measures providing regulating power will also be of value for wind power integration. In the Nordic power system, the owner of electrical heat pumps or boilers will submit bids to the regulating power market offering down- or up-regulation of power consumption. This in turn will reduce the price differences between the regulating power market and the day-ahead market, thereby lowering the imbalance penalties.

Also, power producers with CHP units in their portfolio can use the extra flexibility introduced by these measures when making unit commitment decisions in order to meet production plans. Finally, these measures will also be valuable in their ability to assist CHP plants in covering peak heat loads thereby reducing the use of oil in oil-fired heat boilers.

When electricity price is lower than the price of heat production, it is profitable to operate electric heat boilers to produce heat. Investment costs for electric boilers are low and therefore relatively few operation hours are needed to cover the investments costs. Compared to electric boilers, it is profitable to operate heat pumps more often, since they use two to five times less electricity to produce the same amount of heat.[1] On the other hand, they have higher investment costs. When the system is trying to avoid wind power curtailment with heat pumps or electric boilers, it is more useful to replace CHP production before replacing heat boilers, since one is simultaneously replacing the heat demand-driven electricity production from the CHP plants.

Literature Review

Lund and Münster[2] evaluate the ability of heat pumps and electric boilers to increase the flexibility of a power system with a high share of CHP and wind power production. The model used, EnergyPLAN, is a determin-

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istic simulation input/output model of Western Denmark with the rest of the Nordic power system treated as a price interface to Western Denmark. Results indicate high feasibility of investments in flexibility especially for wind power production inputs above 20% of the electricity consumption.

Elkraft[3] (now Energinet.dk) analyses a high wind power scenario in the Nordic power system with 21 GW wind power capacity in 2025 supplemented with a large increase in natural gas power plants. A bottom-up, deterministic, optimisation model covering the Nordic countries is used in the analysis. The study finds that the costs of operating the power system decreases when installing either 500 MW heat pumps or 1000 MW electric boilers in the CHP systems in Denmark.

Comparing previous approaches[2,3] with the one used in this paper, the main difference on the methodological side is the usage of deterministic models treating wind power production as perfectly predictable, compared to the usage in this paper of stochastic optimisation treating wind power production forecasts as stochastic parameters. The usage of stochastic optimisation is the theoretically soundest way of treating stochastic input parameters compared to e.g. running a deterministic model with different deterministic wind power production inputs. This is due to the unit commitment and dispatch decisions made in the stochastic optimisation model being taken under consideration of the distribution of wind power production forecasts. The stochastic optimisation model allows endogenous evaluation of the value of providing regulating power to the system. As the uncertainties in wind power production predictions generate an increased activation of up- and down-regulation in the operation hour in question, the model is able to quantify the costs connected to the prediction errors of wind power production.

Outline of Approach

Comparison between different heat measures for wind integration is delicate, since there are several determinants for the end results. The model is not capable of doing investment decisions, i.e. determining the optimal mix of heat measures in a given power system. Instead, each heat measure is analysed separately. Three different district heating networks are used to evaluate how much is dependent on the system setting. Two simple criteria have been used to determine the sizes of the heat measures: (i) the heat production capacities of the measures are set to the same value, and (ii) this heat production capacity is set equal to half of the heat production capacity of the CHP plants present in each district heating area. Criteria 1 implies that the impact on the heat system of heat pumps and electric boilers will be comparable in size.

The article has the following structure: Section ‘Model Description’ introduces the model used in the analysis. Section ‘Case Studies’ outlines the cases used in the analysis, and section ‘Simulation Results’ presents results from the model. Section ‘Discussion’ mentions the uncertainties in the study, and ‘Conclusion’ sums up the study and elaborates on the possibilities for future work and on the role of different heat measures.

Model Description

The model analyses power markets based on a description of generation, demand and transmission between model regions and derives electricity market prices from marginal system operation costs. Model regions are defined in order to achieve good correspondence with most important bottlenecks in the power system. The model is a stochastic linear programming model with wind power production as the stochastic input parameter. It optimises the unit commitment, taking into account trading activities of different actors on different energy markets. Three electricity markets and markets for heat are included in the planning model:

1. A system-wide day-ahead market for the planned delivery of electricity being cleared at 12:00 for delivery the next day. The average of the wind power forecasts for the next day is sold at the day-ahead market.
2. A system-wide intra-day market for handling deviations between expected production and consumption agreed upon the day-ahead market and the realised values of production and consumption in the actual operation hour. The demand for regulating power is in the model caused by the forecast errors connected to the wind power production, because wind power production is the only stochastic parameter in the model.

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3. For each model region, a day-ahead market for automatically activated reserve power (frequency activated or load-flow activated). The demand for these ancillary services is determined exogenously to the model.
4. Due to the interactions of CHP plants with the day-ahead and intra-day market, markets for district heating and process heat are included such that each CHP plant is allocated to a specific heat market. A heat market corresponds either to a specific district heating grid or an aggregation of district heating grids or an aggregation of process heat demands. No exchange of heat between heat markets is allowed.

A more detailed description of the model is given in Meibom *et al.*[4]

Objective Function and Restrictions

The objective function consists of the sum of the operational costs of heat and power plants (fuel costs, variable operation and maintenance costs, start-up costs, CO_2 emission costs, taxes and tariffs on certain types of power and heat production), and of the sum of the value in the end of the optimisation period of having energy stored in heat storages, electricity storages and hydropower reservoirs. The model also has the possibility of including price flexible electricity demand in the objective function, but this is not used for these studies. The model thereby minimises the operation costs in the whole system.

The model optimises the unit commitment and dispatch of all units in the system simultaneously. Power production costs of hydro reservoir plants are modelled through water values, which are calculated with the help of a long-term model optimising the use of water over a year-long optimisation horizon using water inflow as a stochastic input parameter.[5]

The technical consequence of the consideration of the stochastic behaviour of wind power generation is the partitioning of decision variables for power production and power transmission. For power production of the unit i at time t in wind power production scenario s, we find

$$P_{i,s,t} = P_{i,t}^{\text{DAY-AHEAD}} + P_{i,s,t}^{+\text{INTRA-DAY}} - P_{i,s,t}^{-\text{INTRA-DAY}}. \tag{1}$$

The variable $\boldsymbol{P}_{i,t}^{\text{DAY-AHEAD}}$ denotes the energy sold at the day-ahead market and has to be fixed the day before. Therefore, it does not vary for different wind scenarios. $\boldsymbol{P}_{i,s,t}^{+\text{INTRA-DAY}}$ and $\boldsymbol{P}_{i,s,t}^{-\text{INTRA-DAY}}$ denote the up- and down-regulation of power production depending on the wind power production scenario. The model allows wind power curtailment in both markets. The decision variables for power transmission are defined accordingly.

The capacity restrictions for electricity-producing units are defined for maximum and minimum electric power output. Since the model is defined as a multi-regional model, capacity restrictions of transmission lines have to be met as well. Transmission loss is considered to be proportional to the amount of electricity transmitted.

In typical unit commitment models, the restrictions for start-up costs, minimum power output, reduced efficiency at partload operation, start-up times and minimum up and down times include integer variables. However, this is hardly feasible for a model covering several countries with the resulting large number of units. Therefore, a linear approximation of these restrictions as proposed by Weber[6] is used in the model. Meibom *et al.*[4] describes these restrictions in more detail. The approximation involves the introduction of an additional decision variable 'the capacity online' with the consequence that the model allows arbitrarily small amounts of capacity to be brought online.

Although the model allows inclusion of minimum up and down times, these constraints have been considered less important than start-up times and start-up costs and are therefore ignored. Ramp rates restricting the up- or down-regulation of the production from committed power plants are for most power plants not binding in an hourly timescale and have been ignored. Unscheduled outages of units and load uncertainty are not included in the model.

The flexibility of the unit dispatch is restricted by the use of lead times that describe the start-up times of conventional power plants. Hence, the model is constrained to make decisions whether to bring additional conventional capacity online before the precise wind power production is known.

Dispatch of heat-generating units like CHP plants and heat boilers at the local heat markets is optimised as well. In order to represent individual district heating grids, the model regions are accordingly subdivided into

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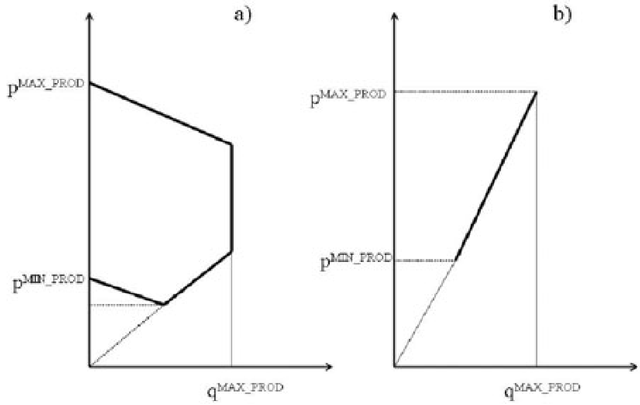

Figure 1. Simplified PQ chart for (a) extraction-condensing turbines and (b) back-pressure turbines

heating areas. CHP plants are distinguished between extraction-condensing units and back-pressure units. The PQ charts (electric power vs. thermal power charts) show the possible operation modes of the CHP plants representing the possible combinations of electric power and thermal power produced. In Figure 1, simplified PQ charts for the two different types of CHP plants included in the model are shown. These technical restrictions require additional equations.

Maintenance rates of power plants in the system are taken into account by week dependant availability factors that express how much of the installed capacity of a unit that is available during the week in question.

The Stochastic Approach of the Model

The inclusion of uncertainty about the wind power production is considered in the optimisation model by using a scenario tree that represents wind power production forecasts with different forecast horizons corresponding to each hour in the optimisation period. For a given forecast horizon, the scenarios of wind power production forecasts in the scenario tree are represented as a number of wind power production outcomes with associated probabilities, i.e. as a distribution of future wind power production levels. The construction of this scenario tree is based on historical data of wind speed and of recorded forecast errors. A multidimensional autoregressive moving average model (ARMA) time series simulates for each station the forecast error increasing with the forecast horizon and additionally taking into account the correlation between the forecast errors at different stations. These ARMA time series contain normal distributed error terms that are generated by Monte Carlo simulations resulting in a pre-defined large number of scenarios for the forecast error.

In order to obtain for each region a forecast for wind power from the wind speed forecast, technological aspects of the wind power stations located in the considered region are needed. Additionally, their spatial distribution within each region has to be taken into account. This yields an aggregation of the power generation in each region by smoothing the wind power curves (see Figure 2).

In order to reduce computation times for models representing a market with a huge number of generating units, only significantly less scenarios than the scenarios created by the Monte Carlo simulations mentioned before can be used. Therefore a stepwise backward scenario reduction algorithm based on the approach of Dupacova *et al*.[8] is used to derive the needed scenario trees.

As it is not possible to cover the whole simulated time period with only one single scenario tree, the model is formulated by introducing a multistage recursion using rolling planning. In stochastic multistage linear recourse models, there exist two types of decisions: 'root' decisions that have to be taken before the outcome of uncertain events (stochastic parameters) is known and hence must be robust towards the different possible

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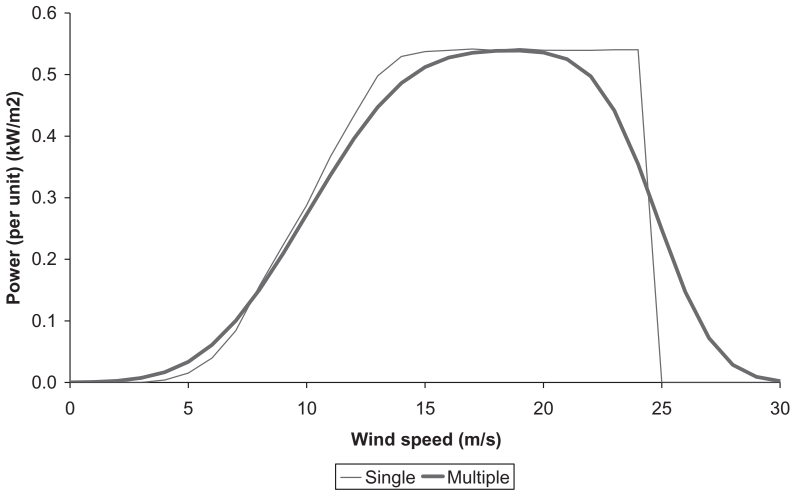

Figure 2. A standard normalised power curve ('single') and the corresponding smoothed power curve ('multiple')[7]

outcomes of the uncertain events, and 'recourse decisions' that can be taken after the outcome of uncertain events is resolved. With these 'recourse decisions', actions can be started which might possibly revise the first decisions. In the case of a power system with wind power, the power producers have to decide on the amount of electricity they want to sell at the day-ahead market before the precise wind power production is known (root decision). In most European countries, this decision has to be taken at least 12–36 h before the delivery period. And as the wind power prediction is not very accurate, recourse actions in the form of up- or down-regulations of power production are necessary in most cases.

In general, new information arrives on a continuous basis and provides updated information about wind power production and forecasts, the operational status of other production and storage units, the operational status of the transmission and distribution grid, heat and electricity demand as well as updated information about day-ahead market and regulating power market prices. Thus, an hourly basis for updating information would be most adequate. However, stochastic optimisation models quickly become intractable, since the total number of scenarios has a double exponential dependency in the sense that a model with $k + 1$ stages, m stochastic parameters, and n scenarios for each parameter (at each stage) leads to a scenario tree with a total of $s = n^{mk}$ scenarios (assuming that scenario reduction techniques are not applied). It is therefore necessary to simplify the information arrival and decision structure in the stochastic model. In the current version of the model, a three-stage model is implemented. The model steps forward in time using rolling planning with a 3 h step. For each time step, new wind power production forecasts (i.e. a new scenario tree) that consider the change in forecast horizons are used. This decision structure is illustrated in Figure 3 showing the scenario tree for four planning periods. For each planning period, a three-stage stochastic optimisation problem is solved having a deterministic first stage covering 3 h, a stochastic second stage with five scenarios covering 3 h, and a stochastic third stage with 10 scenarios covering a variable number of hours according to the rolling planning period in question. In planning period 1 starting at 12:00, the amount of power sold or bought from the day-ahead market for the next day is determined. In the subsequent replanning periods, the variables for the amounts of power sold or bought on the day-ahead market are fixed to the values found in planning period 1, such that the obligations on the day-ahead market are taken into account when the optimisation of the intra-day trading takes place.

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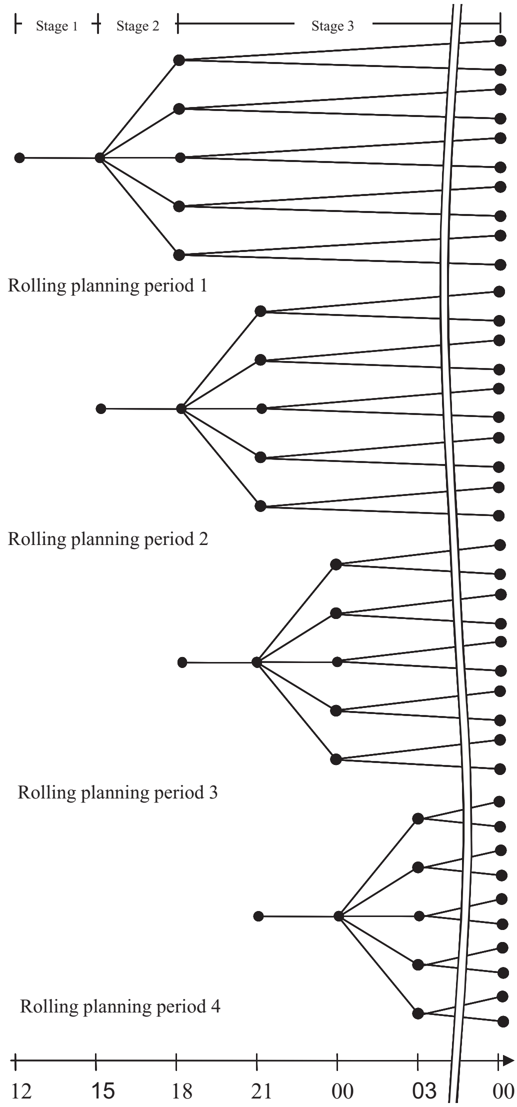

Figure 3. Illustration of the rolling planning and the decision structure in each planning period

Case Studies

The base power system configuration for the cases is a projection of the present power system configuration in Germany and the Nordic countries to 2010 by introducing investments in power plants and transmission lines that are already decided today and scheduled to be online in 2010, and by removing power plants that have been announced to be decommissioned before 2010. As the installed wind power capacity needs to be fairly large for the heat measures to be needed, a strong growth of installed wind power capacity in the period

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2005–2010 has been assumed. Therefore, for Norway, Sweden and Finland, an unrealistic strong expansion of wind power covering 20% of the yearly energy consumption in 2010 is used. For Denmark and Germany, a more plausible high growth scenario has been assumed with the wind power covering 28 and 11%, respectively, of the electricity consumption in 2010. The wind profiles used are based on 2001 wind power production and wind speed data. This wind power case is named the '20%' case. Its wind power production is large enough to bring about situations where one needs to use wind power curtailment or the price goes low enough for the heat measures to be used.

The 2010 system means that planned new transmission lines between Eastern and Western Denmark (Storebælt), Finland and Sweden (Fennoskan2), and north-east and north-west of Germany are in place. Power plant investments are mainly gas in Germany and Norway, nuclear and wood in Finland, upgrade of existing nuclear power plants in Sweden and very little investment in Denmark.

The capacity balance for the 20% case in 2010 is tighter than the capacity balance in 2001, if one does not take wind into consideration. Since wind power has some merits in capacity balance, the situation in the 20% case is only slightly more challenging than in 2001 (Figure 4).

Due to calculation time considerations and data limitations, the units in the model in some cases represent a group of power or heat plants in the real world. Only power plants of the same technology type (e.g. extraction, condensing and hydropower) and main fuel type have been aggregated together. Furthermore, the aggregation also takes the age of the plants into account. Table I shows typical parameters assumed for the power-producing units in the model. All monetary values in this paper are expressed in EUR 2002 values.

CO_2 allowance price is set to 17 EUR ton^{-1} CO_2. The fossil fuel price scenario implies a continuation of the present high price levels with fuel oil, natural gas and coal prices being respectively 6.16, 6.16 and 2.25 EUR GJ^{-1}. All countries share the same fuel prices. Currently there are taxes in the Nordic countries on heat produced by electricity (67.4 EUR MWh^{-1} in Denmark and 6.9 EUR MWh^{-1} in Finland). Danish tax has been implemented in order to decrease the usage of electricity for heat production, since heat production wastes the exergy of electricity. However, during wind power curtailment, electricity would be wasted completely. To improve the feasibility of using electric boilers or heat pumps, we have therefore assumed that there is no such tax. Furthermore in the Nordic countries, there are also taxes on fuel used for producing heat in CHP plants and heat boilers. As we have removed the tax on electricity used to heat production, these fuel taxes are also set to zero to avoid profits from using electricity to produce heat due to tax distortions.

As previously mentioned, heat production capacity from each measure is set to be the same. For each district heating area analysed, we set the heat production capacity from the measure to be equal to half of the

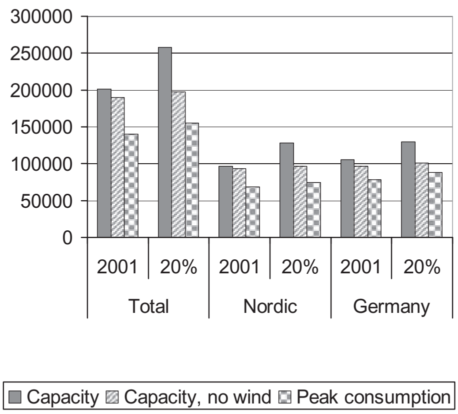

Figure 4. Capacity balance

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Table I. Assumptions about technical characteristics of the power producing units in the model distributed on fuel type and location

Parameter	Assumption			
	Nordic countries		Germany	
Start-up time [h]	20	nuclear	3	biomass, coal, nuclear
	5	biomass, coal	0	natural gas, oil, wind, hydro
	1	natural gas, fuel oil, light oil		
	0	wind, hydro		
Partload factor	0.90–0.96	thermal plants	0.96	thermal plants
	1	wind, hydro	1	wind, hydropower
Minimum load factor	0.50	nuclear	0	wind, hydro
	0.25	biomass, coal	0.50	all other
	0.20	fuel oil		
	0.10	natural gas, light oil		
	0	wind, hydro		
Start up costs [EUR MW^{-1}]	133	nuclear	3	nuclear, natural gas
	20	biomass, coal	6	biomass, coal
	13	fuel oil	5	fuel oil
	2	natural gas, light oil	0	wind, hydro
	0	wind, hydro		

Partload factor is the efficiency when producing at minimum load relatively to the efficiency when producing at maximum load. Minimum load factor is the minimum power production relatively to the installed capacity of the unit. Start-up costs are the costs connected with bringing 1 MW capacity online. Heat boilers have zero start-up time, minimum load factor and start-up costs and 1 in partload factor.

Table II. Capacities of CHP plants and heat boilers in each district heating system in MW

	BP, elec	BP, heat	Extr, elec	Extr, heat	Fuel boiler
Copenhagen	224	612	1069	1232	1500
Odense	24	64	556	776	600
Helsinki	549	898	494	423	2030

BP = back-pressure plant; Extr = extraction plant.

Table III. Capacities of each heat measure in MW

Measure	Copenhagen	Odense	Helsinki
Elec boiler	922	420	660
Heat pump	922	420	660

heat capacity of the area's CHP plants. The data for the CHP systems are shown in Table II and the resulting sizes of each heat measure are shown in Table III. Copenhagen is situated in Eastern Denmark, Odense in Western Denmark, and Helsinki in Finland.

One model run covers all three examined heating areas. A one month stochastic run was done for each measure and also a one month stochastic run without any measures for comparison. The time period chosen is February 2001, which had high wind speeds and high heat demands. The assumptions behind the coefficient of performance (COP) used are given in Table IV. The COP is the ratio between the heat output and the power input of a heat pump, i.e. expresses the efficiency of the heat pump.

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Table IV. COPs of heat pumps in February in each heat area

	Copenhagen	Odense	Helsinki
Heat reservoir	Sea water	Air	Sea water
T_low [°C]	3	0	3
T_high [°C]	100	90	100
COP theoretical	3.8	4.0	3.8
COP realised	2.7	2.8	2.7

The Carnot efficiency (realised COP relatively to theoretical COP) for large state-of-the-art heat pumps in 2010 is set to 0.7.[1,10]

Simulation Results

Price Influence and Utilisation

In the base case without new heat measures, the CHP plants cover 82, 95 and 87% of the heat consumption in February in Copenhagen, Odense and Helsinki, respectively, with the rest being covered by heat boilers. Studied heating areas behave quite differently in regard to the heat measures. During February, Copenhagen uses heat pumps most of the time whereas Odense and Helsinki utilise them with capacity factors of about 45%. Electric boilers have capacity factors of 16% in Copenhagen, 12% in Odense and 7% in Helsinki. Both heat measures replace fuel oil boilers in Copenhagen and Odense and thus decrease the heat prices strongly (Figure 5 showing a high wind situation, where the electricity price goes down especially around 21st of February). Fuel oil boilers in Copenhagen are in the base case without heat measures in some hours used to replace CHP production on extraction plants. This is caused by the low electricity prices in these hours making the marginal heat production price on fuel oil boilers lower than the corresponding price on natural gas-fired extraction plants.

In the base case, Helsinki coal-based heat boiler replaces natural gas extraction plant during high winds, but it does not replace the coal-based back-pressure plant, which is producing most of the demanded heat. However, both heat measures replace part of the coal CHP as well. The profitability of the heat measures stays low in Helsinki, since marginal heating plant is usually CHP and the price of heat is low to start with.

Figure 6 shows the duration curves of power prices (prices sorted in descending order) on the intra-day market in Eastern Denmark for the three cases. As expected, the impact of each heat measure is mainly to increase the lower power prices relatively to the base case. Because of the larger electricity-consuming capacity of the electric boilers relatively to the heat pumps, electric boilers increase the power prices more than heat pumps do. Figure 6 also shows that none of the measures are able to completely remove zero power price hours, i.e. the number of zero price hours is changed from 15 in the base case to 6 and 7 in the case of electric boilers and heat pumps, respectively.

The heat measures will also increase the regulating power capacity in the system. In case of the expected wind power production sold on the day-ahead market being higher than the realised wind power production, the rest of the system will have to up-regulate and as a result the intra-day power price will be higher than the day-ahead price. A wind power producer being in imbalance will be penalised proportional to the price differences between the day-ahead market and the intra-day market. Therefore, the impact of the heat measures on the price of regulating power can be measured by calculating the average price difference between the day-ahead and the intra-day market in the case of up- and down-regulation, respectively (see Figure 7). As expected, both heat measures reduce the penalties connected to being in imbalance. The impact is highest in Eastern Denmark where the capacities of the heat measures are largest relatively to the rest of the production capacity in the region.

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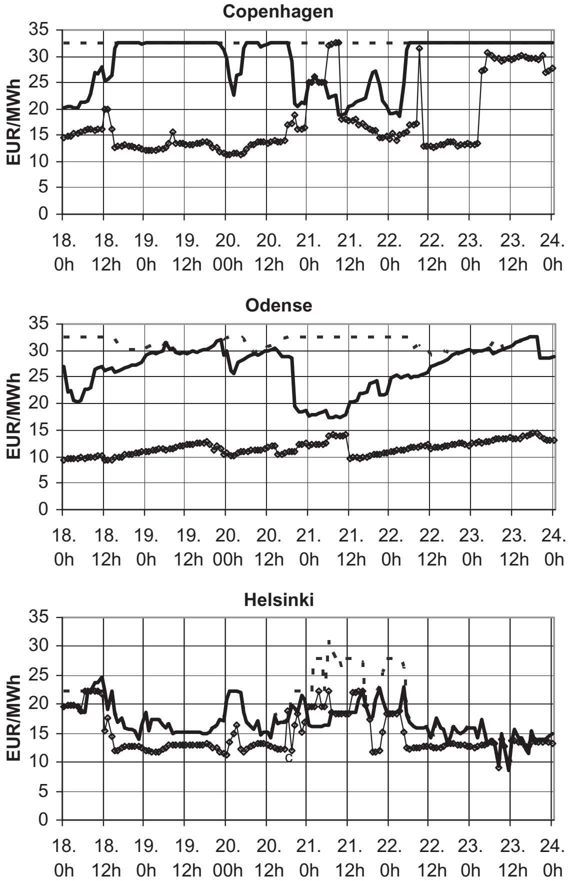

Figure 5. Heat prices of different cases in the studied heating areas. Base case (dotted line), electric boilers (full line), heat pumps (line with diamonds)

Wind Power Curtailment and Wind Power Profit

The total wind power production in the base case in the period 4–28 of February is 12.9 TWh in the whole system. 75 GWh (0.58%) of this production is curtailed, i.e. the wind power production is reduced because this is the optimal way of operating the power system in these situations. The heat measures reduce the amount of wind power curtailment with 13 and 20% for heat pumps and electric boilers, respectively.

