Impacts of Wind Power on Thermal Generation Unit Commitment and Dispatch

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(Invited Paper)

***Abstract*—This paper proposes a new simulation method that can fully assess the impacts of large-scale wind power on system operations from cost, reliability, and environmental perspectives. The method uses a time series of observed and predicted 15-min average wind speeds at foreseen onshore- and offshore-wind farm locations. A Unit Commitment and Economic Dispatch (UC-ED) tool is adapted to allow for frequent revisions of conventional generation unit schedules, using information on current wind energy output and forecasts for the next 36 h. This is deemed the most faithful way of simulating actual operations and short-term planning activities for a system with large wind power penetration. The problem formulation includes ramp-rate constraints for generation schedules and for reserve activation, and minimum up-time and down-time of conventional units. Results are shown for a realistic future scenario of the Dutch power system. It is shown that problems such as insufficient regulating and reserve power—which are typically associated with the variablility and limited predictability of wind power—can only be assessed in conjunction with the specifics of the conventional generation system that wind power is integrated into. For the thermal system with a large share of combined heat and power (CHP) investigated here, wind power forecasting does not provide significant benefits for optimal unit commitment and dispatch. Minimum load problems do occur, which result in wasted wind in amounts increasing with the wind power installed.**

***Index Terms*—Power system integration, unit commitment and economic dispatch, wind power, wind power forecast.**

I. Introduction

IN A NUMBER of European countries and around the world, wind power is rapidly becoming a generation technology of significance. Wind power is commonly regarded as problematic for power system operation due to its limited predictability and variability. In particular, optimal selection of on-line units (unit commitment) and optimal output levels of committed units (dispatch procedures) for conventional generation need to be revised. Additional reserves for wind power must be allocated to guarantee operational reliability and minimize associated cost. Assessment of the wind power's impact on unit commitment and dispatch is, therefore, a fundamental issue when integrating more wind power into power systems.

Besides employing storage and adjusting exchange schedules with neighboring systems, the obvious, and often, the only solution for variability and limited predictability is to use conventional generation units to compensate. Adequate capacity in the presence of wind power is quantified using a Monte Carlo approach, as in [1]. System reserves for combined load and wind forecast errors are assessed using probability density functions [2]. In [3], quantifying reserve requirements for conventional generation systems with large-scale wind power have been described. The probabilistic methodology for the cost assessment of wind power unpredictability, described in [4], differs from a deterministic approach, applied in this paper. Dany [5] investigates wind power's impact on the required system reserves level under central dispatch. However, a number of plant parameters critical to solving the unit commitment problem (minimum up-time and down-time, minimum production, etc.) are not specifically taken into account. In [6], a unit commitment program was adopted to determine wind power's impact on a thermal system operation. Nevertheless, a large part of wind power's integration challenges are effectively solved via the strong interconnections of the investigated Danish system.

This research focuses on investigating the technical capabilities of a thermal generation system for balancing wind power. In the Dutch system used as a case study for this paper, no significant hydro power is installed, and therefore, no storage abilities are present. Moreover, a significant part of installed thermal generation consists of combined heat and power (CHP) units, which impose additional constraints on unit commitment and dispatch due to heat-demand-driven operation. In addition, about 20% of generation is connected at distribution level, and hence, not available for central dispatch. Our objective is to determine wind power's impact on thermal unit commitment, including assessing the benefits of metering and predicting wind. Parameters investigated include operating costs, emission savings, and wind wasted. It is assumed that power variations should be balanced within the system in less than 15 min to bring back exchanges to their schedules, as required by UCTE[1] [7]. Therefore, unit commitment and dispatch calculations are carried out for each 15-min interval, which coincides

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[1]Union for the Coordination of Transmission of Electricity, the association of transmission system operators in continental Europe (http://www.ucte.org/).

with the resolution interval for the Dutch balancing market, also known as the Dutch program time unit (PTU). The simulation method applied here uses a dynamic programming optimization algorithm with a heuristic de-commitment scheme for solving Unit Commitment and Economic Dispatch (UC-ED) under ramp-rate constraints, such as described in [8].

