New Tool for Integration of Wind Power Forecasting into Power System Operation

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Abstract-- The paper describes the methodology that has been developed for Transmission System Operators (TSOs) of Republic of Ireland, Eirgrid, and Northern Ireland, SONI the TSO in Northern Ireland, to study the effects of advanced wind power forecasting on optimal short-term power system scheduling. The resulting schedules take into account the electricity market conditions and feature optimal reserve scheduling. The short-term wind power prediction is provided by the Anemos tool, and the scheduling function, including the reserve optimisation, by the Wilmar tool. The proposed methodology allows for evaluation of the impacts that different types of wind energy forecasts (stochastic vs. deterministic vs. perfect) have on the schedules, and how the new incoming information via in-day scheduling impacts the quality of the schedules. Within the methodology, metrics to assess the quality of the schedules is proposed, including the costs, reliability and cycling. The resulting schedules are compared to the Day-ahead and In-day results of the existing scheduling methodology, Reserve Constrained Unit Commitment (RCUC), with the historical data used as the input for calibration.

Index Terms-- Forecasting, power generation scheduling, reserve optimization, stochastic scheduling, wind power.

I. INTRODUCTION

THE increasing penetrations of wind energy being seen on power systems across the world are presenting a new challenge to the operation of these systems. The nature of wind energy makes it difficult to predict. Much work has been devoted to the development of improved wind forecasting techniques, [1]. The specific application of wind forecasting that are described here are the impact of wind forecasting on the scheduling of the units and the related calculation of reserve targets over different timeframes.

A number of authors have researched the area of wind power forecasting to meet a variety of end-user requirements. An EU project ANEMOS featured an advanced pilot wind power forecasting system that featured improved statistical estimation methods. The ANEMOS forecasting platform features advanced approaches for on-line uncertainty estimation of wind power forecasts using an optimal combination of various short-term prediction models or models fed by different numerical weather prediction models. These features facilitate the functional integration with existing Energy Management Systems at the utilities, [1].

Scheduling of generation in Energy Management Systems generally comprises the two functions, unit commitment and economic dispatch. It optimises planned generation to meet demand at the lowest cost. This takes into account the characteristics of the units such as start up time and costs, minimum up and down times and ramping rates. Methods currently in use are well established, [8]. With low levels of wind power on the system, wind can be ignored and conventional unit commitment methods used in power system scheduling. They are subsequently readjusted when operating the system with wind - this is described as the fuel saver method in [7]. However, when wind power penetration increases, this method will lead to more units being online than needed, and units not operating efficiently. A better approach uses wind forecasts when scheduling the system, and plans reserve based on the expected error of these forecasts. More robust solutions can be provided explicitly accounting for the stochastic nature of wind, which will examine numerous possible scenarios for wind power production.

In [3] and [4], an approach is proposed for the quantification of reserve levels needed on a power system which takes into account the uncertainty of wind power forecasts. For the estimation of the reserve levels, the generator outage rates and forecast uncertainties of load and wind power are taken into consideration. The methodology for reserve calculation relates the reserve level on the system in each hour to the reliability of the system over the year. The reserve levels will vary with the variance of generator scheduling and forecast errors. In the methodology, the probability of generation outages and load shedding are used

as system reliability criteria, instead of reliability analysis focused on generation adequacy calculations (only generation outages). The reliability criterion is defined as the number of load shedding incidents (LSI) tolerated per year. A load shedding incident is defined as an incident when there is not enough reserve to meet a generation shortfall. LSI can be related with loss of load expectation (LOLE) by multiplying the LSI by the average time that load is shed.

These criteria provide for inclusion of the effect of load and wind variations in reserve levels estimation. The methodology also considers the probability of both full and partial generator outages on an hourly basis. The wind and load forecast errors are modelled by a Gaussian stochastic variable. While the load forecast errors are assumed insensitive to the forecast horizon, the wind power forecast errors increase with it. Assuming the non-correlation of the Gaussian errors of load and wind generation, the standard deviation of the total system forecast error is obtained by the same rule. Inspired by the approach in [3] and [4] but assuming wind speed forecast errors as Gaussian stochastic variables instead of wind power production forecast errors, [5] describes methodology for estimation of positive reserves for different forecast horizons.

The successor to ANEMOS, the ANEMOS.plus project is organized under the auspices of European Commission 6th Framework Project as an international collaboration of 21 partners from 8 countries. The project analyses the optimal management of electricity grids linked to large-scale wind power generation with a particular focus on usage of wind forecasting in decision support tools. This paper develops new methodology for application of intelligent management tools for addressing the variability of wind power and provides a basis for a demonstration project. Emphasis is given to the integration of wind power forecasts and related uncertainty in key power system management functions. The demonstration project demonstrates the applicability of such tools at an operational level for managing wind penetration.