Although the reduction in wind power curtailment due to the heat measures only constitutes 0.08 and 0.1% of the total wind power production for heat pumps and electric boilers, respectively, the impact of the heat measures on the revenue for wind power producers is considerably larger, because the power prices increase also in hours without wind power curtailment (see Figure 6) and the penalties of being in imbalance are reduced (see Figure 7). The revenue of wind power producers increases from 381.0 MEUR (million euros) in the base case to 388.7 MEUR in case of electric boilers and 390.8 MEUR in case of heat pumps, i.e. an increase of 2.0 and 2.6% for electric boilers and heat pumps, respectively, relative to the base case. Heat pumps increase the revenue more, because heat pumps are used more than electric boilers, thereby increasing also the higher power prices.

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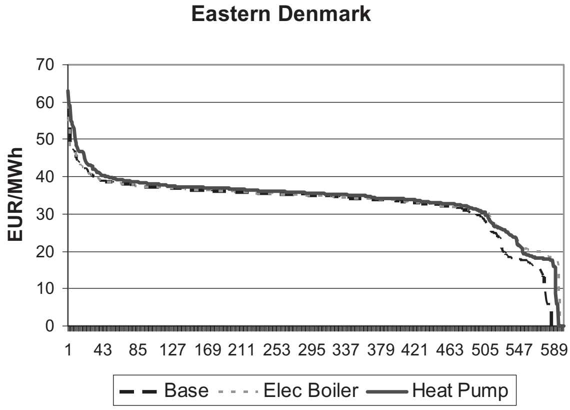

Figure 6. Power prices on the intra-day market in Eastern Denmark sorted in descending order for the three cases in the period 4–28 of February

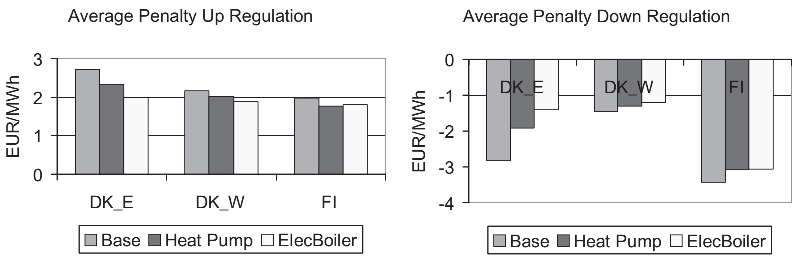

Figure 7. Average difference between day-ahead market prices and intra-day market prices in the case of down-regulation (intra-day price < day-ahead price) and up-regulation for Finland, Eastern and Western Denmark in the three cases in the period 4–28 of February

Operational Example

Figure 8 shows operation of plants grouped according to fuel in Copenhagen during high wind situation 19–22 of February. Electricity price is presented with a black line and for a while it goes down to zero due to wind power curtailment. Uppermost graph is the base case with no heat measures. Oil boilers provide heat when CHP plants are not profitable. In the middle graph, electric boilers take the place of oil boilers when the price of electricity is low enough. In the bottom graph, heat pumps do not wait for low prices — they produce full power almost all the time, replacing natural gas CHP besides oil boilers. Both electric boilers and heat pumps are able to remove the zero price hours occurring around hour 0, on 22 February in the base case.

System-Wide Effects of Heat Measures

Effects of heat measures are not restricted to the areas where the measures take place. Most notably they have a large effect on the usage of hydropower in Sweden and Norway. The hydropower model calculating water values is not yet fully calibrated, which creates uncertainty to the results that concern usage of the reservoir water. Due to this, Table V lists monetary benefits of the heat measures both with and without the value of the changed usage of hydropower.

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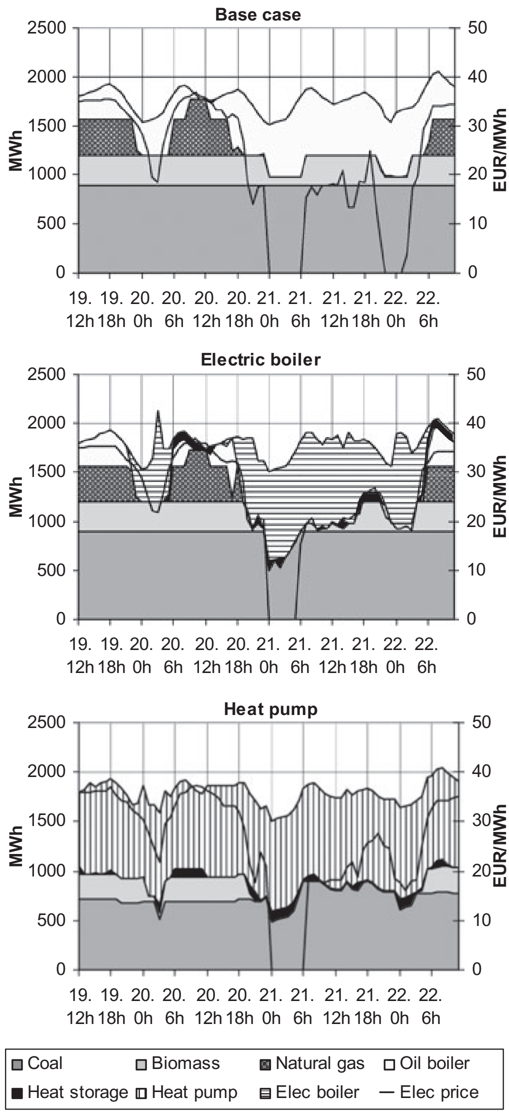

Figure 8. Heat production [MWh per h] of different groups of plants in Copenhagen during high wind situation. Coal plants are in the bottom, wood and straw CHP plants have a bit higher operational costs followed by natural gas plants and oil boilers. Electricity price [EUR MWh^{-1}] is presented with a black line

In the case of heat pumps, reservoir hydropower is used more than in the base case. In system costs, this is partly offset by the higher water value in the end of the period. The higher usage of reservoir water happens because it is profitable to use hydropower to operate heat pumps in Copenhagen.

System benefits are calculated by deducting the operational costs of each heat measure case from the same values of the base case. Operational costs include fuel costs, CO_2 allowance prices, O&M costs, start-up costs, transmission costs and subsidies for wood-based CHP production in Helsinki. For hydropower, the difference

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Table V. Total system benefits in million EUR of the heat measures calculated as change in operational costs from the base case to the case in question

Benefits without hydro		Price of hydro change		Total system benefits	
Heat pump	Elec boiler	Heat pump	Elec boiler	Heat pump	Elec boiler
22.35	1.55	−10.82	−0.12	11.53	1.43

Benefits are calculated both with and without the value of changed usage of hydropower for the analysed period in February.

Table VI. System benefits and annuity in MEUR of the heat measures in each region for February

Region	System benefits		Annuity		Benefits/Annuity	
	Heat pump	Elec boiler	Heat pump	Elec boiler	Heat pump	Elec boiler
DK east	8.30	0.99	37.18	2.48	0.22	0.40
DK west	1.87	0.23	16.94	1.13	0.11	0.21
Finland	1.15	0.10	26.62	1.77	0.04	0.06

Annuities have been calculated based on the following assumptions: Investment costs of 0.6 and 0.04 MEUR MW^{-1} heat for heat pumps[10] and electric boilers,[11] respectively, disregarding annual operation and maintenance costs, a discount rate of society of 3% (we calculate in fixed prices so inflation is excluded from the discount rate), and a lifetime of 20 years.

in operational costs when using more hydropower in one case relatively to the other is the difference in hydropower production times the water value.

To be able to discuss the feasibility of the heat measure in each region, it is required to allocate the system benefits on regions. This can be done approximately by adjusting the system benefits per region for the change in transmission between cases, such that the amount of transmission to and from a region is equalised between the two cases. The correction is based on the observation that power import from other regions replaces production on power plants that have operational costs equal to or higher than the power price in the region, because the power price is equal to the production costs on the most expensive power plant operating in the hour in question. A lower bound on the reduction in operational costs in a region because of net power import is therefore equal to the net import multiplied by the power price in the region. Likewise, an upper bound on the increase in operational costs in a region due to net export to other regions is given by the net export times the power price in the region. When net import into region A is higher in the base case than in the heat measure case, the system benefits are increased by the extra power import in the base case relatively to the heat measure case times the average of the power price in the two cases. A more thorough explanation of the methodology is given in Meibom *et al.*[9]

Table V shows the total system benefits of the heat measures, whereas Table VI shows the system benefits in each region containing a heat measure, where the system benefits have been allocated to regions using the methodology explained earlier.

Comparing the system benefits with the annualised investment costs of heat pumps and electric boilers is difficult, because we have not yet calculated the system benefits for a whole year. Furthermore, the amounts of installed capacities of electric boilers and heat pumps are not optimised in any way. Still the results summarised in Table VI show that in 25 days in February, the system benefits in Copenhagen (DK East) cover 22 and 40% of the annualised investment costs of heat pumps and electric boilers, respectively. Although February probably represents a month with high system benefits of the heat measures due to the high heat demand, the system benefits during a whole year will probably be large enough to cover the investment costs of heat pumps or electric boilers in Copenhagen. The same applies for electric boilers in Odense, whereas heat pumps

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in Odense and both heat measures in Helsinki have lower system benefits compared to the annuity. These results correspond with the higher utilisation times of the heat measures in Copenhagen compared to Odense and Helsinki.

The reason for the high system benefits in Copenhagen compared to Helsinki is mainly that in Copenhagen the heat measures frequently replace production on heat boilers using fuel oil, which have a high heat production costs compared to CHP plants, whereas in Helsinki the heat measures replace production on coal heat boilers and coal CHP plants with lower heat production costs.

The installation of electric boilers or heat pumps decreases total CO_2 emissions in February with 0.04 and 0.6%, respectively, which with the assumed CO_2 allowance price of 17 EUR ton^{-1} CO_2 represents a value of 16 and 29%, respectively, of the total system benefits. The CO_2 emission reductions arise due to reduction in the usage of fuel oil in both cases, natural gas in the case of heat pumps, and on the expense of a growth in production from base load plants using coal in the case of electric boilers.

Profitability of the Heat Measures

A straightforward way to estimate the value of the heat measures for the potential investor is to calculate the revenue from selling heat and deduct the costs of buying power. The results of this calculation are shown under heading Investor profits in Table VII. However, if the heat measure sets the heat price on the heat market, i.e. constitute the marginal plant in the operation hour in question, the power price will directly be transferred into the heat price only modified with the COP value of the heat pump or electric boiler (2.7 or 1), so the profit of the investor is zero in these hours. An alternative approach is to use the heat production price of the marginal plant on the heat market without the heat measure in place as the heat price paid to the heat measure, i.e. calculating investor profits using heat prices from the base case and electricity prices from the heat measure case. The results of this calculation are shown under the heading 'Profits with base case heat prices' in Table VII.

Copenhagen area shows the most promising figures for investments into heat measures. For private investors, we have used 8% interest rate and 15 years payback time. We used the higher profit values from Table V. A 922 MW heat pump in Copenhagen with cost of 0.6 MEUR MW^{-1} would have an annuity of 64.6 MEUR. The 25 days in February would cover about 16% of the annuity. A 922 MW electric boiler with cost of 0.04 MEUR MW^{-1} would mean 4.3 MEUR in annuity. This time the 25 days would cover 19% of this. Especially the electric boiler is getting close to profitability. For other areas, one could try out smaller units and see how they would fare. Profitability would also increase if the share of wind power was higher.

Discussion

Investment costs of heat pumps and electric boilers are not easy to estimate. Especially electric boiler costs are very much dependant on the existing infrastructure and therefore the price of the investment varies a lot. Since operational costs are small, profitability is very sensitive to investment cost. It is also sensitive to the chosen interest rate, although interest rate probably has a smaller range of variation. Analysis of the sensitiv-

Table VII. Investor profits in EUR MW^{-1} from the heat measures during the modelled 25 days

	Electric boiler		Heat pump	
	Investor profits	Profits with base case heat prices	Investor profits	Profits with base case heat prices
Copenhagen	409	901	3,087	10,892
Odense	200	688	517	5,618
Helsinki	32	254	1,200	2,537

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ity of results on the base of assumptions about investment costs and interest rates should be performed in future studies.

The model underestimates prices and price differences compared to the real market. This is due to several factors: (i) the model assumes a perfect market with full information, i.e. it does not include market power and limited information; (ii) transmission line availability is higher than in real life; and (iii) marginal curve of water value is too flat. Higher electricity prices mean less utilisation for the heat measures, but on the other hand more profits once they are utilised. This is a source of further uncertainty for the results.

A more realistic analysis should include power plant outages and load uncertainty in addition to wind power production uncertainty. Outages and load uncertainty will on average increase the demand for regulating power, thereby increasing the profitability of electrical heat pumps and heat boilers. Work is undertaken to extend the model to cover these issues.

Conclusion

This paper has analysed the consequences of introducing heat pumps or electric boilers in three district heating systems in the North European power system characterised by a base configuration, representing the development of the present power system until 2010 and a large share of wind power covering 20% or more of electricity consumption in each Nordic country. Changes in day-ahead and intra-day prices, revenue of wind power production, system benefits and profitability of heat pumps and electric boilers have been analysed using a stochastic partial equilibrium model of the power systems in Denmark, Finland, Germany, Norway and Sweden with wind power productions as a stochastic input parameter.

The introduction of heat pumps or electric boilers is beneficial for the integration of wind power in that the curtailment of wind power production is reduced, the price of regulating power is reduced and the hours with very low power prices are reduced, making the wind power production more valuable. The system benefits of heat pumps and electric boilers are connected to replacing heat production on fuel oil heat boilers and CHP plants using various fuels with heat production using electricity and thereby saving fuel.

The work outlined in this paper will be continued, focusing on extending the analysis to a full year, making estimation of system benefits more precise.

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PUBLICATION IV

Influence of wind power, plug-in electric vehicles, and heat storages on power system investments

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Influence of wind power, plug-in electric vehicles, and heat storages on power system investments

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ABSTRACT

Due to rising fuel costs, the substantial price for CO_2 emissions and decreasing wind power costs, wind power might become the least expensive source of power for an increasing number of power systems. This poses the questions of how wind power might change optimal investments in other forms of power production and what kind of means could be used to increase power system flexibility in order to incorporate the variable power production from wind power in a cost-effective manner.

We have analysed possible effects using an investment model that combines heat and power production and simulates electric vehicles. The model runs in an hourly time scale in order to accommodate the impact of variable power production from wind power. Electric vehicles store electricity for later use and can thus serve to increase the flexibility of the power system. Flexibility can also be upgraded by using heat storages with heat from heat pumps, electric heat boilers and combined heat and power (CHP) plants. Results show that there is great potential for additional power system flexibility in the production and use of heat.

1. Introduction

Wind power is a variable and partly unpredictable power source that influences the rest of the energy system in ways that are different from conventional power plants. Wind power is also quickly becoming a major new source for power generation. As a result, new studies have been made to assess different aspects of integrating wind power into power systems.

One major aspect is the analysis of the additional costs and benefits that rise from power system operation with this variable and partly unpredictable power source. While this has been the dominant focus of research on wind power integration, increasing the share of wind power in the systems will also change the cost-optimal power production portfolio in the long-term. We analyse the investment and operational costs associated with this change. By changing assumptions about the relative costs of producing electricity and heat with different technologies, we arrive at different power system configurations and can demonstrate situations where wind power becomes the dominant source of power production. More flexible power systems enable the less costly integration of wind power. Therefore, we analyse the effect of two new forms of flexibility: plug-in electric vehicles and heat storages operated in tandem with heat pumps and electric heat boilers.

In general, wind power integration costs have been found to be relatively small, at least up to penetration levels of around 25%, as demonstrated by the several studies compared in the IEA collaboration (Holttinen [1]). The literature behind the article also establishes how to carry out wind integration studies (more detail and references in Holttinen et al. [2]). Wind power has influence on several different time scales. The main benefits of wind power result from fuel savings and lower CO_2 emissions as well as a decrease in conventional capacity requirements. Wind power also inflicts costs, mainly due to the variability of the resource and forecast errors. Costs are accrued especially from increases in the cycling of conventional power plants, partial load operation, non-spinning reserve capacity and transmission needs, as well as the relatively lower contribution to capacity than to electricity production.

Impact of wind power increases with penetration, but only a few attempts have been made to estimate the costs and benefits at higher penetrations (Meibom et al. [3], Karlsson & Meibom [4], Ea [5], Milborrow [6], Lund & Mathiesen [7] and earlier work with the same model [8,9], Ummels et al. [10]). One reason why such studies are more difficult to make is that wind power starts to affect the optimal portfolio of other power plants in the system by reducing their full load hours. With higher penetration levels, it becomes

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Nomenclature

Indices

i, I	Unit, set of units
I_a	Set of units in area a
I^{HeatSto}	Heat storage units
I_{PI}	Plug-in electric drive vehicles
$r, \bar{r}, R$	Region, neighbouring region, set of regions
a, A	Area, set of areas
t, T	Time steps, set of time steps
k, K	Country, set of countries

Variables

C	New capacity
P	Power generation
P^{Cur}	Wind curtailment
Q	Heat generation
S	Storage level
T	Electricity exchange between regions
U	Loading of electricity storage
Z	Loading of heat storage

Parameters

av	Availability of the unit
cc	Capacity credit
c^{Loss}	Transmission loss
C^{Ex}	Existing capacity
c^{Inv}	Annualized investment costs
c^{Fix}	Fixed operation and maintenance cost
$c^{\text{Operation}}(\cdot)$	Operation cost function of unit
d	Electricity demand
d^{P}	10-year peak demand
d_{PI}	Demand of plug-in vehicles
h	Heat demand
l	Round-trip storage loss
LC	Loading capacity of storage
SC	Storage capacity
W	Weight of time period

more and more unrealistic to assume that there would be no changes in the rest of the power system (Söder & Holttinen [11]). It is also unrealistic to implement such changes without proper investment optimization.

Karlsson & Meibom [4] use the same investment optimization model as in this article and consider high wind power penetration levels. However, their analysis concentrates on the cost competitiveness of hydrogen in road transport. In the All Island Grid Study, Meibom et al. [3] analyse wind power integration costs for six different power plant portfolios. Doherty [12] created these portfolios using a separate model, arriving at least-cost options according to varying input parameters. Furthermore, the influence of high wind power penetration on transmission systems was analysed by Nedic et al. [13] in the same study. While the study was comprehensive in many respects, it did not include the flexibility mechanisms studied in this article, namely plug-in electric vehicles and heat storages.

Ea [5] employed a similar approach and the same model as here, but again did not include the additional flexibility provided by heat storages and plug-in electric vehicles. Milborrow [6] quotes a tentative study by EnergiNet.DK, which indicates that there are no technical constraints for very large wind power penetrations and that the costs of variability should remain reasonable.

In work by Lund & Mathiesen [7], very large wind penetrations are achieved with power system flexibility from hydrogen generation and biomass CHP plants. Their model does not include endogenous investments and the investment decisions are based on expert opinions about energy system development. The results serve a somewhat different purpose than this article, as we have sought to focus on the merits of different ways of increasing power system flexibility. In another article [14], the same authors compare different ways of facilitating the integration of fluctuating power sources. Again their model does not include endogenous investments. As can be seen from this article, variable sources of power and different flexibility mechanisms change the optimal reference power plant portfolio, leading to deviation in the comparative results. Their analysis demonstrated that heat storages can have an important impact on power system flexibility, which also comes out strongly in our results. They also show that the use of electrolysers to produce hydrogen for fuel cell vehicles or combined heat and power plants does not appear to be cost competitive with the flexibility mechanisms provided by heat measures and battery electric vehicles.

Ummels et al. [10] analysed compressed air energy storage, pumped hydro storage and conventional heat boilers as means to increase flexibility. The model only analysed operational costs and did not make investment decisions. Of the three options, heat boilers were the most promising from the economical perspective, although their usefulness is limited to low load, high wind situations.

For a lower wind power penetration level of 20%, a large study was conducted by the US DoE [15]. The study used a generation expansion model and also incorporated a simple transmission system expansion. The assumptions about the relative costs of different technologies were such that wind power would not be cost competitive even in 2030 and would remain at the preordained 20% minimum. In this study, wind power was more competitive and as a result higher penetration levels were cost-optimal. As there is no a priori knowledge about the relative competitiveness of different power production technologies in 20–30 years – and wind power cost is location dependant – it is prudent to also analyse situations where wind is the least-cost source of electricity. However, there will be a limit on the cost-optimal penetration level as integration costs keep increasing in step with penetration. This article analyses those situations and additionally takes into account the possibility of making use of new forms of flexibility to decrease integration costs.

The different time scales involved in investment optimization and operational optimization make the wind integration problem more complicated. A model that can analyse the operational costs of a power system is too detailed for analysing long-term investments. Therefore we use a model that optimizes the investments and somewhat simplifies the operational characteristics of power plants. This model, Balmorel, does not include start-up costs, part-load efficiencies or wind power forecast errors, all of which would increase the costs of integrating wind power into the system. The next step would be to feed the long-term investment results from Balmorel into a more complete power system model and analyse the missed costs. However, this step is not included in our analysis.

Our analysis seeks to fill a gap in the knowledge of wind power integration. We include long-term investment analysis with wind integration, enabling us to estimate the long-term total system costs of switching from conventional power production toward wind power. Portfolio planning has a long history and work has been done to include wind power (Doherty et al. [16]). Our extension also accounts for the effect of storages in heating and transport in the analysis. Doherty et al. [16] take fuel price volatility into account in their analysis. This would improve our study as well, but due to the hourly time series the complexity of the Balmorel model does not allow for the large number of model runs required to analyse the effect of fuel price volatility on the power plant portfolios.

The analysis made in our study is highly sensitive to the parameters put into the models and therefore the paper includes a detailed description of inputs and assumptions in order to increase transparency. It also means that a single study cannot take all the variables into account and only gives a partial view of the issue. To account for some of this, we have done a sensitivity analysis on a couple of influential variables.

Section 2 describes the Balmorel model. The data used and cases analysed are presented in chapter 3. Chapter 4 presents and analyses the model results. Conclusions are made in chapter 5.

2. Model

The Balmorel model is a linear optimization model of a power system including district heating systems. It calculates investments in storage, production and transmission capacity and the operation of the units in the system while satisfying the demand for power and district heating in every time period. Investments and operation will be optimal under the input data assumptions covering e.g. fuel prices, CO_2 emission permit prices, electricity and district heating demand, technology costs and technical characteristics. The model was developed by (Ravn et al. [17]) and has been extended in several projects, e.g. (Jensen & Meibom [18], Karlsson & Meibom [4]). The main equations of the model as used in this study are presented below with a focus on the contributions to the model in this paper, i.e. the capacity balance equation (eq. (4)) and inclusion of plug-in electric drive vehicles (eqs. 5–8).

The optimization period in the model is one year divided into time periods. This work uses 26 selected weeks, each divided into 168 h. The yearly optimization period implies that an investment is carried out if it reduces system costs including the annualized investment cost of the unit (eq. (1)).

The geographical resolution is countries divided into regions that are in turn subdivided into areas. Each region has time series of electricity demand and wind power production. Transmission lines connect the regions. Each country is divided into several regions to represent its main transmission grid constraints. The transmission grid within a region is only represented as an average transmission and distribution loss. Areas are used to represent district heating grids, with each area having a time series of heat demand. There is no exchange of heat between areas. In this article, Finland is used as the source for most of the input data.

The objective function (eq. (1)) minimizes system costs, which comprise the annualized investment costs of new investments, the fixed operation and maintenance costs of existing units and new investments, and the operational costs of units. The operational costs are fuel costs and costs of consuming CO_2 emission permits during model time periods. Each time period is weighted to represent a longer time span in order to cover full-year costs. Electricity demand in each region (eq. (2)) and district heating demand in each area (eq. (3)) have to be fulfilled in each time period. Wind power production is treated as production following a fixed production time series with the possibility of curtailing wind power if cost-optimal for the system.

Following Doherty et al. [16], a capacity balance equation (eq. (4)) was added to the model to ensure adequate production capacity and reserve margin in a country. The production capacity of each unit (either existing or new) is multiplied with the capacity credit. This is summed over all units and the result must be greater than the 10-year peak in demand. The peak demand for Finland was taken from Nordel [19] and corresponds to the peak demand caused by cold winter weather that is expected to happen once in ten years. It is approximately 5% higher than the peak demand in a normal winter [19]. It was scaled with the ratio between the estimated yearly electricity consumption in 2035 and the consumption in 2007 to get the peak demand in 2035. The capacity credit of conventional units is set to 0.99 (Doherty et al. [16]), and wind power is set to 0.14 (Holttinen [20], Petäjä & Peltola [21]). The capacity credits of conventional units are higher than the availability of these units, being in the order of 0.85–0.95, because the capacity credit is related to the average availability of all units during peak-load hours. More rigorously the capacity value of any generator is the amount of additional load that can be served at the target reliability level with the addition of the generator in question [2].

Equation (5) also influences the demand for capacity by ensuring that the power production from a unit either existing or new is lower than the capacity of the unit multiplied with an average availability. The equation simplifies the availability of power plants by assuming that a constant portion of each power plant type is unavailable due to scheduled maintenance or forced outage. Availability of wind power is included in the wind power production time series.

In the base scenario equations (4) and (5) results in installed capacity of power plants being 17% higher than the peak demand (i.e. a reserve margin of 17%) decreasing to 13%, if it is assumed that wind power has no capacity credit.