The paper is organized as follows. First, an assessment is made of wind power variability for increasing installed wind power levels, in combination with existing load variations (Section II). Then, wind power forecasts are developed and an analysis of wind power prediction errors is given in Section III. Then, the optimization model is described in Section IV, which includes the make-up of the thermal generation system investigated, the simulation setup, and the use of wind power forecast data in the unit commitment and dispatch logic. Simulation results in Section V include wind power produced and wasted and wind power's impact on operating costs and emissions, including the value of wind power predictions. Overall conclusions and an outline of future work are presented in Section VI and Section VII.

II. Load and Wind Power Variability

For the investigation of large-scale wind power, wind power production was modeled using weather data and park-aggregated speed–power curves. Wind speed data have been obtained from the Royal Dutch Meteorological Institute (KNMI). The data concerns 10-min wind speed averages with a resolution of 0.1 m/s for 18 locations in the Netherlands (nine onshore, three coastal, and six offshore) measured between June 1, 2004, and May 31, 2005. Wind speed time series for the study period at planned wind park locations are created such that the spatial correlation between the sites is taken into account. The development of wind power output data is described in more detail in [9] and [10].

In the Netherlands, foreseen levels of wind power include 6 GW located in Dutch coastal waters, and about 2 GW installed onshore. This offshore wind power will have a significant impact on conventional generation unit commitment. To keep generation and demand in balance at all times, variations in system load and wind power must be matched by sufficient regulating power. In this research, we are using a steady-state approach, expressed in megawatts (MW) per 15 min. The total regulating power required at any moment depends on the sum of variations in system load and wind power. Wind power variations may counterbalance or amplify load variations. To determine the total regulating power on a system scale, the aggregated variations must be investigated. This can be done by effectively regarding wind power as negative load.

Fig. 1 shows the need to regulate power due to load and increasing wind power. Upward and downward regulating power are arranged in decreasing order. From the figure, it can be concluded that only with load, downward regulating power is needed more often than is upward regulating power (58% versus 42% of time); while upward regulating power exceeds downward regulating power in size (maximum $+1351$ MW/15 min and -1048 MW/15 min, respectively). This changes as the installed wind power increases: for 8 GW of installed wind power, downward regulating power is needed only 55% of time. As can be expected, as the installed wind power increases, both upward and downward regulating powers increase in size (at 8 GW wind power, $+2243$ and -2190 MW/15 min).

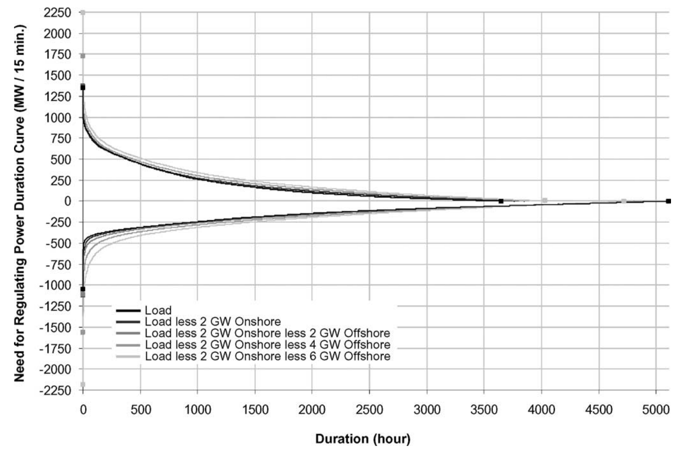

Fig. 1. Need for regulating power duration curve for power variations of load only (black curves) and load and various wind power penetrations combined (gray curves). Total amount of regulating power increases with 3% (2 GW wind power installed), 8% (4 GW), 19% (6 GW), and 33% (8 GW).

III. Limited Predictability of Wind Power

A. Data Development

Day-ahead predictions (12–36 h ahead) have been made with the ECN wind power forecasting method AVDE [11], which is a physical method with a statistics module output [12]. The forecasting method takes into account the local influences of roughness, obstacles, and stability on wind speeds at the specified height. The forecasts are based on underlying runs of the atmospheric high-resolution limited area model (HIRLAM). HIRLAM numerically approximates the physical state of the atmosphere at 6-h intervals with initial conditions taken from recent observations. The wind speeds approximated by HIRLAM are postprocessed by AVDE into 15-min averaged wind speed at sensor height for two onshore and five offshore measurement locations. Using the same method applied for interpolating wind speed data, wind speed forecast errors are interpolated at the planned wind park locations, and finally, added to the measurements to create forecast wind speed time series at the locations of interest.

