PROBABILISTIC MODELLING TECHNIQUES AND
A ROBUST DESIGN METHODOLOGY FOR
OFFSHORE WIND FARMS

A thesis submitted to the University of Manchester for the degree of
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<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R$</td>
<td>Aerodynamic rotor radius</td>
</tr>
<tr>
<td>$P_r$</td>
<td>Gas pressure</td>
</tr>
<tr>
<td>$R_G$</td>
<td>Gas constant</td>
</tr>
<tr>
<td>$T_p$</td>
<td>Gas temperature</td>
</tr>
<tr>
<td>$\rho$</td>
<td>Air density</td>
</tr>
<tr>
<td>$A$</td>
<td>Area swept by the rotor</td>
</tr>
<tr>
<td>$\beta$</td>
<td>Pitch angle</td>
</tr>
<tr>
<td>$\beta_{m,l}$</td>
<td>Ratio of turbine area covered under wake to total rotor area</td>
</tr>
<tr>
<td>$C_t$</td>
<td>Thrust coefficient</td>
</tr>
<tr>
<td>$C_p$</td>
<td>Power coefficient</td>
</tr>
<tr>
<td>$\lambda$</td>
<td>Tip speed ratio</td>
</tr>
<tr>
<td>$\lambda_i$</td>
<td>Variable to calculate $c_2$</td>
</tr>
<tr>
<td>$a$</td>
<td>Coefficient to calculate $C_p$</td>
</tr>
<tr>
<td>$D$</td>
<td>Rotor diameter</td>
</tr>
<tr>
<td>$m_a$</td>
<td>Moving mass of air</td>
</tr>
<tr>
<td>$v$</td>
<td>Incoming wind speed to the turbine</td>
</tr>
<tr>
<td>$P_w$</td>
<td>Power inside moving mass of air</td>
</tr>
<tr>
<td>$P_{rot}$</td>
<td>Mechanical power extracted by the aerodynamic rotor</td>
</tr>
<tr>
<td>$T_{rot}$</td>
<td>Mechanical torque on aerodynamic rotor shaft</td>
</tr>
<tr>
<td>$\omega_{rot}$</td>
<td>Angular speed of the aerodynamic rotor</td>
</tr>
<tr>
<td>$c_1$-$c_6$</td>
<td>Coefficients for calculating $C_p$</td>
</tr>
<tr>
<td>$V_{DC}$</td>
<td>DC voltage</td>
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<tr>
<td>$I_{DC}$</td>
<td>Direct current</td>
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<tr>
<td>$P_{DC}$</td>
<td>DC power</td>
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<tr>
<td>$P_{AC}$</td>
<td>AC power</td>
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<tr>
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<td>Alternating current</td>
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<tr>
<td>$V_{AC}$</td>
<td>AC voltage</td>
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<tr>
<td>$V_{r,dq}$</td>
<td>d, q- axis components of voltage at rotor windings</td>
</tr>
<tr>
<td>$P_{m,dq}$</td>
<td>Modulation factor in d and q axis</td>
</tr>
<tr>
<td>$V_{r,nom}$</td>
<td>Nominal voltage of the rotor</td>
</tr>
<tr>
<td>$I_r$</td>
<td>Current in the rotor windings</td>
</tr>
<tr>
<td>$P_c$</td>
<td>Converter real power</td>
</tr>
<tr>
<td>Symbol</td>
<td>Description</td>
</tr>
<tr>
<td>--------</td>
<td>-------------</td>
</tr>
<tr>
<td>$Q_c$</td>
<td>Converter reactive power</td>
</tr>
<tr>
<td>$P_r$</td>
<td>Power in the rotor winding</td>
</tr>
<tr>
<td>$V_{dc}$</td>
<td>Direct axis component of the converter voltage</td>
</tr>
<tr>
<td>$V_{qc}$</td>
<td>Quadrature axis component of the converter voltage</td>
</tr>
<tr>
<td>$I_{dc}$</td>
<td>Direct axis component of the converter current</td>
</tr>
<tr>
<td>$I_{qc}$</td>
<td>Quadrature axis component of the converter current</td>
</tr>
<tr>
<td>$J_{rot}$</td>
<td>Aerodynamic rotor inertia</td>
</tr>
<tr>
<td>$J_m$</td>
<td>Generator inertia</td>
</tr>
<tr>
<td>$T_{rot}$</td>
<td>Aerodynamic torque of the rotor</td>
</tr>
<tr>
<td>$T_{shaft}$</td>
<td>Torque of the low speed shaft</td>
</tr>
<tr>
<td>$1:n_{gear}$</td>
<td>Gearbox ratio</td>
</tr>
<tr>
<td>$\theta_k$</td>
<td>Angular difference between two ends of the shaft</td>
</tr>
<tr>
<td>$c_d$</td>
<td>Damping coefficient of low speed shaft</td>
</tr>
<tr>
<td>$\xi$</td>
<td>Damping ratio</td>
</tr>
<tr>
<td>$\delta_s$</td>
<td>Logarithmic decrement</td>
</tr>
<tr>
<td>$a(t)$</td>
<td>Amplitude of the signal at the beginning of the period</td>
</tr>
<tr>
<td>$a(t+t_p)$</td>
<td>Amplitude of the signal at the end of the next period</td>
</tr>
<tr>
<td>$K_s$</td>
<td>Stiffness of the low speed shaft</td>
</tr>
<tr>
<td>$M_f$</td>
<td>Modulation factor</td>
</tr>
<tr>
<td>$s_l$</td>
<td>Slip</td>
</tr>
<tr>
<td>$\omega_m$</td>
<td>Mechanical frequency of the generator</td>
</tr>
<tr>
<td>$\omega_s$</td>
<td>Stator electrical frequency</td>
</tr>
<tr>
<td>$P_m$</td>
<td>Mechanical power at the generator shaft</td>
</tr>
<tr>
<td>$H_m$</td>
<td>Inertia constant of the generator rotor</td>
</tr>
<tr>
<td>$T_m$</td>
<td>Mechanical torque on the high-speed shaft</td>
</tr>
<tr>
<td>$T_e$</td>
<td>Electromagnetic torque of the generator</td>
</tr>
<tr>
<td>$L_m$</td>
<td>Mutual inductance</td>
</tr>
<tr>
<td>$L_{so}$</td>
<td>Stator leakage inductance</td>
</tr>
<tr>
<td>$L_{ra}$</td>
<td>Rotor leakage inductance</td>
</tr>
<tr>
<td>$p$</td>
<td>Number of poles</td>
</tr>
<tr>
<td>$R_s$</td>
<td>Resistance of the stator windings</td>
</tr>
<tr>
<td>$R_r$</td>
<td>Resistance of the rotor windings</td>
</tr>
<tr>
<td>$I_{ds}$</td>
<td>d-axis component of stator current</td>
</tr>
<tr>
<td>$I_{dr}$</td>
<td>d-axis component of rotor current</td>
</tr>
<tr>
<td>$I_{qs}$</td>
<td>q-axis component of stator current</td>
</tr>
<tr>
<td>$I_{qr}$</td>
<td>q-axis component of rotor current</td>
</tr>
</tbody>
</table>
$R_c$ Resistance of the crowbar