Plug-in electric drive vehicles are modelled as electricity storage with storage (eq. (6)), loading (eq. (7)) and unloading (eq. (8)) capacities depending on the number of vehicles connected to the grid in each time step. The balance equation for the electricity storage of plug-ins (eq. (9)) includes the electricity consumption of the plug-in vehicles. It is assumed that the investment costs of plug-in vehicles are covered by benefits in the transport sector, such that the model does not invest in plug-ins. The Balmorel model includes restrictions specifying the technical capabilities of CHP plants, heat pumps and electric boilers, heat and electricity storages, and hydropower with reservoir, although they are not shown here. The same applies to restrictions limiting the ramping up of units and the yearly usage of specific fuels.

$$\min\left(\sum_{i\in I} c_i^{\mathrm{Inv}} C_i + \sum_{i\in I} c_i^{\mathrm{Fix}}\left(C_i^{\mathrm{Ex}} + C_i\right) + \sum_{t\in T}\sum_{i\in I} w_t c_i^{\mathrm{Operation}}\left(P_{i,t}, Q_{i,t}\right)\right) \tag{1}$$

s.t.

$$\sum_{a\in A(r)}\sum_{i\in I_a} P_{i,t} - P_t^{Cur} + \sum_{\bar r\in R}\left(\left(1 - c^{Loss}\right)\cdot T_{r,\bar r,t}\right) = d_{r,t} + \sum_{\bar r\in R} T_{\bar r,r,t} + \sum_{i\in I_a^{Pl}} U_{i,t} \quad \forall t\in T; r\in R \tag{2}$$

$$\sum_{i\in I_a} Q_{i,t} = h_{r,t} + \sum_{i\in I_a^{\mathrm{HeatSto}}} Z_{i,t} \quad \forall t\in T; a\in A \tag{3}$$

$$\sum_{a\in A(k)}\sum_{i\in I_a} cc_i\left(C_i^{Ex} + C_i\right) \geq d_k^p \quad \forall k\in K \tag{4}$$

$$P_{i,t} \leq \left(C_i^{\mathrm{Ex}} + C_i\right)\cdot av_i \quad \forall i\in I; t\in T \tag{5}$$

$$S_{i,t} \leq SC_{i,t} \quad \forall i\in I_{PI}; t\in T \tag{6}$$

$$U_{i,t} \le LC_{i,t} \quad \forall i \in I_{PI}; t \in T \tag{7}$$

$$P_{i,t} \le C_{i,t} \quad \forall i \in I_{PI}; t \in T \tag{8}$$

$$S_{i,t+1} = S_{i,t} + U_{i,t} - P_{i,t}/l_i - d_{PI,t} \quad \forall i \in I_{PI}; t \in T \tag{9}$$

3. Cases

3.1. Description of the analysed system

The analysis is performed on the power system of Finland. The Finnish system gets about 10% of its production from hydropower and most of it is controllable to a smaller or larger extent. The share of global electricity production accounted for by hydropower was around 16% in 2004. Therefore we believe that the Finnish system is a good representative of a more general power system. Representativeness increases due to the long timeframe, since many of the power plants that are now in operation will be retired before the year of analysis and local historical decisions will have less influence. Our target year is 2035, which is far enough into the future that by then there will have been major turnover in the power plant fleet.

Finland is a northern country where heating is required during the winter. The country has many combined heat and power units for district heating. The model includes three heating areas for Finland, all of which have to fulfil their heating requirements separately. The first of these areas is the capital region, the second aggregates industrial heat demand, and the last aggregates district heat demand for space heating in other population centres with district heating.

The model can invest in electric heat boilers, heat pumps, and heat storages. This enables the model to further increase the flexibility of the power system to accommodate larger amounts of variable power (Meibom et al. [22]). Although more southern countries do not have similar heating needs, they could use district cooling in the summertime and have similar connections between cooling and power in the future, especially when climate change leads to warmer summers. Some district cooling networks are already operational in the Nordic countries. Similar operational benefits can also be achieved without district heating or cooling networks using local hot water tanks or ice storage. Many local water heat tanks already exist in Finland, but the heat demand fulfilled by these devices is not covered by this analysis. Industrial heat demand uses a large fraction of global primary energy and could serve as a source of flexibility for the power system, especially in countries where space heating and cooling has a lesser role. Although heat demand in Finland is comparatively high in principle, only part of it was available for the model: types of heating other than district heating were not included and a large fraction of industrial heat was served by cost-free wood waste from industrial processes.

Other options for increased flexibility may emerge in the future, such as electric vehicles or cost competitive electricity storages. We analyse the effect of plug-in electric vehicles by approximating them as electricity storages with capacity limitations that vary according to plug-in availability. The time series for plug-in availability have been derived from the National Travel Survey conducted during 2004–2005 in Finland (WSP LP Consultants [23]). It gave information on the purpose, timing, and distance of personal travel. The information was processed to give estimates of the times when people driving cars might arrive at their workplaces and home as well as of the distances they travelled to get there. The Balmorel model does not do investment optimization for plug-in vehicles, as the transport sector is not covered by the model. Instead, it is assumed that the investment costs of the plug-in electric vehicles are covered by fuel savings and other benefits (e.g. reduction of local pollutants) in the transport sector.

Table 1
Definitions of words used in scenario names.

Base	Wind at 800 €/kW, no flexibility, nuclear allowed, high fuel prices
700	Wind at 700 €/kW
900	Wind at 900 €/kW
OnlyPlug	One million plug-in vehicles with flexible charging/discharging
OnlyHeat	Heat storages, heat pumps and electric heat boilers allowed
HeatPlug	Both plug-in vehicles and heat measures
NoNuc	No new nuclear plants allowed
LowFuel	Lower fuel price scenarios as indicated in Table 2

3.2. Input data for investments

Assumptions made for the model runs are crucial for the results and the results should not be interpreted without taking the assumptions into account. The paper does not try to assume the most likely future costs for investments, fuels, and CO_2 emissions. Rather, it seeks to chart how large penetration of wind power could affect the rest of the power system and identify the situations where this might happen. Cost assumptions therefore intentionally set up situations where wind power is a very large contributor to electricity production.

To create different scenarios, we varied the cost of fuels and the cost of wind power as well as allowed and disallowed different technologies. The scenario names are described in Table 1. Most scenarios use the high fuel prices indicated in Table 2. The number of plug-in vehicles is exogenously set at one million, which is about half of the personal car fleet of Finland.

What is important about the cost assumptions is the relative cost between the different technologies rather than the absolute cost level. The costs do not reflect the recent price hikes of building all kinds of power plants due to scarcity in commodity markets. There are two reasons for this choice: first, costs should come down when the markets are once again well supplied; second, the relative costs between capital-intensive forms of power production have not changed much due to the price increases. Simultaneously, fuel dependant power production has seen cost increases in the form of higher fuel prices.

The fuel costs are for 2035 and it is impossible to predict costs so far into the future. Natural gas prices are assumed to be higher than coal, since natural gas should have more resource constraints [26]. The costs of biomass and peat-based fuels are slightly higher than at present, since the resource base should stay similar, but higher natural gas prices should give some leeway for price increases. In

Table 2
Assumptions in high and low fuel price scenarios and average 2007 prices in Finland for comparison.

	HighFuel	LowFuel	2007	
Interest rate	9.0	9.0		%
CO_2 cost	45	20		€/tCO_2
Coal (CO)	3	2.1	2.2	€/GJ
Natural gas (NG)	11	6	5.8	€/GJ
Light oil (LO)	16	13	12.9	€/GJ
Fuel oil (FO)	13	10	7.5	€/GJ
Peat (PE)	2.8	2.8	2.3	€/GJ
Industrial wood waste (WW)	0	0		€/GJ
Forest residues (WR)	4.2	3.5	3.4	€/GJ
Wood and straw (WO)	7.5	5.3		€/GJ
Municipal waste (MW)	0	0		€/GJ
Nuclear fuel (NU)	0.4	0.4		€/GJ

Table 3
Power plants available for investment [24], [25]. For wind power the investment cost is for the base scenario and for heat storage the investment cost unit is €/MWh of storage capacity.[a]

Unit	Comments	Source	Type	Fuel	Avg Eff	CHP CB	Ext CV	Availability	Invest. costs [€/kW]	Variable O&M [€/MWh]	Annual O&M [€/kW]	Life time
NG_CC_EX	Large combined cycle CHP	DEA et al., 2005	Extraction	Natural gas	0.62	1.7	0.13	0.94	550	1.5	12.5	25
WW_EX	Large scale biomass plant	DEA et al., 2005	Extraction	Ind. wood waste	0.49	0.84	0.15	0.9	1300	2.7	25	30
WR_EX	Large scale biomass plant	DEA et al., 2005	Extraction	Forest residues	0.49	0.84	0.15	0.9	1300	2.7	25	30
WO_EX	Large scale biomass plant	DEA et al., 2005	Extraction	Wood and straw	0.49	0.84	0.15	0.9	1300	2.7	25	30
CO_EX	Advanced coal plant	DEA et al., 2005, 2010–15 data	Extraction	Coal	0.53	0.95	0.15	0.91	1200	1.8	16	35
EL_HP	Very large heat pumps	DEA et al., 2005; eff. down 10%	Heat pump	Electricity	4.5			1	900	0	2	40
WO_HB	District heating boiler	DEA et al., 2005; eff. estimated	Heat boiler	Wood and straw	0.91			0.97	250	2	15	35
NG_HB	District heating boiler	DEA et al., 2005; eff. estimated	Heat boiler	Natural gas	0.93			0.96	50	1	2	40
EL_HB	Electric boiler	Estimates; Eloverløbsrapport	Heat boiler	Electricity	1			1	40	0	1	40
CO_HB	District heating boiler	Estimates	Heat boiler	Coal	0.9			0.95	100	1	7	40
FO_HB	District heating boiler	Estimates	Heat boiler	Fuel oil	0.9			0.97	55	1	2	40
NU_CON	Nuclear	IEA 2007, improved effic.	Condensing	Uranium	0.37			0.92	2625	7.2	52	40
NG_CC_CON	Combined cycle, condensing	IEA 2007	Condensing	Natural gas	0.58			0.95	553	3.2	20	25
NG_OC_CON	Open cycle, condensing	IEA 2007	Condensing	Natural gas	0.37			0.95	320	2.4	16	25
CO_CON	Pulverised coal, condensing	IEA 2007	Condensing	Coal	0.46			0.93	1260	5.6	40	35
WIND	Wind	Estimate	Wind	–	1			0.32	800	0	20	20
HEATSTO	Heat storage (inv.: €/MWh)	Estimate	Storage	–				1	1840			20

[a] Average efficiency is defined as power output divided by fuel input for condensing and extraction plants, and heat output divided by fuel input for heat boilers. Heat pump efficiency is heat output divided by electricity consumption, i.e. the low temperature heat input extracted from the surroundings is not included when calculating heat pump efficiency. Investment cost is €/kW$_{elec}$ for electricity producing plants and €/kW$_{heat}$ for plants producing only heat.

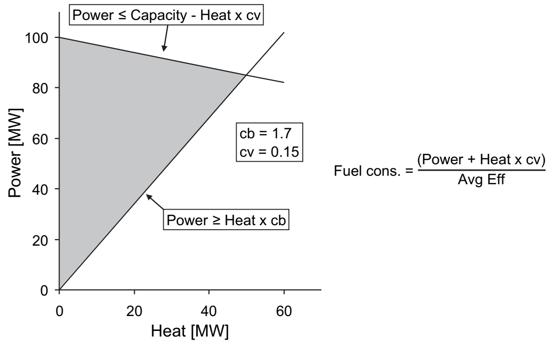

Fig. 1. Operating area of extraction CHP plants. Model decides the capacity to be invested.

the case of CO_2 prices, the high fuel price scenarios assume that marginal CO_2 reductions in the global emissions market are from coal power plants with carbon capture and storage (CCS). In the low fuel price scenarios, we assume that enough low carbon energy sources will replace a large amount of coal and natural gas at the global level, resulting in lower fuel prices and eliminating the need to use CCS as the marginal CO_2 reduction source. A similar effect would be achieved if the global CO_2 quota were to be set higher.

The characteristics and costs of power plants that are available for investment are presented in Table 3. The number of options has been kept as small as possible, since additional options increase the size of the model, making it insolvably large. Therefore some power plants where investments were not made in the initial model runs were removed from further model runs. These include oil-based heat or power plants.

One of the sources for economic data, IEA [24], did not include construction-phase financing costs. These were estimated and are included in the investment costs of Table 3.

The assumed investment cost for wind power in the base scenario is on a par with or slightly lower than what was realized in some of the larger onshore projects in 2003–2004. Since then, higher commodity prices and the tight supply of wind turbines have increased the costs considerably (BTM [27]). This situation masks any cost reductions due to advances in technology, which should be more rapid in the relatively immature field of wind power technology than for conventional power plants. Once the wind turbine markets are well supplied and commodity prices lower, technological advances will push down costs over several years, which should be reflected in the cost of wind power. Further advances should be made by 2035. Therefore, the cost assumptions for wind power in comparison with other technologies should be reasonable, if not pessimistic. In all scenarios, wind power is the cheapest source of electricity per MWh when comparing other plants operating at maximum availability and the assumed 2823 full load hours for wind power. This is probably a rather high figure for Finnish onshore wind power in 2035, but a lower number would

Table 4
Energy sources with resource limitations in primary energy TWh due to domestic resource constraints.

Resource limitations	TWh
Peat	30
Industrial wood waste	65
Forest residues	20
Wood and straw	33
Energy waste	5

Table 5
Electricity and heat demand in model regions. The model has one region for electricity and three regions for heat demand. Only heat demand in district heating systems is considered.

	Region	TWh	Assumption
Elec demand	FI_R	113.0	20% over projected 2010 consumption
Heat demand	FI_R_Urban	6.2	projected 2010 consumption
	FI_R_Rural	21.0	30% over projected 2010 consumption
	FI_R_Industry	46.8	projected 2010 consumption

have resulted in smaller wind penetration and the purpose of the article is to analyse high penetrations instead of focusing on the specifics of Finland.

Wind resources at different onshore sites are not equal and this means that while the best wind power sites might be competitive, sites with lower wind speeds might not be. This increases the costs of building more and more wind power in certain areas. An increasing cost curve is difficult to implement in a linear investment model without making the model too large to solve. As a simplification, the whole resource was assumed to have the same wind power production potential and the same investment cost. In the results, this can be interpreted as an average cost for wind power. It was also assumed that the hourly variation in wind power production remains unchanged regardless of the amount built.

CHP power plants available for investment are extraction-type plants. Their operating area in the model is described in Fig. 1. The figure also explains some of the parameters in Table 3.

The investment model does not take into account the need to improve the transmission system as the share of wind power increases. Since wind power production is variable, the transmission requirements per produced MWh are larger than for conventional power production. This is not a problem when penetration levels are low, since wind power can use existing transmission lines and probably only changes the utilization rate of the lines. In the study by US DoE [15], the costs of new transmission lines caused by 20% wind power penetration represented about 7% of the total wind power costs. Greater penetration increases the need to strengthen existing transmission lines or build completely new ones. One of the two studies carried out thus far addressing transmission limitations at high wind penetration levels indicated that in the case of Ireland, the transmission system would need to be redesigned somewhere between wind power energy penetration levels of 34% and 47% (Nedic et al. [13]). The cost of a redesign was not estimated. However, Ireland has a relatively small and isolated power system. In larger systems with more transmission links, the need for a redesign would arise later, although internal weak links and the relative location of wind resources and load centres can also force it earlier. Ea [5] estimated that the Danish grid would be able to handle wind power at a 50% energy penetration level with quite reasonable onshore network reinforcements. The Danish system is strongly interconnected and can use the reservoir hydropower resources of other Nordic countries.

3.3. Resource limitations and existing power plants

Renewable energy resources have resource limitations. Our model has hard limits on resources in order to simplify the problem. In real life, higher cost could make additional resources available. The same limitations apply in all of the scenarios. These limitations are presented in Table 4. As in most other countries, wind power resources in Finland are much larger than the consumption and do not need hard limits.

Electricity and heat demand were estimated for 2035 and are presented in Table 5. FI_R_Urban represents the capital region and it is assumed that any increase in the heating area by 2035 will be compensated by efficiency gains from better insulation. In FI_R_Rural, there are more cities and towns installing district heating networks, leading to increased demand. The industrial base might change by 2035, but in FI_R_Industry it is assumed that the total heat consumption will remain at the same level.

The current power plants that are expected to still be in operation in 2035 include all hydropower plants, most nuclear units and some CHP capacity (Table 6). They have been aggregated from a database of actual units in Finland (unpublished). Except for some light oil capacity, the current condensing fossil fuel power plants will be retired. The only heat boilers in the system are for municipal waste. It is assumed that these boilers are primarily meant for

Table 6
Existing power plants. NG_CHP_UR includes 2 units in the model, one back pressure and one extraction unit and is presented here as one back pressure unit. For back pressure units power = heat * CHP cb.

Unit	Fuel	Capacity, elec [MW]	Capacity, heat [MW]	CHP cb	Variable O&M [€/MWh]	Avg Eff	Availability
FO_BP_IN	Fuel oil	36	185.7	0.19	1.6	0.9	0.94
HY_01	Hydro	133.6			−2.8	1	0.9
HY_02	Hydro	883.1			2	1	0.9
HY_03	Hydro	239.3			3	1	0.9
HY_04	Hydro	93.1			4.7	1	0.9
HY_05	Hydro	215.7			5	1	0.9
HY_06	Hydro	183.6			5.9	1	0.9
HY_07	Hydro	224.1			6.2	1	0.9
HY_08	Hydro	274			6.7	1	0.9
HY_09	Hydro	181.7			6.8	1	0.9
HY_10	Hydro	705.7			7	1	0.9
LO_CON	Light oil	180.6			1.3	0.33	0.95
MW_BP_UR	Municipal waste	40.7	110	0.37	19	0.9	0.93
MW_HB_RU	Municipal waste	500			10	0.91	0.9
MW_HB_UR	Municipal waste	50			10	0.91	0.9
NG_BP_IN	Natural gas	249.3	530.4	0.47	1.3	0.9	0.94
NG_BP_RU	Natural gas	192.1	195.5	0.98	1	0.9	0.94
NG_CHP_UR	Nat. gas, 2 units	785	707	1.07	1.4	0.91	0.93
NG_CON	Natural gas	80.3			1.3	0.3	0.95
NU_CON	Uranium	2440		0	7.2	0.35	0.92
PE_BP_IN	Peat	386.5	546.1	0.71	2	0.9	0.92
PE_BP_RU	Peat	139	290	0.48	2.7	0.88	0.92
WO_BP_RU	Wood and straw	246.8	264.8	0.93	1.8	0.91	0.91
WR_BP_IN	Forest residues	44.7	180	0.25	1.8	0.91	0.9
WW_BP_IN	Ind. wood waste	2031	7120.4	0.29	2.8	0.88	0.9

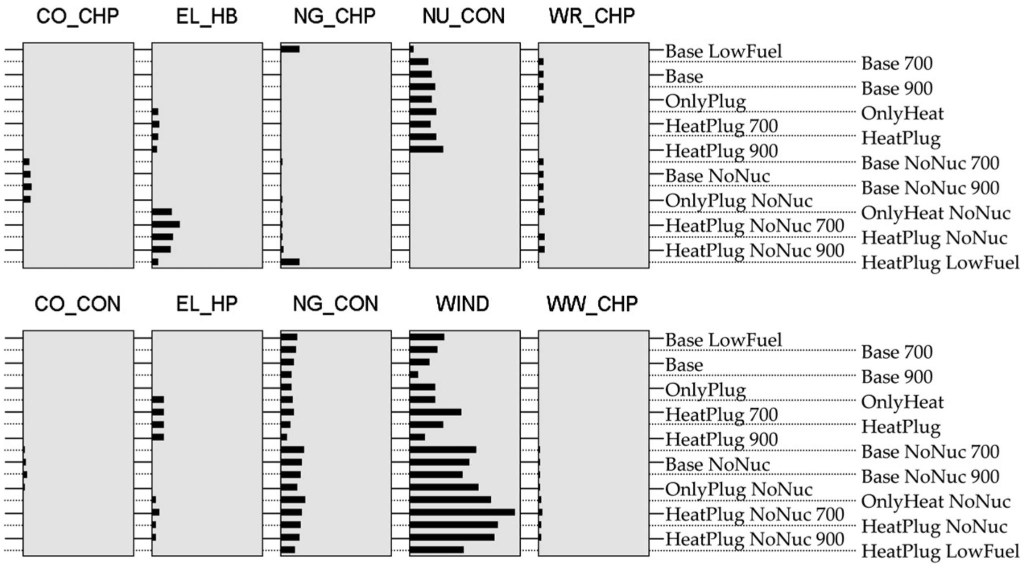

Fig. 2. Investments in new production capacity. Electrical capacity given for all plants except EL_HB and EL_HP (electric heat boilers and heat pumps), which have capacity defined on heat production. The *x*-axis scale is from 0 to 27 GW.

getting rid of waste and that heat production is a side-benefit. Other heat boilers are relatively cheap to build or retrofit for new fuels and for this reason full flexibility of choice was left to the investment model.

The model runs in one-hour time steps. Non-nuclear units are considered to be capable of full ramp up or ramp down inside the hour. Ramp rate for old nuclear units is set to 20% of capacity per hour and for new units to 50%. When ignoring industrial biomass with zero-cost fuel and wind power, nuclear is the least-cost source of electricity for high full load hours.

Hydropower capacity is divided into ten blocks with variable O&M costs. This simulates the fact that different water reservoirs end up with different water values and have different reservoir sizes in comparison with production capacity and inflow. This division is based on an analysis of Finnish river systems (Kiviluoma et al. [28]).

The industrial CHP has quite a large amount of heat production capacity using zero-cost wood waste as fuel. This strongly restricts new investment in industrial heat production.

4. Results

The results from the model runs are naturally sensitive to the assumptions in the input data. However, clear trends emerge in the different scenarios when the assumptions are modified. Fig. 2 shows the general trends in the investments in power and heat production capacity.

The base scenario was selected to have a reasonable but not excessive amount of wind power (12% of produced electricity). Any changes that are made will thus be reflected in the wind power penetration level. In the scenarios with higher fuel prices, the new capacity is mainly nuclear and wind power as shown in Table 7 and Fig. 2. In the scenarios with lower fuel prices, new nuclear power is for the most part replaced with fossil fuels, mainly natural gas. Also, wind power increased penetration as it is more economical to have lower utilization of fossil fuel power plants than nuclear power plants. As the base scenario, we selected a scenario with high fuel prices and 800 €/kW investment cost for wind power. Finland has greater opportunities for combined heat and power production than most other countries and it seems likelier that the strongest competitor to wind power will be nuclear power if CO_2 emissions have to be cut dramatically and fossil fuel prices stay at a relatively high level.

While nuclear or wind power take the dominant position in new capacity, their relative share depends on the assumptions about their relative cost and the fuel costs of other production types.

4.1. *Increasing the flexibility of the power system*

Flexibility in the power system will make it easier and less costly to integrate energy forms with variable or otherwise inflexible production. Allowing the model to use new forms of energy system flexibility increases investments in inflexible forms of power production. The scenarios include two kinds of flexibility: plug-in electric vehicles and heat measures.

Charging of plug-in electric vehicles offers some flexibility as it takes only a few hours to charge a vehicle after typical daily use. The timing of the charging can be optimized in line with the requirements of the power system. Furthermore, plugged in vehicles can provide ancillary services for the system, thereby decreasing the need for power plant capacity dedicated to ancillary services. It is assumed that when power prices are very high, it can also be profitable to discharge the batteries in order to shave demand

Table 7
Electricity production [TWh] from new power plants in some of the scenarios. The first three scenarios used the higher fuel price assumptions and the last one used the lower fuel price assumptions. The number refers to the assumed wind power cost [€/kW].

	CHP	Cond.	Nuclear	Wind
700	7.9	0.9	36.9	19.5
800 (Base)	8	0.7	42.6	13.3
900	8	0.5	50.2	5.6
800 LowFuel	27.9	1	6	24.1

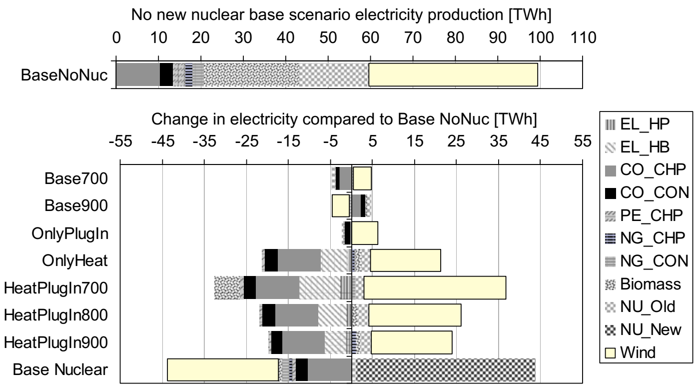

Fig. 3. Electricity production in the scenario runs without new nuclear power. First the production from different sources in the base scenario without new nuclear is shown. Changes compared to this are then shown in the lower part of the figure. Heat pumps (EL_HP) and electric heat boilers (EL_HB) will increase electricity consumption and are therefore negative changes in the graphs. Hydropower is not shown, as electricity production from hydropower does not change between scenarios.

peaks. Thereby plug-in vehicles can contribute 500 MW to the capacity balance restriction in the model (eq. (4)), reducing investments in peak-load capacity in some cases.

Electric heat boilers use electricity to produce heat. Heat pumps also use electricity, but they are more efficient since they refine ambient heat to a higher temperature with the help of high exergy electricity. Efficiency increases come with a higher investment cost. When any kind of electric heater is connected to heat storage, heat can be produced from the electricity at the times when it suits the power system most and the heat can be used when there is demand for it. These options are enabled in the scenarios with the heat measures.

First we look at results without nuclear power. This makes it easier to see the effects of heat measures and plug-in electric vehicles on the integration of wind power.

In scenarios with plug-in electric vehicles, electricity consumption is higher due to the consumption of the vehicles. Wind power is the cost-effective source of electricity for new consumption, as can be seen from Fig. 3. In addition, the flexibility provided by the plug-in electric vehicles helps wind power to increase its market share a little bit in the long-term. Flexibility from the heat measures increases the market share of wind power much more than the flexibility provided by plug-in electric vehicles. The reason is that the energy storage capacity of heat storages is much larger than the electricity storage capacity of plug-in electric vehicles. This can be seen in the scenario 'OnlyHeat' where a great deal of heat production is switched away from coal CHP to electric heat boilers running with wind electricity. Furthermore, the additional flexibility makes wind power more competitive with condensing coal electricity. When the price of wind power is decreased (scenario 'HeatPlug 700'), biomass based on forest residues is also forced out by wind. The additional wind power production in 'HeatPlug 800' compared to the base scenario is larger than the sum of the additional wind power production in 'OnlyHeat' and 'OnlyPlug-In', showing that combining the flexibility measures does not reduce their value with regard to wind power integration.

When nuclear is allowed, it pushes out a large amount of wind and is competitive enough to push out coal CHP without using flexibility mechanisms (see Fig. 4). In these scenarios, the additional flexibility from heat measures forces biomass and natural gas out and increases the share of nuclear and wind. On the other hand, lower fuel prices make natural gas CHP combined with wind power competitive with nuclear, and the result is very little or no new nuclear (Base_LowFuel & HeatPlug_LowFuel).

Fig. 5 displays heat production in the scenarios. The figure also shows the aggregated size of the heat storages the model decides to

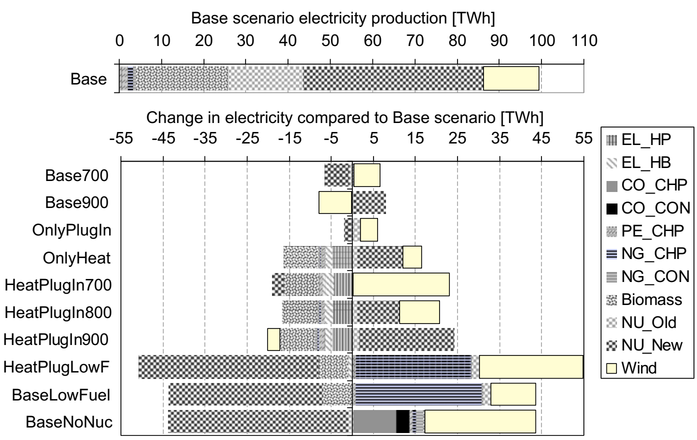

Fig. 4. Same as Fig. 3 except with new nuclear allowed.