The minimum lead-time of a numerical weather prediction (NWP)-model fed forecasting method as used here is usually 3–6 h. Forecasts for the first 0–3 h are usually covered by persistence-based forecasting method fed by real-time measurement data. To fill in the data for the missing forecast lags, the 12–36 h ahead aggregated wind power forecast errors are modeled as an auto-regressive moving average [ARMA(1,1)] process:

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

where $\gamma(t) \sim \mathcal{N}(0, \sigma)$ is a zero-mean, normally distributed noise term of standard deviation σ. The parameters a, b, and σ of the ARMA process are estimated via the maximum likelihood

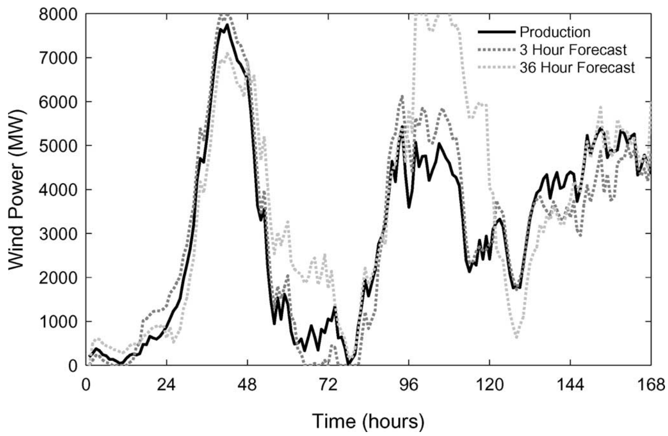

Fig. 2. Example of wind power forecasts 3 and 36 h ahead of operation compared to realized wind power production for one week, 8 GW.

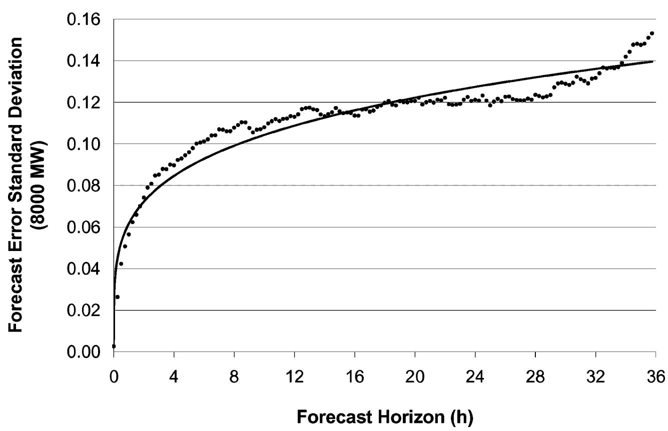

Fig. 3. Forecast error normalized standard deviation for 8000 MW installed wind power (2000 onshore, 6000 offshore). The equation of the fitted trend line is $y = 0.0616x^{0.2285}$, the square of residuals R^2 is 0.9644.

estimator (MLE) method [13]. Finally, forecast and measured wind speeds are passed through the speed-power curves by location and aggregated at the system level. Fig. 2 shows an example of the realized and predicted wind power for 3 and 36 h ahead, over a one-week horizon.

B. Analysis of Forecast Data

The forecast error ϕ (MW) is defined as the difference between forecast and actual wind power output at the system level:

$$\phi = P_{\text{forecast}} - P_{\text{measured}}. \tag{2}$$

The normalized standard deviation per forecast lag σ_j, where $j = 1, 2, \ldots, 36$ is determined for each separate wind power penetration:

$$\sigma_j = \frac{1}{P_{\text{inst}}} * \sqrt{\sum_{i=1}^{n} \frac{(\phi_{ij} - \mu_j)^2}{n}} \tag{3}$$

in which μ_j equals the mean of all forecast errors (MW) for a particular forecast lag, n the total data sample available for a given lag, and P_{inst} the amount of installed wind power in MW.