The paper is organised as follows. Section I presents the current state-of-the-art tools for wind forecasting, Anemos, and for stochastic operation scheduling, Wilmar. In Section II, the current scheduling practice at the National Control Centres of All Island Grid is outlined, and Section III discusses the current scheduling practice The demonstration project is outlined in Section IV to introduce advanced scheduling functions into the NCC. Finally, a discussion of the project aims and milestones is provided in Section V.

II. FORECASTING AND SCHEDULING TOOLS

A. Anemos

As a state-of-the-art model for two-day-ahead estimations of the wind farm hourly power generation, the Anemos tool will be used, [1], [2]. The tool uses statistical wind forecasting approach, well suited for the system complexity and the fast fluctuations of wind speed. Typical inputs to the Anemos include Numerical Weather Prediction (NWP), climate measurements, the information on the physical system (e.g. availability of the turbines), timestamp, as well as the output

measurements of the current wind power production. The NWPs are provided every 6 hours at the level of the wind farm as interpolated values. They are continuously fed to the Anemos on-line predictor that periodically updates the underlying forecasting models (typically twice per hour). The output of Anemos comprises the forecasted wind power production and the associated uncertainty. A forecast can span a wind farm, a region of interest, or the entire system. The forecasts for the individual wind farms are scaled up to generate regional forecasts. A region may contain wind turbines grouped according to geographical similarities or their legal status (price maker or -taker). In our study, Anemos will use HIRLAM NWPs and on-line measured wind production data as input.

B. Wilmar

The Wilmar planning tool comprises two main parts. The Scenario Tree Tool generates scenarios for wind power production and load based on the respective historical time series and statistical data describing the errors in wind and load forecasting dependent on forecast horizons, [5],[11]. Furthermore, time series for forced outages of units in the power system are generated. It is possible to include more extreme forecast errors than already included in the wind power production and load forecasts. This is achieved by generating demands for replacement reserves (positive reserves) associated with each combination of wind power production and load scenarios by combining wind power production and load forecasts errors with forced outages [5]. The scenarios are then used as inputs to the second part, the Scheduling Model. The Scheduling model is a stochastic, mixed-integer linear programming model calculating optimal unit commitment and dispatch of power plants using a range of wind power production and load forecasts [6], [5], [9]. The model covers day-ahead and intraday scheduling of power plants, heat and electricity storages and transmission lines. It optimises the provision of different types of reserves. Rescheduling is done in regular intervals to include updated wind and load forecasts as well as forced outages.

The type of forecasts used determines the type of scheduling process. In stochastic scheduling, stochastic forecasts of wind power production and load are used, and deterministic scheduling only requires expected values of the two variables. A perfect forecast schedule would be obtained using the historical measured values of load and wind power production. While Anemos is capable of providing deterministic as well as stochastic wind power forecast, load forecasting function in EMS only generates a deterministic, point forecast of load. For this purpose, the Scenario Tree Tool of Wilmar could be used to provide associated uncertainty to the load forecast. Its parameters calibrated using the historical data on load, the STT would use the Monte Carlo-type simulation for every time step using an econometric approach to create a number of load forecast scenarios. In order to keep the calculation burden manageable, the number of scenarios would have to be reduced using the mathematical reduction algorithm.

III. CURRENT SCHEDULING PRACTICE

The Single Electricity Market comprises the two power systems, the Republic of Ireland power system operated by Eirgrid, and Northern Ireland power system, operated by SONI. The two Transmission System Operators (TSOs) use the Reserve Constrained Unit Commitment tool (RCUC) to determine an All Island Indicative Operation Schedules (IOS). The schedules determine key operational quantities for all generators and demand-side units for the entire optimization horizon, up to 30 hours ahead. Within the RCUC model, each power system constitutes a separate area for which distinct system data, wind generation forecast and load forecast is produced, Fig. 1.
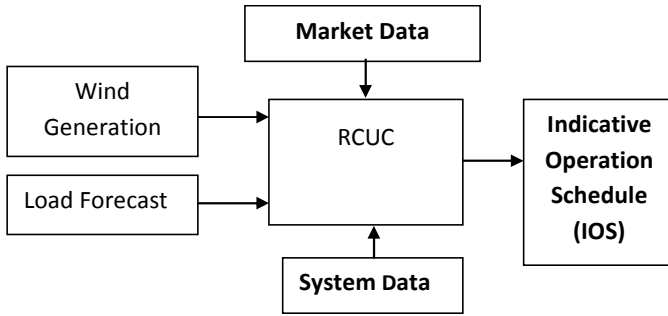