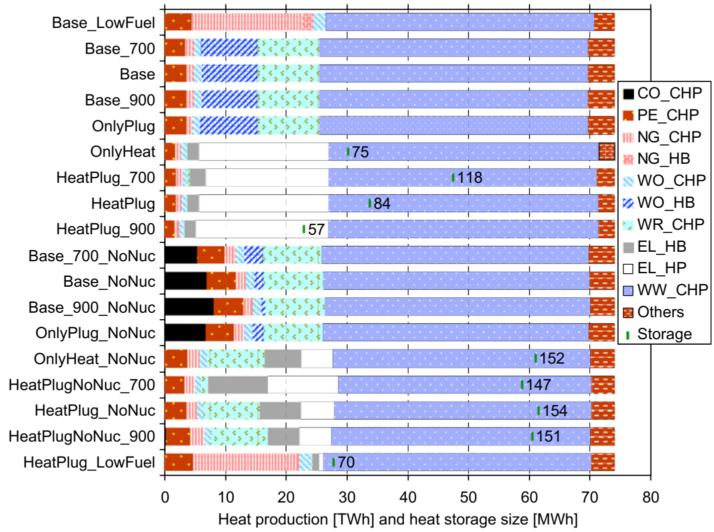

Fig. 5. Heat production [TWh] and the size of heat storages [GWh] in different scenarios.

invest in, when those are allowed. When the heat measures were allowed, the model switched a large part of the heat production to heat pumps and electric heat boilers. The exception was the scenario with low fuel prices, in which natural gas CHP-based heat production remained competitive. The large block of heat production based on wood waste comprises the industrial use of waste material from pulp and paper industry. As the fuel is practically free and the power plants are in operation, the share accounted for by this type of heat production hardly changed between scenarios.

Heat storage size was largest in the scenarios where nuclear power was not allowed. In these scenarios, the share of wind power was larger and heat storages were a cost-effective source of flexibility. However, heat storage size appears to have a limit. One might assume that when wind power production goes up, heat storages would be charged with electric boilers. However, this happens only during periods of very high wind power production. Usually heat storages *discharge* during good wind power production. The reason behind this is that CHP plants shut down to save on fuel costs and to make room for wind power electricity. During periods of lower wind power production, CHP plants and heat pumps charge heat storages slowly. The rate of charge is limited by the heat production capacity available after heat demand has been served. Heat production capacity is set by the periods of highest heat demand and it is not cost-effective to overbuild heat production capacity. The length of the low wind power production period multiplied with the spare heat production capacity limits the optimal size of the heat storage. As a complicating factor, the model has a large amount of old CHP capacity that cannot be replaced by heat pumps.

One of the heat areas, FI_R_Rural, includes less old CHP capacity and the results show that heat storage size actually decreases as wind power production increases (no new nuclear scenarios). A combination of heat pumps and electric heat boilers out-competes CHP production, which means that CHP plants provide less cheap heat during low wind power production. With less CHP, there is no excess heat from CHP during these periods, and a smaller heat storage capacity is enough to take care of shorter time scale fluctuations.

Fig. 6 shows how the flexibility mechanisms facilitate wind power integration in practise. The time scale is two weeks in March. The period was chosen to show very high wind power production and very low wind power production. The chosen scenario (HeatPlug NoNuc 700) has the highest wind power penetration out of all the scenarios. Wind power electricity production in the scenario corresponds to 65% of electricity demand, without taking into

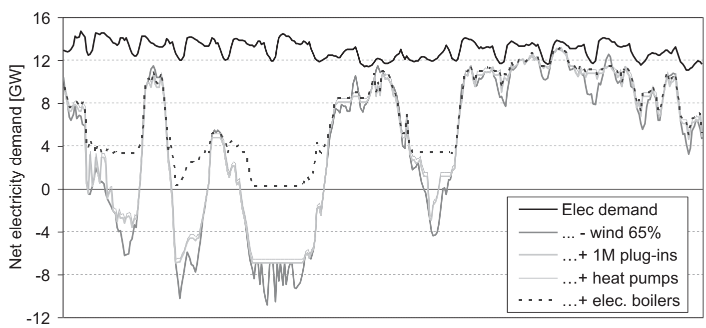

Fig. 6. Changes in net electricity demand when flexibility mechanisms are overlaid on top of each other. Two weeks in 'HeatPlug NoNuc 700' scenario in March.

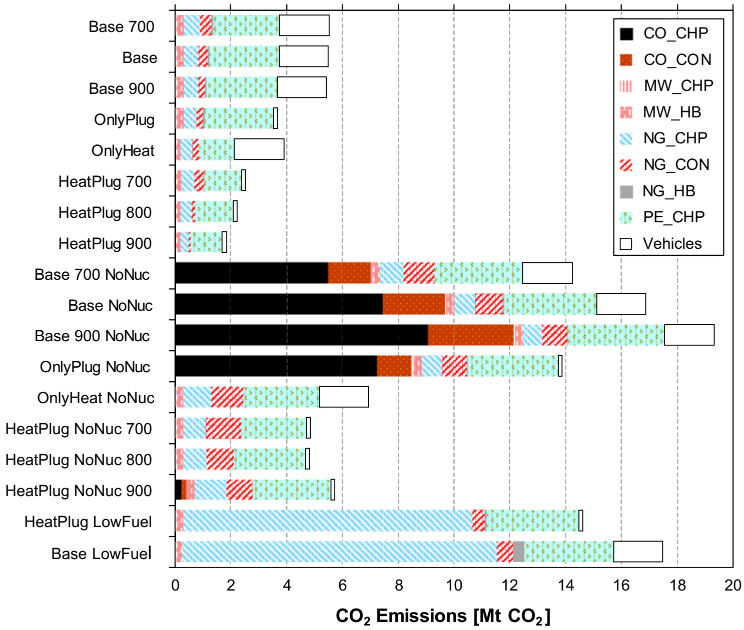

Fig. 7. CO_2 emissions in different scenarios. Vehicles refers to emissions from gasoline and diesel light vehicles, which were assumed to be replaced by electric vehicles in the scenarios where that emission source is not present.

account new demand from heating and plug-in vehicles. In the figure, different flexibility mechanisms are overlaid on top of each other and cumulative changes are shown. Wind power production is first subtracted from electricity demand to show the remaining demand and what the flexibility mechanisms and conventional power plants have to cope with. The electricity consumed during the smart charging and discharging of one million electric vehicles is then added to the remaining electricity consumption. The next steps are to add consumption from heat pumps and electric heat boilers. The dotted line after all the changes shows what the conventional power plants have to produce. The flexibility mechanisms are meaningful: wind power production does not need to be curtailed and the full load hours of conventional plants are reasonable. For example, the 2440 MW of old nuclear capacity still gets 8250 full load hours in a year even though wind power makes such a large contribution to the system.

4.2. CO_2 emissions

Finnish CO_2 emissions from the sources covered in this analysis were in the order of 45 Mt of CO_2 in 2006. This includes all power production, most of heat production and about one third of road transport emissions. Fig. 7 shows that emissions in the different modelled scenarios are much lower than historical values; the new range is 2–20 Mt of CO_2. This is a direct result of the assumed CO_2 price, fuel costs, and the new power plant investment costs. The emissions from the one million gasoline and diesel vehicles that the electric vehicles would replace are calculated at 90 g of CO_2 per kilometre and an average annual driving distance of 20 000 km. Newly registered vehicles in Finland currently average around 160 g/km. In the scenarios where plug-in vehicles are present, the emissions in the figure are generated by fuel use in plug-in hybrids. The CO_2 emissions from vehicle electricity consumption are included in the electricity production emissions.

4.3. Costs of different scenarios

The cost of serving electricity consumption varied between 33 and 43 €/MWh in the different scenarios, if old power plants were assumed to have been fully amortized and the value of heat was 10 € per produced MWh. The cheapest scenarios were those with low fuel costs and low wind power costs and the most expensive were those where the construction of new nuclear was not allowed, additional flexibility was not available and wind power costs were higher. Table 8 shows the cost differences between scenarios. The cost refers to the average cost for produced electricity including annualized investment costs.

The scenarios implied that the cost of not allowing new nuclear to be built is 0–4.1 €/MWh. The cost rises as wind power cost increases. However, the low fuel price scenarios have the cheapest costs and in the 'HeatPlug LowFuel' scenario no new nuclear is built although it is allowed. Accordingly, banning nuclear would not have increased costs in this scenario. Table 8 also shows that electricity gets cheaper when the flexibility mechanisms are available. Heat measures have a greater cost impact than plug-in electric vehicles. Even though plug-in electric vehicles increase electricity consumption, their flexibility allows changes in power

Table 8
Average cost of producing electricity [€/MWh] in different scenarios. 700, 800, and 900 in the scenario name refer to wind power investment cost [€/kW].

	Base	OnlyHeat	OnlyPlug	HeatPlug
700 Nuclear	37.9	–	–	34.7
800 Nuclear	38.4	36.0	37.3	35.6
900 Nuclear	38.8	–	–	36.2
700 No nuclear	40.0	–	–	36.0
800 No nuclear	41.5	39.1	39.8	37.7
900 No nuclear	42.8	–	–	40.3
800 Low fuel prices Nuclear	33.6	–	–	32.5

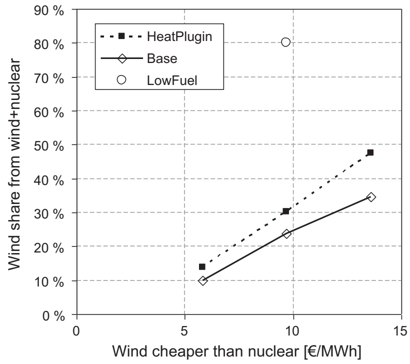

Fig. 8. Optimal share of wind power as a function of the cost difference between wind and nuclear. Only production from new nuclear plants is included.

plant investment patterns, which outweigh the cost of the additional electricity consumption. From the system point of view, it would be practically free to provide the energy required by the plug-in vehicles in exchange for flexibility services – at least when power system investments are factored in and with the caveat that the plug-ins are likely to be more flexible in the model than in real life due to consumer preferences and modelling simplifications.

Since wind power production is variable and nuclear serves the base load, wind power is less valuable to the power system than base load power. Therefore wind power must be less costly than nuclear in terms of €/MWh in order to compete in an optimized system, at least if environmental and social concerns apart from CO_2 emissions are not factored in. The wind power cost varies between 34.2 and 42.0 €/MWh and the nuclear cost is 47.8 €/MWh assuming 92% utilization. Fig. 8 shows how much wind power the model decides to build at different cost difference levels. There is a shift from nuclear toward wind power when the cost of wind power is decreased from 900 €/kW to 700 €/kW and everything else remains the same. Lower fuel prices mean that natural gas largely out-competes nuclear, and wind stays competitive as it saves fuel costs.

The cost-optimal share of wind and nuclear capacity is in reality dependant on several factors. These results only highlight the precariousness of the balance. Uncertainties concerning the future costs and societal acceptance of wind and nuclear power are large in comparison with the cost area where they would both be large contributors in a power system.

The analysis did not consider several factors that would influence the societal decision on permitting new power plants to be built. These include environmental concerns about nuclear waste disposal, the risk of major accidents and nuclear proliferation. Furthermore, using current nuclear technology would cause constraints on uranium resources, if nuclear power were to be used as a major global source of electricity production in the future. Other nuclear fuel cycles still have to demonstrate economical or even technical feasibility.

Wind power has an increasing cost curve, since the best sites are used up first, and further wind farms have to be built on less attractive sites,. The very best sites might be competitive, but these sites often have limited resource potential. Furthermore, higher wind penetration increases transmission costs disproportionately. At very high penetrations it might not be enough to merely reinforce the grid; a complete redesign might be required (Nedic et al. [13]). Costs related to ancillary services and power plant cycling are not as binding as in conventional wind integration studies, since heat measures and plug-in electric vehicles provide more new flexibility in the system to cope with variation and prediction errors.

5. Conclusion

In the scenarios where it was assumed that future fossil fuel prices are high and CO_2 emissions have a substantial cost, the model assumptions caused wind and nuclear to dominate the new power capacity. In the case of wind power, the variability of the production has to be compensated by lower production costs. Costs due to the variability are more influential at higher wind power penetration levels. The conclusions are sensitive towards the price assumptions in the input data, e.g. wind power penetration increased from 8% to 29% when wind power investment cost decreased from 900 €/kW to 700 €/kW in the scenarios with flexibility from heat measures and electric vehicles.

In the low fuel price scenario, nuclear was replaced by natural gas combined cycle power plants together with wind power, although the use of wind will be dependant on the uncertain investment costs of the future. The price of natural gas changed from 11 €/GJ to 6 €/GJ between the high and low fuel price scenarios. No social, environmental or resource constraints for nuclear power were assumed in the scenarios where the construction of nuclear power plants was allowed. However, these constraints could be binding in real life. In addition, wind power resources or permitting and grid integration were assumed to pose no constraints on wind power penetration. However, new flexibility mechanisms, especially heat measures, displayed a large capacity to balance out fluctuations in wind power production. It is conceivable that energy systems with a very high share of electricity from variable power sources can be created without the use of dedicated electricity storage, which is known to be expensive. Systems relying heavily on wind power and flexibility from heating, cooling and transport could be more economical than the alternatives, if the assumptions in the study turn out to be realistic.

When introducing new flexibility into the system, the share of wind power increased against other types of power production in all scenarios. The effect was larger when wind power was less costly i.e. at higher wind power penetration levels, because the variability of wind power induces more costs at higher penetration levels. Hence making the flexibility measures more beneficial for wind power. Nuclear also gained from the additional flexibility, although not quite as much as wind power. Heat storages with heat pumps benefit base load power relatively more than variable power, while plug-in electric vehicles and heat storages with electric boilers are more helpful for variable power. Heat pumps are capital-intensive and require more operating hours during the year to be economical than electric heat boilers, i.e. a high number of hours during the year with low power prices, which can be better provided by base load power plants. In absolute terms the increase in wind was much larger with the heat measures than with plug-in electric vehicles. It was evident from the results that heat measures can offer large amounts of flexibility to the system, while plug-in electric vehicles would have a more limited, although important effect. Combining the flexibility measures did not reduce their value with regard to wind power integration.

If the fuel and CO_2 cost assumptions in the article are realized in the future, then a large reduction in CO_2 emissions will not pose an economic problem, because it will be cost-effective to do so. This would happen at least in the electricity and district heating sector. In the transport sector, investments in electric vehicle fleets were assumed to be covered by benefits in the transport sector, and the results only show that those vehicles would be powered with electricity from new low emission power plants, at least in the context of the study assumptions. The introduction of flexibility to the power system with the integration of heating and transport can actually induce cost-effective emission reductions in power production while simultaneously producing electricity for transport and heating with near-zero CO_2 emission sources. The flexibility benefits from plug-in electric vehicles could be larger than the costs of producing the electricity consumed by the vehicles, when power production investments are optimized to take full advantage of the flexibility.

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PUBLICATION V

Flexibility from district heating to decrease wind power integration costs

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FLEXIBILITY FROM DISTRICT HEATING TO DECREASE WIND POWER INTEGRATION COSTS

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ABSTRACT

Variable power sources (e.g. wind, photovoltaics) increase the value of flexibility in the power system. This paper investigates the benefits of combining electric heat boilers, heat pumps, CHP plants and heat storages in a district heating network when the share of variable power increases considerably. The results are based on scenarios made with a generation planning model Balmorel [1]. Balmorel optimises investments and operation of heat and power plants, including heat storages. It uses hourly resolution and enforces temporal continuity in the use of the heat storages. Scenarios with high amount of wind power were investigated and the paper describes how the increase in variability changes the profitability and operation of different district heating options in more detail than was described in the article by Kiviluoma and Meibom [2]. Results show that district heating systems could offer significant and cost-effective flexibility to facilitate the integration of variable power. Furthermore, the combination of different technologies offers the largest advantage. The results imply that, if the share of variable power becomes large, heat storages should become an important part of district heating networks.

NOMENCLATURE

Indices	
i, I	Unit, set of units
$I^{HeatSto}$	Heat storage units
t, T	Time steps, set of time steps
a, A	Area, set of areas
Variables	
C	New capacity
P	Power generation
Q	Heat generation
Z	Charging of heat storage
Parameters	
c^{Inv}	Annualized investment cost
c^{Fix}	Fixed operation and maintenance costs
$c^{Operation}$	Operation cost function of the unit
w	Weight of time period
h	Heat demand

INTRODUCTION

Wind power is projected to be a large contributor to fulfil electricity demand in several countries. This could take place due to relatively low cost of wind power electricity or policy mechanisms promoting renewable energy. In any case, power systems with a large fraction of power coming from a variable power source will need to be flexible. Flexibility is used to cope with the increased variation in residual load (electricity demand minus variable power production) and with the increased forecast uncertainty in the residual load. On the other hand, lack of flexibility will cause larger costs from increased variability and forecast errors. Therefore, it is prudent to investigate the cost optimal configurations for the combined power and heat generation portfolios.

Heat generation could offer significant possibilities for increasing the flexibility of the power system. Currently, part of the inflexibility of the power system comes from CHP plants that are operated to serve the heat load while electricity is a side product. Installation of electric resistance heaters next to the CHP units or elsewhere in the heat network could break this forced connection. During periods of low power prices, which will become more common with high share of wind power, CHP plants could be shut down and heat would be produced with electricity. The dynamics can be made more economic with the use of heat storages. Further option is to have heat pumps in the DH network, but they will require large amount of full load hours to be profitable and will compete with CHP plants for the operating space.

In most countries heat demand is in the same order of magnitude as electricity demand. For example, in UK the demand for primary energy due to heat is around 40% of total primary energy demand [3]. About 25% of the primary energy demand is due to space and non-industrial water heating. In the US all kind of heat use accounts for about 30% of the primary energy consumption [estimated from 4].

Heat is inexpensive to store compared to electricity. Electricity storage has been seriously considered to alleviate the variability of wind power [5-6]. Therefore, it is apparent that the use of heat storages should also receive serious consideration in the current context. Some work has been done [7-9], but not considering optimal investments in new power plants and heat storages.

The study has been restricted to residential and industrial district heating systems. Buildings not connected to district heating systems were not considered, although these also require heat. Cooling demand could also offer similar possibilities, but the problem was not addressed here. Industrial heat demand and water heating do not usually have strong seasonal variation and can therefore be more valuable towards the integration of variable power.

METHODS AND DATA

The model and assumptions used for the analysis are described in more detail in [2]. For convenience, most important sections are referenced below. The heat sector of the model is described more thoroughly here.

The Balmorel model is a linear optimization model of a power system including district heating systems. It calculates investments in storage, production and transmission capacity and the operation of the units in the system while satisfying the demand for power and district heating in every time period. Investments and operation will be optimal under the input data assumptions covering e.g. fuel prices, CO2 emission permit prices, electricity and district heating demand, technology costs and technical characteristics (eq. 1). The model was developed by (Ravn et al. [1]) and has been extended in several projects, e.g. (Jensen & Meibom [10], Karlsson & Meibom [11], Kiviluoma & Meibom [2]).

$$\min\left(\sum_{i\in I} c_i^{Inv} C_i + \sum_{i\in I} c_i^{Fix}\left(C_i^{Ex} + C_i\right) + \sum_{t\in T}\sum_{i\in I} w_t c_i^{Operation}\left(P_{i,t}, Q_{i,t}\right)\right) \quad (1)$$

The optimization period in the model is one year divided into time periods. This work uses 26 selected weeks, each divided into 168 hours. The yearly optimization period implies that an investment is carried out if it reduces system costs including the annualized investment cost of the unit.

The geographical resolution is countries divided into regions that are in turn subdivided into areas. Each country is divided into several regions to represent its main transmission grid constraints. Each region has time series of electricity demand and wind power production. The transmission grid within a region is only represented as an average transmission and distribution loss. Areas are used to represent district heating grids, with each area having a time series of heat demand. There is no exchange of heat between areas. In this article, Finland is used as the source for most of the input data.

The hourly heat demand has to be fulfilled with the heat generation units, including heat storages (eq. 2). Loading of heat storage adds to the heat demand. Loss during the heat storage process is not considered. The dynamics of heat networks were not taken into account.

$$\sum_{i\in I} Q_{i,t} = h_{r,t} + \sum_{i\in I_a^{HeatSto}} Z_{i,t} \qquad \forall t \in T; a \in A \qquad (2)$$

Analysis is done for the year 2035. By this time, large portion of the existing power plants are retired. Three district heating areas were considered. These have a rather different existing heat generation portfolio by 2035. This helps to uncover some interesting dynamics in the results section.

In this paper, scenarios without new nuclear power are compared (scenarios 'Base NoNuc' and 'OnlyHeat NoNuc' in article [2]). This meant that wind power had a very high share of electricity production. Accordingly, there was more demand for flexibility in the system.

'Urban' area presents the heat demand in the capital region of Finland. The existing power plants in 2035 cover over half of the required heat capacity. Largest share comes from natural gas, which is a relatively expensive fuel in these model runs. The annual heat demand is smallest of the considered areas: 6.2 TWh.

'Industry' area aggregates the known industrial district heating demand from several different locations. This is a necessary simplification, since Finland has over hundred separate DH areas and the model would not be able to optimise all of these simultaneously. The industrial heat demand in Finland is driven by paper and pulp industry, which produces waste that can be used as energy input. This capacity is assumed to be available in 2035 and as a consequence the model does not need more industrial heat capacity. The annual heat demand is 46.8 TWh.

'Rural' area aggregates non-industrial heat demand excluding the capital region considered in 'Urban'. This is probably the most interesting example, as the existing capacity covers only 20% of the heat capacity demand. Therefore, the model has to optimise almost the whole heat generation portfolio. There are wood resources (limited amount of forest residues and more expensive solid wood) available unlike in the urban area. The annual heat demand is 21.0 TWh.

RESULTS

Figures 1-3 give an example how heat production meets heat demand in the different areas during the same 4.5 days in January. Negative production indicates charging of heat storage. Electricity price is on separate axis together with the cumulative content of heat storage. When electricity price is low, storage is loaded with electricity using heat boilers and heat pumps. When electricity price is high, CHP units produce heat and electricity. Fluctuations in electricity price are mainly driven by changes in wind power production, since these are larger than changes in electricity demand (Fig. 4).

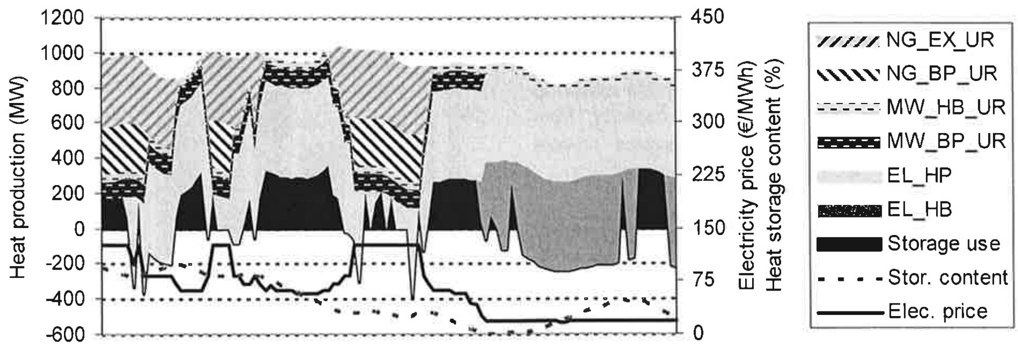

Fig. 1. Example of operation in 'Urban' heat area. Negative production indicates charging of heat storage.

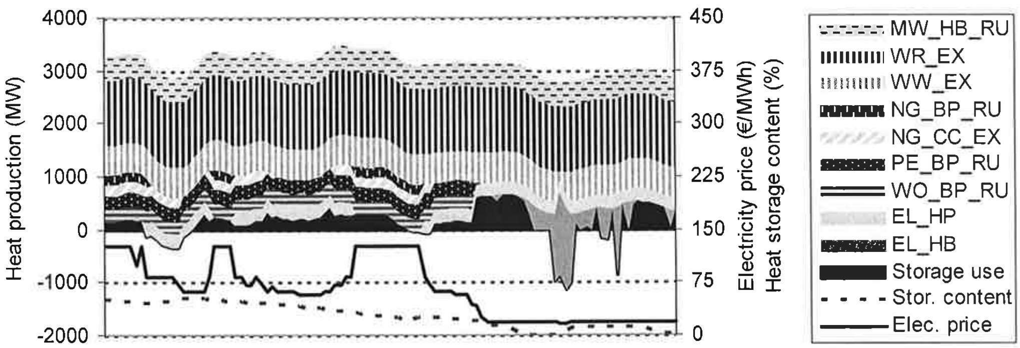

Fig. 2. Example of operation in 'Rural' heat area. Negative production indicates charging of heat storage.

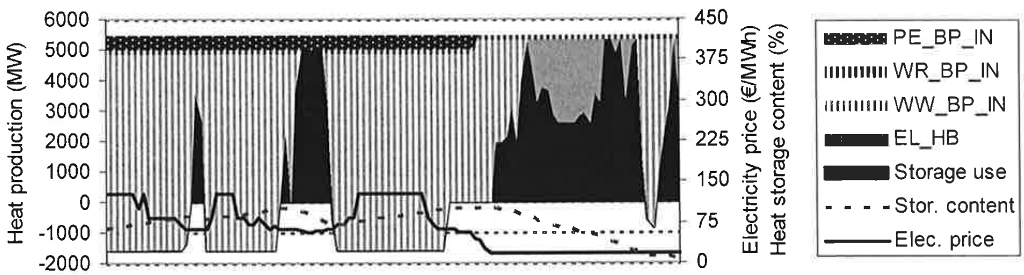

Fig. 3. Example of operation in 'Industrial' heat area. Negative production indicates charging of heat storage.

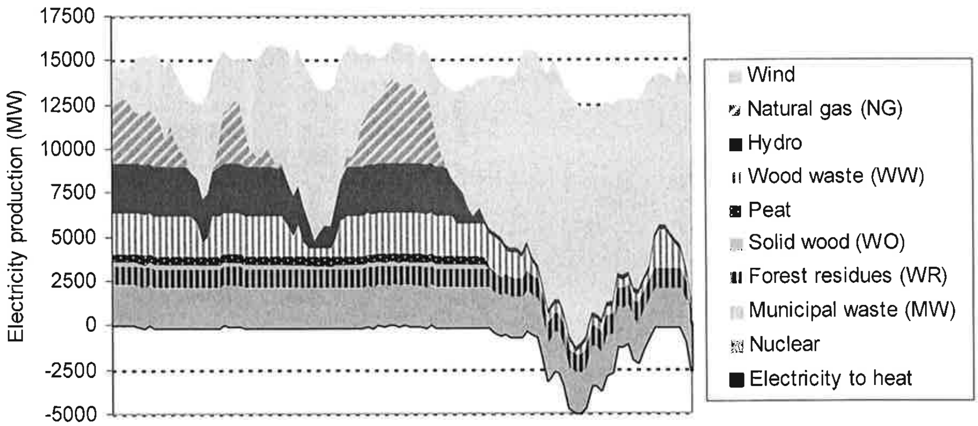

Fig. 4. Electricity production. Negative production indicates the use of electric heat boilers and/or heat pumps.