Fig. 3 develops the normalized standard deviation of the prediction error for 0–36 h ahead wind power forecast. Further statistical analysis of the forecast data shows that about 99% of the probability mass is within $\mu \pm 3\sigma$, which, for the 8 GW installed wind power and a +36-h lag, translates to about 4 GW or 50% of the installed capacity. The normalized standard deviation is comparable in size and trend to the values reported in [14], for an aggregate of 30 wind farms in Germany. Fig. 3 shows that the forecast error's normalized standard deviation drops to half from the 36 to the 2–3 h ahead prediction. Forecast data compared here are from the Danish system operator Energinet.dk, and show that the mean absolute percent error of the forecast is in very good agreement (7.83% versus 6.57% for the Danish data).

IV. Simulation Model

Unit commitment decisions are typically assessed only once or twice a day, while generation unit output changes may be carried out continuously during the day (dispatch). Due to the reasonable predictability of system load, intra-day calculations for unit commitment may be necessary only when unexpected, significant changes occur in generation (i.e. outages) or demand. As wind power is far less predictable than is system load, the integration of significant wind power requires unit commitment calculations to be carried out more often, preferably each time updated wind power forecasts are available.[2] The availability of accurate, near real-time wind power measurements are a necessity for unit commitment and dispatch decisions.

A. Simulation Objective and Constraints

Our unit commitment and dispatch tool uses three execution time horizons: an annual horizon for maintenance scheduling, a weekly horizon for production cost optimization, and an hourly or other short-time horizon for unit dispatch. The model inputs heat demand areas, system load, generation unit capabilities, wind power, and hourly updated wind power forecasts. Unit commitment and dispatch are optimized on a 15-min basis to achieve minimum operating cost, while all of the following constraints are met:

1) electricity demand;
2) heat demand in all heat areas;
3) ramping capabilities of generation units;
4) minimum up-time and down-time.

Optimization of unit commitment and dispatch are performed using the so-called equal marginal cost method, in which the objective function is the total cost for generating both heat and power. Decremental dispatch and de-commit costs are calculated for all 74 units included in the model and the unit with highest decremental or de-commitment gain is ramped down or de-committed, taking into account heat demands in the heat areas and system load.

It can be noted that the decremental cost of wind power has been set to zero. Wind power will, therefore, be ramped

[2]For example, in Western Denmark, where the relative amount of installed wind power is amongst the highest in the world, the TSO Energinet.dk receives a wind power forecast update every 6 h.

TABLE I
INSTALLED GENERATION IN 2012, EXCLUDING WIND POWER

Generation Type	GW	%
Gas-Fired	12.1	53
Coal-Fired	4.1	18
Nuclear	0.4	2
Other	1.3	4
Distributed Generation	5.2	23
Total Installed	22.9	100
of which CHP		55

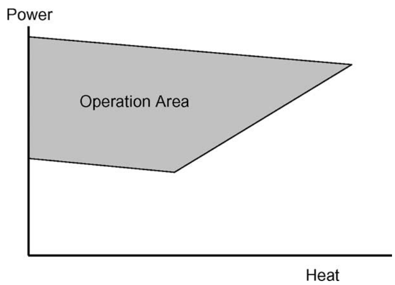

Fig. 4. Example of an operation area of a CHP unit.

down only as a last resort (i.e., wasted wind in minimum output constraints). Unscheduled thermal generation unit outages are modeled using Monte Carlo. No power reserves requirements have been formulated to accurately assess the balancing reserves held for wind power's variability and limited predictability. The system studied here comprises a generation mix expected to be installed in the Netherlands in 2012. Interestingly, 55% of all installed generation capacity consists of CHP units while hydro-power, which is commonly regarded as an ideal solution for balancing wind power variations, is absent (Table I). Furthermore, the amount of distributed generation, which can be regarded as must-take power, is significant (23%).

B. Thermal Generation Units

1) CHP Units: An important portion of Dutch generation units supplies both heat and power. As a result, each CHP unit has additional operation constraints, defining the area (power P and heat H) in which a CHP unit can be operated. The operation area of each CHP unit can be described as a set of n linear inequality constraints of the type

$$x_i P + y_i H \geq z_i \tag{4}$$

for $i = 1, 2, \ldots, n$, and has a general form as shown in Fig. 4. From Fig. 4, it follows that power output flexibility decreases for high heat demand.