$X_c$ Reactance of the crowbar

$V_{dr}$ d-axis component of rotor voltage

$V_{qr}$ q-axis component of rotor voltage

$V_{ds}$ d-axis component of stator voltage

$V_{qs}$ q-axis component of stator voltage

$\Psi_{ds}$ d-axis of stator flux linkage

$\Psi_{qs}$ q-axis of stator flux linkage

$\Psi_{dr}$ d-axis of rotor flux linkage

$\Psi_{qr}$ q-axis of rotor flux linkage

$P_s$ Stator active power

$Q_s$ Stator reactive power

$P_r$ Rotor active power

$Q_r$ Rotor reactive power

$P_{total}$ Total active power fed into the grid by a DFIG

$Q_{total}$ Total reactive power fed into the grid by a DFIG

$V_{r,dq}$ d,q-axis components of rotor voltage affected by the rotor-side converter

$|V_{st}|$ Stator terminal voltage magnitude

$Z_L$ Impedance of the line (cable)

$R_L$ Resistance of the line (cable)

$X_L$ Reactance of the line (cable)

$Y_L$ Admittance of the line (cable)

$B_L$ Susceptance of the line (cable)

$C$ Capacitance of the line (cable)

$G$ Conductance of the line (cable)

$X_M$ Magnetizing reactance of the core

$Z_M$ Magnetizing impedance of the core

$R_{FE}$ Iron loss resistance of the transformer winding

$i_o$ No load current in a transformer winding

$I_o$ Measured no load current at the transformer winding

$P_{FE}$ Measured no load losses in a transformer winding

$P_{Cu}$ Copper losses in a transformer winding

$R_{Cu,HV}$ Winding resistance of the HV-side of transformer

$R_{Cu,LV}$ Winding resistance of the LV-side of transformer

$X_{o,HV}$ Winding reactance of the HV-side of transformer

$X_{o,LV}$ Winding reactance of the LV-side of transformer
**V_{HV}**  Voltage at the HV-terminal of the transformer