Fig. 1 RCUC Operational Diagram

In addition to the TSOs' schedule calculations using RCUC, there is a parallel process that facilitates the electricity market, resulting in the market-based schedules. It is executed by the Single Electricity Market (SEM) Operator who operates a mandatory gross Pool, in which Ex-ante Market Schedule (EAS) is produced using day-ahead complex bidding, [12], [13]. In the market, ex-post System Marginal Price (SMP) pricing is used which excludes transmission, reserve and other constraints, producing a single island-wide price for each Trading Period (30 minutes). In the market, a separate Capacity Payments Mechanism exists and locational transmission losses are accounted for through other mechanisms. The TSOs thus use the Market Data (commercial and technical offer data) as an input to RCUC to produce an All Island indicative operational schedule which is used to support dispatch decisions by the TSOs, Fig. 1.

To calculate IOS as the minimum-cost schedule, the RCUC takes into account various system constraints including system energy limits and area constraints. The area transmission constraints are implicitly modelled through time-dependent, unit-specific generation limits, dubbed Transmission Constraint Groups (TCGs) that are determined experimentally. The generating units are scheduled respecting the TCGs to provide a congestion-free schedule without explicit modelling of the network. In IOS, the RCUC co-optimizes the energy and reserve schedules for the primary, secondary, tertiary 1, tertiary 2 and negative reserve. At the same time, it calculates the contribution of the optimized schedule to the replacement, substitute and contingency reserve.

The inputs to the RCUC scheduling process include the following information:

- **Market data**, provided by SEM, and comprising Ex-ante Market Schedule (D-1), generators' bids and offers and information on core market and system operation.
- **System data** for both areas, including unit loading status, unit availabilities, generic operation constraints and static generator data.
- **Wind generation forecasts** for both areas. In Eirgrid, the forecast for some 50 wind farms (over 1000 MW installed capacity) is prepared on wind farm level and upscaled to the system total capacity. It is updated every 6 hours for the entire optimization horizon. For 21 wind farms (292 MW installed capacity) in SONI, Anemos tool is used for forecasting at the turbine level, based on the specific characteristics of each turbine.
- **Load forecast** for both areas, updated every 4 hours for the optimization horizon.

The resulting Indicative Operation Schedule consists of half-hour periods, containing the on-off status and planned power for every generating unit on the system. In addition, for every unit the actual reserve schedule held for each reserve type is obtained for each trading period of the study.

The RCUC scheduling process comprises the following sequence of functions: retrieval of all necessary input data, RCUC optimization, publication of indicative operation schedules and data archive. The RCUC is executed prior to the Trading Day and during the Trading Day, as needed by the TSOs, Fig. 2. The Trading Day (in the figures denoted as D) spans the time period between 6:00 AM and 6:00 AM the next calendar day. The main two types of IOS arise as follows:

- **Day-ahead IOS (DA-IOS):** Calculates the optimum half-hourly commitment and dispatch schedules for the 30 hour period from 6:00 (D) until 12:00 (D+1) that meets the demand, reserve requirements and area security requirements. The output of the DA-RCUC is the indicative operations schedule DA-IOS(D).
- **In-Day IOS (IN-IOS):** Calculates the new IOS during (D) as needed to take into account new information regarding load forecast, wind forecast or resource availability. In Fig. 2, this TSO update information is denoted as a black and white octagon. The optimization horizon of the In-Day RCUC run starts from an input start time to the 12:00 on the (D+1). It spans up to 30-hour period.

The DA-RCUC run for the trading day (D), DA-RCUC(D), executes on (D-1) after completion of the Ex-Ante run for (D), EA(D). Using the market data in the last approved Ex-Ante schedule EAS(D), it retrieves the latest TSO updates and calculates the IOS(D) for the optimization horizon between 6:00 (D) and 12:00 (D+1).