Effects of heat measures in the three heat areas

In the 'Industry' heat area availability of heat measures (electric heat boilers, heat pumps, and heat storages) had relatively little effect (Fig. 2). The main reason is that the existing heat production capacity from industrial wood waste and the associated no-cost

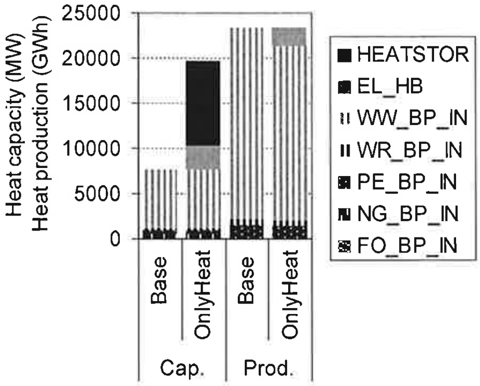

Fig. 2. Heat capacity and production[1] in the 'Industrial' heat area.

waste wood were not easily replaced. However, there were some high wind situations with low power prices where it was beneficial to use electric heat boilers to produce heat and decrease heat production from wood waste in the 'Industry' area. There was an annual resource limit on wood waste on the country level and the wood waste use was transferred to the 'Rural' heat area. It was also profitable to install some heat storage capacity. This enabled the full shut down of wood waste back pressure power plants for the duration of low electricity prices. This decreased electricity production and gave more room for the upsurge in wind power production.

In the 'Urban' heat area heat measures enabled the replacement of CHP coal units with production from heat pumps and to smaller extent from electric heat boilers (Fig. 3). Also wood based heat boilers were replaced. Investment in heat storage was relatively smaller. However, they were cycled more due to faster charging rate.

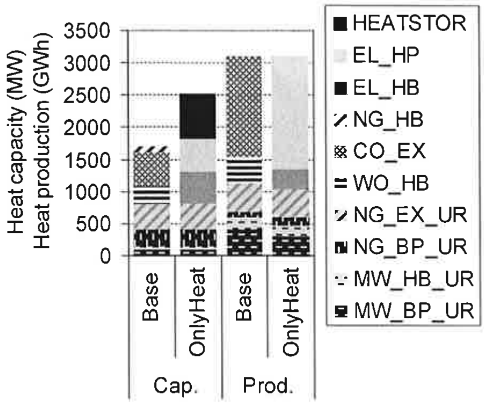

Fig. 3. Heat capacity and production[1] in the 'Urban' heat area.

The combined utilization of the heat measures was used to shut down existing natural gas based CHP power plants during hours of average or lower electricity prices. During low electricity prices electric heat boilers were used to charge heat storage. Accordingly, during average electricity prices heat was used from heat storage to prevent the use of electric heat boilers. During the highest electricity prices electric heat pumps were also shut down with the help of heat from the heat storages.

The most important difference between 'Urban' and 'Rural' heat areas is the availability of wood residues in the 'Rural' heat area (Fig. 4). For the most part this resource was able to outcompete heat pumps as means to produce heat. Heat measures still helped to replace coal CHP. The combination of electric heat boilers and heat storages was again a large source of additional flexibility to the system.

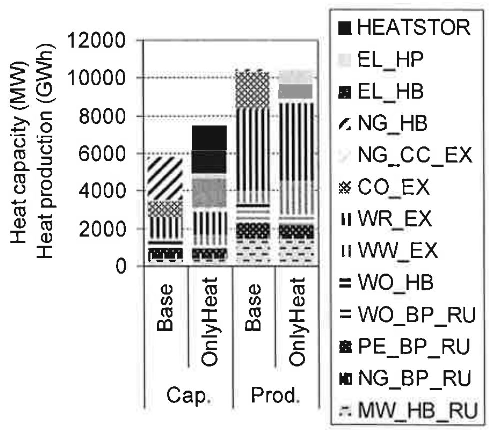

Fig. 4. Heat capacity and production[1] in the 'Rural' heat area.

[1] Heat production is from the modelled 26 weeks and should be multiplied by 2 to get an estimate on annual production.

Dynamics of heat storage

Most of the daily fluctuation in heat demand was smoothed with heat storages and electric heat boilers in all heat areas. If CHP units were operated, they were usually operated at maximum heat output.

The investment cost for heat storage was assumed to be 1840 €/kWh. With the assumed ratio of 12 between storage capacity and heat capacity this translates to 153 €/kW. In comparison the capacity cost of electric heat boilers was assumed to be 40 €/kW and 50 €/kW for natural gas heat boiler. This means that investment into heat storage capacity was not driven by need for new capacity since heat boilers were cheaper. There had to be operational benefits from the use of heat storage to cover the additional investment costs.

Heat storages create operational benefits by moving consumption from more expensive sources of heat to less expensive by shifting demand in time. In all heating areas whole operating ranges of heat storages were extensively utilized. During most 168 hour periods heat storage reached both the minimum and maximum storage capacities. In the 'Rural' area heat storage was 2.1% of the time either full or empty. With a larger storage capacity this could have been reduced, but it was not worth the investment.

The size of the heat storage in 'Industry' area was larger than in other areas in relation to daily heat demand (Fig. 5). In 'Industry' area charging of heat storages took place over several days during higher power prices, when wood waste CHP units were producing extra electricity. Storing the extra heat required larger heat storage capacity. On the contrary, in 'Rural' and 'Urban' charging and discharging was more balanced and smaller heat storage was enough.

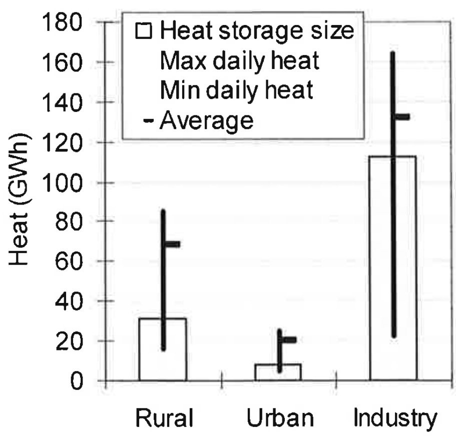

Fig. 5. Heat storage size compared to maximum, minimum and average daily heat demands.

In the 'Rural' area during winter time, charging of heat storages is mostly based on the use of electric heat boilers. They create large amount of heat in relatively short time during periods of low power prices. During summer time, heat storages are charged by turning on wood waste and forest residue CHP units. During spring and fall CHP units operate more often, since the heat load is larger, but still the heat storage helps to shut them down for periods of some hours.

'Urban' area has similar dynamics, but during summer time the adjustment is made by heat pumps instead of CHP. In the winter during high power prices old natural gas CHP units are less expensive to operate than the heat pumps.

CONCLUSIONS

District heating systems offer good possibilities for increasing the flexibility of the power system, if the penetration of variable power like wind power increases greatly in the future. According to the results, main vessels to increase flexibility are the use of heat storages, electric heat boilers and flexible operation of CHP units.

Investment in electric heat boilers in district heating systems is driven mainly by periods of very high wind power production. The resulting cheap electricity is converted to heat and to some extent stored in heat storages for later use. Investments in heat storage in turn are driven by the same mechanisms, but also to create flexibility in the electricity production when prices are higher. To enable this, the operation of CHP units and heat pumps is altered with the help of heat storages. Heat pumps mainly compete against CHP as a source of heat. They succeed in replacing coal CHP, but are not very competitive against wood residues. This is naturally due to assumed costs where coal has a considerably penalty due to CO_2 cost. Heat pumps are not very important as a source of flexibility, since they require lot of full load hours due to their investment cost.

While the research has been conducted on district heating, similar dynamics could be achieved in household heating not connected to district heating networks. However, the costs are likely to be larger unless there is an existing hot water tank. Flexibility could also be gained from district cooling or air-conditioning units with the addition of a cold storage.

Further research should also address some of the shortcomings of current study. Sensitivity analysis would be important, especially concerning the cost estimates of the analysed heat measures. Heat storage model was very simple and this should be improved. Heat grade, especially in the industrial environment, can vary and the model should take this into account. Heat pumps were assumed to work at constant COP and this is a crude approximation even if the heat source is groundwater or sea water.

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PUBLICATION VI

Coping with wind power variability

How plugin electric vehicles could help

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Coping with Wind Power Variability: How Plug-in Electric Vehicles Could Help

Juha Kiviluoma
Peter Meibom

Abstract

Plug-in electric vehicles could offer flexibility for wind power and an attempt was made to quantify the effect with a power system model Wilmar. Wilmar simulates unit commitment and dispatch using mixed integer p[1]rogramming and includes wind power and load stochasticity as well as a module for plug-in electric vehicles.

Forecast errors of wind power increase the need for balancing and ancillary services. The model is able to use the plug-in electric vehicles (PHEVs) to participate in the balancing and ancillary services and decrease the costs of these services. The charging and possible discharging of the vehicles can also be optimized to most beneficial hours within the limits caused by vehicle use. We have calculated the benefits at different PHEV penetration levels.

The results indicate that benefits of peak shaving using vehicle to grid are limited due to the rather small size of storage in the batteries even with a large number of vehicles. Benefits can best be seen in the smart charging of the vehicles and in the correction of forecast errors. The marginal benefits of introducing PHEVs capable of smart charging and discharging are high for low numbers of PHEVs in the power system, but declines with higher penetration levels of PHEVs, because the demands for power system reserves and flexibility are limited.

I. INTRODUCTION

Plug-in electric vehicles have recently attracted considerable attention as means to reduce oil-dependence and CO2 emissions in the transport sector. As a result, there has also been interest to asses the possible power system benefits of smart charging and discharging [1-10].

Benefits are due to several different reasons. First, controlled charging of the vehicle batteries leads to more charging during hours with lower power prices. Second, vehicles waiting to be charged can participate in the balancing markets. These two are the main scope of this article. Third, PHEVs can act as disturbance reserves, especially if they have vehicle-to-grid (V2G) capability. We have analysed how much capacity could be available for disturbance reserves, but we have not tried to quantify the monetary benefits. Fourth, with V2G, PHEVs can shave peaks, if the daily price difference is large enough. Fifth, they can reduce the need for peak capacity. Sixth, in the long-term PHEVs can enable more cost-effective power system through changes in the power plant investments that will reflect the additional flexibility in the system.

To analyse the last two benefits requires a generation planning model and is not part of the scope of this article. We have analysed it elsewhere [11] .

The demand side flexibility due to PHEVs will help to decrease the operational costs of the power system. However, the benefits will be divided between market participants through the market mechanisms. This means, that some part of the benefits is likely to go to other market participants than the vehicle owners or their representative. We have analysed both the system benefit and the market prices from the perspective of a car owner.

The article first outlines the model and the data that has been used for the analysis. Then we proceed to show some results of PHEVs on a power system with a limited amount of wind power. We also demonstrate how PHEVs could fulfil different roles in the power system. Lastly, we discuss some problems in analysing the combination of wind power and PHEVs.

II. THE MODEL AND DATA

The model used in the analysis is called WILMAR (Wind Power Integration in Liberalised Electricity Markets) and is publicly available from the internet [4], although only as an older version with a restricted set of data. The model has been enhanced with a module to handle the plug-in electric vehicles. WILMAR analyses power markets based on a description of generation, demand and transmission between reasonably defined model regions and derives electricity market prices from marginal system operation costs. The model uses linear programming (LP) or mixed integer programming (MIP) with wind power production and electricity demand as optional stochastic input parameters. It optimises unit commitment in a day-ahead market and corrects for arising prediction errors in intraday market clearings. It also sets requirements for spinning and non-spinning reserve capacity. The latter is influenced by the

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predicted wind power production. Since the model has been developed for the Nordic countries, it has separate markets for producing heat for district or process heat networks. These are often tied to power production through combined heat and power plants (CHP). Model also handles the use of hydro power reservoirs through water values, which are either derived by luring the model towards historical levels or with a separate simplified model, which solves production for a whole year at a time and can therefore assign a value for the water value. A more detailed description of the model is given in [12, 13].

The model includes a module to handle the PHEVs from the network perspective. Work is underway to document the PHEV module in more detail, in here we just describe the general principles.

A. Data for PHEVs

Electric vehicles need to be plugged in order to be charged or discharged. Since the number of vehicles is very large, statistical behaviour is rather predictable although individual drivers might behave erratically. We assumed that there are two possible places where the vehicles might be plugged-in: at work and at home. Most people would be plugging in only at home, some would do it at both locations and only few at work. The data used for estimating the leaving and arriving vehicles was derived from the National Travel Survey conducted during 2004-2005 in Finland (HLT). It gave information on the timing and distance of travel with personal vehicles as well as data on the purpose of all travel. The information was processed to give estimates when people driving cars might arrive at work places and at homes and what kind of distances they had travelled before that.

This set of data made it possible to describe the PHEVs from the power system perspective. We derived a set of equations, which govern the use of the batteries for charging and discharging. The equations also make sure that the vehicles have enough stored electricity when leaving the network.

It was assumed that people plug-in once they arrive and that 95% do this at home and 40% at work. The data was used to derive typical daily patterns on hourly time scale and these were modified to take into account differences between weekdays, Fridays, Saturdays, Sundays, holidays, and weekdays between a holiday and a weekend. A weekly index, which held the changes in driving over the year, was multiplied into the data. Then assumptions about specific consumption and plugging in were overlaid on the data.

All this lead to a couple of different full year input time series in hourly time scale for the power system model: Share of vehicles plugged in the network changes over time. This affects the size of the usable electricity storage and the charging and discharging capacities. Time series for leaving vehicles directs the amount of electricity drawn from the storage pool. Arriving vehicles bring half empty batteries that will need recharging before the vehicles leave again.

Limit to recharging is usually set by the capacity of electric wiring at home or at work. Batteries can usually take more amperes, although many battery types can prolong their lifetime with slower charging. We assumed that half of the vehicles were plug-in hybrids, which can also run on gasoline, and that half of the vehicles were full electric vehicles. For plug-in hybrids charging capacity is set to an average of 4 kW per vehicle and for full electric vehicles it is 6 kW. Average consumption of grid electricity is 0.25 kWh/km, which is a rather high estimate. On average a vehicle does three trips per day, drives 52 kilometers and has a charge opportunity every 39 kilometers. A yearly consumption of half a million of battery electric vehicles amounts to 2.16 TWh and the same for plug-in hybrids is 1.83 TWh. The total consumption of one million vehicles was just below 5 % of total electricity demand. Active personal car fleet of Finland is about two million vehicles.

B. Description of the modelled power system

The Finnish power system has a rather large amount of combined heat and power plants (CHP). Therefore heat demand is also included in the model runs and there are over hundred separate heating areas. Electricity demand and power production were divided into seven regions.

Electricity and heat demands were estimated for 2015. Heat and power plants for the system were those that were assumed to be in place by 2015. Reservoir hydro power plants were taken away, since they complicate the comparison of the scenarios. They would also offer inexpensive ancillary services and flexibility, which would overshadow the effect of the plug-ins.

Electricity demand has a large baseload fraction due to industrial use of electricity. The peak demand is 14.4 GW. Almost all CHP units follow the heat demand with a fixed ratio for producing electricity, which means that their contribution for balancing the system was small. However, they were able to act as reserves. The total electric capacity of conventional power plants was close to 16 GW and the division can be seen in Figure 1. In the base scenario wind power capacity was 2 GW, which meant 5% penetration.

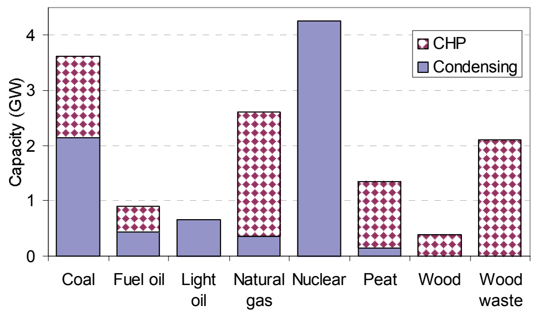

Figure 1. Capacity of conventional power plants in the analysed system.

III. RESULTS

We ran the model in two modes in order to calculate the benefits of the PHEVs. Dumb charging means that the vehicles start charging when they are plugged in and stop charging once they are full. Also a scenario without plug-in vehicles was run. We define that the difference between no plug-ins and dumb charging gives the cost of electricity to provide the required electricity for the vehicle fleet. The difference between smart and dumb charging gives the benefit of allowing the vehicle charging to be controlled according to the market conditions.

A. System benefits and market prices

We have calculated the operational costs and benefits per vehicle for different fleet sizes and different penetrations of wind power. First we consider the effects of PHEV fleet size. The costs and benefits are summed from modelling power markets for one year. The results with different electric vehicle fleet sizes are summarized in Table 1. As the number of PHEVs increased, the additional costs of operating the power system increased compared to the case where there were no PHEVs. With one thousand PHEVs and dumb charging, the additional annual cost was 156 000 euros, which means 156 €/vehicle. When the model was allowed to use smart charging and discharging, the additional cost went down to 61 €/vehicle. The benefit of smart charging was then 96 €/vehicle.

Table 1. System cost of charging electric vehicles (€/vehicle/year) for different electric vehicle fleet sizes. 'Dumb' and 'smart' charging are costs while 'benefit' indicates the benefit of smart charging over dumb charging. Results are only indicative as there were some problems with the model runs.

No of cars	Dumb	Smart	Benefit
1 000	156	61	96
10 000	186	89	98
100 000	190	120	71
1 000 000	215	173	41

It can be seen that the system benefit per vehicle drops when there are more and more vehicles participating in the smart charging scheme. The reason for this is simple – the services the vehicles are providing get saturated and further increase in the capacity does not lead to as large cost reductions in the system. This implies that it does not make sense from the system perspective to equip all electric vehicles with vehicle-to-grid capability. It is enough to have the capability in vehicles that can provide higher than average benefit, e.g. those with large battery packs and most flexibility in their use. However, smart charging makes sense for higher number of vehicles as this is cheaper to implement and helps the system to fill valleys in the consumption, or more properly in the net load, which takes into account wind power or any other energy production dependant on utilizing variable energy flows.

Table 2. Market price of charging electric vehicles (€/vehicle/year) for different electric vehicle fleet sizes. This table includes the use of vehicles for peak shaving and intraday adjustments.

No of cars	Dumb	Smart	Diff.
1 000	257	0	257
10 000	258	23	234
100 000	263	113	150
1 000 000	315	278	37

Table 1 displayed system costs of plug-in electric vehicles. If vehicle owners use real time pricing for purchasing power for their plug-in vehicles as well as real time prices for using the vehicles in intraday trading, the cost of electricity will look markedly different from system costs as can be seen from the Table 2. Real time prices in the model are based on the cost of producing one more unit of electricity, which in practice is the marginal cost of the last dispatched unit. The cost of electricity is dependant on which hours the charging happens. In the dumb charging case with low number of PHEVs, charging takes mostly place in hours of lower than average demand. With a larger number of vehicles, the shape of the demand curve changes and the prices on hours with high charging start to increase. Smart charging avoids this, especially with low PHEV penetration. When the penetration increases, the valleys of low demand start to get filled with plug-in charging and the market price increases during those hours. Revenue from intraday trading also gets lower per vehicle. However, in the long term, higher prices will attract new power plant investments that will conform to the demand curve and existing power plant fleet. Therefore, PHEVs should attract new investment and market prices will once again get lower.

B. Changes in the load duration curve

In fact it is perilous to take Table 2 for granted. The scenario with one million smart charging PHEVs would mean that the average price of electricity would be 6 €/MWh higher. This should attract investments in new power plants and the results in the table would not any longer hold true. It makes more sense to have a look at the effect of PHEVs on load duration curves (see Figure 2). This will give an indication how the power system would need to change. Not surprisingly, smart charging smoothes the curve and therefore enables larger fraction of the power to be produced with baseload power plants. Dumb charging leads to steeper load duration curve and opposite effect.

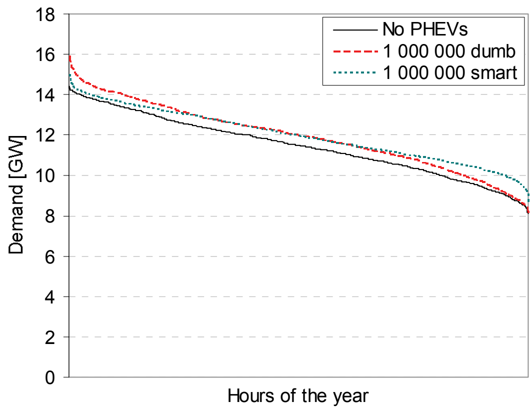

Figure 2. Load duration curves without PHEVs and with one million PHEVs. Smart charging smoothes the curve while dumb charging makes the curve steeper.

C. Start-up costs

Another result worth having a look is the changes in the start-up costs of conventional power plants. PHEVs without smart charging increase the need for starting up power plants while smart charging PHEVs can decrease the start-ups considerably (Figure 3). Especially peak power plants are prevented from starting up by discharging the batteries at peak demand. However, the magnitude of start-up costs in these model runs was quite small compared to the total operating costs or to other benefits the PHEVs bring to the system.

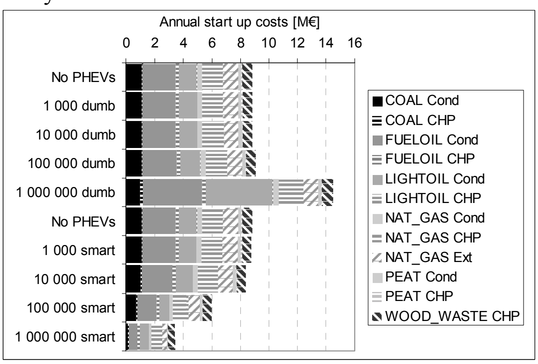

Figure 3. Changes in start-up costs between different plug-in scenarios.

While WILMAR model reserves capacity for primary and secondary reserves, for the most part this did not appear as a cost for the system in our model runs. During most situations there were reserves available without any extra effort, for instance CHP plants were considered capable of increasing their output if the need arises. Our model runs did not include events where the reserves would have actually been used, so the associated costs did not show up either. This part of the analysis should be improved. However, the changes in the wind power and load forecasts did take place in the stochastic model runs and PHEVs were able to decrease the costs of forecast errors.

D. Available capacities

Based on our assumptions, the share of PHEVs plugged in at the network varies between 50-90 % during a typical weekday. If the average network connection has a capacity of 6 kW and there are one million vehicles, then the plugged-in capacity varies between 3 and 5.4 GW. This is a rather large number in a power system with peak load of about 15 GW. However, unless every vehicle is equipped with V2G and has spare electricity in the battery pack, this capacity is not fully available. Figure 4 demonstrates capacities available for the power system. Highest line shows the output capacity if all vehicles have V2G. The lines depicting the two different charging patterns show how much capacity could be stopped from charging if the power system would require that. The charging capacity could act as disturbance reserves unless the charging has to happen in order to get the battery pack full in time. The demand for positive primary reserve in this 15 GW peak system has been 464 MW and secondary reserve demand has been 1300 MW.

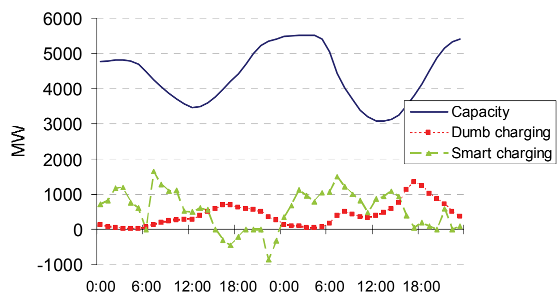

Figure 4. Behavior of PHEVs during typical Sunday and Monday.

E. Balancing

As said before, the forecast errors of both load and wind have been considered separately from the primary and secondary reserve requirement. In the case of 100 000 smart charging PHEVs, these vehicles covered over 30% of the balancing of the forecast errors. In case of one million PHEVs, they covered almost all of the errors. This means that most of the time the conventional power plants do not need to be rescheduled in order to correct the prediction errors from wind and load. Wind power penetration in these scenarios was about 5% of electricity consumption.

F. Wind power and PHEVs

We also ran scenarios with different wind power penetration levels. The penetration increased from 0% to 15% in 5% steps. The benefits of smart charging changed rather unpredictably from scenario to scenario. One would have assumed that the benefit would increase with increasing wind power penetration. However, wind power changes the net load duration curve and change the utilization times of different power plants. In effect the scenarios were not comparable between each other as we were not able to keep all other things constant. In order to understand how the results came by, a more simple power system should be inspected. Our data set had over 500 heat and power plants divided between seven regions and over 100 separate district heating areas. It could also be that the analysis cannot be made without including a generation planning model to properly take into account the changes caused by increasing wind power penetration.

IV. CONCLUSIONS

Plug-in electric vehicles increase the power system flexibility, if they are capable of smart charging. They can give a sizable contribution to system reserves just by being able to stop charging. With V2G the contribution can be much larger than what the system actually requires, which means that at least disturbance reserves can be saturated with PHEVs. PHEVs also change the shape of the load duration curve, so that either more baseload or more variable production can be accommodated in the system. However, it proved to be difficult to setup scenarios to prove the latter. Despite this, the results did show that the smart charging PHEVs can be very useful in correcting prediction errors of wind power.

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PUBLICATION VII

Methodology for modelling plug-in electric vehicles in the power system and cost estimates for a system with either *smart* or *dumb* electric vehicles

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Methodology for modelling plug-in electric vehicles in the power system and cost estimates for a system with either *smart* or *dumb* electric vehicles

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ABSTRACT

The article estimates the costs of plug-in electric vehicles (EVs) in a future power system as well as the benefits from smart charging and discharging EVs (smart EVs). To arrive in a good estimate, a generation planning model was used to create power plant portfolios, which were operated in a more detailed unit commitment and dispatch model. In both models the charging and discharging of EVs is optimised together with the rest of the power system. Neither the system cost nor the market price of electricity for EVs turned out to be high (36–263 €/vehicle/year in the analysed scenarios). Most of the benefits of smart EVs come from smart timing of charging although benefits are also accrued from provision of reserves and lower power plant portfolio cost. The benefits of smart EVs are 227 €/vehicle/year. This amount has to cover all expenses related to enabling smart EVs and need to be divided between different actors. Additional benefits could come from the avoidance of grid related costs of immediate charging, but these were not part of the analysis.

1. Introduction

Higher transport fuel prices due to oil scarcity and decreasing costs for plug-in electric vehicles (EVs) have the potential to roll-out EVs on a large scale. Large-scale introduction of EVs could bring major changes to the power system operations and to the power plant investments. This article attempts to explore the most important system-wide effects from both perspectives.

