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WP3 Prototype development for operational planning tool

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Abstract:

This report documents the model development carried out in work package 3 in the SUPWIND project. It was decided to focus on the estimation of the need for reserve power, and on the reservation of reserve power by TSOs. Reserve power is needed to cover deviations from the day-ahead forecasts of electricity load and wind power production, and to cover forced outages of power plants and transmission lines. Work has been carried out to include load uncertainty and forced outages in the two main components of the Wilmar Planning tool namely the Scenario Tree Tool and the Joint Market Model. This work is documented in chapter 1 and 2. The inclusion of load uncertainty and forced outages in the Scenario Tree Tool enables calculation of the demand for reserve power depending on the forecast horizon. The algorithm is given in Section 3.1. The design of a modified version of the Joint Market Model enabling estimation of the optimal amount of reserve power to reserve day-ahead before the actual operation hour is documented in Section 3.2.

With regard to the evaluation of a power system, its ability to cope with extreme events is crucial to be investigated. Chapter 4 gives a definition of such extreme events. Further, the methodology to identify extreme events on the basis of the existing tools is described.

Within the SUPWIND consortium there has been an interest in using the Joint Market Model to model smaller parts of a power system but with more detailed representation of the transmission and distribution grid. Chapter 5 documents this work.

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Preface

One purpose of the SUPWIND project was to modify and extend the Wilmar Planning tool, such that it can be used to support decisions related to the day-to-day operation of the power system. Examples of day-to-day operational decisions are:

- Estimation of capacities of international transmission lines available for the day-ahead power market. This is done by the transmission system operator (TSO) in the Scandinavian power system.
- Power producers bidding on the day-ahead power market, e.g. the spot market on the Nordic power pool Nord Pool.
- Unit commitment and dispatch of power plants by power producers or TSOs taking the obligations undertaken at the day-ahead power market into account.
- Estimation of the need for different types of reserve power.
- Reservation of reserve power by TSOs.

There are two TSOs in the SUPWIND consortium, the Danish Energinet.dk and the Greek TSO (HTSO), and no power producers. Although some transmission system operators, such as EirGrid in the Republic of Ireland, are still involved in the unit commitment and dispatch of power plants, this is not the case for Energinet.dk and HTSO. It was therefore decided to focus on the estimation of the need for reserve power, and on the reservation of reserve power by TSOs.

Reserve power is needed to cover deviations from the day-ahead forecast of electricity load and wind power production, and to cover forced outages of power plants and transmission lines. Subsequently, work has been carried out to include load uncertainty and forced outages in the two main components of the Wilmar Planning tool namely the Scenario Tree Tool and the Joint Market Model. This work is documented in chapter 1 and 2. The inclusion of load uncertainty and forced outages in the Scenario Tree Tool enables the calculation of the demand for reserve power depending on the forecast horizon. The algorithm is given in Section 3.1. The design of a modified version of the Joint Market Model enabling estimation of the optimal amount of reserve power to reserve day-ahead before the actual operation hour is documented in Section 3.2.

With regard to the evaluation of a power system, its ability to cope with extreme events is crucial to be investigated. Chapter 4 gives a definition of such extreme events. Further, the methodology to identify extreme events on the basis of the existing tools is described.

Within the SUPWIND consortium there has been an interest in using the Joint Market Model to model smaller parts of a power system but with more detailed representation of the transmission grid. Chapter 5 documents this work.

1 Load forecasting

Since electricity cannot be stored on a large scale, the demand for electricity has to be satisfied in real time. Additionally, the operational flexibility of some power plant types to react on load changes is limited. As a consequence, the optimal unit commitment requires a precise load forecast. However, the load forecast is associated with errors. The Joint Market Model includes these load forecast errors in its stochastic optimization. The Scenario Tree Tool provides realistic scenarios of load forecasts and it preprocesses the required load data for the further use in the Joint Market Model. The simulation of the statistical nature of the load forecast error is described in 1.1. Section 1.2 explains the general approach for load forecasting and the processing of the data within the Scenario Tree Tool. Section 1.3 deals with the inclusion of the load forecast in the Joint Market Model.

1.1 Statistical model for load forecasting

The generation of the load forecast error is based on an ARMA approach, i.e. Auto Regressive Moving Average series, following (Söder 2004). For example by using an ARMA(1,1) approach, this series is defined as

$$\begin{aligned} &X(0) = 0 \\ &Z(0) = 0 \\ &X(k) = \alpha X(k-1) + Z(k) + \beta Z(k-1) \end{aligned} \tag{1}$$

X(k) = forecast error in forecast hour k $\in$ N

Z(k) = random Gaussian variable with standard deviation σ_Z in forecast hour k $\in$ N

α, β = parameter of the ARMA series.

The variance of the exemplarily ARMA(1,1) model, i.e. the variance of X(k), can be calculated in the following way:

$$\begin{aligned} &V(0) = 0 \\ &V(1) = \sigma_Z^2 \\ &V(k) = \alpha^2 V(k-1) + (1+\beta^2 + 2\alpha\beta)\sigma_Z^2 \end{aligned} \tag{2}$$

For $k \geq 2$, this equation can be rewritten as

$$V(k) = \sigma_Z^2 \left(\alpha^{2(k-1)} + (1+\beta^2 + 2\alpha\beta)\sum_{i=1}^{k} \alpha^{(i-1)} \right) \tag{3}$$

The standard deviation of the forecast error is then calculated as

$$\sigma\big(X(k)\big) = \sqrt{V(k)} \tag{4}$$

To estimate the parameters of the ARMA series, the standard deviations of the ARMA series (that can be calculated theoretically) are compared to empiric standard deviations for every forecast hour that can be estimated analyzing historic forecasts. By comparing the empiric and ARMA standard deviations and trying to have a minimal deviation between the two values one obtains a typical optimization problem that allows the estimation of the parameters of the ARMA time series. After the calculation of α and β, these parameters are included in the Scenario Tree Tool.

1.2 Inclusion of load forecasting in the Scenario Tree Tool

Based on the methodology as described in 1.1, a set of load forecast error scenarios is generated by Monte-Carlo-simulations. The load forecast scenarios are determined on the basis of historical data of load time series plus the forecast error simulated. This process is shown in *Figure 1*.

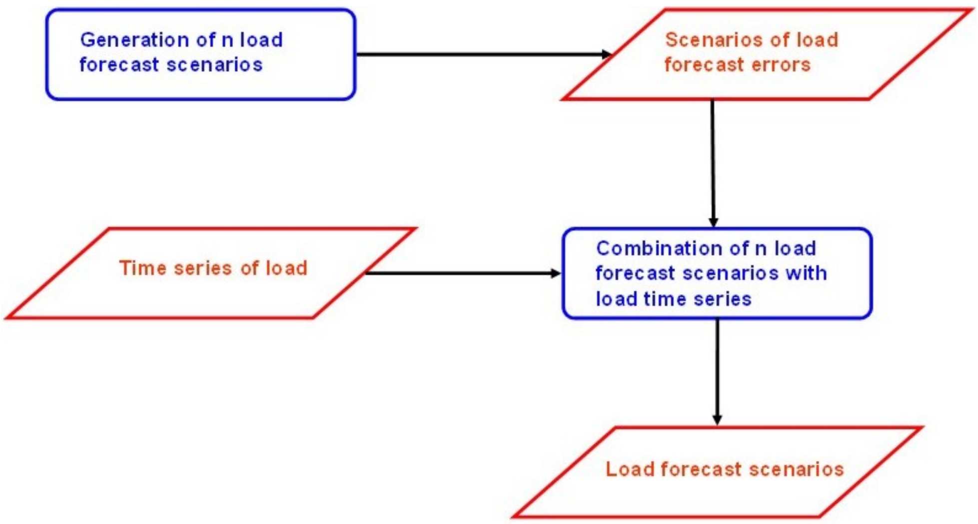


Figure 2: Data processing in the Scenario Tree Tool

The high number of load scenarios that are obtained by the Monte-Carlo-simulations as described above, are randomly combined with wind scenarios. It is assumed that the errors of load forecasts are uncorrelated with the errors of wind forecasts. As a consequence, forecast errors can compensate partially. However, the high number of scenarios from the Monte-Carlo-Simulations has to be reduced. Hence, a scenario reduction algorithm follows the scenario generation (Barth et al. 2006). The reduced number of scenarios is the basis for the scenario trees that serve as input for the Joint Market Model.

1.3 Inclusion of load forecasting in the Joint Market Model

The functionality of the Joint Market Model has been described in detail in (Meibom et al. 2006) available from www.wilmar.risoe.dk, so extensive reference to this publication will be made in the following.