**S_{rat}**  Rated power of the transformer

**V_{rat}**  Rated voltage at the transformer winding

**I_{rat}**  Rated current at the transformer winding

**V_{SC}**  Positive sequence short-circuit voltage at the transformer windings

**S_{ref}**  Reference power similar to HV-side rated power of the transformer

**r_o**  Wind turbine rotor radius

**k**  Entrainment constant

**x_o**  Distance between two turbines

**r_w**  Wake radius

**u_1**  Wind speed behind a turbine separated by **x_o**

**u_2**  Wind speed at third turbine in a row

**v_m**  Wind speed entering into turbine under partial wake shade

**V_{ps,l}**  Wind speed inside wake of turbine **l**

**B_{m,l}**  Ratio of rotor area under wake of turbine **l**

**v_n**  Wind speed entering the **n^{th}** turbine under multiple wake

**z**  Height of the turbine

**z_{ref}**  Height at which wind speed is measured

**z_o**  Surface roughness

**U(z_{ref})**  Wind speed at height **z_{ref}**

**U(z)**  Wind speed at the height of the turbine

**u**  Free-stream wind speed

**S_c**  Scale parameters of Weibull distribution

**k_s**  Shape parameter of Weibull distribution

**P_{loss}**  Active power losses in a radial network string

**Q_{loss}**  Reactive power losses in a radial network string

**R_i**  Resistance of the **i^{th}** portion of the string

**X_i**  Reactance of the **i^{th}** portion of the string

**P_{loss,WF}**  Active power losses inside the wind farm

**Q_{loss,WF}**  Reactive power losses inside the wind farm

**I_{WF}**  Total current flowing out of the wind farm

**S_{WF}**  Apparent power of a wind farm

**I_{eqWTj}**  Current from an aggregate wind turbine

**S_{eqWTj}**  Rated capacity of the aggregate wind turbine

**P_{loss,eqWFj}**  Active power losses in a cable connected to the aggregate turbine
<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>( Q_{\text{loss,eqWFj}} )</td>
<td>Reactive power losses in a cable connected to the aggregate turbine</td>
</tr>
<tr>
<td>( P_{\text{loss,eqWTj}} )</td>
<td>Active power loss in the string connected to an aggregate turbine</td>
</tr>
<tr>
<td>( Q_{\text{loss,eqWTj}} )</td>
<td>Reactive power loss in the string connected to an aggregate turbine</td>
</tr>
<tr>
<td>( R_{\text{eq}} )</td>
<td>Equivalent resistance of the cable connecting the aggregate turbine</td>
</tr>
<tr>
<td>( X_{\text{eq}} )</td>
<td>Equivalent reactance of the cable connecting the aggregate turbine</td>
</tr>
<tr>
<td>( M_p )</td>
<td>Number of turbines clustered into an equivalent turbine ( p )</td>
</tr>
<tr>
<td>( S_{\text{eq,WT}} )</td>
<td>Rated apparent power of the equivalent turbine</td>
</tr>
<tr>
<td>( S_{\text{individual,WTs}} )</td>
<td>Rated apparent power of each wind turbine</td>
</tr>
<tr>
<td>( S_{\text{coh,mat}} )</td>
<td>The size of the coherency matrix</td>
</tr>
<tr>
<td>( n_{WD} )</td>
<td>Number of wind directions considered</td>
</tr>
<tr>
<td>( n_{WTs} )</td>
<td>Number of wind turbines</td>
</tr>
<tr>
<td>( n_{WS} )</td>
<td>Number of wind speeds considered</td>
</tr>
<tr>
<td>( \sigma )</td>
<td>Standard deviation of wind speed over a period of 10 min or 1 hour</td>
</tr>
<tr>
<td>( \bar{U} )</td>
<td>Mean wind speed</td>
</tr>
<tr>
<td>( s )</td>
<td>Distance between turbines in separate rows</td>
</tr>
<tr>
<td>( s_1 )</td>
<td>Separation between wind turbines in a row normalised by rotor diameter</td>
</tr>
<tr>
<td>( I_{\text{addwf}} )</td>
<td>Added wind farm turbulence intensity</td>
</tr>
<tr>
<td>( I )</td>
<td>Turbulence intensity</td>
</tr>
<tr>
<td>( \beta_w )</td>
<td>Characteristic width of the wake</td>
</tr>
<tr>
<td>( \beta_i )</td>
<td>Angle between line connecting the turbines and the wind direction</td>
</tr>
<tr>
<td>( I_o )</td>
<td>Ambient turbulence</td>
</tr>
<tr>
<td>( I_w )</td>
<td>Wake added turbulence</td>
</tr>
<tr>