The charging of the vehicle batteries without any control is likely to result in a new peak in electricity demand during the late afternoon. The new peak could be avoided and the shape of electricity demand flattened with optimised timing of the battery charging, e.g. smart charging. Smart EVs could also bring other benefits to the power system by participating in ancillary services. In contrast, dumb EVs will start charging immediately after plugging in and would keep charging until their batteries are full. When comparing a power system to a hypothetical national car fleet consisting only of EVs, the vehicle fleet has much more power capacity than the power system. However, in most cases available capacity from EVs would be limited by household electrical wirings. These can usually handle much smaller power flows than the batteries could charge or discharge. Even when taking the limitations of EV grid connections into account, EVs potentially constitute a large resource of flexible demand suitable for providing up and down regulation and reserve power.

There have been several articles and reports about the possible benefits from the participation of EVs in the electricity markets. Articles [1–3] and dissertation [4] represent calculations of the possible benefits of using EVs and fuel cell vehicles as a new power source, in which the authors use power market prices as a reference. Several vehicle setups and electricity markets are analysed. In reports [5,6], a dispatch model is used to estimate the cost of charging plug-in hybrid EVs (PHEVs). The generation portfolio is taken from an external estimate and is not influenced by the introduction of the flexible demand from PHEVs. The PHEVs are dispatched according to a preset schedule, and no vehicle-to-grid (V2G) is considered. Article [7] considers the effect of EVs on future generation portfolios and uses a simplified model to dispatch EVs on top of the demand profile. V2G or the use of EVs as reserves was not considered. Report [8] estimated the effect of PHEVs on future generation portfolios and report [9] analysed how dispatch might be affected. Costs and benefits were not analysed. In article [10], the costs and benefits of the use of vehicle batteries for peak shaving were calculated. Article [11] simulated the effect of the electricity consumption from the EVs on the CO_2 emissions. The results were based on the assumption that the emissions of the marginal power plants would be allocated to EVs. Article [12] analyses the effect of smart EVs in integrating variable wind power.

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Nomenclature

Indices

g, G vehicle groups
n, N stochastic scenarios
t, T hourly time steps
tArr(t) hours when vehicles arrive to the grid
tLeave(t) hours when vehicles leave the grid
day, D days within the optimization

Endogenous variables

$S_{g,n,t}^{Grid}$ storage level in grid-connected batteries
$S_{g,n,t}^{Leav}$ storage level in batteries leaving the grid
$S_{g,n,t}^{Arr}$ storage level in batteries arriving to the grid
$E_{g,n,t}^{Charge}$ charging
$E_{g,n,t}^{ChargeDayAhead}$ day-ahead scheduled charging
$E_{g,n,t}^{ChargeUp}$ increase to the day-ahead scheduled charging
$E_{g,n,t}^{ChargeDown}$ decrease to the day-ahead scheduled charging
$E_{g,n,t}^{Discharge}$ discharging
$E_{g,n,t}^{DischargeDayAhead}$ day-ahead scheduled discharging
$E_{g,n,t}^{DischargeUp}$ increase to the day-ahead scheduled discharging
$E_{g,n,t}^{DischargeDown}$ decrease to the day-ahead scheduled discharging
$E_{g,n,t}^{Motor}$ production of grid electricity with a motor in a plug-in hybrid
$S_{g,n,tLeav}^{Add}$ stored electricity above the required minimum for a group of vehicles leaving the grid at tLeav
$R_{g,n,t}^{PosNonSpin}$ positive non-spinning reserve by discharging
$R_{g,day}^{PosSpin}$ positive spinning reserve by discharging
$R_{g,day}^{NegSpin}$ negative spinning reserve by means of discharging less than originally committed
$R_{g,day}^{NegSpinChrg}$ negative spinning reserve by promising to increase the charging
$R_{g,day}^{PosSpinChrg}$ positive spinning reserve by promising to reduce the charging
$R_{g,n,t}^{PosNonSpinChrg}$ positive non-spinning reserve by promising to reduce the charging

Parameters

C_g maximum charge capacity
D_g maximum discharge capacity
$v_{g,n,t}^{Arr}$ share of vehicles arriving to the grid
$v_{g,n,t}^{Leav}$ share of vehicles leaving the grid
$v_{g,n,t}^{Grid}$ share of grid-connected vehicles
$v_{g,n,t,tLeav}^{Arr}$ share of vehicles arriving to the grid at hour t, that have left the grid at hour tLeav
$s_{g,min}$ minimum amount of stored electricity a vehicle group must have when it leaves the grid
$s_{g,max}$ capacity of battery storage in a group of vehicles
$V_{g,n,t}^{ArrCons}$ consumption of electricity during the road trip
Eff efficiency of the charge/discharge processes

This article tries to improve earlier work by using a stochastic mixed-integer unit commitment and dispatch model in combination with a generation planning model. The unit commitment and dispatch model is named wind power integration in liberalised electricity markets (WILMAR) [13,14] and the generation planning model is named Balmorel [15,16]. Balmorel takes into account that as the demand curve changes, the investment patterns into power plants will also change. This in turn will influence the total cost of the power system. Furthermore, increased demand-side flexibility will make investments in base load or variable production more competitive against intermediate and peak production plants. Up and down regulation of power production due to load and wind power forecast errors take place in WILMAR. Hence, it can quantify the value of EVs providing the needed flexibility to cope with the partial predictability of load and wind.

For this article, an EV model was developed and incorporated in WILMAR. The methodology includes more detailed data and equations of the vehicle behaviour than in previous studies. Furthermore, the operational model can utilize the EVs for correcting prediction mistakes in demand and in variable generation as well as for reserve purposes.

The purpose of the scenario runs was to examine the impact of various assumptions about the behaviour of the EVs and their use in the power system. How often the capabilities of smart EVs are really used is up to the functioning of the power system, which is largely determined by the markets that operate around the system. Benefits are estimated by comparing the costs of a power system with smart EVs and forced dumb-charging EVs. In addition, when compared with a scenario not having EVs, the smart and dumb EV scenarios also give lower and upper estimates for the increased cost of the power system with EVs. Respective market prices and CO_2 emissions of the vehicles are derived from the results. We also examined how the use of some modelling methodologies would influence the results.

It is clear that the benefits of smart EVs will be system-dependent. In the analysis of the results, the causes of the benefits are displayed, and this should increase understanding concerning which situations the benefits might be larger or smaller in, even if only one system is analysed. If EVs become commonplace, there will be a need for more detailed studies focusing on a certain power system during a specific period.

In Kiviluoma and Meibom [17], the effect of increasing the quantity of EVs in the system was calculated. The main conclusion is that the system benefits per smart vehicle decrease substantially with an increasing number of EVs. This paper continues the analysis by examining the sources of the benefits when the EV penetration is high (about half of the active personal vehicle fleet). We have estimated the share of benefits from various ancillary services and from the use of the V2G. V2G could increase the benefits of smart EVs by enabling the EVs to discharge their batteries to the power grid at times when it is economic to do so.

The article is structured in the following manner. The WILMAR model is described first. Then the equations to handle EVs in WILMAR are presented. The derivation of the data for the behaviour of EVs is next. It is followed by a description of the scenarios. The scenarios depict a hypothetical power system in 2035 based on results from Balmorel and data from the Finnish power system. Next, the results from the scenarios are presented. Lastly, the methodology and the results are discussed.

2. Methodology

2.1. Model description

The WILMAR model has been enhanced with an EV model. WILMAR analyses electricity markets based on a description of generation, demand and transmission between model regions in hourly time resolution and derives electricity market prices from marginal system operation costs. The unit commitment decision is most correctly modelled using binary variables leading to a mixed integer programming (MIP) problem. A linear approximation – where the model is allowed to bring only parts of a power plant online – has also been implemented, due to calculation time considerations. The model treats wind power production and electricity demand as optional stochastic input parameters. The stochastic scenarios for wind power and load are generated, but they mimic the characteristics of real forecasts and forecast errors. WILMAR optimises unit commitment in a day-ahead market and corrects for emerging prediction errors in intraday market clearings. It also sets requirements for spinning[1] and non-spinning reserve[2] capacity. It is assumed that the latter will be influenced by the predicted wind power production in the year 2035. Production of district heating or process heat in combined heat and power (CHP) plants is included in this model, as CHP plants are important in the case of Finland. The model handles the use of hydropower reservoirs through water values, which are derived by an algorithm ensuring that the reservoir levels in the model follow historical reservoir levels during the year. A more detailed description of the model is given in Refs. [13,14].

For current analysis, we have assumed no transmission bottlenecks. However, transmission bottlenecks are common in many power systems and can have important impacts on the benefits of EVs.

2.2. Data for the behaviour of the EVs

EVs need to be grid-connected in order to be charged or discharged. Since the number of vehicles is very large, statistical behaviour is rather predictable, though individual drivers might behave erratically. We assumed that there are two possible places where the vehicles might be plugged in: at work and at home. Most people would be plugging in only at home; some would do it at both locations and only a few solely at work. The data used for estimating the leaving and arriving vehicles was derived from the National Travel Survey conducted during 2004–2005 in Finland [19]. It provided information on the timing and distance of travel with personal vehicles as well as data on the purpose of all travel. Available travel data was one of the reasons to model the Finnish energy system. The information was processed to estimate when people driving cars may arrive at their workplaces as well as at home, and what kind of distances they had travelled before that.

It was assumed that people plug-in once they arrive and that 98% do this at home and 20% at work. The data was used to derive typical daily driving patterns on an hourly time scale, and these were modified to take into account typical differences between weekdays, Fridays, Saturdays, Sundays, holidays and weekdays between a holiday and a weekend. A weekly index which held the changes in driving over the year was multiplied into the data. The index was calculated from the same National Travel Survey. Then assumptions about specific consumption of grid electricity (0.2 kWh/km)[3] and plugging in were overlaid on the data. Vehicles arriving during different hours of the day have, on average, different trip lengths behind them, and this was also taken into account.

All this lead to a couple of full-year input time series on an hourly time scale for the power system model:

- Share of vehicles plugged in. This affects the size of the usable electricity storage and the charging and discharging capacities. ($v^{\mathrm{Grid}}_{g,n,t}$)
- Share of vehicles leaving the grid. ($v^{\mathrm{Leav}}_{g,n,t}$)
- Share of vehicles arriving to the grid and plugging in ($v^{\mathrm{Arr}}_{g,n,t}$)
- Arriving vehicles have partially empty batteries due to the consumption during driving. ($V^{\mathrm{ArrCons}}_{g,n,t}$)
- A link between vehicles leaving at certain hours and arriving at a later hour was established. A rather complex model was developed to create realistic schedules from the available data while ensuring consistency between the number of arriving and leaving vehicles. The model is not yet documented. ($\sum_{tLeav=t_0\ldots t_{current-1}} S^{\mathrm{Add}}_{g,n,tLeav}\cdot v^{\mathrm{Arr}}_{g,n,t,tLeav}$)

Recharging is usually limited by the capacity of electric wiring or charger. Batteries could usually take more amperes, though many battery types can prolong their lifetime with slower charging. For PHEVs, charging capacity was set to an average of 4 kW per vehicle, and for full EVs (FEVs) that use only electricity (also known as battery EVs) it is 6 kW[4]. Average consumption of grid electricity was 0.2 kWh/km. The assumed usable size was 40 kWh for EV batteries to achieve a 200 km range and 20 kWh for PHEV batteries to achieve a 100 km all electric range[5]. On average, a vehicle makes three trips per day at a combined distance of 52 km and has a charge opportunity every 39 km. All the EV scenarios had one million EVs: a yearly consumption of half a million of FEVs amounted to 2.16 TWh, and the same for half a million PHEVs was 1.83 TWh.

2.3. The EV model

The model for EVs treats the vehicles as electricity storages which are not always connected to the power grid and, while gone, spend some of their stored electricity. An important part of the model is the data for the share of vehicles arriving and leaving the network, which is described later.

Each vehicle type has its own general electricity storage pool in each model region. It would naturally be more correct to have separate storage for each vehicle, but the problem would not be possible to solve with thousands of vehicles, and some simplification has to be made. Restrictions were applied to keep the influence of aggregation small (Eqs. (12), (13) and (16)). Similarly, aggregation of storages is common in modelling reservoir hydropower.

When a vehicle leaves the network, it takes electricity from the storage pool and when it arrives in the network, it releases what is left to the pool (Eq. (1)).

$$S^{\mathrm{Grid}}_{g,n,t} = S^{\mathrm{Grid}}_{g,n,t-1} - S^{\mathrm{Leav}}_{g,n,t} + E^{\mathrm{Charge}}_{g,n,t}\cdot \mathrm{Eff}_g - \frac{E^{\mathrm{Discharge}}_{g,n,t}}{\mathrm{Eff}_g} + S^{\mathrm{Arr}}_{g,n,t} \quad \forall\ g\in G, n\in N, t\in T \tag{1}$$

[1] Spinning reserves in these model runs refers to the frequency controlled reserves (both normal operation and disturbance) that have been allocated to Finland by Entso-E Nordic [18].

[2] Non-spinning reserve or replacement reserve is the fast active disturbance reserve allocated to Finland by Entso-E Nordic [18]. They need to be available within 15 min.

[3] The estimate is somewhat high in comparison to the estimates quoted for the near-term EVs. However, the near-term EVs are usually small in comparison to average vehicle size and therefore not representative of the consumption in an average vehicle. It should also be noted that WILMAR requires the consumption of grid electricity and the estimate has to include charging and network losses. Rousseau et al. [20] provides estimates for pre-transmission energy consumption for midsize car, cross-over sub-urban vehicle (SUV) and midsize SUV and our estimate is in comparable range.

[4] It was assumed that it will be more beneficial for FEV users to install three-phase plugs, since they cannot rely on fuel if the batteries are not charged fast enough. One-phase 220 V connection with either 10 A or 16 A could provide 2.2 kW or 3.5 kW while a three-phase plug with 25 A could provide 10 kW.

[5] The ranges are higher than what are expected for the first series production EVs, but the analysis is made for 2035 and by that time batteries could be cheap enough to justify the higher range. PHEV prototype vehicle ranges are quoted in Bradley and Frank [21]. For EVs the average range will be very dependant on the highly uncertain battery cost as demonstrated by Kromer and Heywood [22].

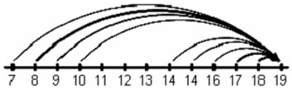

Fig. 1. Simplified example pattern of electric vehicles arriving at the power grid at 19.00 h. The thicker the line, the greater the share of vehicles which return to the network at that time.

Charging and discharging are divided into parts (Eqs. (2) and (3)). $E^{ChargeDayAhead}$ is determined during the clearing of the day-ahead spot market. $E^{ChargeUp}$ and $E^{ChargeDown}$ can modify this during the intraday solves, taking updated wind power production and demand forecasts into account.

$$E^{Charge}_{g,n,t} = E^{ChargeDayAhead}_{g,n,t} + E^{ChargeUp}_{g,n,t} - E^{ChargeDown}_{g,n,t} \quad \forall\ g \in G, n \in N, t \in T \tag{2}$$

$$E^{Discharge}_{g,n,t} = E^{DischargeDayAhead}_{g,n,t} + E^{DischargeUp}_{g,n,t} - E^{DischargeDown}_{g,n,t} \quad \forall\ g \in G, n \in N, t \in T \tag{3}$$

The model includes a relation between the vehicle departure and arrival times. In Fig. 1 there is an example pattern of EVs that arrive at 7 pm in the network. Some of them had left in the morning and some of them during the afternoon. This influences the calculated consumption of electricity during the trip, since the distribution of trip lengths varies throughout the day. Furthermore, there can be system benefits if the batteries do not need to be completely full upon departure. Eq. (4) enables this option. The arriving storage content S^{Arr} is a sum of the electricity EVs took with them deducted by the consumption of electricity on the road. If EVs had to have full batteries on departure, the minimum level would be the same as the maximum, and variable s^{Add} would not be used. In the event that EVs are not required to leave with a full battery, the variable s^{Add} will hold the additional electricity above the minimum level required (Eq. (4)).

$$S^{Arr}_{g,n,t} = v^{Arr}_{g,n,t} \cdot s_{g,min} + \sum_{tLeav = t_0 \ldots t_{current-1}} S^{Add}_{g,n,tLeav} \cdot v^{Arr}_{g,n,t,tLeav} - V^{ArrCons}_{g,n,t} \quad \forall\ g \in G, n \in N, t \in T \tag{4}$$

Eqs. (5) and (6) set a minimum level for the leaving battery and a variable additional charge for the model to optimise. Partially full batteries can provide additional flexibility for the power system and be economic in situations where electricity prices have been exceptionally high during the previous charge opportunity. Partially full departing batteries can be realistic in situations where a person either owns a PHEV or normally drives short daily distances by means of an EV that has a long range. The equations mean that all the vehicles of same type join one electricity storage pool upon arrival.

$$S^{Leav}_{g,n,t} = v^{Leav}_{g,n,t} \cdot s_{g,min} + \sum_{tArr \text{ iff } tLeav = t} s^{Add}_{g,n,tLeav,tArr} \quad \forall\ g \in G; n \in N; t, tArr, tLeav \in T \tag{5}$$

$$s^{Add}_{g,n,t} \le s_{g,max} - s_{g,min} \quad \forall\ g \in G, n \in N, t \in T \tag{6}$$

In the model, EVs are assumed to leave the network at the start of the hour. Therefore, batteries need to be charged during the previous hour. In real life, EVs leave all the time during the hour. This creates a small buffer, so that on average an EV has to be charged 30 min before it is actually used.

The minimum storage content is restricted by the use of reserves. There has to be enough electricity in the batteries to be able to produce for a while, if there is a need to use the committed reserves (Eq. (7)).

$$S^{Grid}_{g,n,t} \ge R^{PosNonSpin}_{g,n,t} + R^{PosSpin}_{g,day} \quad \forall\ g \in G, n \in N, t \in T, day \in D \tag{7}$$

A set of equations restricting the abilities to charge/discharge and provide reserves according to available capacities are also required. The WILMAR model already incorporates electric storage and many of the equations used there also apply to EVs (Fig. 2).

Eq. (8) limits the sum of actual charging and negative spinning reserve that is based on increasing the charging of the vehicles. The limit is the charging capacity of the vehicles plugged-in during each hour.

$$E^{Charge}_{g,n,t} + R^{NegSpinChrg}_{g,day} \le C_g \cdot v^{Grid}_{g,n,t} \quad \forall\ g \in G, n \in N, t \in T, day \in D \tag{8}$$

Eq. (9) restricts the sum of positive reserves that are available from decreased charging. This has to be lower than the actual charging of the vehicles.

$$R^{PosNonSpinChrg}_{g,n,t} + R^{PosSpinChrg}_{g,day} \le E^{Charge}_{g,n,t} \quad \forall\ g \in G, n \in N, t \in T, day \in D \tag{9}$$

In Eq. (10), the positive reserve from increased discharging of the vehicles has to be lower than the capacity of the vehicles to discharge, minus the current level of discharge.

$$R^{PosNonSpin}_{g,n,t} + R^{PosSpin}_{g,day} \le D_g \cdot v^{Grid}_{g,n,t} - E^{Discharge}_{g,n,t} \quad \forall\ g \in G, n \in N, t \in T, day \in D \tag{10}$$

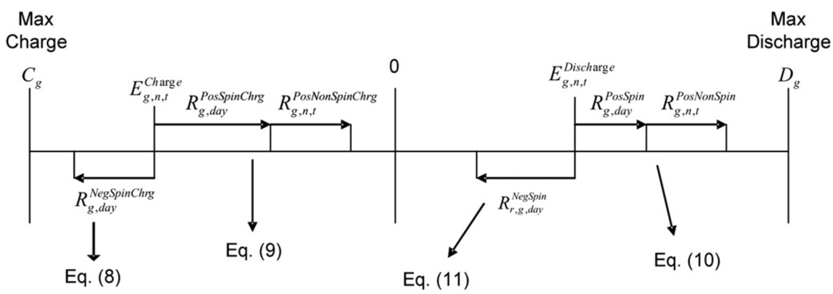

Fig. 2. Equations in WILMAR to limit the use of reserves based on electricity storages like EVs.

Negative spinning reserve from discharging requires that the discharging is decreased and this reserve should therefore be restricted to the level of discharging (Eq. (11)).

$$R^{\mathrm{NegSpin}}_{\mathrm{g,day}} \le E^{\mathrm{Discharge}}_{\mathrm{g,n,t}} \quad \forall \ \mathrm{g}\in \mathrm{G}, \mathrm{n}\in \mathrm{N}, \mathrm{t}\in \mathrm{T}, \mathrm{day}\in \mathrm{D} \tag{11}$$

These equations are designed for single large storage. However, the storage from EVs is formed from a large number of separate small storages. This will pose additional limitations to the use of the capacity from the storages. Individual vehicle storages do not fill up all at once – as single large storage would do. When the total storage level is for example 80% full, half of the vehicles might already have completely full storage, since the vehicles try to fill their batteries during the lowest prices. These vehicles cannot provide reserves that are based on increased charging. Therefore, a new Eq. (12) was introduced as shown by Fig. 3. There was no data available to estimate the form of the function. However, since it is apparent that more and more vehicles will have full batteries when the single large storage approaches full, a value for '*a*' and '*b*' in Eq. (12) had to be estimated. Both '*a*' and '*b*' were set to 1.6 for the scenarios presented in the results. By doing this we have assumed that after the single large storage is 38.5% full, the share of full vehicle batteries will start to linearly approach 100% and charging capacity will decrease accordingly. Similarly, discharging should be restricted, and this is presented in Eq. (13). When the model was used, Eq. (12) was often binding, while Eq. (13) was not.

$$E^{\mathrm{Charge}}_{\mathrm{g,n,t}} + R^{\mathrm{NegSpinChrg}}_{\mathrm{g,day}} \le C_{\mathrm{g}} \times \left[-a \cdot S^{\mathrm{Grid}}_{\mathrm{g,n,t}} \Big/ \left(v^{\mathrm{Grid}}_{\mathrm{g,n,t}} s_{\mathrm{g,max}} \right) + b \right] \quad \forall \ \mathrm{g}\in \mathrm{G}, \mathrm{n}\in \mathrm{N}, \mathrm{t}\in \mathrm{T}, \mathrm{day}\in \mathrm{D} \tag{12}$$

$$E^{\mathrm{Discharge}}_{\mathrm{g,n,t}} + R^{\mathrm{PosNonSpin}}_{\mathrm{g,n,t}} + R^{\mathrm{PosSpin}}_{\mathrm{g,day}} \le D_{\mathrm{g}} \times \left[\frac{a \cdot S^{\mathrm{Grid}}_{\mathrm{g,n,t}}}{v^{\mathrm{Grid}}_{\mathrm{g,n,t}} \cdot s_{\mathrm{g,max}}} \right] \quad \forall \ \mathrm{g}\in \mathrm{G}, \mathrm{n}\in \mathrm{N}, \mathrm{t}\in \mathrm{T}, \mathrm{day}\in \mathrm{D} \tag{13}$$

The model can handle both FEVs and PHEVs. In the data set, PHEVs have lower average consumption of electricity during road trips, since it is assumed that some part of the total mileage is done with the energy from the engine. This was calculated from the trip lengths in the vehicle travel data. Some share of PHEVs can also run their engine to produce power or ancillary services for the grid while being plugged in (Eq. (14)).

$$E^{\mathrm{Motor}}_{\mathrm{g,n,t}} + E^{\mathrm{Discharge}}_{\mathrm{g,n,t}} + R^{\mathrm{PosNonSpin}}_{\mathrm{g,n,t}} + R^{\mathrm{PosSpin}}_{\mathrm{g,day}} \le v^{\mathrm{Grid}}_{\mathrm{g,n,t}} \cdot D_{\mathrm{g}} \quad \forall \ \mathrm{g}\in \mathrm{G}, \mathrm{n}\in \mathrm{N}, \mathrm{t}\in \mathrm{T}, \mathrm{day}\in \mathrm{D} \tag{14}$$

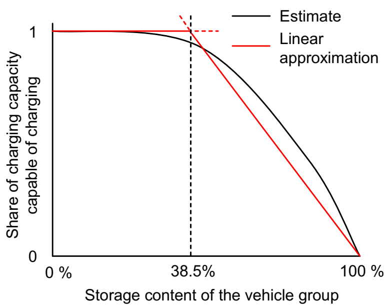

Fig. 3. Principle to limit the use of the aggregated battery storage when some of the batteries are full. Eqs. (9) and (13) constrain the charging and usage of increased charging to provide reserves to be below the red line in the figure. Realistic estimates were not available, which meant that an educated guess was made for this article. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article).

Possible charge of the batteries should not exceed the capacity of the batteries (Eq. (15)). It is assumed that the maximum length for the actual use of reserves is one hour. In Eq. (16), individual vehicles are restricted from charging and discharging at the same time.

$$S^{\mathrm{Grid}}_{\mathrm{g,n,t}} + R^{\mathrm{NegSpin}}_{\mathrm{g,day}} \le S^{\mathrm{Grid}}_{\mathrm{g,max}} \quad \forall \ \mathrm{g}\in \mathrm{G}, \mathrm{n}\in \mathrm{N}, \mathrm{t}\in \mathrm{T}, \mathrm{day}\in \mathrm{D} \tag{15}$$

$$E^{\mathrm{Chrg}}_{\mathrm{g,n,t}} \cdot \frac{D_{\mathrm{g}}}{C_{\mathrm{g}}} + E^{\mathrm{Dischrg}}_{\mathrm{g,n,t}} \le D_{\mathrm{g}} \cdot v^{\mathrm{Grid}}_{\mathrm{g,n,t}} \quad \forall \ \mathrm{g}\in \mathrm{G}, \mathrm{n}\in \mathrm{N}, \mathrm{t}\in \mathrm{T} \tag{16}$$

In addition to these specific restrictions, the charging and discharging of EVs determined a day ahead are included in the day-ahead electricity balance equation and likewise with the up or down regulation of charging or discharging being included in the intraday electricity balance equations.

2.4. Scenarios

The purpose of the scenario runs was to examine the impact of various assumptions about the behaviour of the EVs and their use in the power system. By comparing different scenario runs the benefits due to smart charging could be split into benefits due to a) the ability to provide spinning reserves, b) providing non-spinning reserves and intraday flexibility by up and down regulation of charging and discharging schedules determined day-ahead, and c) being able to make an optimal day-ahead schedule for the charging and discharging. We also examined how use of the deterministic model influences the results. So far, only deterministic models have been used to study EVs, and this could have been a major weakness in the studies. WILMAR can be run in deterministic or stochastic mode. Stochastic mode takes the uncertainty in wind power production and in electricity demand into account. Stochastic forecasts are updated every 3 h and the power system is re-dispatched according to the new information. The influence of the modelling of unit commitment was also studied by comparing MIP model runs vs. linear programming (LP) model runs.