Load forecasting is introduced in the Joint Market Model in the same way as wind power forecasting. For each optimization period a scenario tree with the load forecasts is given in input parameter “O Parameter BASE_DE_VAR_NT.inc” in folder Base\Model\inc_database. In the optimization period covering the day-ahead market (see (Meibom et al. 2006) for an explanation of the rolling planning structure of the Joint Market Model) the expected load hour per hour for the following day is included in the power balance restriction for the day-ahead market (*QEEQDAY* in the terminology of (Meibom et al. 2006)). The expected load is calculated as the average of the load forecasts in the scenario tree.

For each optimization period, in the power balance for the intraday market (*QEEQINT*) the difference between the expected load bid into the day-ahead market and each load forecast (each branch in the scenario tree) is calculated, and up- or down-regulation activated in each hour to cover the deviations between these two.

A restriction ensuring enough supply of replacement reserves (named non-spinning secondary reserves in (Meibom et al. 2006)) exists (*QNONSP_ANCPOSEQ)* in the Joint Market Model. The restriction reserve production capacity on top of the production capacity already reserved due to up- or down regulation planned in *QEEQINT*. Therefore the demand for replacement reserve in *QNONSP_ANCPOSEQ* has to be reduced with the demand for up-regulation activated by the load forecast errors. This is done for each optimisation period by including the difference between each load forecast and the average of the load forecasts in *QNONSP_ANCPOSEQ*.

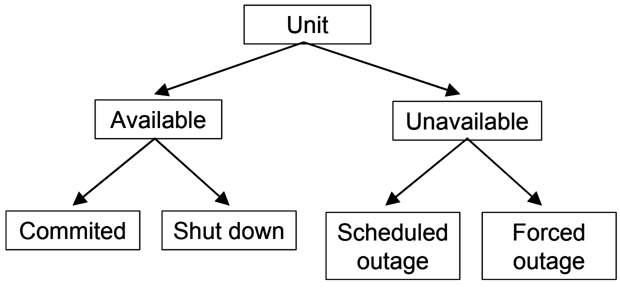
Finally when determining shadow values for online unit and electricity storages (see page 32 in (Meibom et al. 2006)) the load forecasts are used in stead of the deterministic load in the previous version of the Joint Market Model.

2 Outages of power plants

Determining the optimal unit commitment and dispatch, the possible unavailability of power plants has to be taken into account. The unavailability of a power plant can be caused by maintenances, which are of deterministic nature, or it can be caused by unplanned forced outages, which are of stochastic nature. Section 2.1 describes the stochastic approach to model outages. Afterwards, section 2.2 describes the inclusion of power plant outages in the Scenario Tree Tool. Last, section 2.3 addresses the issue of power plant outages in the Joint Market Model

2.1 Statistical model for outages

The Joint Market Model has to consider, both forced and scheduled outages, during the optimisation of the unit commitment and dispatch. Hence, the status of an individual unit (or unit group, if aggregation of individual units is used to reduce the computational effort) has to be known. The status of a unit is conventionally described as residing in one of several possible states, see *Figure* 2. These operating states can be classified according to the availabilities. In the case that a unit is available, it may be in two other states: committed or shut down. In the case that a unit is unavailable, it is under repair and cannot generate power. The unavailability can be due to a scheduled or forced outage.

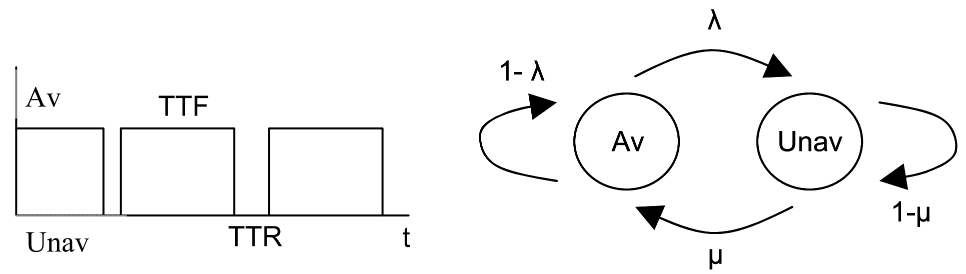


modified from (Valenzuela; Mazumdar 2001)

Figure 2. Generating unit states.

Possible states of a system or component can be described with the state-space method (Endrenyi 1978). It identifies the particular states of a system or component and the possible transitions between them. All of the possible states of a certain system or component make up the state-space. Generally a Markov model is applied to describe the process of the system changing state. Therefore possible states and the transition rates from state i to j are considered. As generally in Markov processes, the probability of being in one state at time t+Δt depends on the state at time t, but not on the states occupied earlier.

The state of availability and unavailability of a unit may be described with a two state Markov process. The process consists of alternating "availability" and "unavailability" periods. The state space diagram, see *Figure 3*, shows the states of availability "Av" with the time duration "time to failure" (TTF) and unavailability "Unav" with the time duration "time to repair" (TTR). The transition rates are described with the failure rate λ and repair rate μ. Perfect repair is assumed, thus the cycles are repeated.



modified from (Endrenyi 1978)

Figure 3. Repairable unit cycle.

The transition rates λ and μ can be expressed with the mean time to failure (MTTF) and the mean time to repair (MTTR), respectively (Endrenyi 1978):

$$\lambda = \frac{1}{MTTF} \tag{5}$$

$$\mu = \frac{1}{MTTR} \tag{6}$$

In the case that the durations of the time to failure (TTF) and time to repair (TTR) are exponential distributed, the failure rate λ and repair rate μ are constant and the Markov process is called homogenous (Endrenyi 1978), (Anderson, Davidson 2005). This means that the transition rates are dependent on the length of the time interval but independent on the point in time. The probability density function of an exponential distribution e.g. for the TTF is defined as follows:

$$f(t;\lambda) = \lambda \cdot e^{-\frac{t}{\lambda}} \tag{7}$$

Further assuming that the unit is available at time 0, the state probabilities $p_{Av}(t)$ and $p_{Unav}(t)$ becomes (Endrenyi 1978):

$$p_{Av}(t) = \frac{\mu}{\lambda+\mu} + \frac{\lambda}{\lambda+\mu} e^{-(\lambda+\mu)t} \tag{8}$$

$$p_{Unav}(t) = \frac{\lambda}{\lambda+\mu} + \frac{\lambda}{\lambda+\mu} e^{-(\lambda+\mu)t} \tag{9}$$

The long term probabilities, that are independent of the initial conditions, are derived by making the transition $t \rightarrow \infty$:

$$p_{Av} = \frac{\mu}{\lambda + \mu} = \frac{MTTF}{MTTR + MTTF} \tag{10}$$

$$p_{Unav} = \frac{\lambda}{\lambda + \mu} = \frac{MTTR}{MTTR + MTTF} \tag{11}$$

p_{Unav}, compare equation (11), corresponds to the so called "forced outage rate" (FOR), which is in fact not a rate. The FOR is further commonly described by:

$$FOR = p_{Unav} = \frac{forced\ outage\ hours}{forced\ outage\ hours + available\ hours} \tag{12}$$

Although it is often realistic to model times to failure by an exponential distribution, repair and maintenance durations are better represented with bell-shaped distributions, compare e.g. (Endrenyi 1978). E.g. the fraction longer than the expected MTTR is smaller for the bell-shaped distribution than for the exponential distribution due to the longer tail of the exponential distribution. Thus, the generation of homogenous Markov processes describing the unavailability of a unit with exponential distributed TTR may lead to unrealistic results. As alternative to the exponential distribution, the two-parameter Weibull distribution is proposed, see (Van Casteren et al. 2000), (Anderson, Davidson 2005). The probability density function of a Weibull distribution e.g. for the TTR is defined as follows:

$$f(t, \mu, k) = \frac{k}{\mu}\left(\frac{t}{\mu}\right)^{k-1} \cdot e^{-(\frac{t}{\mu})^k} \tag{13}$$

The Weibull distribution with the shape factor $k = 1$ corresponds to an exponential distribution. Using shape factors $k > 1$, the Weibull distribution becomes bell-shaped.