<td>( \alpha_w )</td>
<td>Constant expressed by ( I_o ) and ( I_w )</td>
</tr>
<tr>
<td>( P_J )</td>
<td>Heat gain due to joule heating</td>
</tr>
<tr>
<td>( P_M )</td>
<td>Heat gain due to ferromagnetic heating</td>
</tr>
<tr>
<td>( P_S )</td>
<td>Heat gain due to solar heating</td>
</tr>
<tr>
<td>( P_i )</td>
<td>Heat gain due to ionization heating</td>
</tr>
<tr>
<td>( P_{\text{con}} )</td>
<td>Heat loss due to convection</td>
</tr>
<tr>
<td>( P_R )</td>
<td>Heat loss due to radiation</td>
</tr>
<tr>
<td>( P_W )</td>
<td>Heat loss due to evaporation</td>
</tr>
<tr>
<td>( k_i )</td>
<td>Takes into account thermal diffusion</td>
</tr>
<tr>
<td>( f_Y )</td>
<td>Discrete probability density function</td>
</tr>
<tr>
<td>( F_Y )</td>
<td>Probability distribution function</td>
</tr>
<tr>
<td>( h_Y )</td>
<td>Frequency of ( y )</td>
</tr>
<tr>
<td>Mathematical Symbol</td>
<td>Description</td>
</tr>
<tr>
<td>---------------------</td>
<td>-------------</td>
</tr>
<tr>
<td>$P_{\text{cable to shore}}$</td>
<td>Active power loss in cable connected from the turbine array to the shore</td>
</tr>
<tr>
<td>$P_{\text{total loss}}$</td>
<td>Total active power loss in array and cable/s to the shore</td>
</tr>
<tr>
<td>$P_{\text{string loss}}$</td>
<td>Active power loss in a wind turbine array string</td>
</tr>
<tr>
<td>$P_{\text{total star loss}}$</td>
<td>Active power loss in starburst array</td>
</tr>
<tr>
<td>$\lambda$</td>
<td>Failure rate</td>
</tr>
<tr>
<td>$r$</td>
<td>Repair time</td>
</tr>
<tr>
<td>$p$</td>
<td>Availability of each wind farm component</td>
</tr>
<tr>
<td>$q$</td>
<td>Unavailability of each wind farm component</td>
</tr>
<tr>
<td>$l$</td>
<td>Length of the cable</td>
</tr>
<tr>
<td>$p_c$</td>
<td>Availability of the cable</td>
</tr>
<tr>
<td>$q_c$</td>
<td>Unavailability of the cable</td>
</tr>
<tr>
<td>$p_{wt}$</td>
<td>Availability of a wind turbine</td>
</tr>
<tr>
<td>$p_{mc}$</td>
<td>Availability of the main cable</td>
</tr>
<tr>
<td>$p_{tr}$</td>
<td>Availability of wind turbine transformer</td>
</tr>
<tr>
<td>$P_{\text{WT}}$</td>
<td>Overall availability of a wind turbine</td>
</tr>
<tr>
<td>$Q_{\text{WT}}$</td>
<td>Overall unavailability of a wind turbine</td>
</tr>
<tr>
<td>$cs$</td>
<td>Component statuses</td>
</tr>
<tr>
<td>$N_{cs}$</td>
<td>Number of component statuses</td>
</tr>
<tr>
<td>$C_i$</td>
<td>Status of a cable $i$</td>
</tr>
<tr>
<td>$T_i$</td>
<td>Status of a wind turbine and its transformer $i$</td>
</tr>
<tr>
<td>$K_r$</td>
<td>Number of wind turbines in a row</td>
</tr>
<tr>
<td>$p_{cs}$</td>
<td>Probability of certain combination of component statuses</td>
</tr>
<tr>
<td>$P_{\text{row}(k)}$</td>
<td>Probability that in one row $k$ turbines are available</td>
</tr>
<tr>
<td>$K$</td>
<td>Number of wind turbines</td>
</tr>
<tr>
<td>$k$</td>
<td>Number of wind turbines available in a row</td>
</tr>
<tr>
<td>$S_{\text{WT}_{eq}}$</td>
<td>Equivalent power curve of a wind turbine</td>
</tr>
<tr>
<td>$\Delta t$</td>
<td>Discretisation step</td>
</tr>
<tr>
<td>$T_c$</td>
<td>Number of hours with transmission congestion</td>
</tr>
<tr>
<td>$X$</td>
<td>Amount of power transmitted through bottleneck before wind power installation in MW</td>
</tr>
<tr>
<td>$Y$</td>
<td>Wind power production in MW</td>
</tr>
<tr>
<td>$Z$</td>
<td>Transmission after wind power is installed</td>
</tr>
<tr>
<td>$N$</td>
<td>Number of wind speed measurements</td>
</tr>
<tr>
<td>$T$</td>
<td>Time period</td>
</tr>
<tr>
<td>$f_c(x)$</td>
<td>Discrete probability density function of power transmission before wind power is installed</td>
</tr>
<tr>
<td>$F_x(x)$</td>
<td>Discrete probability distribution function of power transmission before wind power is installed</td>
</tr>
</tbody>
</table>
\( f(z) \) Discrete probability density function of transmission with wind power installed