The total fuel cost for a CHP unit is defined as the sum of a quadratic function of the electric power output, a quadratic function of the heat output, plus a crossover term linearly dependent on the product of the two:

$$F(H,P) = f(1)H + f(2)P + f(3)PH. \tag{5}$$

The previous cost function for each CHP is added to the total objective function to be minimized under the unit commitment and dispatch problem formulation. CHP units are scheduled to meet typical heat demand curves for their associated areas, depending on the type of heat load (district or industrial). The power production that coincides with heat production serves part of the system load. Other thermal units, then, serve the remaining load, taking into account distributed generation, import schedules, and wind power.

2) Heat Boilers: Due to overall unit efficiency considerations, the operation of CHP units is most commonly heat-driven. The presence of heat boilers adds extra flexibility to CHP units because during low heat demand, heat boilers may take over the heat supply to enable unit shutdown, while during high demand, both the unit and the boiler will operate. In the system simulation, all existing heat boiler capacity was taken into account. For all new CHP units in 2012, it has been assumed that these units are equipped with heat boilers to enable maximum unit flexibility. The simulations are set up such that heat boiler operation (enabling CHP unit shutdown and lower minimum load) is preferred to wasting available wind resources.

TABLE II
SIMULATED WIND POWER PENETRATIONS

Onshore (GW)	Offshore (GW)	Total (GW)	Produced Energy (% of annual load)
0	0	0	0
2	0	2	3.5
2	2	4	9.7
2	4	6	16
2	6	8	22

C. Simulation Setup

The simulations of unit commitment and dispatch in this paper are carried out for one year, with a resolution of 15 min, for different installed wind power capacities (Table II). Load data for the year 2012 have been generated by an extrapolation of Dutch system data made available by the Dutch TSO TenneT. The calculations are carried out using an hourly update of wind power forecast for 0–36 h ahead as developed in Section III. It is assumed that a re-calculation of unit dispatch is performed every 15 min using updated system measurements of load and actual wind power production levels. Furthermore, it is assumed that wind power can be fully managed (ramped down) if required and that no prediction errors apply for system load.

In the simulations, the following situations may occur, indicating possible technical limitations for the integration of large-scale wind power.

- *Insufficient downward regulating power:* This results in increased heat production by heat boilers and in wasting available wind resources.
- *Minimum load problems:* This results in increased heat production by heat boilers and in wasting available wind resources.
- *Insufficient upward regulating power:* This is caused by insufficient available spinning reserve or insufficient ramp rates of available spinning reserves, and results in unserved energy.

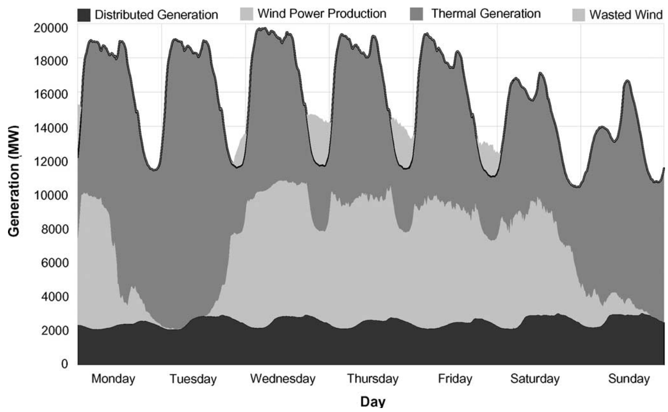

Fig. 5. Unit commitment and dispatch for one week of the simulated year for 8 GW installed wind power capacity.

This research focuses on wind power's impact on the operation of a thermal generation system, the system is assumed to be one area under central dispatch, with the TSO as the sole reserve and regulation provider. System interchange is assumed to be zero to assess the technical capabilities of the system itself. Obviously, interconnection of the system would provide additional technical space for integrating wind power. The output of distributed generation units is assumed to be 50% constant and 50% variable with system load, and is entirely independent of central unit commitment.

As an illustrative example of the simulations, Fig. 5 provides an overview of unit commitment and dispatch during one week of the simulated year for 8 GW wind power installed. The graph shows generation levels by distributed generation, thermal units, wind power, and wasted wind (wind power production equals available wind power production minus wasted wind). Total generation by distributed generation, wind power, and thermal generation equals system load. In this particular week, wind power is ramped down at moments of high wind power and low load (Tuesday, Wednesday, Thursday, and Friday night) to prevent minimum load problems. The use of thermal generation for balancing load and wind power variability can be seen on Monday (thermal generation ramp up), Tuesday (ramp down), and Saturday (ramp up).