Semi-Markov models are applied for non-exponential distributions; compare e.g. (Anderson, Davidson 2005), (Perman et al. 1997), (Pievatolo et al. 2004) and (Van Casteren et al. 2000). A main characteristic feature of Semi-Markov models is the use of a random value which describes the sojourn of a unit in a given state. Thereby the distribution of this random value can be chosen to meet the characteristics. I.e. if $X(t)$ is the state of the unit at time t and S_n represents the time of the n^{th} transition, the duration $U_n = S_n - S_{n-1}$ is a random draw of the considered duration for the present state $X(t)$. Hence, U_n depends only on the present state $X(t)$ and not on the states $X(t)$ with $t < S_{n-1}$ (Anderson, Davidson 2005). The generation of Semi-Markov processes for consideration of forced outages for each unit in the Joint Market Model are based on given data of FOR and MTTR. Based on this data, the MTTF can be calculated after some rearrangement of equation (11) and (12):

$$MTTF = MTTR \cdot \frac{1 - FOR}{FOR} \tag{14}$$

The algorithm to generate Semi-Markov processes describing the availability or unavailability of a unit proceeds as follows. For each individual unit, a Semi-Markov process covering a whole year is generated. Thereby it is assumed that forced outages of individual units are uncorrelated.

1. To start a Semi-Markov process, the state of a unit at the beginning of the process has to be determined. This is done by drawing a random number y on the unit interval and by comparing it to the “full outage probability” (FOP):

$$FOP = \frac{FOR}{MTTR} \tag{15}$$

   In the case that the drawn random number y is smaller than FOP of a unit, i.e. y ≤ FOP, the unit is considered to be unavailable. Otherwise if y > FOP, the unit is considered to be available.

2. In the case that a unit is unavailable, a random value of the TTR is drawn from a Weibull distribution with scale factor equal to the given MTTR and shape factor k. When the drawn sample of TTR has elapsed, the state of the unit changes to available.

   In the case that a unit is available, a random value of the TTF is drawn from an exponential distribution. The MTTF is used as distribution parameter. When the drawn sample of TTF has elapsed, the state of the unit changes to unavailable.

3. Generate successive TTR and TTF until a whole year is covered.

4. The Semi-Markov processes of the individual units only cover forced outages. Thus, scheduled outages have to be included into the Semi-Markov processes describing the availability or unavailability of an individual unit. To include these time-series of scheduled outages, the following rules are applied:

   a. In the case that the drawn sample of the TTF extends into the time period of a scheduled outage, the state of the unit is changed to be unavailable at the time when the scheduled outage begins.

   b. In the case that the drawn sample of the TTR after a forced outage extends into the time period of a scheduled outage, the duration of the scheduled outage is not altered. Since there is no knowledge whether the cause for the forced outage is related to the coverage of the maintenance work, no assumption of a possible reduction or extension of the time duration of the scheduled outage can be made.

   c. After the termination of a scheduled outage, the unit is considered to be available for a random value of TTF until the next forced outage.

5. The resulting FOR of the yearly Semi-Markov processes due to forced outages is compared to the given FOR of each unit. The algorithm is restarted until the resulting FOR is equal to the given FOR with a given tolerance.

2.2 Inclusion of outages in the Scenario Tree Tool

Basically the Scenario Tree Tool determines the availability/unavailability of each unit following the Semi Markov process described above. A large number of units may become intractable to be solved. As a consequence, it can be preferable to consider the availability and the unavailability on the level of unit groups, not on the level of single units. Unit groups describe the aggregation of power plants with similar characteristics concerning certain predefined criteria, like fuel type, technology and vintage. The Scenario Tree Tool offers the option to aggregate units in predefined unit groups and to calculate the availability of each unit group. This is done by superposition and results in a factor between 0 and 1 that indicates the percentage of the overall unit group capacity that is available. For this purpose, first the capacity of the unit groups is calculated, see *Figure 4*. In a next step, it is determined for each unit at which fraction the total group capacity is represented by the unit. Finally, the superposition of the units takes place. The group availability is the cumulative availability of all member units, which have to be weighted with their capacity share.

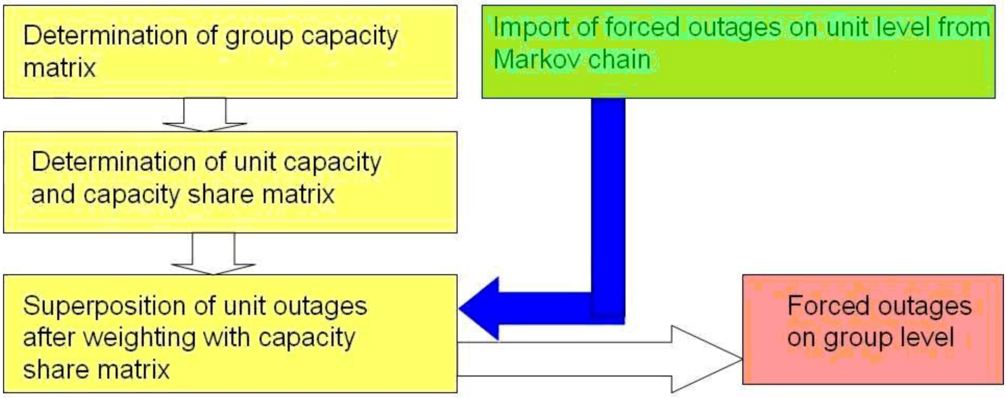


Figure 4: Aggregation to unit groups

2.3 Inclusion of outages in the Joint Market Model

Forced outages of individual power plants have to be considered during the optimisation of the unit commitment in the Joint Market Model. This consideration is done in two ways:

- Forced outages (besides scheduled outages) are considered when the requirements for the forecast and time dependent replacement reserve due to the total forecast error in the power system are determined by the Scenario Tree Tool. Hence, the model is obliged to reserve power plant capacity to provide positive replacement reserves according to these requirements.
- One Semi-Markov process for each individual unit is forwarded to the Joint Market Model describing the availability or unavailability of the unit due to forced outages during a whole year. Units that are unavailable at a certain time cannot be committed at the day-ahead and intraday scheduling process during this time, i.e. their capacity is expected to be 0 during this time. This Semi-Markov process, generated by the Scenario Tree Tool (see Section 2.1), is dependent on time and independent on forecast.

Since there is only one independent Semi-Markov process describing the availability or unavailability of an individual unit, forced outages are treated as deterministic exogenous parameter to the Joint Market Model. In the case that this information is accessible at the day-ahead scheduling process or at the second and third stages of the planning loops describing the intraday rescheduling, the unit commitment would take into account forced outages that are unknown at these time steps in reality. To avoid this unrealistic consideration of forced outages, the following approach is implemented:

In the hour when the day-ahead scheduling is optimised, i.e. at 12 o'clock, any future forced outages as determined following the Semi-Markov process are not considered. This means that all units are expected to be available during the optimisation horizon up to 36 hours, expect those that (a) are planned to have a scheduled outage during the optimisation period, (b) suffer a forced outage at 12 o'clock or (c) have suffered a forced outage before and are still under repair during the optimisation period.

This means that the parameters describing forced outages for the forecast time steps T13 - T36 are set to "available" except for those units where:

- A scheduled outage is planned during the forecast time steps T13 - T36, i.e. a further parameter is needed describing scheduled outages depending on unit and time.
- The considered unit is unavailable due to a forced or scheduled outage at forecast time step T01, i.e. at 12 o'clock, and the repair time extends into the forecast time steps T13 - T36.

During the optimisation of the subsequent planning loops describing the intraday rescheduling, the Joint Market Model considers the information of forced outages that occur within the first stage of the scenario tree. The knowledge of future outages in the stages 2 and 3 of the scenario tree has to be neglected since this would correspond to an unrealistic knowledge of future forced outages, too.

This means that the parameters describing forced outages for the time steps of the second and third stage are set to "available" except for those units where:

- A scheduled outage is planned during the time steps of the second and third stage.
- The considered unit is unavailable due to a forced or scheduled outage at forecast time steps T01 - T03 and the repair time extends into the time steps of the second or third stage.

In the case that an individual unit suffers a forced outage during the first stage of the intraday rescheduling, i.e. at forecast time steps T00 – T03, its committed power at the day-ahead scheduling is not available any more. Hence, the production planned for the day-ahead scheduling (value of the variable vgelec_t) of this unit has to be subtracted also in the electricity balance equation for the intraday rescheduling (QEEQINT) for the time duration of the outage.

The forced outage of a unit is considered by the reservation of capacity to provide positive replacement reserves. The amount of reserved capacity is forecast and time dependent. This capacity may have to be disposable for committing at the intraday rescheduling to balance the forced outage. This can be achieved by reducing the size of the capacity that has to be reserved to cover the remaining forecast error (e.g. due to wind power and load forecast error) by:

- In case of a spinning unit suffering a forced outage: the online capacity of the unit planned in the previous planning loop.
- In case of a non-spinning unit suffering an outage: the replacement reserve obligation undertaken by the unit in the previous planning loop.