\( F_z(z) \) Discrete probability distribution function of transmission with wind power installed

\( p_{WF}(k) \) Availability density of a starburst configured wind farm

\( L_{av} \) Range of losses due to unavailability of wind farm components

\( L_{curtail} \) Curtailment losses

\( l_c \) Number of components in a row

\( k_n \) Number of available wind turbines in a wind farm

\( p_m \) Availability of the main cable to shore

\( \Delta y \) Step at which wind production probability distribution function \( F_Y(y) \) is discretised

\( C \) Transmission line capacity

\( A_1 \text{ to } A_3 \) Cost coefficients for submarine cables

\( S_n \) Rated power of the cable

\( V_r \) Rated voltage of the cable

\( I_r \) Rated current of the cable

\( A_p \text{ and } B_p \) Offset constants to calculate cost of wind turbines

\( P_{WT} \) Rated power of a wind turbine

\( N_{WT} \) Number of wind turbines in a wind farm

\( h \) Height of the turbine

\( S_d \) Sea depth for wind turbine foundations

\( \text{Cost}_{WT} \) Cost of a wind turbine

\( \text{Cost}_{WT\_TI} \) Cost of wind turbine including transport and installation

\( \text{Cost}_F \) Cost of wind turbine foundation

\( \text{Cost}_{F\_TI} \) Cost of wind turbine foundation including transport and installation

\( \text{Cost}_{AC\_CABLE} \) Cost of manufacturing for AC submarine cable

\( \text{Cost}_{AC\_T&I} \) Cost of transport and installation of AC submarine cable

\( \text{Cost}_{AC\_CABLE\_TOTAL} \) Total cost of manufacturing, transport and installation of AC submarine cable

\( \text{Cost}_{DC\_CABLE\_150kV} \) Cost for 150 kV submarine DC cable

\( \text{Cost}_{DC\_CABLE\_320kV} \) Cost for 320 kV submarine DC cable

\( \text{Cost}_{TRANS} \) Cost of a transformer

\( T_1, T_2 \text{ and } T_3 \) Offset constants to calculate cost of transformers

\( g \) Slope constant to calculate cost of transformers

\( P_{TRANS} \) Capacity of the transformer

\( S_1, S_2 \) Offset constant, slope constant for switchgear

\( N_{WT\_cap} \) Number of wind turbine capacities considered
<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$N_{arr}$</td>
<td>Number of different types of array configurations considered</td>
</tr>
<tr>
<td>$N_{arr_Vol}$</td>
<td>Number of different MV levels considered</td>
</tr>
<tr>
<td>$N_{coll_trans_win}$</td>
<td>Number of different types of collector transformer windings considered</td>
</tr>
<tr>
<td>$N_{coll_trans_cap}$</td>
<td>Number of different collector transformer capacities considered</td>
</tr>
<tr>
<td>$N_{transm_Vol}$</td>
<td>Number of different HV levels considered at collector transformer secondary windings</td>
</tr>
<tr>
<td>$N_{coll_trans_red}$</td>
<td>Number of extra options considered having redundant collector transformers</td>
</tr>
<tr>
<td>$N_{Tot_HVAC}$</td>
<td>Total number of electrical layouts when an HVAC link is used to connect the offshore platform with the shore</td>
</tr>
<tr>
<td>$N_{Tot_HVDC}$</td>
<td>Total number of combinations if the electrical network from the wind turbines to the collector transformer is considered</td>
</tr>
<tr>
<td>$N_{transm_cab_quant}$</td>
<td>Number of different quantities of HVAC cables considered</td>
</tr>
<tr>
<td>$N_{Tot_HVDC}$</td>
<td>Number of different EHV voltage levels considered at the converter transformer secondary windings</td>
</tr>
<tr>
<td>$N_{conv_tr_cap}$</td>
<td>Number of different capacities of converter transformers considered</td>
</tr>
<tr>
<td>$N_{conv_cap}$</td>
<td>Number of different VSC converter capacities considered</td>
</tr>
<tr>
<td>$N_{Tot}$</td>
<td>Total number of electrical layouts when both HVAC link and HVDC link options are considered</td>
</tr>
<tr>
<td>$L_{LOAD}$</td>
<td>Load VSC converter losses</td>
</tr>
<tr>
<td>$L_{NO-LOAD}$</td>
<td>No-load VSC converter losses</td>
</tr>
<tr>
<td>$P_b$</td>
<td>Power in a bin in a power frequency curve</td>
</tr>
<tr>
<td>$H_b$</td>
<td>Ratio of hours in that bin to the total number of hours (8760)</td>
</tr>
</tbody>
</table>
## Abbreviations