V. Result

The simulation results show the impacts of wind power on the operation of the thermal generation system investigated. The impacts of wind power's variability (Section II) and limited predictability (Section III) are assessed for different wind power penetration levels. In this section, wind power forecasting value for minimizing operating costs is investigated and a discussion of results (wind power production, wasted wind, and system emissions) is provided.

A. Wind Power Production and Wasted Wind

The results of the simulations show that the first minimum-load problems occur at 2–4 GW installed wind power. At certain moments, distributed, base-load thermal, and CHP units generation cannot be decreased and threaten to exceed load minus wind power. As a result, wind power is regulated downwards and wind energy is increasingly wasted as installed wind power capacity increases (Fig. 6). Up to about 4 GW installed wind power capacity, the amount of wasted wind is insignificant. The appearance of minimum load problems can be explained by the large percentage of CHP units and distributed generation outside the scope of central dispatch in the Dutch system (Table I). The operation of these two is heat-driven, with significant must-take power for the Dutch system. During times of low system load, excess production from wind power is, therefore, wasted. For the system studied here, forecasting wind power does not significantly reduce the wasted wind.

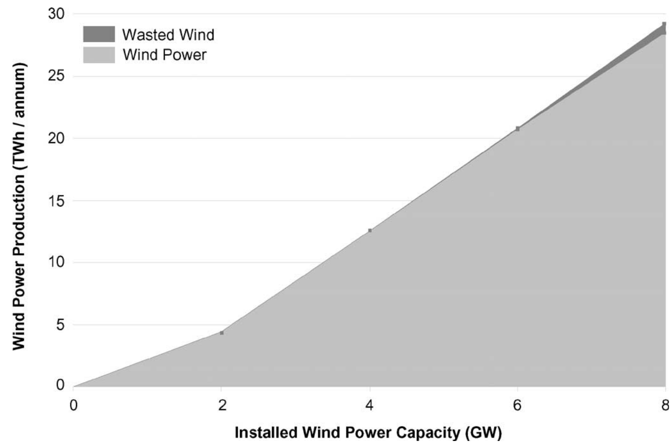

Fig. 6. Wind power production and wasted wind for the investigated levels of installed wind power. Absolute annual amounts of wasted wind power are are 0.034 GWh (2 GW installed wind power), 0.46 GWh (4 GW), 58 GWh (6 GW), and 795 GWh (8 GW). The latter amount represents 0.6% of annual consumption.

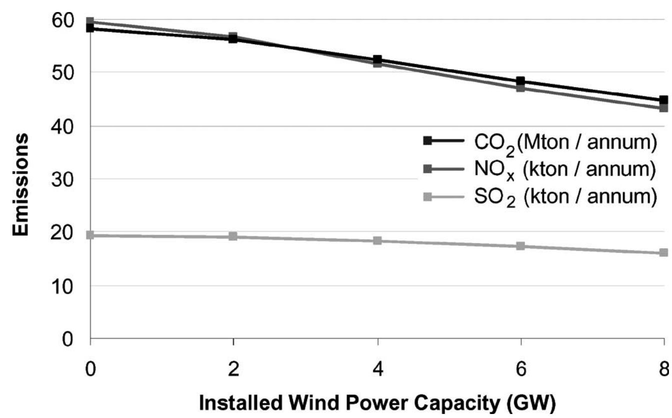

Fig. 7. System emissions with increasing amounts of installed wind power.

B. System Emissions

The use of wind energy for power generation saves fossil fuel consumption at conventional power plants, and emissions decrease. In Fig. 7, an indication of the system emissions is given for various wind power penetration levels. Fig. 7 shows that the emissions decrease at a less steep slope after installed capacities of 4 GW (decreasing returns).