The first In-Day RCUC run for the (D), ID-RCUC(D), executes after 6:00 on (D). Based on DA-IOS(D), it considers the latest TSO updates and calculates the updated IN-IOS(D) for the optimization horizon starting from the input start time that is after the execution time and also on the half-hour boundary to 12:00 on the trading day (D+1). In the control centre, there may be several subsequent ID-RCUC(D) runs,

however for the purpose of our study, we have limited the scheduling process to the two runs per trading day. The reasons for this are that the number of calculations required for more in-day runs would be impractical, and the new wind-forecast information is only available every six hours.
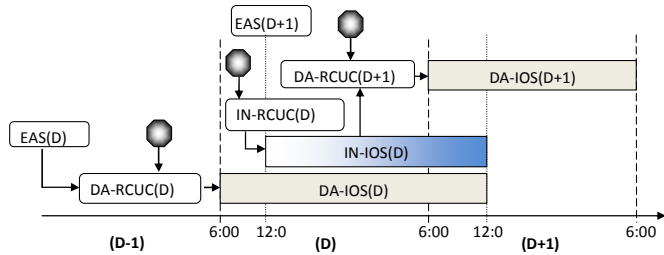

Fig. 2 RCUC Scheduling sequence

IV. DEMONSTRATION PROJECT

A. WALT Methodology

To help the TSOs investigate the possibility and the benefits of installing a new short-term wind forecasting tool, ANEMOS, for use in the control centre, a new study methodology was needed that would combine innovative tools and could serve as a means for operational scheduling improvement. The existing operational scheduling tools are proprietary and do not offer the possibility to investigate new optimisation routines. For this purpose, a methodology has been devised that employs a tool set up consisting of WILMAR, ANEMOS and the supporting interfaces (Wilmar and Anemos scheduLing meThodology - WALT). The WALT has been developed with the following aims:

- To enable the uncertainty to be adequately accounted for in the scheduling process. This could be achieved by introduction of the stochastic information contained in the ensemble predictions of wind energy into generation scheduling process.
- To assess the factors which contribute to improved schedules, and quantify the level of improvement.
- To assess the impact of new information, either deterministic or stochastic, on the schedules during the in-day rescheduling.
- To provide an envelope for interfacing of two stand-alone tools, ANEMOS and WILMAR, in an operational EMS environment in the control centre.
- To set up the data interchange protocols and the necessary infrastructure to prepare for the demonstration of the WALT methodology in the TSO control centre.

The methodology will enable the TSO to analyse and evaluate the effects of the stochastic vs. deterministic wind forecasting, optimisation of different types of the reserves and investigate the impact of different goodness measures for comparison of the schedules. At the same time, the TSO will be able to use WALT to evaluate the current scheduling methodologies and practices, including the TCG determination, through the comparison of the actual schedules with the RCUC dispatch.

B. Treatment of the Uncertainties

The WALT methodology introduces uncertainty in the scheduling process through the load- and wind energy forecasts as well as through forced outages. Currently, the TSO is using a point forecast of the load through the load forecasting function of the EMS. For each trading period, the point forecast provides only a single expected value of the load, with no information on its uncertainty. Instead of point forecast, WALT could also use the stochastic forecast in scheduling, which could be obtained by transforming the point forecast via the Scenario Tree Tool (STT) of Wilmar.

The investigation of WALT effectiveness was designed to consider the impacts of the following drivers on the quality of the schedules, as discussed in [14]:

- Forecasting horizon: the impact of the in-day rescheduling upon availability of new information on the alignment of the planned- and the actual schedule?
- Consideration of the forecast uncertainty: does the probabilistic forecasting of wind and load improve the schedules?

The types of WALT schedules that were calculated to investigate these impacts are described in the matrix in Tab. I. They included three types of scheduling, perfect foresight, deterministic and stochastic, and two timeframes, day-ahead and in-day WALT schedules. They were compared to three types of RCUC-generated IOS:

- PF-IOS: Perfect foresight: based on actual wind generation and load (measured data).
- DA-IOS: Day-ahead, based on forecasted wind power and load.
- IN-IOS: In-Day, based on forecasted wind power and load.

TAB. I
THE MATRIX OF SCHEDULE COMPARISONS IN THE INVESTIGATION

Timeframe	Type	PF-IOS	DA-IOS	IN-IOS
Day-ahead	Perf. Foresight	√	√	
Day-ahead	Deterministic	√	√	
Day-ahead	Stochastic	√	√	
In-day	Deterministic	√		√
In-day	Stochastic	√		√

To determine the effectiveness of the proposed approach, the proposed WALT methodology would need to be applied on an All Island basis in line with the IOS produced by RCUC.