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>DFIG</td>
<td>Doubly Fed Induction Generator</td>
</tr>
<tr>
<td>IGBT</td>
<td>Insulated Gate Bipolar Transistor</td>
</tr>
<tr>
<td>RSC</td>
<td>Rotor-Side Converter</td>
</tr>
<tr>
<td>GSC</td>
<td>Grid-Side Converter</td>
</tr>
<tr>
<td>BERR</td>
<td>Department for Business Enterprise &amp; Regulatory Reform</td>
</tr>
<tr>
<td>PWM</td>
<td>Pulse Width Modulation</td>
</tr>
<tr>
<td>VSC</td>
<td>Voltage Source Converter</td>
</tr>
<tr>
<td>LCC</td>
<td>Line Commutated Converter</td>
</tr>
<tr>
<td>HVAC</td>
<td>High Voltage Alternative Current</td>
</tr>
<tr>
<td>HVDC</td>
<td>High Voltage Direct Current</td>
</tr>
<tr>
<td>SVC</td>
<td>Support Vector Clustering</td>
</tr>
<tr>
<td>PCC</td>
<td>Point of Common Coupling</td>
</tr>
<tr>
<td>WT</td>
<td>Wind Turbine</td>
</tr>
<tr>
<td>WF</td>
<td>Wind Farm</td>
</tr>
<tr>
<td>NPV</td>
<td>Net Present Value</td>
</tr>
<tr>
<td>CSA</td>
<td>Cross Sectional Area (of a cable)</td>
</tr>
<tr>
<td>OFTO</td>
<td>Offshore Transmission Owner</td>
</tr>
<tr>
<td>AEI</td>
<td>Annual Energy Interruption</td>
</tr>
<tr>
<td>VeBWake</td>
<td>Vector Based Wake Calculation Program</td>
</tr>
<tr>
<td>FR</td>
<td>Failure rate</td>
</tr>
<tr>
<td>MTTR</td>
<td>Mean Time to Repair</td>
</tr>
<tr>
<td>WPPDF</td>
<td>Wind Power Production Distribution Function</td>
</tr>
<tr>
<td>ADF</td>
<td>Availability Density Function</td>
</tr>
<tr>
<td>WPDC</td>
<td>Wind Production Duration Curve</td>
</tr>
<tr>
<td>ADC</td>
<td>Availability Duration Curve</td>
</tr>
<tr>
<td>WPDC'</td>
<td>New Wind Production Duration Curve</td>
</tr>
<tr>
<td>UDC</td>
<td>Unavailability Distribution Curve</td>
</tr>
<tr>
<td>TDC</td>
<td>Transmission Duration Curve</td>
</tr>
<tr>
<td>TDF</td>
<td>Transmission probability Distribution Function</td>
</tr>
<tr>
<td>WDF</td>
<td>Wind farm production probability Distribution Function</td>
</tr>
<tr>
<td>NTDF</td>
<td>New Transmission probability Distribution Function</td>
</tr>
<tr>
<td>TL</td>
<td>Transmission Limit</td>
</tr>
<tr>
<td>XLPE</td>
<td>Cross-linked Poly Ethylene</td>
</tr>
<tr>
<td>AIS</td>
<td>Air Insulated Switchgear</td>
</tr>
<tr>
<td>GIS</td>
<td>Gas Insulated Switchgear</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Full Form</td>
</tr>
<tr>
<td>--------------</td>
<td>-----------</td>
</tr>
<tr>
<td>PI</td>
<td>Power Interrupted</td>
</tr>
<tr>
<td>MV</td>
<td>Medium Voltage</td>
</tr>
<tr>
<td>HV</td>
<td>High Voltage</td>
</tr>
<tr>
<td>EHV</td>
<td>Extra High Voltage</td>
</tr>
<tr>
<td>API</td>
<td>Application Programming Interface</td>
</tr>
</tbody>
</table>
Abstract

Wind power installations have seen a significant rise all over the world in the past decade. Further significant growth is expected in the future. The UK’s ambitions for offshore wind installations are reflected through Round 1, 2 and 3 projects. It is expected that Round 3 alone will add at least 25 GW of offshore wind generation into the system. Current research knowledge is mostly limited to smaller wind farms, the aim of this research is to improve offline and online modelling techniques for large offshore wind farms.