In the second and third stage of the planning loop the reserved capacity for replacement reserves has to be recovered to the original required capacity to be able to consider a further forced outage. I.e. there is no subtraction of the committed power in the second and third stages.

3 Reserve management

3.1 Estimation of need for replacement reserves using the Scenario Tree Tool

Reserve capacity has to be provided to cope with forecast errors of load and wind power and with unexpected events happening in a power system like forced outages. In the Joint Market Model one reserve category named replacement reserve is used to cope with these uncertainties in an activation time of 5 minutes or more, and three reserve categories are representing the demand for spinning reserves with activation times lower than 5 minutes. The demand for replacement reserves is determined by the Scenario Tree Tool corresponding to the total forecast error of the power system considered which is defined according to the hourly distribution of wind power and load forecast errors and the possibilities of forced outages. Since the forecast errors and the probability of outages vary during the time, the demand for replacement reserves varies as well. Furthermore, since the Joint Market Model considers individual scenarios of the forecast error within the scenario tree, the demand for replacement reserves varies within the scenario tree, too. Thereby it is assumed that a certain percentile of the total forecast error has to be covered by the replacement reserves. Before the methodology of the determination of the demand for replacement reserves is illustrated, considered indices and parameters are defined:

Indices:

r:	model region
g:	generating unit
g(r):	generating units in region r
n:	node in the scenario tree
t:	hour t
t_0:	the first hour of the scenario tree, i.e. the hour when the wind power forecasts are made
f:	the horizon for the wind power production forecasts, i.e. f = (1,2,3, …, 36)
i:	number of generated scenarios
s:	scenario
$s_F(n,f)$:	the part of unreduced scenarios that belong to node n, i.e. the unreduced scenarios s covering the hours f belonging to node n that are bundled into n by the scenario reduction algorithm

Parameters:

$W_E(r,t_0,f)$:	expected wind power production in region r, in time t_0 at forecast horizon f considering the weighted average of the forecast scenarios
$W_F(r,t_0,f,s)$:	forecasted wind power production in region r, in time t_0 at forecast horizon f in scenario s
$L_E(r,t_0,f)$:	expected load in region r, time t_0 at forecast horizon f considering the weighted average of the forecast scenarios

$L_F(r,t_0,f,s)$: forecasted load in region r, time t_0 at forecast horizon f in scenario s

$C(r,g)$: installed capacity of generating unit g in region r

$Y(r,g,t)$: state (available or unavailable) of installed capacity of generating unit g in region r in time step t in scenario s

$P_{Ref}(r,t)$: reference of the power balance in region r in time t

$P(r,t_0,f,s)$: power balance in region r in time t_0 at forecast horizon f in scenario s

$\Delta P(r,t,n)$: total forecast error in region r at time t in node n

$\Delta P_{nth}(r,t,n)$: n^{th} percentile of the total forecast error in region r at time t in node n

The methodology proceeds as follows:

1. Generate i scenarios of wind power forecasts $W_E(r,t_0,f,s)$ in region r in time t0 at forecast horizon f based on Monte-Carlo-simulations, compare section 1.1.
2. Generate i scenarios of load forecasts $L_E(r,t_0,f,s)$ in region r in time t0 at forecast horizon f based on Monte-Carlo-simulations, compare section 1.1
3. Generate scenario of Y(r,g,t) describing availability / unavailability capacity of each generating unit g at forecast horizon f in time step t based on Monte-Carlo-simulations of Semi-Markov processes, compare section 2.1
4. Determine the reference of the power balance P_{Ref} in model region r at time step t. Since perfect foresight cannot be assumed, the reference power balance P_{Ref} has to consider the expected wind power feed-in and load as well as the installed capacity minus scheduled outages but ignoring forced outages:

$$P_{\text{Ref}}(r,t_0) = \sum_{g\in G(r)} C(r,g) + W_E(r,t_0,f) - L_E(r,t_0,f) \tag{16}$$

5. Determine the power balance of scenario s. Thereby the hours of the forecast horizon f are allocated to the corresponding hours of the Markov chains describing the availability of the generating unit g. The individual scenarios of wind power forecasts, load forecasts and forced outages are randomly allocated to each other.

$$P(r,t_0,f,s) = \sum_{g\in G(r)} C(r,g)Y(r,g,t) + W_F(r,t_0,f,s) - L_F(r,t_0,f,s) \tag{17}$$

6. Determine the difference between the reference power balance and the power balance of scenario s. This is equal to scenarios of the total forecast error within the considered region r due to errors of wind power forecasts and of load forecasts as well as of forced outages (t is equal to t_0 + f):

$$\Delta P(r,t_0,f,s) = P_{\text{Ref}}(r,t) - P(r,t_0,f,s) \tag{18}$$

7. The number of scenarios s of wind power and load forecasts is reduced according to the applied scenario tree. Thereby it is recorded which scenarios are represented by a reduced scenario belonging to node n, i.e. which scenarios represent the set of scenarios $s_F(n,f)$ belonging to node n. Based on this

allocation, the distribution of the total forecast error $\Delta P(r,t,n)$ in the considered region r of node n in time t is determined.

8. Determine the e.g. n^{th} percentile of $\Delta P(r,t,n)$, labelled $\Delta P_{nth}(r,t,n)$. This percentile of the total forecast error is considered to be the demand of non-spinning positive reserves.

3.2 Model for reservation of tertiary reserves

3.2.1 Introduction

In the Nordic countries, the transmission system operators are mostly state-owned companies, non-commercial and independent with respect to the market, and responsible for the security of supply (NordPool). Considering Denmark in particular the tasks of the system operator Energinet.dk further includes the integration of renewable energy, wind power currently being the most significant source.

To secure that supply covers demand, Energinet.dk activates so-called manual regulation (balancing power) bought within the Nordic market. Due to market imperfections, manual regulation may not always be directly available in the market and often has to be reserved prior to activation. Up-regulation is activated in the case that supply is insufficient to fully meet demand and was first solely reserved through bilateral contracts of a year or more before monthly and daily auctions were introduced. The bilateral contracts have been kept for the purpose of reducing risk of investment for market entrants but the total volume is now limited. Down-regulation is activated in case supply is more than sufficient to meet demand and is reserved only on daily auctions (Energinet).

1In the present paper we present a modelling framework for optimizing manual regulation reserves bought by the system operator on a day-to-day basis, such reserves also being referred to as tertiary reserves within the association of transmission system operators in continental Europe UCTE. We use Denmark and the Nordic markets as a case study although the model applies in general to a power system for which ancillary services are subject to similar market conditions.

3.2.2 Tertiary reserves

The Nordic electricity system operates with a day-ahead and two intra-day markets. The day-ahead market Elspot is a spot market established for the delivery of power from producers to consumers and has its name from the practice of committing to deliver a day in advance. The two intra-day markets comprise the aftermarket to Elspot named Elbas and the regulating power market. Unlike in Elspot and Elbas, in the regulating power market producers and consumers make supply and demand offers to be activated by the system operator.

Although the day-ahead market aims at balancing supply and demand, real-time imbalances may still occur due to potential differences between expected values at the time of planning and realized values at the time of operating and due to possible contingencies during operation of the system. Whereas contingencies are caused by forced outages of generating units and failures of transmission lines, discrepancies result from unpredicted variations in demand and notably wind power. A rebalancing of supply

1

and demand is possible through the aftermarket. Since historical records show that the actual volume exchanged in the aftermarket is limited we do not consider this market. The real-time balancing of supply and demand is the responsibility of the system operator and is achieved by means of so-called regulation. Depending on activation time, regulation divides into the following:

- Frequency regulation/primary reserves: Frequency regulation or primary reserves stabilize the frequency after an imbalance of the system. The frequency may be stabilized at a stationary value different from the nominal. The time of activation is a few seconds or minutes and the duration at most 15 minutes.
- Automatic regulation/secondary reserves: The aim of automatic regulation is to restore the nominal frequency value. It is automatically activated within a few seconds or minutes and usually stays active for 15 minutes.
- Manual regulation/tertiary reserves: Manual regulation is used to manually restore its primary or secondary equivalents and is therefore activated within 15 minutes. Mostly, it is obtained through the regulating power market. To ensure sufficiency, the system operator is allowed to reserve the regulation ahead of operation, such reserves also being referred to as tertiary reserves. Regulation reserved is still exchanged through the regulating power market, however.