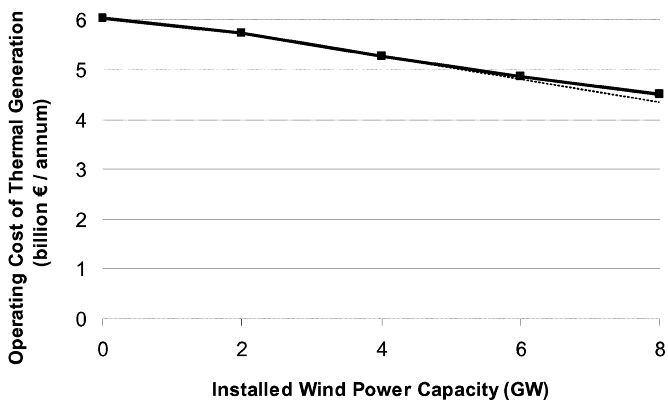

Fig. 8. Operating costs for centrally dispatched thermal generation units for different wind power penetration levels. Operating costs decrease to 95%, 87%, 81%, and 75% at installed capacities of 2, 4, 6, and 8 GW, respectively. Decreasing returns apply for increasing amounts of wind power, as shown by the *dotted line*.

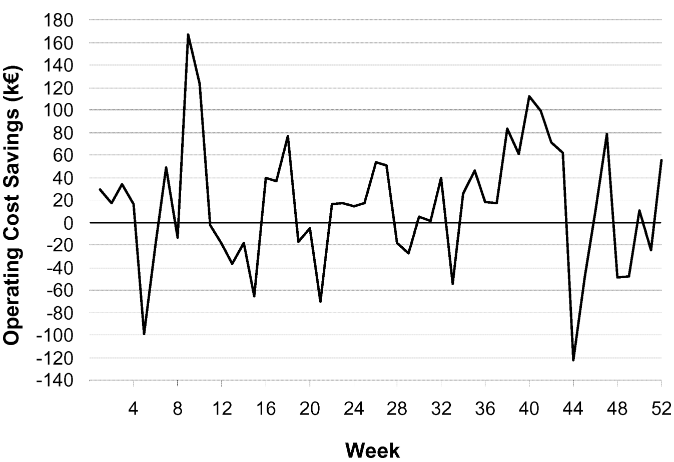

Fig. 9. Operating cost savings per week relative to a 0-MW wind forecast due to the use of forecasts (0–36 h ahead with 15-min resolution) of 8 GW installed wind power capacity in the unit commitment and dispatch calculation.

C. Operating Costs

Variable operating costs are assessed to determine the benefits of wind power. Fig. 8 presents the results for the total operating costs for various levels of installed wind power capacity. Operating costs of individual units (not shown here) show that overall operation of units differ only slightly among different wind power forecasts, indicating that forecasts do not result in significantly different unit commitment and dispatch decisions.

D. Value of Wind Power Forecast

In Fig. 9, wind power forecast data's impact on annual system operating cost, relative to a 0-MW prediction, are shown for 8 GW installed wind power capacity. Operating cost savings as a result of wind power prediction vary significantly per week. Interestingly, wind power forecasts save operating costs only 54% of time because, often, wind power forecasting increases operating costs. This may be the result of accidental over-predictions of wind power, leading to a de-commitment of units. As the wind power falls short, units must be committed resulting in additional start-up costs. Overall, however, the calculated value of wind power forecast is only 0.02% of system operating costs. This appears insignificant compared to the overall operating cost savings of wind power, which represent 25% of operating costs for 8 GW installed wind power. The annual value of wind power forecasts for unit commitment and dispatch, expressed as annual operating cost savings, are estimated to be 0.8 million € for 8 GW installed wind power. This value is highly dependent on parameters such as starting and stopping costs of units, and is therefore, a rough estimate. However, this estimate seems to indicate that the value of wind power forecasts for unit commitment and dispatch are limited.

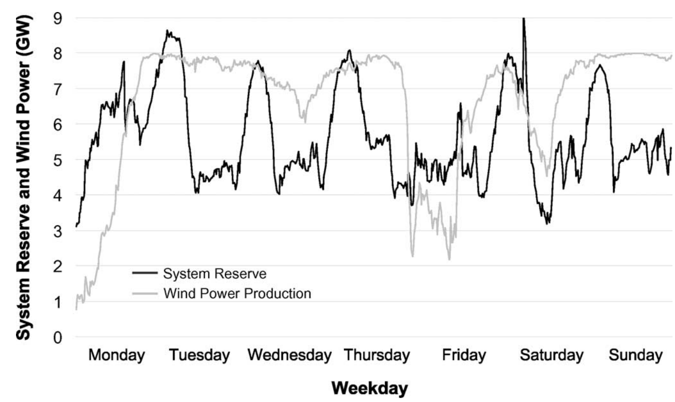

Fig. 10. Spinning reserves available within 15 min and wind power for one week of the simulated year for 8 GW wind power installed.