A critical part of offline modelling is the design of the wind farm. Design of large wind farms particularly requires careful consideration as high capital costs are involved. This thesis develops a novel methodology which leads to a cost-effective and reliable design of an offshore wind farm. A new industrial-grade software tool is also developed during this research. The tool enables multiple offshore wind farm design options to be built and tested quickly with minimal effort using a Graphical User Interface (GUI). The GUI is designed to facilitate data input and presentation of the results.

This thesis also develops an improved method to estimate a wind farm’s energy yield. Countries with large-scale penetration of wind farms often carry out wind energy curtailments. Prior knowledge of estimated energy curtailments from a wind farm can be advantageous to the wind farm owner. An original method to calculate potential wind energy curtailment is proposed. In order to perform wind energy curtailments a network operator needs to decide which turbines to shut down. This thesis develops a novel method to identify turbines inside a wind farm that should be prioritised for shut down and given priority when scheduling preventive maintenance of the wind farm.

Once the wind farm has been built and connected to the network, it operates as part of a power system. Real-time online simulation techniques are gaining popularity among system operators. These techniques allow operators to carry out simulations using short-term forecasted wind conditions. A novel method is proposed to probabilistically estimate the power production of a wind farm in real-time, taking into account variation in wind speed and effects of turbulence inside the wind farm. Furthermore, a new probabilistic aggregation technique is proposed to establish a dynamic equivalent model of a wind farm. It determines the equivalent number and parameters of wind turbines that can be used to simulate the dynamic response of the wind farm throughout the year.
Declaration

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To my loving parents
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Wind power has experienced a dramatic rise since the last decade. Volatility in fuel prices and climate change has pushed the energy sector to look for more renewable and emission free electricity sources. Wind energy has answered the call. Due to its free fuel and emission free output it has become an attractive option in the current scenario.

In 2010, total wind energy deployment around the globe reached 197 GW [1] which is 180 GW more than the deployments in 2000 [2]. Through regional distribution illustrated in Figure 1.1, it can be seen that Europe is leading the world with the largest number of wind installations. Amongst European countries, Germany and Spain have the highest portion of total installed capacity [1] as seen from Figure 1.2.

The wind energy sector is expected to achieve an even faster growth rate in the future. One reason for this drive is the European Union’s Renewable Directive of 2008 that committed its member countries to satisfy 20% of their energy needs through renewable sources by 2020. The UK has a national target to satisfy 15% of its energy needs through renewable sources, where as much as 40% of this is expected to be in the form of renewable electricity generation [3, 4]. Although modern technology allows electricity production from various renewable sources such as solar, wind, geothermal etc. the offshore wind is likely to play a vital role in achieving this target. A substantial amount of Europe’s offshore wind resource is located in Britain’s waters which is another reason for investing in electricity production from offshore wind [5]. According to [6], theoretically it is possible to generate more than 1000 TWh per annum from wind in the UK, far exceeding the electricity consumption of the entire nation.
Figure 1.1: Regional distribution of globally installed wind power capacity in 2010

Figure 1.2: Distribution of wind power installations inside Europe (GW capacity in brackets)

As of 30 June 2011, there were 1,247 offshore wind turbines connected to transmission grids across nine European countries, with a total capacity of 3.3 GW. The UK is making the greatest investment, installing 93.5% of all European off-shore turbines connected in the first six months of 2011 [7]. This is of little surprise when considering the Offshore Development Information Statement (ODIS) 2011, produced by National Grid Electricity Transmission
plc (NGET) which suggests that offshore wind generation capacity is expected to increase from roughly 1.5 GW at present to between 25 GW and 59 GW by 2030 (dependent upon the level of investment) [8].

Development of offshore wind farms in the UK is segmented into three phases known as Round 1, 2 and 3. The first phase was initiated at the end of 2000 with the aim of achieving 2 GW of installed capacity. Unfortunately, many of these wind farms are still in development or have been subjected to downsizing or complete abandonment. Round 2 wind farm sites were announced at the end of 2003, with a combined capacity of 7.2 GW. In general, Round 1 wind farms are closer to the shore and connect mostly at medium voltage (MV) level (33 kV) whereas Round 2 wind farms are more distant and connected to the shore at higher voltages. Round 3 (launched in 2008) aims to deliver a quarter of the UK’s total electricity needs by 2020 through an additional 32 GW of offshore wind generation. So far only wind zones have been detailed as to where these potential installations will take place [9]. A complete list of Round 3 offshore wind zones is given in Table 1.1.