For further references on reserves within the Nordic countries and the European Union, see (Nordel) and (UCTE).

From a social perspective sufficient regulation should always be available during operation and thereby directly in the regulating power market, uncovered imbalances being highly expensive. Still, since regulation is a public good everybody enjoys the regulation supplied by others and the resulting security of supply and insufficiencies occur. Indeed, since the benefits of regulation are not fully remunerated producers may have no incentive to produce it voluntarily even though the system would benefit. This lack of incentives must handled within the system design. The transmission system operator will reserve regulation ahead of operation to ensure availability of this public good and pay up the social value for availability, thereby compensating for the contribution. Such regulation reserves may be seen as real options of the transmission system operator and the corresponding payments as option prices. Upon exercise, producers are obligated to offer the reserves to the regulating power market in the fashion as regulation offered directly.

To reflect the situation that regulation reserves are bought ahead of operation it is assumed that the scheduling of reserve capacity takes place at the time of day-ahead market commitment. In contrast, both reserved and direct regulation is bought during operation. The challenge of the system operator is therefore the day-ahead scheduling of regulating reserve capacity such as to facilitate the balancing of supply and demand by regulation.

A major problem in scheduling regulation reserves is that of reserving ahead of operation and hence with only limited information on supply and demand. On one hand reserve capacity may turn out insufficient in the case of discrepancies between expected and realized supply and demand and shortage may induce considerable costs. On the other hand reserve capacity constitutes serious costs making abundance unwanted. We therefore propose a model that optimizes manual regulation reserves taking into account the uncertainty in supply and demand by using stochastic programming.

The emphasis of this paper is placed on scheduling manual regulation reserves since frequency regulation and automatic regulation is controlled on a timescale that generally calls for other types of models. As concerns reserve requirements manual regulation may be divided into normal operating reserves and disturbance reserves (UCTE). In balancing, however, no distinction is made between the two types of manual regulation and therefore here the reserve requirements are considered in one.

3.2.3 Modelling tertiary reserves

The model takes as a starting point a mixed-integer linear programming model for unit commitment and dispatch, cf. (Takriti, Birge 1996), and includes the optimization of reserves. Since, however, reserve requirements are determined by the discrepancies between expected and realized power supply and demand at the time of operating and non-anticipated contingencies during operation of the power system, the model is formulated as a stochastic programming model taking into account uncertainty in both power supply and demand. The stochastic programming model is an extension of the Joint Market Model, cf. (Meibom et al. 2006).

Demand and supply uncertainty is described by a multivariate distribution of forecast errors and failures of the system. In this application, only forecast error uncertainty is considered. For computational reasons the distribution is assumed to be discrete with a finite number of outcomes referred to as scenarios and indexed $\{1,\ldots,S\}$. The scenario probabilities are denoted by $\pi^1,\ldots,\pi^S$.

The generation of the scenarios for forecast errors and failures is outlined in Section 3.2.6.

Letting reserve requirements be determined on a day-to-day basis, decisions are made over a time horizon of 36 hours. Regulation is reserved from 12-15 a day ahead of operation whereas both reserved and direct regulation is activated continuously over the operation day from 00-00. Hence, decisions are made for a time horizon of 24 hours. As an approximation, the $T = 24$ hours are divided into hourly intervals, $\{1,\ldots,T\}$.

To reflect the behavior of power producers in the Nordic market and in Denmark in particular, the Joint Market Model, cf. (Meibom et al. 2006), includes both the spot and the regulating power markets. As production can be dispatched in both markets, it divides into day-ahead and intra-day production, intra-day production also being referred to as regulation. In a similar fashion, unit commitment takes place either a day ahead of operation or at the day of operation, depending on the start-up times of the units. Short start-up times allow for intra-day commitment of the units, whereas longer start-up times enforce day-ahead commitment. Regulation may therefore on one hand be provided by fast starting units within the operation day, referred to as direct regulation. On the other hand, it may be supplied by slowly starting units which means capacity has to be reserved before the operation day, this type of regulation being referred to as reserved regulation. From the perspective of the system operator, direct regulation is automatically available in the regulating power market, whereas reserved regulation is available only when actually reserved.

Reserved regulation is referred to as manual regulation or tertiary reserves. Since the reserves have an activation time of a number of minutes or hours, the system also operates with a type of reserves where the activation time is in seconds, i.e. the frequency regulation or primary reserves. Since primary reserves are still obtained on long term contracts we assume that the demand for primary reserves is exogenously given. In case the system also operates with secondary reserves or automatic regulation, these can be included in the model like primary reserves.

For modelling unit commitment and dispatch, let I index the set of power generating units. This set is divided into slow and fast starting units,

I^{slow} and I^{fast}, with $I = I^{slow} \cup I^{fast}$.

Slow starting units are defined by a start-up time of at least an hour and fast starting units by a start-up time of less than an hour. Accordingly, we let the variables

$u_{it} \in \{0,1\}, i \in I^{slow}, t = 1,\ldots,T, u_{it}^{s}, i \in I^{fast}, t = 1,\ldots,T, s = 1,\ldots,S$

represent the online status of such units. Dispatch is described by the variables

$p_{it} \in \mathrm{R}_{+}, i \in I, t = 1,\ldots,T$,

representing day-ahead production, and

$p_{it}^{up,s}, p_{it}^{down,s} \in \mathrm{R}_{+}, i \in I, t = 1,\ldots,T, s = 1,\ldots,S$,

modelling intra-day up- and down-regulation. Primary reserves are modelled by the variables

$r_{i}^{down,pri}, r_{i}^{up,pri} \in \mathrm{R}_{+}, i \in I^{slow}, t = 1,\ldots,T$.

Finally, optimizing tertiary reserves, these are represented by the variables

$r_{i}^{up,ter}, r_{it}^{up,s} \in \mathrm{R}_{+}, i \in I^{slow}, t = 1,\ldots,T, s = 1,\ldots,S$,

describing reserved and activated up-regulation, respectively. There is no need to reserve down-regulation prior to activation.

The costs of unit commitment and dispatch are start-up and production costs. Fixed start-up costs amount to

$$\sum_{s=1}^{S} \pi^{s} \sum_{t=1}^{T} \Big(\sum_{i \in I^{slow}} S_i(u_{it}, u_{it-1}) + \sum_{i \in I^{fast}} S_i(u_{it}^{s}, u_{it-1}^{s}) \Big),$$

which, when considering the unit start-up costs, $c_i^{start-up}$, compute as

$$S_i(u_{it}, u_{it-1}) = c_i^{start-up} \max\{u_{it} - u_{it-1}, 0\}.$$

Variable production costs are

$$\sum_{s=1}^{S} \pi^{s} \sum_{t=1}^{T} \Big(\sum_{i \in I^{slow}} C_i(p_{it} + p_{it}^{up,s} - p_{it}^{down,s} + r_{it}^{up,s} - r_{it}^{down,s}, u_{it}) +$$

$$\sum_{i \in I^{fast}} C_i(p_{it} + p_{it}^{up,s} - p_{it}^{down,s} + r_{it}^{up,s} - r_{it}^{down,s}, u_{it}^{s}), \Big)$$

and include unit specific operation and maintenance costs, fuel costs,

c_i^{oper} and c_i^{fuel},

and taxes on fuel and emissions,

$r_i^{fueltax}, r_i^{emstax}$.

Like fuel costs, fuel consumption is assumed a linear function of the production level. The linear function is defined by defined by

$f_i^{fuel,1}, f_i^{fuel,2}$.

Emission is modelled as a fixed fraction, f_i^{ems}, of the fuel consumption. As a result

$$C_i(p_{it}, u_{it}) = c_i^{oper} p_{it} + (c_i^{fuel} + r_i^{fueltax} + r_i^{emstax} f_i^{ems})(f_i^{fuel,1} u_{it} + f_i^{fuel,2} p_{it}).$$

To compensate for using a finite time horizon, units online at the end of the horizon are assigned a value. This value is the shadow price of an online unit. However, due to the ambiguity of shadow prices in a mixed-integer problem, we have chosen those of the linear relaxation as an approximation.