The analysis is performed on the power system of Finland. The Finnish system gets about 10% of its production from hydropower, with most of it being controllable. Finland is a northern country where heating is required during the winter. The country has many combined heat and power units for district heating. The model includes three heating areas for Finland, all of which have to fulfil their heating requirements separately. Large portion of the power plants were retired by the study year of 2035. Notable exceptions are 2440 MW of nuclear capacity, 1310 $\mathrm{MW_{el}}$ of natural gas capacity, all the hydropower plants and 2030 $\mathrm{MW_{el}}$ of industrial back pressure power plants using wood waste from industrial processes.

Scenarios were compared against the base scenario. The base scenario uses the power plant portfolio from Balmorel smart EV scenario, which is described in article [23]. The base scenario was run with MIP in stochastic mode. In the base scenario, departing EVs had to have full batteries and they were charged and discharged in optimal manner from the system perspective. Grid-connected EVs were able to provide reserves for the power system and all of them were capable of V2G. In addition, 10% of PHEVs were capable of E2G (engine-to-grid). Other scenario runs had some deviation from this basic setting as shown in Table 1 and described in the Results section. Dumb EVs start charging when they are plugged in, stop charging once they are full, and they cannot provide reserves. In addition, a scenario without EVs was run for both stochastic and deterministic model versions (not included in Table 1).

Table 1
Model properties in use in different WILMAR scenarios.

Scenario	Stochastic	Spinning	Intraday	Smart	Leaving full	MIP
Base	×	×	×	×	×	×
Det.		×	×	×	×	×
Add	×	×	×	×		×
No spinning	×		×	×	×	×
No flexibility	×			×	×	×
No V2G	×	×	×	×	×	×
V2G PHEV only	×	×	×	×	×	×
V2G PHEV + No E2G in PHEVs	×	×	×	×	×	×
LP	×	×	×	×	×	
LP Det.		×	×	×	×	
LP dumb	×				×	
LP Det. & dumb					×	
Dumb	×				×	×
Det. & dumb					×	×

Stochastic = model solved in stochastic or in deterministic mode.
Spinning = participation of EVs in the spinning reserve.
Intraday = participation of EVs in the intraday market to correct forecast errors.
Smart = smart or dumb EVs.
Leaving full = all EVs required to have full battery when leaving the grid.
MIP = model solved in MIP or in LP mode.

EVs capable of V2G can discharge their batteries to the grid, but there has to be an economic incentive for this to happen. In the modelling context, it was assumed that the cost of wear and tear on the batteries for the extra use is 10 €/MWh, and the roundtrip efficiency is 85% (same efficiency as in Peterson et al. [10]). There has to be a corresponding difference in power price fluctuations before the use of V2G for peak levelling is economical. Another use of V2G is the provision of the ancillary services. EVs with V2G could be especially useful as disturbance reserves[6] since these are rarely actually used, but the capacity has to be online. It was assumed that it does not cost anything extra to have the capacity online when the vehicles are plugged in. Therefore, more expensive sources of reserve capacity were replaced by the EVs.

In power markets, new electricity consumption will raise the prices in the electricity markets – all other things being equal. This in turn will attract new investments in power generation. New investments are also influenced by the retirement of old power plants and by policy. EVs will increase the electricity consumption and change the profile of the consumption. Four different situations are therefore analysed in terms of generation investments: no EVs, dumb EVs, smart EVs, and smart EVs without a capacity adequacy contribution. All of these will have induced a somewhat different power plant portfolio given enough time. The analysis tries to capture this by using a generation planning model (Balmorel) to estimate the different power plant portfolios. Two of the portfolio scenarios (no EVs and smart EVs) are borrowed from another article [23] and the details of the model assumptions and portfolios can be seen there.

In the smart EVs scenario of Balmorel, the EVs were considered to contribute to the power system capacity adequacy with 500 MW. The low electricity storage capacity of the EVs will limit the length of the production period and they cannot be trusted to provide energy for prolonged periods. For the smart EV scenarios in Balmorel, it was assumed that 1 h of non-spinning reserves could be maintained at the 500 MW level. In terms of capacity only, a V2G share of about 20% could provide 500 MW from the plugged-in vehicles during the highest net load hours. This 500 MW decreases the need for additional power plant capacity in the generation planning model. For comparison 500 MW of open cycle gas turbine (OCGT) would have an annuity of 16.3 M€/year in the model runs. In principle, the capacity effect could be assumed higher, if more EVs had V2G. In the WILMAR runs, it was possible to require the EVs to have enough stored electricity to provide the reserve for at least an hour (Eq. (7)).

Table 2 shows the differences in the power plant portfolios created by the Balmorel runs. The smart EVs reduce the need for power plant capacity through the timing of the charging as compared to their dumb-charging counterparts, since the dumb EVs create a new peak in the net load. The difference in the peak demand was 544 MW (in the WILMAR scenarios). The flexibility of smart EVs induced a larger proportion of variable wind power production, whereas inflexible dumb EVs leaned more on adjustable conventional power plants.

3. Results

WILMAR analyses only operational costs and does not include investment costs. These are estimated from the aforementioned Balmorel runs. The investment costs for new power plants required by the year under study, 2035, were 2.29 billion € in the scenario with smart EVs (Table 3). This was 91 M€ more than the investment costs in the scenario without EVs. This indicates that in the longer term, EVs attract more costly power plant investments, which in turn decrease the operational costs of the system. The overall result is lower average cost of electricity. In contrast, dumb EVs will increase the average cost of electricity.

There are differences between the two model setups, and the differences in costs and benefits are therefore only indicative. As expected, the more detailed WILMAR reveals costs that the Balmorel was unable to capture. With the smart EVs, these hidden costs are smaller, even though there is a higher share of variable wind power production in the smart EVs scenario. The smart EVs help the system to operate in a more efficient manner.

The difference between no EVs and dumb EVs gives the cost of electricity to provide necessary energy for the EV fleet. The difference between smart and dumb EVs gives the benefit of allowing the vehicle charging and discharging to be controlled in accordance with the market conditions. This benefit has to be shared between the vehicle owners and an entity that controls the charging in keeping with the market conditions and the needs of vehicle owners. This article does not consider how the benefit is shared; it only tries to estimate the magnitude of the benefit in different conditions. PHEVs will have additional costs due to fuel use when using the engine. As the PHEV fuel usage does not change, these costs were not considered.

For the rest of the article, the annual benefit of smart EVs compared with dumb EVs is used as a metric. The operational model (WILMAR) is used to estimate the operational costs and the costs for annualized power plant investments and fixed costs are taken from the difference between the generation planning model

Table 2
Capacity of new power plants in the different Balmorel scenarios.

Power plant type	MW of electricity			
	No EVs	Dumb	Smart	No 500
NatGas comb. cycle cond.	363	520	16	16
NatGas comb. cycle CHP	3	0	0	0
NatGas open cycle cond.	2861	3580	2519	3024
Nuclear	5312	5688	5312	5312
Wind	4705	5130	6122	6122
Forest residue CHP	1203	1206	1196	1192
Wood waste CHP	76	73	73	75

[6] Also known as contingency reserves or automatic frequency control reserves, which activate automatically following a fault in the system, if the system frequency drops below a certain threshold.

Table 3
Annualized system costs of the power system in various scenarios by using a generation planning model (Balmorel) and an operational model (WILMAR). The cost (€/MWh) is the total cost divided by the annual electricity consumption, which includes the new consumption from EVs.

	Balmorel no EVs	WILMAR no EVs	Balmorel dumb EVs	WILMAR dumb EVs	Balmorel smart EVs	WILMAR smart EVs
Investm. (M€/year)	2203	←	2370	←	2294	←
Fixed (M€/year)	485	←	528	←	501	←
Variable (M€/year)	1955	1976	2011	2034	1930	1900
Hydro (M€/year)	–	47	–	44	-	53
Total (M€/year)	4644	4713	4909	4976	4725	4749
Diff (M€/year)	68		67		24	
Cost (€/MWh)	41.1	41.8	41.9	42.7	40.4	40.7

The cost of hydropower in the WILMAR scenarios refers to the difference in the year-end hydro reservoir level compared to Balmorel runs, where this was fixed.

runs (Balmorel). The annualized investment costs and the fixed costs for the smart EVs scenario were 102 M€/year less expensive than in the dumb EVs scenario. As there are one million EVs in the scenarios, this means 102 €/vehicle/year. The investment and fixed costs for the smart EVs scenario were 106 M€/year more expensive than the scenario without EVs. These costs are included in the numbers presented later in this article.

3.1. Effect of modelling features on the calculated benefit from EVs

Since we analysed the operational costs of the power system with a stochastic unit commitment and dispatch model (WILMAR), we were able to compare the calculated benefits of the deterministic and stochastic modes (Fig. 4). In the stochastic mode, both wind power production and electricity demand have a probabilistic tree with 10 branches. The model has to optimise the unit commitment and dispatch with this uncertainty taken into account. In the deterministic mode, the model had a forecast error based on the average forecast from the stochastic scenarios.

In the stochastic mode, the model sees a distribution of possible outcomes and this additional information should help the model to make better unit commitment decisions, which will, on average, turn out to be more economic than in the deterministic mode. The stochastic mode reduced operational costs in no EVs, smart EVs and dumb EVs scenarios by 0.26%, 0.76%, and 0.35% respectively compared to deterministic results. This should be significant since 0.1% is more than 2 M€.

MIP and LP solutions were also compared. The assumption was that the MIP solution would increase the calculated benefit. Both models have a start-up cost, but in the LP model, it is possible to start up a fraction of a unit due to the linear simplification (described in Ref. [13]). In the MIP model unit has to start fully and this will be more costly than partial start-ups (MIP model is described in Ref. [14]). In the LP model, unit can reach full efficiency even if it is only partially started and this too increases the cost difference. Furthermore, in the MIP model, units operate more at partial load in order to avoid start-ups. These factors should increase the costs of the MIP model compared to the LP model. Smart EVs were able to keep the cost increase smaller and the system benefit of smart EVs over dumb EVs was about 2% larger in the stochastic MIP solution compared to the stochastic LP solution.

The difference between stochastic MIP and LP solutions is surprisingly small. Furthermore, there was no visible difference in the deterministic runs. The explanation is that there was a large number of small units (mainly open cycle gas turbines) as well as flexible hydropower. Even in the MIP mode, these provide a very economic combination to meet the changes in the net load. There is a small difference in the absolute cost when starting up a small unit fully or partially. This means that the difference between MIP and LP results could be considerably higher in a system with less flexible units.

The results from the Balmorel runs are rather different. The main reason is that units are simplified and more aggregated compared to the WILMAR runs. The benefits of smart EVs are smaller in Balmorel runs, since the units do not have minimum operation limits or part-load efficiencies, which create additional costs that the smart EVs could reduce.

3.2. Sources of benefits from smart EVs

Smart EVs can help the system in various ways (Fig. 5). The system benefit of smart EVs compared to dumb EVs was 227 €/vehicle/year in the studied system. Part of the benefits come from less expensive operations and part comes from smaller investment and fixed costs. To see the benefit of EVs in the spinning reserves, the base scenario was compared with a scenario where the EVs were not able to provide spinning reserves ('No Spinning'). The provision of spinning reserves benefitted 38 €/vehicle/year (17%). The model calculates only the reservation of the capacity and

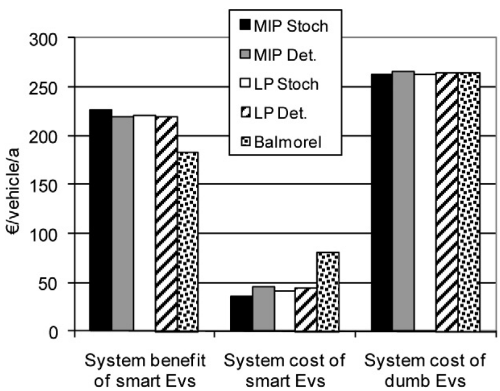

Fig. 4. The influence of various modelling methods on the simulated costs of the EVs. System cost of smart and dumb EVs is the additional total cost of the energy system compared to a situation without EVs. System benefit of smart EVs is the difference between the system cost of dumb EVs and the system cost of smart EVs.

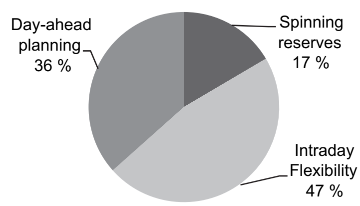

Fig. 5. The division of the benefit from smart EVs over dumb EVs between different components. The total benefit was 227 €/vehicle/year.

not the actual use. Intraday flexibility means that the EVs were allowed to correct the forecast errors in wind and load by up and down regulation of the charging and discharging schedules determined day-ahead. The benefit of intraday flexibility (47%) was calculated by comparing a scenario where the EVs were not flexible in the intraday (‘no flexibility’) with the scenario ‘no spinning’. The ‘no flexibility’ WILMAR scenario used a power plant portfolio based on the Balmorel scenario where the EVs did not contribute to the power system capacity adequacy as reserves (scenario “no 500” in Table 2), because they are not able to provide non-spinning reserve without intraday flexibility. Day-ahead planning benefits (36%) are due to the more economic charging/discharging pattern decided day-ahead before the intraday adjustments. This was calculated by comparing the ‘dumb’ scenario with the ‘no flexibility’ scenario.

The model does not analyse intra hour load following or regulation, and possible benefits from these are missing from the analysis. Grid reinforcements were not taken into account, either. Due to the availability of flexible hydropower and OCGTs (open cycle gas turbines) the model was able to reserve the capacity for non-spinning reserves without extra cost at all times, and therefore EVs did not create cost savings for the provision of non-spinning reserves.

3.3. Benefits of vehicle-to-grid

The benefits of the V2G mostly derive from the provision of the reserves. Furthermore, most of the benefits can be achieved by having only a portion of the EV vehicle fleet capable of V2G (Table 4). This suggests that it does not make sense to equip all EVs with the V2G, because V2G capability will incur extra costs in the vehicles and in the grid connection. With E2G, 10% of the PHEVs (5% of all EVs) were assumed to have E2G. For most vehicles it is not possible to let the grid-connected car engines start by themselves when the power grid could use the power or the capacity. All the V2G scenarios were run with the same power plant portfolio based on the ‘smart’ Balmorel scenario. Balmorel was able to use the V2G, but not the E2G. The cost of the ‘no V2G’ scenario in the Table 4 should be lower, if the power plant portfolio was separately optimised for smart EVs without V2G.

In the ‘battery not full’ scenario of Table 4, V2G was fully allowed, but the EVs were not required to have completely full batteries when leaving the grid. FEVs had to have at least 80% full batteries and PHEVs at least 50% full batteries. The supposed benefit of this additional flexibility was lost within modelling inaccuracies.

3.4. Market prices

The analysis so far has concentrated on the system costs, which means that all the costs of running the system have been summed up. Another perspective is to look at the prices at the electricity markets (day-ahead and short-term markets). This reflects what the EV owners will have to pay for their electricity consumption. The costs here are based on the marginal cost of the model. If the market functioned perfectly and the cost assumptions were correct, the marginal cost should be the same as the market price. In reality, market prices are very likely to be at least somewhat higher. Furthermore, market prices are very sensitive to the actual capacity balance in the system. When there is a shortage of capacity, power plants with very high marginal costs need to be used more and the average market price can be much higher than if plenty of spare capacity existed.

In these model runs, the capacity balance is tight, since the generation planning model has invested in just enough capacity to cover for the worst situation plus some reserve margin. In reality, there could be too much or too little capacity due to investment uncertainty in combination with long building times.

Fig. 6 shows the results concerning market prices. The cost to buy electricity for smart EVs from the electricity markets was 157 €/vehicle/year. This takes into account the purchase of electricity for charging the battery as well as the sale of electricity by discharging or engine power. It does not take into account the sale of spare capacity as spinning reserve. If the shadow price of the equation requiring enough spinning reserves is taken as the market price for spinning reserves, then the sales would yield 1.7 €/vehicle/year.

In the operational phase simulated by the WILMAR runs, there were couple of hours where there was not enough available production capacity in the day-ahead spot market. This resulted in the use of dummy variables at a very high marginal cost. Since the values were unrealistic, a price ceiling of 400 €/MWh was used instead.

The average intraday market price in the WILMAR model with smart EVs and without EVs was almost the same (41.61 €/MWh vs. 41.62 €/MWh). This is despite the rather different power plant structure (Table 2). For comparison the average system cost of electricity was correspondingly 40.7 €/MWh and 41.8 €/MWh.

3.5. CO_2 emissions

There has been considerable interest in the future CO_2 emissions from the EVs. For conventional vehicles it is relatively straightforward to calculate the emissions from the use of the vehicles. It is not so with the EVs. The authors believe it would be misleading to assess marginal emissions in a long-term study, since emissions due to EV electricity consumption should not be more marginal than any other electricity consumption in the long term. It would be more appropriate to use average emissions. Based on the scenario results, the average emissions in 2035 were 29.2 $kgCO_2$/MWh in the dumb EVs scenario and 26.0 $kgCO_2$/MWh in the smart EVs scenario. This would result in CO_2 emissions of 104–117 $kgCO_2$/vehicle/year for FEVs. PHEVs would have larger emissions, since they will also use fuel when driving. In comparison, a future hybrid vehicle with specific emissions of 90 gCO_2/km and annual driving distance of

Table 4
Cost of scenarios compared to the base scenario, in which V2G was fully allowed.

Scenario	Cost over base (€/vehicle/year)
No V2G	53
V2G half of the vehicles	6.7
V2G half, no E2G	8.0
Battery not full	0.4

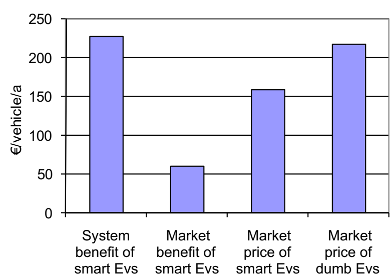

Fig. 6. Market benefits and prices of smart and dumb EVs. Market price of smart and dumb EVs is the sum of hourly market prices for charging the EVs in these scenarios. This includes revenue from discharging in the smart EVs scenario. Market benefit of smart EVs is the difference between the dumb and smart scenarios.

20,000 km would cause emissions of 1800 $kgCO_2$/vehicle/year. The large difference between FEVs and regular hybrids is due to the very low carbon intensity of electricity production in the model scenarios. This was a result of the CO_2 price, which caused minimal investments in power generation with CO_2 emissions.

However, there is another relevant approach. It is a comparison between the scenario where there was no EVs and the scenarios where there are EVs. The changes in the emissions of the whole power system can be seen as a consequence of the introduction of the EVs. In the case of dumb EVs, this change was $+169$ $kgCO_2$/vehicle/year. In the case of smart EVs, the change would be -211 $kgCO_2$/vehicle/year. The smart EVs would make the power system emit less CO_2 by enabling a higher share of CO_2 free production (wind and nuclear).

4. Discussion

The cost estimates would change from power system to power system. The analysed system had about 3000 MWs of reservoir hydropower with an electricity production share of about 8%. Flexible hydropower and smart EVs compete by providing similar services to the system. If there was less flexibility from the hydropower, smart charging would be more beneficial than it was. Benefits could be higher also if the system had grid bottlenecks, as these often limit the efficient dispatch of power plants. Smart EVs could bring local flexibility and therefore ease bottleneck situations. On the other hand, conventional power plants built in the future could be more flexible to operate than current power plants – especially when the growing share of variable generation (e.g. wind power) increases the need for economic cycling. This would decrease the benefits of smart EVs. The benefit would also change, if the capacity balance was different. If the capacity balance was less tight, changing the charging time of EVs would in many situations move production from intermediate power plants to base load power plants instead of peak power plants to intermediate power plants. This would yield less cost savings.

The changes in the system costs are different from the changes in the market prices, because system costs just sum the total costs whereas market prices take into account how the costs and benefits are shared between the market participants. The prices in the electricity market provide the reference price for the agents selling power to EV owners. The smart EVs will buy electricity at a different price than the dumb EVs due to the different time of charging. The smart vehicles can also benefit from the sale of electricity, if they have V2G. While the results provide an estimate how the market prices would affect EVs, market prices have a very large uncertainty. Nevertheless, the estimated cost difference between smart and dumb EVs was about 59 €/vehicle/year. This should cover for the expenses of the smart charging system. The remainder has to be divided between the vehicle owner and the entity acting between the vehicle owner and the wholesale power markets. Then the question becomes: for how many vehicle owners is the benefit large enough to compensate for any inconvenience caused by the postponed charging as well as the battery degradation in case of discharging? The size of the compensation appears to be such that not all vehicle owners will sign in. However, this means a larger piece of the cake for those who do participate in smart charging.

In the current model, all vehicles of the same type joined one single pool of electricity storage. An improved solution would be to have a separate pool for each hour of leaving vehicles. All vehicles arriving during certain hour should be divided into the hourly pools of leaving vehicles based on the patterns of driving behaviour. This would restrict the model from creating electricity transfers that would not necessarily be possible in the real world. This is to be implemented, but is not present in results of the article.

As usual, future fuel costs and investment costs of the power plants would also influence the results. The transmission links to other systems are also very relevant and variable from system to system. The analysis of all relevant sensitivities and uncertainties would require a very large number of burdensome model runs. Those should be done only when all the relevant characteristics of the EVs and the energy system are factored into the models. The improvements to the modelling presented here are a step closer, but more remains to be done. There is a need to increase the accuracy of the driver behaviour and account for the grid improvement costs as well as intra hour balancing benefits.

5. Conclusions

The analysis has estimated two extremes of EV charging intelligence and how these might influence the total costs of an optimised future power system. The methodology employed brings rigour to the way the costs should be estimated. The results of the article demonstrate that it is not enough to assess operational costs – also impacts of the new consumption patterns in the development of the long-term power plant portfolio should be taken into account. In the estimation of operational costs, stochastic model with binary unit commitment decisions was used to achieve more accurate results compared to previous studies.

The results exclude grid and intra hour balancing related costs and benefits. Furthermore, the restrictions in the use of the flexibility of the smart EVs are not as binding as they are likely to be in the real life. This includes the omission of uncertainty in driving behaviour, although the model had a safety margin for filling up the batteries.

In the case of smart EVs, the system cost to charge an EV was around 36 €/vehicle/year. In the case of dumb EVs the system cost was around 263 €/vehicle/year. Depending on the share of smart EVs vs. dumb EVs, the realised average cost should fall between these extremes – excluding the uncertainties in the article results. Most of the benefits come from the smart timing of charging. This can be divided between the benefits accrued on the day-ahead planning phase and the intraday adjustments to mitigate the forecast errors of electricity demand and variable generation.

Acknowledgements

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PUBLICATION VIII

Decrease of wind power balancing costs due to smart charging of electric vehicles

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Decrease of wind power balancing costs due to smart charging of electric vehicles

Juha Kiviluoma
Peter Meibom

***Abstract*—A combination of a generation planning model and a stochastic unit commitment model was used to analyze the impact of electric vehicles on power system balancing costs from the perspective of wind power. When smart charging and discharging was available, wind power balancing costs decreased by approx. 30% assuming that half of the personal vehicle fleet consisted of EVs.**

***Index Terms*—Balancing, electric vehicles, power markets, wind power**

I. NOMENCLATURE

t		set of hours
BC_1	€/MWh	average balancing cost in the one-price system
BC_2	€/MWh	average balancing cost in the two-price system
BP	€/MWh	real time price
WR	MWh	realized wind power production
WF	MWh	day-ahead forecasted wind power production

II. INTRODUCTION

INCREASED variation and uncertainty due to wind power will increase the power system balancing[1] costs. The costs will be largely born by wind power producers, since at large penetration levels wind power will be the main cause for balancing. The cost increase can be mitigated by the use of flexible resources that can economically integrate the variations and prediction errors in different time scales. One such option is the smart charging, and possibly discharging, of electric vehicles (EVs). Earlier work by the same authors analysed the general impacts of EVs on the power system [1], [2] and this article expands to impacts on wind power balancing costs.

The results show that EVs decrease the balancing costs of wind power and increase the share of wind power in the cost optimal power plant portfolio. Vehicle-to-Grid (V2G) has an important effect on wind power balancing costs, but most of the benefit can be accrued from relatively small share of EVs having V2G.

EVs can increase the power system flexibility in three ways. First, with smart charging the charging would occur during the hours with low electricity prices, if possible. Second, V2G would enable discharging the batteries to the grid during hours of high prices. Third, the charging and discharging decisions can be changed when new wind and demand forecasts arrive or at the operational stage, if the system needs upward or downward regulation. There have been several articles and reports about the possible benefits from the participation of EVs in the electricity markets [1]-[19]. Studies [3], [4], [5], and [6] use historical market prices to analyze the costs and benefits of EVs and hence do not contain dynamic impact of EVs on the prices and system operation. Reports [7] and [8] analyze only the impact of immediate charging. Only few studies [1], [2], [9], [10], [18] consider that EVs can have an impact on the future generation portfolio.

Article [9] considers the effect of EVs on future generation portfolios and uses a simplified model to dispatch EVs on top of the demand profile. V2G or the use of EVs as reserves was not considered. Report [10] estimated the effect of plug-in hybrid electric vehicles (PHEVs) on future generation portfolios and report [11] analyzed how dispatch might be affected. Costs and benefits were not analyzed. Article [14] analyses the effects of PHEVs on household electricity bill based on end-user rates in combination with household scale wind power or solar PV production and thus do not have a systems perspective. Article [16] analyses the effect of smart EVs in integrating variable wind power. While the article has results on CO2 emissions, it does not include costs and benefits. Article [18] is the only one that includes endogenous investments in transport sector as well as in power generation. However, it does not analyse the effect of EVs on wind power balancing costs. Article [19] has applied a unit commitment model to analyse the impacts of EVs. The method uses measured driving profiles and includes a piecewise approximation of depth of discharge costs. The article indicates the saturation of spinning reserve market with increasing share of EVs. The results are in line with the articles [1] and [2] by current authors.

The next section summarizes the tools and the scenarios that were used to create the results, which are presented in section IV. The article finishes with discussion in section V.

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[1] Balancing corrects most of the forecast errors that accrue after the original day-ahead forecast in demand and wind power. Intra-hour corrections are not included – it is assumed that these are in the domain of reserves.

III. METHODS AND SCENARIOS

EVs will not appear in the power system overnight without a forewarning. Their introduction, and any assumptions about that, will affect what kind of power plants will be built in the future. Smart charging EVs will exhibit a markedly different behavior from traditional consumption. They offer flexibility in the timing of the electricity consumption. Additional flexibility will promote certain types of power generation over others. As demonstrated in [2], the impact is noteworthy. The methods and scenarios have been presented in detail before [1], and are hence only summarized here.

Generation planning model Balmorel was used to create generation portfolios for different EV scenarios. Balmorel operates in hourly time resolution and therefore sees the variation in demand and in large-scale wind power, excluding sub-hourly variations. It assumes a perfect foresight, which means that it does not see the uncertainty in the wind power or demand forecasts. It optimizes the dispatch of generation for the whole year simultaneously and uses annualized investment costs to decide what power plants should be built in addition to existing plants in order to meet demand during every hour of the year and fulfill a yearly capacity balance requirement ensuring enough capacity to cover extreme peak load situations.