E. Results

The results obtained show that the integration of wind power in the Dutch system leads to minimum load problems at high levels of installed wind power capacity. This may be explained by the large must-take power generated by CHP units running to serve heat demands. Therefore, large amounts of power reserves are present in the Dutch system (one week's in Fig. 10), providing sufficient regulating power to simultaneously balance load and wind power variations. The presence of power reserves probably reduces the value of wind power forecasts, because forecasting only reduces the balancing reserves held for wind power variability, not the amount actually required.

The results for wind power forecast have been verified by comparing the results for wind power production, wasted, wind, and emission savings for a 0-MW wind power forecast and perfect prediction. With a 0-MW forecast, wind power is assumed to be 0 MW at all times, resulting in a conservative estimate of wind power and an over-commitment of thermal units. With a perfect wind power forecast scenario, it is assumed that future wind power production is known exactly. A perfect wind power forecast would enable a calculated optimal integration of wind power, as zero reserves for the limited wind power predictability would be needed. The difference between 0-MW results and perfect prediction represent the range within which lies the added value of wind power forecasting.

Simulations show that the differences between a 0-MW prediction and a perfect forecast of 8 GW wind power are small.

For the perfect forecast, wind power production (megawatthour) is $+0.01\%$, wasted wind is -0.4%, SO_2 -0.8%, NO_x -0.6%, CO_2 -0.3%, all relative to the 0-MW forecast. These small ranges are consistent with the indication that the added value of wind power forecasts for unit commitment and dispatch is found to be small. It was found that a perfect prediction would double the value of the wind power forecast for unit commitment and dispatch. It should be noted that, in a liberalized environment, the added value of wind power forecasting lies not only in unit commitment and dispatch, but may also lie in spot market bidding, power reserve bidding, etc., which have not been considered here.

VI. Conclusion

A new simulation method has been developed for assessing wind power's impact on system operation cost, reliability, and emissions. The method has been applied to assess wind power impacts on unit commitment and dispatch of thermal generation units in the Dutch system for increasing wind power penetrations. It is shown that wind power production reduces total system operating costs and emissions exhaust.

Simulations performed show that for the Dutch thermal generation system, ramp-rate problems as a result of wind power are absent. However, significant wind power opportunity must be wasted to prevent minimum load problems. It is shown that the limited predictability of wind power, even though certainly significant for longer time horizons, does not require additional power reserves in the system investigated. This can be explained by existing unit commitment constraints imposed on CHP units due to heat demand, resulting in a high-power reserve level. The high reserve levels also provide sufficient ramping capacity for balancing wind power variability in addition to existing load variations.

Surprisingly, the results indicate that wind power prediction has a negligible effect on thermal system operating cost, emission reductions, and wasted wind at the wind power penetration levels investigated. The limited predictability of wind power has an insignificant effect on unit commitment and dispatch for the system investigated here. For the optimization of system operation with large-scale wind power, accurate, near-real-time wind power measurements and a continuous re-calculation of unit commitment and dispatch are essential.

VII. Future Work

The research method developed here will be extended to include a number of aspects that have been deemed essential for future research. To determine any technical limits to system balancing with large-scale wind power, some relevant aspects such as transmission constraints and market design have been neglected. For this research, it has been assumed that the transmission system will be developed in such a way that wind power will not cause any extra congestion. These developments should be assessed to anticipate possible bottlenecks to the integration of large-scale wind into the transmission system.

In this paper, it has been assumed that imports in the Dutch system are zero. In reality, the Netherlands depend on power imports from Germany and France/Belgium and intensive cross-border trading takes place. Therefore, the impact of international markets and prices must be integrated into the unit commitment and dispatch calculation. The simulation tool will be programmed to include spot market prices. In this way, the true economic value of wind power and the costs of variability and limited predictability of wind power can be assessed for a market environment.

In this research, central dispatch has been assumed to have the maximum technical space on a system level. In reality, wind power is integrated by market parties. Wind power is subject to program responsibility [15] resulting in incentives for market parties to minimize their individual power imbalances, including wind power. As each market party is, therefore, inclined to individually provide reserves for wind power, this may pose a nontechnical limit to the integration of wind power, which has not been considered in this study.

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