A crucial factor in determining reserves requirements is the costs of being unable to cover imbalances between supply and demand. To model these, let therefore the variables

$q_t^{up,s}, q_t^{down,s} \in \mathrm{R}_+, t = 1, \ldots, T, s = 1, \ldots, S$

represent shortage and redundance in power. The shortage and abundance costs are estimates given by the system operator which sum to

$$\sum_{s=1}^{S} \pi^s \sum_{t=1}^{T} (c^{pen} q_t^{up,s} + c^{pen} q_t^{down,s}).$$

Recall that the model includes both the spot and the regulating power markets. From the perspective of the system operator, these markets facilitate the match of supply and demand. In the day-ahead market, production is dispatched such as to match expected net demand a day ahead of operation. Expected net demand consists of predicted electricity demand minus predicted wind power generation. Hence, the following day-ahead balance applies

$$\sum_{i=1}^{I} p_{it} = d_t^{exp} - w_t^{exp}, t = 1, \ldots, T, \tag{1}$$

where d_t^{exp} and w_t^{exp} denote expected (forecasted) electricity demand and wind power, respectively, for time interval t, known at the time of forecasting.

Realized electricity demand and wind power may, however, be different from expected and intra-day balancing comes into play. In a regulating power market, up- and down-regulating power is meant to cover imbalances caused by such differences between expected and realized net demand. Nevertheless, regulation may be insufficient to fully cover imbalances and shortage or abundance may occur. This leads to

$$\sum_{i=1}^{I} (p_{it}^{up,s} - p_{it}^{down,s} + r_{it}^{up,s} - r_{it}^{down,s}) + q_t^{up,s} - q_t^{down,s} = \Delta d_t^s - \Delta w_t^s, t = 1, \ldots, T, s = 1, \ldots, S, \tag{2}$$

where $\Delta d_t^s = d_t^s - d_t^{exp}$ and $\Delta w_t^s = w_t^s - w_t^{exp}$ denote the difference between realized and expected demand and wind in time period t and scenario s.

Exogenous demand for primary reserves induce the constraints

$$
\begin{aligned}
&\sum_{i=1}^{I} r_i^{up,pri} \geq d_t^{up,pri}, t = 1,\ldots,T \\
&\sum_{i=1}^{I} r_i^{down,pri} \geq d_t^{down,pri}, t = 1,\ldots,T
\end{aligned}
\tag{3}
$$

in which $d_t^{up,pri}$ and $d_t^{up,pri}$ are the given demands for up- and down regulation in time period t.

In much the same fashion, tertiary reserves may be subject to some minimum requirements determined by the system operator

$$
\begin{aligned}
&\sum_{i=1}^{I} r_i^{up,ter} \geq r^{min,up,ter}, t = 1,\ldots,T \\
&\sum_{i=1}^{I} r_i^{down,ter} \geq r^{min,down,ter}, t = 1,\ldots,T
\end{aligned}
\tag{4}
$$

where $r^{min,up,ter}, r^{min,down,ter}$ denote the minimum requirements of up-regulation and down-regulation reserved.

Before the operation day, the unit commitment of slowly starting units is determined by production sold in the day-ahead market, primary reserves and tertiary reserves, ignoring direct supply to the regulating power market

$$
\begin{aligned}
&p_{it} + r_i^{up,pri} + r_i^{up,ter} - r_i^{down,ter} \leq cap_i^{max} u_{it}, i \in I^{slow}, t = 1,\ldots,T \\
&p_{it} - r_i^{down,pri} + r_i^{up,ter} - r_i^{down,ter} \geq cap_i^{min} u_{it}, i \in I^{slow}, t = 1,\ldots,T.
\end{aligned}
\tag{5}
$$

Direct supply to the regulating power market can be ignored since usually day-ahead operation is only planned in view of the day-ahead market, this market being the spot market for electricity. Hence, producers do not hold back capacity for the regulating power market unless reserved.

Within an operation day, realized production, including the tertiary reserve activated, is subject to capacity constraints resulting from the unit commitment of slowly starting units

$$
\begin{aligned}
&p_{it} + r_i^{up,pri} + p_{it}^{up,s} - p_{it}^{down,s} + r_{it}^{up,s} - r_{it}^{down,s} \leq cap_i^{max} u_{it}, \\
&i \in I^{slow}, t = 1,\ldots,T, s = 1,\ldots,S \\
&p_{it} - r_i^{down,pri} + p_{it}^{up,s} - p_{it}^{down,s} + r_{it}^{up,s} - r_{it}^{down,s} \geq cap_i^{min} u_{it}, \\
&i \in I^{slow}, t = 1,\ldots,T, s = 1,\ldots,S
\end{aligned}
\tag{6}
$$

whereas the unit commitment of fast starting units is determined by realized production, including activated reserves,

$$p_{it} + r_i^{up,pri} + p_{it}^{up,s} - p_{it}^{down,s} + r_{it}^{up,s} - r_{it}^{down,s} \le cap_i^{max} u_{it}^s,$$
$$i \in I^{fast}, t = 1,\ldots,T, s = 1,\ldots,S$$
$$p_{it} - r_i^{down,pri} + p_{it}^{up,s} - p_{it}^{down,s} + r_{it}^{up,s} - r_{it}^{down,s} \ge cap_i^{min} u_{it}^s,$$
$$i \in I^{fast}, t = 1,\ldots,T, s = 1,\ldots,S. \tag{7}$$

both subject to the constraints that regulation activated is within the regulation reserved

$$r_{it}^{up,s} \le r_i^{up,ter}, r_{it}^{down,s} \le r_i^{down,ter}, i \in I^{slow}, t = 1,\ldots,T, s = 1,\ldots,S. \tag{8}$$

Day-ahead unit commitment is planned in view of up- and down-time constraints on the units

$$u_{it-1} - u_{it} \le u_{i\tau}, i \in I^{slow}, \tau = t - t_i^{up},\ldots,t-1, t = 1,\ldots,T, \tag{9}$$

in which t_i^{up} denotes the minimum up-time of a unit and

$$u_{it} - u_{it-1} \le 1 - u_{i\tau}, i \in I^{slow}, \tau = t - t^{down},\ldots,t-1, t = 1,\ldots,T \tag{10}$$

where t_i^{down} denotes the minimum down-time of a unit.

Intra-day commitment is subject to similar constraints, i.e.

$$u_{it-1}^s - u_{it}^s \le u_{i\tau}^s, i \in I^{fast}, \tau = t - t_i^{up},\ldots,t-1, t = 1,\ldots,T \tag{11}$$

and

$$u_{it}^s - u_{it-1}^s \le 1 - u_{i\tau}^s, i \in I^{fast}, \tau = t - t^{down},\ldots,t-1, t = 1,\ldots,T. \tag{12}$$

3.2.4 Including transmission

Since exchange of power with other areas affects the requirements for reserves, transmission constraints have been included in the model. It is assumed that transmission contributes in balancing supply and demand on both the spot and the regulating power markets. Evidently, with the possibility of import and export, up- and down-regulation are less likely to be insufficient and reserve requirements are less. Due to transmission capacity limits insufficiencies may however still occur.

To include transmission, let M index the set of areas, areas being regions or countries. Let the variables

$l_{mnt} \in \mathbb{R}_+, m, n = 1,\ldots,M$

represent the transmissions between areas used for day-ahead balancing and let likewise $l_{mnt}^{up,s}, l_{mnt}^{down,s} \in \mathbb{R}_+, m, n = 1,\ldots,M$

denote the up- and down-regulation exchanged between countries. Note that

l_{mn} and l_{nm}

denote export from area m and import to area m , respectively.

Costs of transmission are

$$\sum_{s=1}^{S}\pi^s\sum_{t=1}^{T}\sum_{m=1}^{M}\sum_{n=1}^{M}c_{mn}^{trans}(l_{mnt}+l_{mnt}^{up,s}-l_{mnt}^{down,s}), \tag{13}$$

where c_{mn}^{trans} is the transmission cost from m to n.

Including import and export, the day-ahead balance is

$$\sum_{i=1}^{I_m}p_{it}+\sum_{n=1}^{N}((1-r^{loss})l_{nmt}-l_{mnt})=d_{mt}^{exp}-w_{mt}^{exp}, m=1,\ldots,M, t=1,\ldots,T, \tag{14}$$

where r^{loss} is the loss of the transmission line. Day-ahead transmission is subject to the capacity limits

$$l_{mnt}\le l_{mn}^{max}, m,n=1,\ldots,M, \tag{15}$$

in which l_{mn}^{max} is the capacity of the transmission line from m and n.