The generation portfolios from Balmorel were taken to unit commitment and dispatch model WILMAR, which includes uncertainty in the form of stochastic representation of net demand. WILMAR performs a day-ahead unit commitment including demand for spinning and non-spinning reserves once per day. This includes a dispatch for the first three hours. After this, the model rolls three hours forward and receives updated forecasts. These are used to refine the original unit commitments and to dispatch the next three hours. The rolling is repeated until the next day-ahead solve is due.

The shadow prices of the intraday power balance equation are assumed to reflect the real time market prices for energy. The results on balancing costs are based on a one-price system (1). In this system forecast error is always billed according to the real time price. Another system in use is the so-called two-price system (2), where a forecast error that increases the system error pays the balancing price and a forecast error that decreases the system error receives the original day-ahead price. The WILMAR model co-optimizes the day-ahead market and the expected up and down regulation in the future balancing markets. Therefore the day-ahead market prices in the WILMAR model will not be a good representation of real day-ahead market prices, due to real electricity markets such as the Nord Pool market clearing the day-ahead market independently from the balancing markets. Hence, the two-price system balancing prices were not calculated.

$$BC_1 = \frac{\sum_t BP_t \times (WR_t - WF_t)}{\sum_t WR_t} \quad (1)$$

$$BC_2 = \frac{\sum_t \max\left((DP_t - BP_t) \times (WR_t - WF_t); 0\right)}{\sum_t WR_t} \quad (2)$$

The study assumes that all wind power errors are balanced together. In reality different actors will have independent forecast errors and are being penalized individually, hence the overall bill would be larger especially in the two-price system.

The scenarios are based on a medium size power system with a high wind power penetration. The wind penetration is a result of relatively low investment cost for wind power and it differs between the scenarios. The number of EVs was exogenously defined to present about half of the personal vehicle fleet in the example system. In the scenario 'No EVs', there were no EVs in the system. In 'Dumb' scenario the EVs started charging when they were plugged in and charged until they were full. In 'Smart' scenarios EVs were able to change the charging period to optimize the power system costs – within the restrictions due to vehicle use.

IV. RESULTS

The impact of EVs on cost optimal generation plant investments can be seen in Figure 1. In addition to the investments in the figure, also biomass based CHP received investments, but these changed only very little between the scenarios. In comparison to the scenario without EVs, 'Dumb' scenario required more flexibility (open cycle gas turbines) and more energy (nuclear and some wind). 'Smart' scenario required less flexibility from conventional power plants and was able to support higher share of wind power.

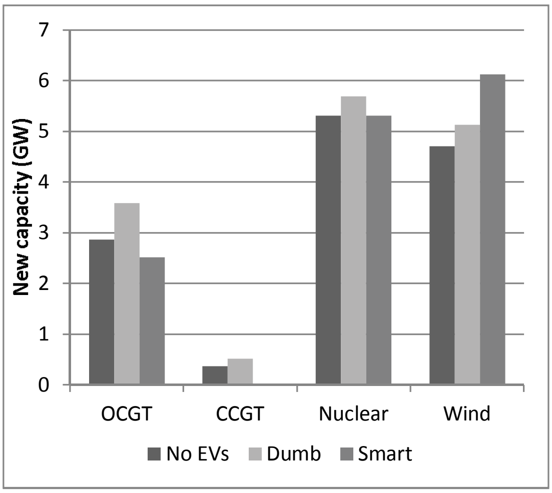


Figure 1. New investments in power generation in different EV scenarios. OCGT refers to an open cycle gas turbine and CCGT refers to a combined cycle power plant.

Figure 2 displays the wind power balancing costs in different EV scenarios calculated according to the one-price system. The balancing costs are smaller in the 'Smart' scenario. In comparison to 'No EVs' and 'Dumb', the flexibility of smart charging EVs decreases the real time prices. Annual balancing cost for wind power is 32% ('No EVs') and 41% ('Dumb') smaller. Electric vehicles provide balancing service at no cost, if they are able to move their charging to another point in time. If they utilize V2G, balancing from EVs has a price due to losses (85% round trip efficiency) and variable costs (assumed to be 10 €/MWh). In 'No EVs' and 'Dumb' scenarios use of EVs for balancing is not possible and the balancing is done with more expensive power plants.

The impact of V2G on balancing costs was also tested (Figure 2). If only half of the vehicles (PHEVs in this case, hence the acronym 'V2G PHEV only'), were allowed to perform V2G, average wind power balancing cost increased by 13%. If V2G was disallowed altogether ('No V2G'), the balancing cost increased by 67% compared to the 'Smart' scenario.

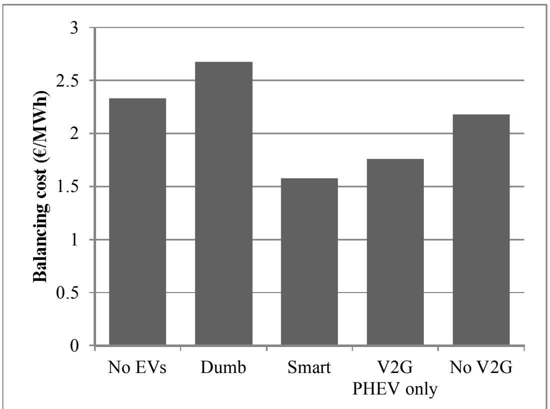


Figure 2. Wind power balancing cost in different scenarios.

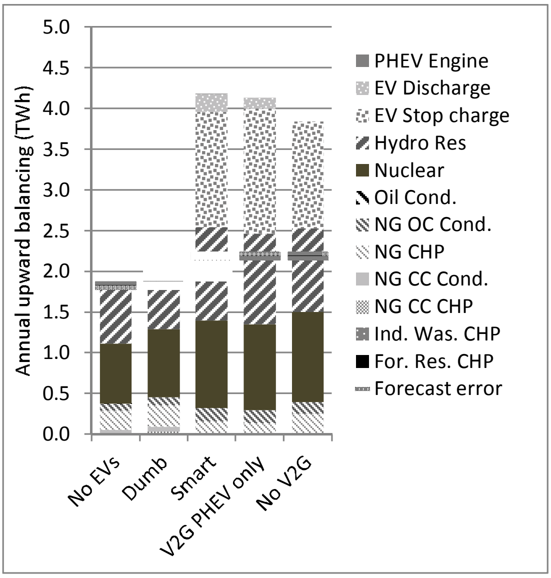


Figure 3. Sources of annual upward balancing. NG OC Cond. refers to OCGT, NG CHP refers to a combined heat and power plant using natural gas, NG CC Cond. refers to CCGT, and NG CC CHP refers to a natural gas based CHP plant using combined cycle. Ind. Was. is industrial waste and For. Res. is forest residues.

While balancing costs decrease with EVs, the amount of balancing increases considerably (Figure 3 and Figure 4). The need for balancing due to forecast errors (also in the figures) increases less: only in relation to increased wind power penetration. What happens is that the balancing with costly power plants decreases, which explains the overall cost decline in balancing. The increased balancing activity is due to transfers that optimize the system operation. The new transfers reschedule EVs to increase the full load operation of the conventional thermal fleet. This includes increased capacity factor for nuclear. Occasionally a thermal power plant can be shut down due to the transfers and this saves on fuel costs.

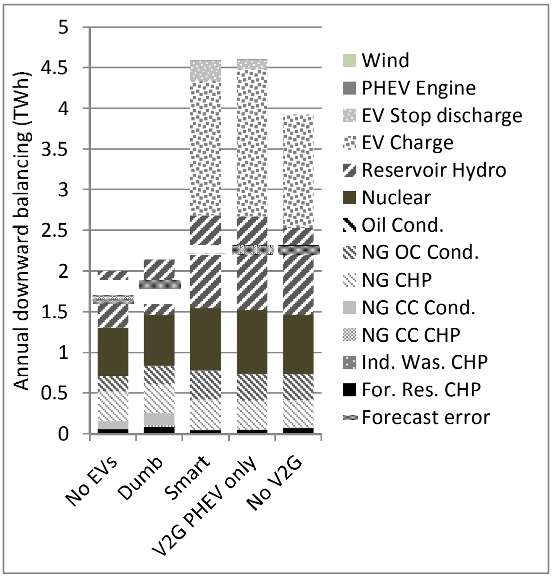


Figure 4. Sources of annual downward balancing.

Introduction of EVs will affect the real time prices and hence the revenues per MW will vary between different scenarios. Figure 5 shows revenues for wind and OCGT power plants. The revenues in scenarios with less V2G are higher in comparison to the 'Smart' scenario, since the power plant portfolios are the same and the system operation is less optimal when the EVs cannot discharge batteries to the grid, which leads to higher power prices. OCGTs receive additional revenue from fulfilling spinning reserve requirements, but this is removed when there are enough EVs to take care of this market for no cost.

Figure 6 displays the annual net profit of different power plant types using the assumed costs in the models and the market prices from the WILMAR runs. Costs include investment annuity, fixed costs, fuel costs, CO_2 price, and variable O&M costs. Revenues are from energy sales, including balancing, and procurement of spinning reserve.

OCGT has an annual net loss instead of profit. One reason for this is the capacity balance equation in Balmorel, which forces the model to build enough capacity to match the combined peak demand and reserve requirements. The investment cost of OCGT is not captured back in the operational phase simulated by WILMAR and the result is a net loss. Highest amount of OCGT is built in the 'Dumb' scenario and the scenario also has the lowest net loss for OCGT – there is less competition from EVs and more net demand variability due to the inflexible charging of EVs.

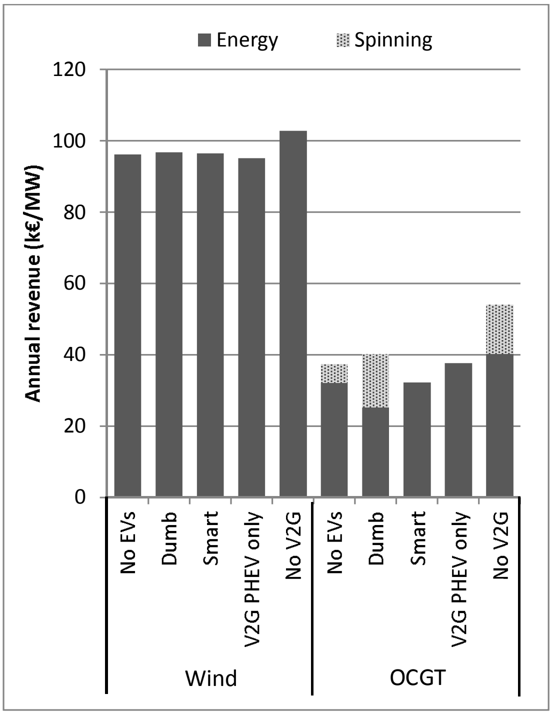


Figure 5. Annual revenue for wind and OCGT plants from real time market and provision of spinning reserves.

Balmorel approaches long-term marginal cost equilibrium in the optimization. WILMAR, on the other, optimizes according to short-term marginal (i.e. variable) costs. This means that power plants that set the peak and near peak prices will not recapture their investments costs unless scarcity pricing is present. WILMAR does not calculate scarcity prices when there is enough capacity as is the case in these scenarios. Hence, OCGTs and CCGTs are producing annual net loss in WILMAR runs. However, OCGTs and CCGTs produce more electricity in WILMAR runs than in Balmorel runs, which is a result of uncertainty in WILMAR. This does not help to capture the long-term costs, as the power prices remain too low for the price setters. OCGTs are barely getting more revenue than what are their variable operational costs. For CCGTs the margin is larger, but not nearly high enough to recapture investment annuity and fixed costs. The phenomenon is called "missing money" i.e. the inability of power plants to recover their fixed costs in electricity markets.

Annual net loss for wind remains rather stable over the different scenarios. Smart EVs will smooth price fluctuations and wind generation is experiencing a balance of price decreases and price increases in different scenarios. Annual net loss is explained by the same rationale as for OCGTs and CCGTs, WILMAR does not include long-term marginal costs and the prices are lower due to that. Nuclear on the other hand, receives a profit during most hours since the price setters are more expensive units.

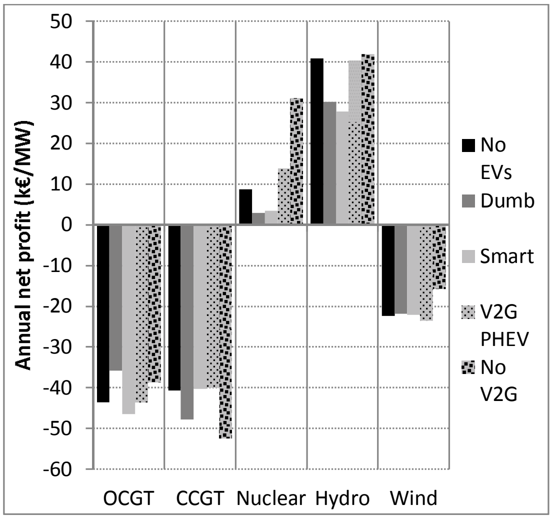


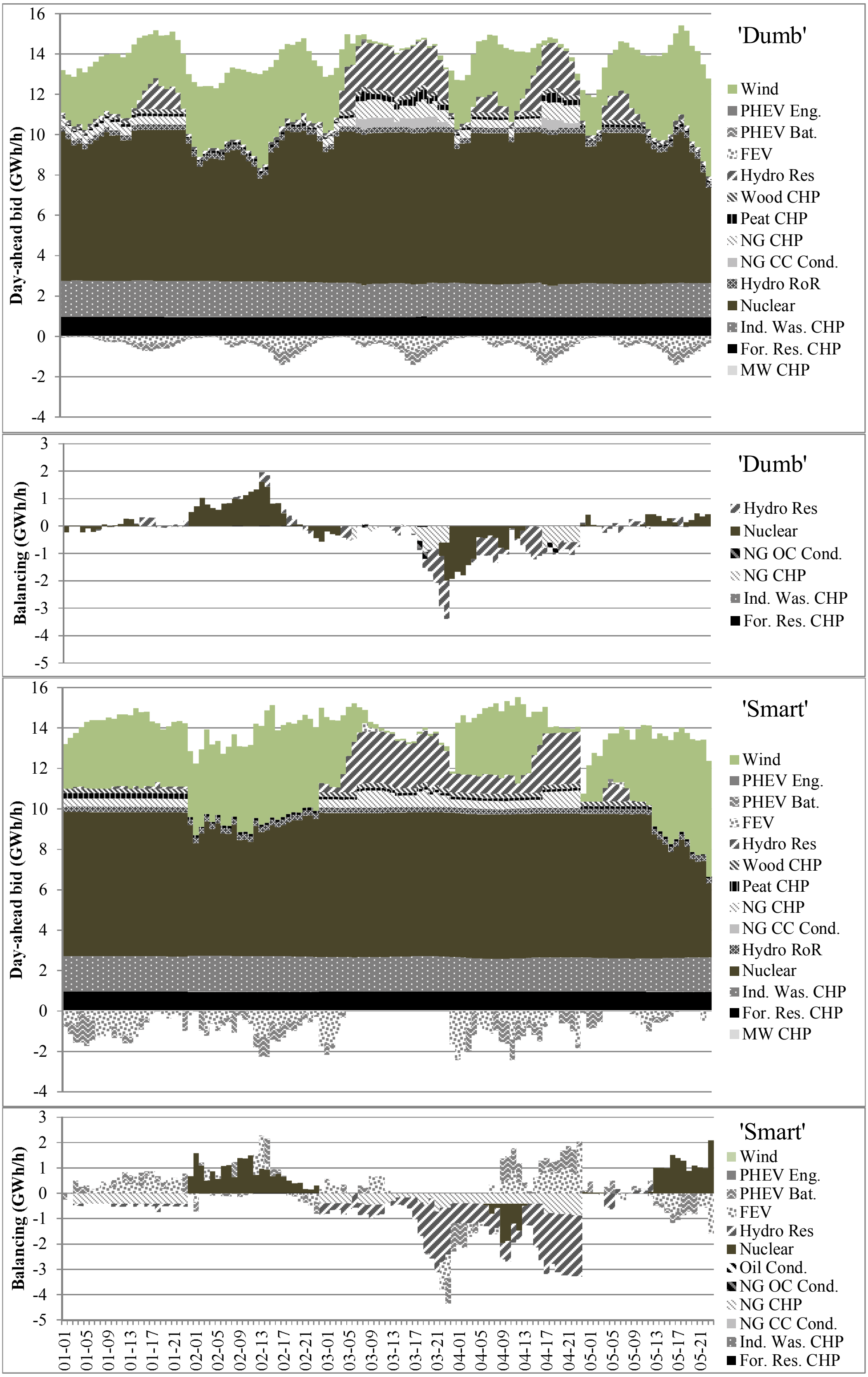
Figure 6. Annual net profit for different power plant types. To facilitate comparison, reservoir hydro power was assumed to have an investment annuity of 200 k€/MW, although it was not an investment choice.

Figures 7, 8, 9, and 10 show four days from the beginning of April. The figures show how the system copes with the largest downward balancing need during the analyzed year. Figures 7 and 8 are from the 'Dumb' scenario and figures 9 and 10 from the 'Smart' scenario. There are two major differences between the scenarios.

First, the EVs in the 'Smart' scenario make it feasible to schedule the thermal power plants in a more economic manner. Especially nuclear power plants are scheduled for full load operation almost all the time. The power plant portfolio has a very large share of nuclear and wind and hence this is not easy to achieve. Intraday balancing further increases the full load hours of nuclear power plants.

Second, in the 'Dumb' scenario, only the original forecast errors in demand and wind power forecasts are corrected. The balancing includes only very little re-organization of the power plant schedules. In 'Smart' scenarios, it becomes economic to re-organize the original power plant schedules and hence there is much more balancing transfers in the 'Smart' scenario.

On the next page:
Figure 7. Day-ahead power plant schedules for four days in the 'Dumb' scenario.
Figure 8. Intraday balancing for four days in the Dumb' scenario.
Figure 9. Day-ahead power plant schedules for four days in the 'Smart scenario.
Figure 10. Intraday balancing for four days in the Smart' scenario.


'Dumb'
Day-ahead bid (GWh/h)
Wind
PHEV Eng.
PHEV Bat.
FEV
Hydro Res
Wood CHP
Peat CHP
NG CHP
NG CC Cond.
Hydro RoR
Nuclear
Ind. Was. CHP
For. Res. CHP
MW CHP
'Dumb'
Balancing (GWh/h)
Hydro Res
Nuclear
NG OC Cond.
NG CHP
Ind. Was. CHP
For. Res. CHP
'Smart'
Day-ahead bid (GWh/h)
Wind
PHEV Eng.
PHEV Bat.
FEV
Hydro Res
Wood CHP
Peat CHP
NG CHP
NG CC Cond.
Hydro RoR
Nuclear
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PHEV Bat.
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V. DISCUSSION

Some power plants receive a net loss in the WILMAR runs (Figure 6). Balmorel does not optimize investments based on market revenue – it minimizes total system costs and approaches long-term marginal cost equilibrium. This means that power plants that serve the high price hours are not able to recapture their fixed costs, since they set the market price based on their short-term marginal costs in WILMAR.

The accuracy of the results is limited, since the investment model does not see uncertainty of wind power forecasts. The omission of short-term uncertainty may be a problem for investment models in power systems with high amount of uncertain generation. If uncertainty was included already in the generation planning phase, higher share of wind power should have induced more flexibility in the generation fleet. More flexibility should have resulted in smaller balancing costs. Hence, the result that EVs decrease balancing costs considerably is uncertain. However, energy balancing with EVs should be less expensive than with thermal power plants. Changing the charging time creates only minimal costs when the enabling system has been built. In contrast, the use of e.g. open cycle gas turbines means that fuel is used in a low efficiency power plant, which increases the overall fuel use in the system.

The results have assumed that the charging time of EVs can be changed without a cost as long as it is feasible from the vehicle use perspective. However, there is a cost for setting up the system and a cost for operating the system. These need to be recuperated from the operational savings, or more correctly, from the power markets. At this point it is unclear how large the variable operating costs would be. Variable operating costs of EVs would affect wind power balancing costs directly, as these would be reflected in the real time prices. The fixed operating costs and investment costs would have an indirect effect, since if they are deemed too high, the investments will not be made and there will be less EVs that participate in the balancing of the power system.

For V2G, the results have assumed a round-trip efficiency of 85% and a variable cost of 10 €/MWh due to wear and tear. The latter should be a function of depth-of-discharge and it should be varied to show sensitivity, since there are many different battery chemistries and it is highly uncertain which ones will be predominant in future EVs. Other factors for sensitivity and scenario analysis would include different wind power penetrations, EV penetrations, power plant portfolios, and fuel prices. Before more of this done, it is too early to conclude how large is the impact of EVs for wind power balancing or for coping with the wind power variability. However, the mechanisms are visible in the modeling results so far and the direction of the impacts is clear. Wind power balancing costs are reduced with EVs.

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VII. BIOGRAPHIES

Juha Kiviluoma (M.Sc., Env.), Senior Scientist and Team Manager for Wind Integration. His main interest is economic integration of variable power generation. Juha uses and develops stochastic unit commitment models and generation planning models, including model and database development for reservoir hydro power, EVs and heat storages combined with electric heating.

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VTT Science 35

Title	**Managing wind power variability and uncertainty through increased power system flexibility**
Author(s)	Juha Kiviluoma
Abstract	Variability and uncertainty of wind power generation increase the cost of maintaining the short-term energy balance in power systems. As the share of wind power grows, this cost becomes increasingly important. This thesis examines different options to mitigate such cost increases. More detailed analysis is performed on three of these: flexibility of conventional power plants, smart charging of electric vehicles (EVs), and flexibility in heat generation and use. The analysis has been performed with a stochastic unit commitment model (WILMAR) and a generation planning model (Balmorel). Electric boilers can absorb excess power generation and enable shutdown of combined heat and power (CHP) units during periods of high wind generation and low electricity demand. Heat storages can advance or postpone heat generation and hence affect the operation of electric boilers and CHP units. The availability of heat measures increased the cost optimal share of wind power from 35% to 47% in one of the analysed scenarios. The analysis of EVs revealed that smart charging would be a more important source of flexibility than vehicle-to-grid (V2G), which contributed 23% to the 227 €/vehicle/year cost savings when smart charging with V2G was compared with immediate charging. Another result was that electric vehicles may actually reduce the overall CO_2 emissions when they enable a higher share of wind power generation. Most studies about wind power integration have not included heat loads or EVs as means to decrease costs induced by wind power variability and uncertainty. While the impact will vary between power systems, the thesis demonstrates that they may bring substantial benefits. In one case, the cost optimal share of wind-generated electricity increased from 35% to 49% when both of these measures were included.
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VTT Science 35

Nimeke	**Tuulivoimatuotannon vaihteluiden ja epävarmuuden hallinta sähköjärjestelmän joustavuutta parantamalla**
Tekijä(t)	Juha Kiviluoma
Tiivistelmä	Tuulivoimatuotannon vaihtelevuus ja ennusvirheet lisäävät energiatasapainon ylläpitämisen kustannuksia sähköjärjestelmissä. Tuulivoiman osuuden kasvaessa näiden kustannusten suhteellinen merkitys kasvaa. Tämä väitöskirja tutkii eri tapoja lieventää kustannusten nousua lisäämällä järjestelmän joustavuutta. Tarkempi analyysi on tehty kolmelle eri menetelmälle: perinteisten voimalaitosten joustavuuden lisääminen, sähköautojen älykäs lataaminen sekä lämmön tuotannon ja kulutuksen mahdollisuudet joustavuuden lisäämisessä. Analyysit on tehty stokastisella ajojärjestysmallilla (WILMAR) sekä investointimallilla (Balmorel). Sähkökattilat voivat hyödyntää liiallista sähköntuotantoa ja samalla mahdollistaa sähkön ja lämmön yhteistuotantolaitosten alasajon ajanjaksoina, jolloin tuulivoimatuotanto on suurta ja kulutus vähäistä. Lämpövarastot voivat siirtää lämmöntuotannon ajoitusta ja sitä kautta lisätä sähkökattiloiden sekä sähkön ja lämmön yhteistuotantolaitosten joustavia käyttömahdollisuuksia. Tulokset indikoivat merkittävää potentiaalia suhteellisen pienillä kustannuksilla. Analyysin mukaan sähköautojen älykäs lataaminen tarjoaa enemmän joustavuutta kuin sähkön syöttö verkkoihin sähköautoista tarvittaessa. Sähkönsyötön osuus älykkään lataamisen kokonaissäästöistä (227 €/auto/vuosi) oli 23 %. Toinen tulos oli, että sähköautot näyttäisivät vähentävän sähköntuotannon päästöjä, koska niiden tuoma joustavuus johtaa entistä suurempaan tuulivoiman osuuteen sähköjärjestelmässä. Suurin osa tuulivoiman vaihtelevuuden ja ennusvirheiden kustannuksia arvioineista tutkimuksista ei ole huomioinut sähköautojen tai lämmön tuotannon ja kulutuksen mahdollistamaa lisäjoustavuutta. Vaikutukset vaihtelevat järjestelmästä toiseen, mutta väitöskirja osoittaa, että näistä voidaan saada merkittäviä hyötyjä. Yhdessä tutkitussa tapauksessa tuulivoiman kustannustehokas osuus kasvoi 35 %:sta 49 %:iin, kun sekä lämmön kulutuksen että sähköautojen joustavuus huomioitiin.
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Managing wind power variability and uncertainty through increased power system flexibility

Wind power generation can replace fuel-based power generation, but it is inherently variable and only partially predictable. As the share of wind power increases, these characteristics will impact the cost-effective upkeep of the balance between power generation and load. This dissertation explores methods to mitigate these impacts.

The approach taken in the dissertation is based on cost optimisation models for two time scales. The generation planning model for the investment time scale matches selected periods of hourly electricity load with generation from existing and new power plants. Several scenarios with high levels of wind power were explored. The unit commitment and dispatch model for the operational time scale included forecasts of wind power and load for the electricity spot market time horizon of 36 hours. In some cases, stochastic forecasts were used to increase the accuracy of the cost optimisation.

The results highlight that even without any additional measures, conventional generation can go a long way towards mitigating the variability and forecasting errors at a low cost. The cost can be further cut with additional measures. Flexibility from heat use in district heating systems proved to be especially useful. Periods with surplus generation were mitigated by electric boilers and heat pumps. Heat storage introduced additional flexibility to keep combined heat and power units running even though there is increased variation in the system. Large numbers of electric vehicles can also be helpful, but their contribution is limited by the relatively small amounts of electricity they consume. Discharging their batteries was of limited use.

The results improve the understanding of how energy futures with high amounts of variable power generation can function in a cost-effective manner. This may be useful for decision-making in different realms: politics, policy, energy regulation, power grid operation and planning, and energy business. There is also considerable public discussion on the feasibility of high amounts of variable power generation. The dissertation provides research-based evidence for that discussion.

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