Fig. 3 presents the diagram of WALT schedule generation. In the first step, Anemos is fed with the NWP data, as well as the power system static data (units' parameters and their operational characteristics). For the two areas, an identical set of input data is needed, and a joint wind generation forecast is produced. The Anemos wind power forecast is then supplied to Wilmar, in addition to load forecast, market data and power system data (e.g. parameters, operational characteristics, unit availabilities, constraints, their current loading, operating

status, and their TCGs) for both areas. For the demonstration case, the Anemos wind power forecast data is provided to Wilmar via text files.
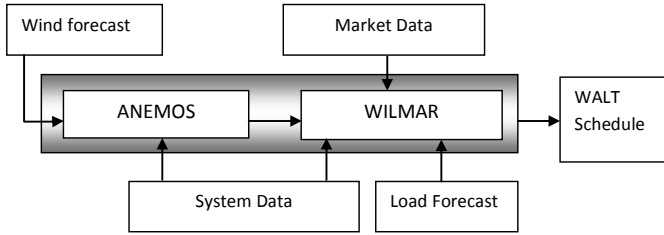

Fig. 3 Proposed WALT operational diagram

To determine the quality of the resulting WALT schedules, they would be compared to RCUC-generated Indicative Operation Schedules, as outlined in Tab. I. Their characteristics should be comparable, especially the length of the forecast horizon (30 hours), timing of execution and the planning step (30 minutes). The WALT schedule should also estimate the reserves for the same types, accounted for in RCUC.

C. Metrics for the Schedule Comparison

The optimization function in the scheduling tool minimizes cost, while the schedule must obey the operational limits at all times. For comparison of the IOS and WALT schedules, appropriate metrics is needed. Some **goodness of fit measure** would need to be designed to be effective in comparison and evaluation of the WALT schedules. The following parameters could be included in the measure:

- **Costs**: Costs of unit startups; cycling costs (increased O&M costs, capital costs due to equipment replacements and reduced income from reduced availability due to cycling); reduction in constraint costs due to reserve optimisation; fuel costs and emission costs.
- **Non-financial measures** that could either be accounted for as limits or included into the criterion function: unit's capacity factor, connected to its flexibility, number of unit's operating hours (e.g. total per year or average online stretch), and system-wide reserve requirements. Reduction in load shedding incidents could also be incorporated.

The metrics for schedule comparison should also consider the value of the schedule robustness and the improved reliability of a schedule with a greater number of units running. Through the comparison of schedules prepared with deterministic and stochastic planning process, the cost of the uncertainty could be determined. The design of the goodness of fit measure is currently a research topic of the ANEMOS.Plus project.

V. DISCUSSION

In the paper, an innovative methodology for scheduling of power system with large share of wind generation is presented. The WALT methodology links state-of-the-art wind generation forecasting tool, Anemos, and Wilmar scheduling tool to provide for deterministic as well as stochastic scheduling of the system, driven by uncertainties in wind and load forecasts.

The planned rollout of the demonstration case involves two phases. In Phase 1, the tools of the WALT will be set up and calibrated. The objective of this phase is to create the deterministic PF, DA and IN WALT-generated schedules that will resemble RCUC-generated IOS. The stochastic WALT schedules will then be compared to the corresponding deterministic IOS and any differences evaluated.

In Phase 2, the WALT schedules are to be compared to the actual measured schedules. The objective is to change some of the modelling assumptions or planning procedures for WALT schedules to resemble measured ones. Then, the changes would be evaluated against those settings used in fitting the RCUC-generated schedules. This way, an insight could be gained in how the RCUC could be improved to schedule the system closer to it actual operation.

The WALT tools are currently being installed in EirGrid as a part of the demonstration project. The project will combine advanced forecasts with stochastic optimization and enable the TSOs to obtain more reliable and less costly schedules. Calibrated on measured historical data, the WALT methodology will enable the TSOs to evaluate the impact of the inclusion of forecasting uncertainty in the scheduling process. Through the use of the WALT study, the TSOs will gain an understanding of what improvements may be implemented in the current scheduling process.

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VII. BIOGRAPHIES

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Jonathan O'Sullivan received B.E. and Ph. D. degrees from University College Dublin in 1992 and 1996 and a D.M from Henley College in 2005. He has worked for the Irish Transmission System Operator (EirGrid) since 1996. He has held senior engineering positions in the planning and operation departments. In addition he has spent over eight years in the management, operation and design of the Irish electricity market and was the Project Manager of the Single Electricity Market (SEM) that launched on an island of Ireland basis in November 2007. He is currently the Manager Operational Policy and Performance and is charged with coordinating EirGrid's efforts in facilitating the integration of up to 40% of electricity by renewable sources by 2020.

Tom McCartan received B.Eng from Queens University Belfast in 1986 and M.Sc in Manufacturing technology, design and management from Queens in 1997. He has worked in the electricity industry since 1986 both on generation operations and transmission technical sides. He joined SONI, the N. Ireland TSO, in 2007 and is responsible for the Generation scheduling day ahead, outage schedules and wind power predictions. He is a member of the IET.

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