Allowing for import and export of up- and down-regulation, intra-day balancing means

$$\begin{aligned}&\sum_{i=1}^{I_m}(p_{it}^{up,s}-p_{it}^{down,s}+r_{it}^{up,s}-r_{it}^{down,s})+\sum_{n=1}^{N}((1-r^{loss})(l_{nmt}^{up,s}-l_{nm}^{down,s})-(l_{mnt}^{up,s}-l_{mnt}^{down,s}))\\&+q_t^{up,s}-q_t^{down,s}=\Delta d_{mt}^{s}-\Delta w_{mt}^{s}, m=1,\ldots,M, t=1,\ldots,T, s=1,\ldots,S.\end{aligned} \tag{16}$$

subject to the constraints

$$l_{mnt}+l_{mnt}^{up,s}-l_{mnt}^{down,s}\le l_{mn}^{max}, m,n=1,\ldots,M. \tag{17}$$

3.2.5 Stochastic programming

To illustrate the structure of the two-stage decision process, the model for optimizing tertiary reserves or manual regulation can be formulated as follows. For ease of exposition, the model does not include transmission issues. The first stage consists in planning unit commitment and dispatch and reserving regulation a day ahead of operation, considering only load and wind forecasts and not anticipating future outages of the units

$$\min Q(\{u_{it}\},\{p_{it}\},\{r_i^{pri}\},\{r_i^{ter}\})$$

$$\text{st } (1),(4),(5),(9),(10)$$

$$u_{it}\in\{0,1\}, p_{it}, r_i^{up,pri}, r_i^{down,pri}, r_i^{up,ter}, r_i^{down,ter}\ge 0, i\in I^{slow}, t=1,\ldots,T,$$

where expected future costs are

$$Q(\{u_{it}\},\{p_{it}\},\{r_i^{pri}\},\{r_i^{ter}\})=\sum_{s=1}^{S}\pi^s Q(\{u_{it}\},\{p_{it}\},\{r_i^{pri}\},\{r_i^{ter}\},s)$$

and arise from planned production as well as reserved and direct regulation, given the realized load and wind and the observed unit outages and taking place in the second stage

$$Q(\{u_{it}\},\{p_{it}\},\{r_i^{pri}\},\{r_i^{ter}\},s) =$$

$$\min \sum_{t=1}^{T} (\sum_{i \in I^{slow}} C_i (p_{it} + p_{it}^{up,s} - p_{it}^{down,s}, u_{it}) + \sum_{i \in I^{fast}} C_i (p_{it} + p_{it}^{up,s} - p_{it}^{down,s}, u_{it}^{s})) +$$

$$\sum_{t=1}^{T} (\sum_{i \in I^{slow}} S_i (u_{it}, u_{it-1}) + \sum_{i \in I^{fast}} S_i (u_{it}^{s}, u_{it-1}^{s})) +$$

$$\sum_{t=1}^{T} (c^{pen} q_t^{up,s} + c^{pen} q_t^{down,s})$$

st (2),(6),(7),(11),(12)

$$u_{it}^{s} \in \{0,1\}, p_{it}^{up,s}, p_{it}^{down,s} \geq 0, i \in I^{fast}, t = 1,\ldots,T$$

The decision process is divided into two to reflect the interplay between regulation reserved in advance and regulation purchased directly in the market. Since in fact uncertainty is disclosed gradually and direct regulation is able to adapt to realized load and wind and observed unit outages, the two-stage problem serves as an approximation of a multi-stage problem.

3.2.6 Scenario generation

The scenarios that serve as input to the stochastic programming model are generated by simulating forecast errors an hourly basis up to 36 hours ahead. Load forecast errors are simulated directly whereas wind power data is first transformed to wind speed data before wind speeds are simulated and finally wind speed scenarios is transformed to wind power scenarios from which forecast errors can be derived. The simulations include the autocorrelation of forecast errors over the forecast horizon, for wind speed given a specific measurement site. Further, wind speed simulations account for the correlation of forecast errors between individual measurement sites for a specific hour.

Based on data from Denmark 2003, the time series of load and wind speed forecast errors are fit statistical models to be used for sampling. Load and wind is assumed statistically independent. The univariate processes of load forecast errors and wind speed forecasts at individual sites are modelled as ARMA(1,1) processes. For estimation of the parameters, see (Söder 2004). Wind speed forecasts are modelled as a multivariate ARMA process. However, by means of Cholesky decomposition of the covariance matrix the multivariate process decomposes into univariate. Hence, estimating the covariance matrix, the model requires no further estimation of parameters. Furthermore, it is possible to sample from independent variables. The transformation of wind speed time series and wind speed scenarios into their wind power equivalents is handled using site specific aggregated power curves. For further references, see (Barth et al. 2006) and references therein.

The number of scenarios obtained by sampling should on one hand be sufficient to approximate the true distribution of forecast errors but on the other hand be feasible for computations. The idea is therefore to start from a large number of Monte Carlo simulations and reduce the number of samples by clustering, loosing as less information as possible. The clustering algorithm allocates scenarios to clusters at the time such that a scenario is allocated to a cluster if closest in some distance to some other scenario from the cluster. For a reference on the scenario reduction algorithm, see (Dupacova 2003).

As concerns reserve requirements, it is relevant to distinguish between normal operation and disturbances of the system. To reflect this in the scenario generation, scenarios are divided into 'typical case' and 'worst case', likely to induce normal operation or disturbance. As a first attempt of dividing scenarios into 'typical case' and 'worst case' scenarios we use the following approach. Given a cluster, a 'typical case' scenario is obtained as the scenario closest to the other scenarios of the cluster in terms of the distance used for clustering. A 'typical scenario' is assigned 0.99 times the probability of the cluster. A 'worst case' scenario is given by some extreme event such as the 99th quantile of the distribution of the cluster and is assigned a probability of 0.01.

3.2.7 Further work

For the optimization of tertiary reserves throughout a year, the model will be integrated in the framework of rolling planning. The model is solved recursively day by day, constantly updating the data involved, including supply and demand.

The model will be tested with data from the Danish power system and the Nordic market and computational results will be analysed.

We have considered the system-wide model for the joint market clearing of the day-ahead spot and the intra-day regulating power markets based on social welfare maximization and used to investigate the requirements of regulating power reserves from the perspective of the transmission system operator. In a competitive (Walrasian) equilibrium the regulating power market will allocate resources (Pareto) efficiently. The regulating power market will provide the information that facilitates a sufficient supply of resources from producers and a reservation of regulation resources is not necessary. Online capacity will be able to cover imbalances during system operation. The theory is supported by test results of our model. In practice, however, inefficiencies occur due to the externality that arises as security of supply is a public good with benefits not fully remunerated by the suppliers. Since everybody enjoys regulation supplied by others, producers may have no incentive to produce sufficient regulation voluntarily although the system would benefit substantially. Hence, insufficient resources can be imputed to the free rider problem. We will assume this externality is captured by the failure of the regulating power market to appropriately inform producers and exclude the regulating market clearing from the social welfare maximization. Online capacity will enable the clearing of the spot market but may not fully cover imbalances. This type of market failure must be circumvented by intervention of the system. The transmission system operator will reserve regulation ahead of operation and pay up the social value for availability. Such regulation reserves may be seen as real options of the transmission system operator and the corresponding payments as option prices. Upon exercise, producers are obligated to offer the reserves to the regulating power market. Reserve requirements will therefore be determined as the difference in online capacity in a efficient and an inefficient regulating power market, respectively. The exclusion of the regulating power market and the calculation of the reserve requirements is work in progress.

4 Extreme events

For the focus of the project the presented tools should be applicable to the decision support for the day to day operation of the power system. One main issue for the day to day operation is reserve estimation as described above. Due to high welfare losses caused by blackouts, the power system further should remain in stable operation during extreme situations. In order to assess the ability of a power system to cope with such extreme events, the definition and mapping of extreme events have to be investigated. Extreme events can lead to power system stress, either if the remaining security margins become considerable low or if the power system can barely cope with load and wind power fluctuations.

Extreme events may occur during peak demand periods. The remaining margin between load and further available power plant capacity is smaller, when a high percentage of the power plant capacity is already used for covering the load. The remaining security margin may be further reduced in the case of a high number of simultaneous power plant outages. When there is no security margin left, each further outage has to be answered by shedding of load in order to keep the system stable.

Additional extreme events are defined by high gradients the power system has to cope with. The first example is large forecast errors. The Joint Market Model and the Scheduling Model optimize the power plant portfolio taking into account stochastic mapping of the forecast error. The model considers load and wind power forecasts for the next following time periods. In the subsequent time period, it balances the difference between the realized value and the forecasted value. As a consequence, the power system has to be operated flexibly to be able to balance forecast errors of load and wind. To balance extreme forecast errors, enough balancing power has to be reserved. In this category, the second and the third example for power system stress are high gradients in load and wind power feed-in, both leading to a high gradients of the remaining demand that has to be satisfied by conventional power stations.

In all cases, the definition of extreme events has to consider the structure of the power plant portfolio. For example in thermal dominated systems, power plants generally have longer startup times and lower ramp rates than in hydro dominated systems, for example. As a consequence, it is more difficult for thermal dominated systems to cope with high net load gradients. In addition to the installed generation technologies, the transmission system is important, too. In a well developed transmission system without bottlenecks, regionally different fluctuations can compensate each other. Hence, the identification of extreme events has to consider the existing power system design.

Qualitative criteria have been formulated for the definition of extreme events. These definitions are helpful for understanding the phenomena of extreme events, but for the model simulations quantitative criteria have to be defined. The fixing of quantitative criteria is heavily influenced by the way these extreme events are generated. For an analysis of the capacity margin in peak load situations, the difference between available output capacity and load for each time period has to be taken. If the value of this margin is lower than a certain threshold, the situation has to be considered as extreme event. For the identification of high forecast errors and net load gradients, both forecast errors and the residual net load time-series have to be analyzed by application of the Scenario Tree Tool. Extreme forecast errors are identified by comparison of the forecasted with the realized values whereas extreme gradients are identified by considering the deviation between the starting value and the ending value of time periods of a predefined length. If the determined values exceed a certain value, the corresponding situation is defined as extreme event.

5 Load flow

The transport of electricity obeys physical laws, namely the laws of Ohm and Kirchhoff. Power flow spreads out in the whole network, if there is a power injection in one region of the network and a withdrawal in another region of the network. These power flows have to be taken into account in order to accurately consider possible binding network constraints. The consideration of power flow in the Joint Market Model is done via a simplified linear version, named DC power flow. Section 5.1 summarizes the formulation and the properties of the DC power flow, which is the basis of the load flow implementation in the model. Section 5.2 describes implementation of power flow in the Joint Market Model and the way how loss factors, which are an optional extension of the Dc power flow are included.

5.1 Model for load flow

In transmission systems, the part of power which is available for the transformation into other types of power, like kinetic or thermal power is named active power. The transport of electricity in an AC (alternating current) system is accompanied with the phenomenon of reactive power. The alternating current and voltage of AC transmission systems causes electrical and magnetic fields, which are time variant. With the increasing and decreasing of these fields, a certain phase shift between voltage and current occurs. This phase shift leads to a power flow, which is called reactive power.

The detailed AC power flow equations are as follows (Handschin 1987):

$$P_k = U_k \sum_n \left[U_n G_{k,n} \cos(\theta_k - \theta_n) + U_n B_{k,n} \sin(\theta_k - \theta_n) \right] \tag{19}$$

$$Q_k = U_k \sum_n \left[U_n G_{k,n} \sin(\theta_k - \theta_n) - U_n B_{k,n} \cos(\theta_k - \theta_n) \right] \tag{20}$$

P_k denotes the active power balance of node k, Q_k the reactive power balance of node k. U_k denotes the voltage angle of node k, $B_{k,n}$ the network susceptance between nodes k and n, $G_{k,n}$ the network conductance between network node k and n, θ the voltage angle of node k. The line susceptance and the line conductance are parameters that mainly depend on the physical and technical properties of the transmission equipment. Due to the non-linear and non-convex nature of full AC power flow, the solution may not be obtained in all cases. In addition to that, AC power flow requires large calculation resources. As a consequence, for models where changes in the network state are quasi-static, a linearization of the AC power flow called DC power flow is commonly used. The main assumptions of DC power flow are (Hogan 1998):

- reactive power is neglected
- the magnitude of the voltage at all nodes is approximately one per unit
- the resistance R is small compared to the Reactance; in its basic form DC-Power Flow is lossless (losses can be introduced via loss coefficients, which will be dealt with later)
- the voltage angle θ is small, so that $\sin(\theta) \approx \theta$ and $\cos(\theta) \approx 1$

Generally these assumptions are satisfyingly fulfilled in high voltage transmission networks. Taking these simplifications into account, following (Purchala et al. 2005), the above equation can be simplified to:

$$P_{k,n} = B_{k,n} (\theta_k - \theta_n) \tag{21}$$

According to the assumptions and the formulation of DC power flow, in meshed transmission networks, the power flow spreads out in the network depending on the susceptances of the network lines. This is illustrated in *Figure 5*. The example shows a power transport from network node A to network node B of 400 MW. If the circuits are closed, there is a power flow directly from network node A to network node B and additionally, there is a power flow from A to B via the network nodes D and C. The distribution between those two alternative routes depends on the ratio of the susceptances of the two routes. If one assumes equal susceptances for all lines, one fourth of the overall transaction passes the line between D and C.

Looking at this distribution of the power flow, it is obvious that a power transit between network node A and network node B is not necessarily limited by the direct interconnection between A and B. The limiting factor can also be the interconnection between the two nodes C and D. If, for example, the line between network node D and C is limited to 50 MW, the transaction between network node A and network node C must not exceed 200 MW. The consideration of a conventional transportation model would neglect this characteristic property of the meshed transmission grid. Applying a conventional transportation model would assume, that the whole transmission volume charges the line between network node A and network node B. As a consequence, the limitative impact of the line between network node C and network node D is neglected in a conventional transportation model. However, this transmission system bottleneck influences the solution, if one applies a load flow based transmission representation.

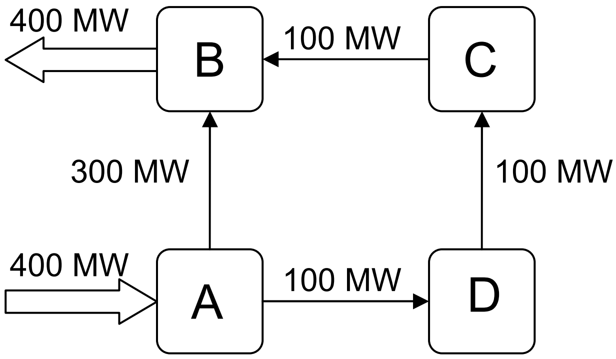


Figure 5: Flow in demonstration network

5.2 Load flow in JMM

The Joint Market Model offers three possibilities to include the transport of electricity. The user can set an option that allows him to use a conventional transportation model, where electricity exchange is determined by point to point transfer. By default the Joint Market Model applies DC power flow as described in the previous section (see 5.1). Another option activates DC power flow with an extension taking into account losses on transmission lines. The methodology behind this loss module is described in the following paragraphs.

In a first step line losses are calculated by assuming loss coefficients $\lambda_{n,k}$ that are indicating which percentage of the overall power flow through that line are losses. $Lloss_{k,n}$ denotes the line loss of the line connecting node k and n:

$$Lloss_{k,n} = P_{k,n}\lambda_{k,n} \tag{22}$$

Based on the line losses, the total transmission system losses are the sum of all line losses. *Tloss* denotes the total transmission losses:

$$Tloss = \sum_{n,k} Lloss_{k,n} \tag{23}$$

The total transmission losses are allocated to the nodes according to the factor υ_k. The factor υ_k represents node k`s load fraction of the total system load. The application of other criteria like the share of installed generation capacity in relation to all generation capacity in the system is also possible with this approach. It is important that the sum of all υ_k is one. $Loss_k$ denotes the losses allocated to node k:

$$Loss_k = \nu_k \times Tloss \tag{24}$$

After the allocation of losses to the individual nodes, the losses can be included into the optimization by considering them in the power balance equation. G_k denotes the power generation at node k and D denotes the power demand at node k:

$$G_k + \sum_n P_{k,n} = D_k + Loss_k \tag{25}$$

6 Conclusions

This report has documented the additions to the Wilmar Planning tool made in WP3 in the SUPWIND project. The following work has been done:

- Treatment of load as a stochastic input parameter involving generation of load forecast by the Scenario Tree Tool and inclusion of these forecasts in the Joint Market Model.
- Algorithm for generation of time series of forced outages of power plants implemented in the Scenario Tree tool. Modelling of forced outages in the Joint Market Model using these time series.
- Algorithm for calculation of the need for up-regulation reserves depending on forecast horizon.
- Model for estimating the optimal amount of reserve power to reserve day-ahead.
- Modelling of network restrictions with a DC load flow algorithm implemented in the Joint Market Model.

The usefulness and adequacy of these model additions will be investigated in WP7 in the SUPWIND project. The Danish TSO Energinet.dk and Risø-DTU will test the model for day-ahead reservation of reserve power in a Danish context. Further, in case studies for selected countries carried out in WP6 of the SUPWIND project, extreme events as described in section 4 are going to be considered to evaluate electricity network expansions.

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