<table>
<thead>
<tr>
<th>Wind Zones</th>
<th>Capacity (MW)</th>
<th>Location</th>
</tr>
</thead>
<tbody>
<tr>
<td>Moray Firth</td>
<td>1300</td>
<td>Scotland</td>
</tr>
<tr>
<td>Firth of Forth</td>
<td>3500</td>
<td>Scotland</td>
</tr>
<tr>
<td>Dogger Bank</td>
<td>9000</td>
<td>North Sea</td>
</tr>
<tr>
<td>Hornsea</td>
<td>4000</td>
<td>North Sea</td>
</tr>
<tr>
<td>Norfolk Bank</td>
<td>7200</td>
<td>Southern North Sea</td>
</tr>
<tr>
<td>Navitas Bay Wind Park</td>
<td>900</td>
<td>South</td>
</tr>
<tr>
<td>Rampion</td>
<td>600</td>
<td>South</td>
</tr>
<tr>
<td>Bristol Channel</td>
<td>1500</td>
<td>South West</td>
</tr>
<tr>
<td>Irish Sea</td>
<td>4200</td>
<td>Irish Sea</td>
</tr>
</tbody>
</table>

Building wind farms offshore is more expensive than building them onshore due to additional costs of the foundations (per turbine), platform, vessel hire and transportation of the components out to sea. The development work offshore can be affected by sea currents and weather resulting in delays of the project affecting the completion deadlines. However, resentment by the public due to obstructions in visibility as well as higher wind speeds away from land [6] have made offshore wind farms the preferred choice.

In the UK, winds generally come from the Atlantic and are observed to be highest in the North and in the East, making these locations an ideal place for
wind farms. Integration of large-scale offshore generation into the grid requires an upgrade of existing transmission lines and development of new networks. Widespread installations at wind hot spots around the country can take generation far from demand. At times, power generated in the North (Scotland) may have to be exported in order to satisfy load demand in the South (London). In such scenarios, the transmission network might require a redesign to carry the wind power all the way to the South with least amount of loss. Although there are transmission links between England and Scotland their capacity is limited, so as the amount of wind power generation increases in the North it will become essential to build new lines to transmit this power to the load centres, predominantly located in the south of the country.

1.1 The Need for Improved Modelling and Design

Offshore wind farms installed in Round 1 and Round 2 projects are relatively small in capacity and nearer to the shore compared to the Round 3 projects. In Round 3, offshore wind farms will be large in capacity and further away from the shore which as a consequence, will dramatically increase their project costs. These large offshore wind farms will have to be designed so that they lead to maximum benefits at lower costs. The knowledge gained by designing smaller wind farms may not be directly applicable when designing large offshore wind farms that are much deeper in the sea. Furthermore, large-scale integration of wind power into the network requires a change in the way wind farms are currently modelled in the power system. Considering this scenario, it can be deduced that an improvement is needed in modelling techniques for integration and design of large offshore wind farms.

There are two types of modelling techniques investigated in this research i.e. offline and online analysis. Offline analysis is often carried out by system operators when stability of a system has to be tested prior to integration of a new line, a customer (load) or a generator etc. Such studies have been and still are a popular type of analysis. But with large-scale integration of rapidly varying power generators and loads (electric vehicles), a new type of modelling is gaining importance in industry, which is the online analysis. Through this, system operators will be able to regularly test the stability of a network in real-time, a few minutes or hours ahead, using forecasted wind speed and load demand. Such analysis will gain importance in future when several large wind
farms will be installed at various geographical locations. Since wind is stochastic in nature, power generation from wind farms will vary according to the wind conditions therefore real time modelling of power flows is needed. System operators would thus need rapid analysis to estimate power generation for a given forecast and to test the stability of the network. In such scenario online analysis will be crucial for efficient operation of the network. This was not the case prior large-scale integration of renewable generation as power output from conventional generators was largely controllable.

The use of offline analysis is not just restricted to system operators. Designing the layout (including electrical network) and carrying out a pre-feasibility study for a new wind farm is also part of the offline analysis. The pre-feasibility study of new a wind farm determines whether it is economically and technically feasible to connect a wind power plant to the grid. The method of evaluation should consider all realistic factors so that a reliable energy estimate can be obtained. Such studies normally include determination of energy yield, power loss evaluation due to electrical and reliability based losses as well as fault current analysis. In cases where a wind farm is located in a remote area connected with a weak electrical infrastructure, it may lead to additional losses known as energy curtailments. This type of energy loss is usually not considered during the pre-feasibility studies.

Curtailing wind energy is a common practice in countries with a large presence of wind farms, where some countries pay the wind farm owner for curtailing the wind power but others don’t. In either case, the curtailments take place with bilateral agreement between the wind farm owner and the utility. Energy curtailments are often regional and they normally take place if there is a sufficient level of wind power available at any one time but there is less demand. Internationally carried out energy curtailment practices compiled in [10] show that a certain level of compensation is made to the wind farm owners in Germany and Ireland, whereas in Spain and New Zealand no compensation is made. Therefore, it would be useful if a wind farm owner can determine, prior to investing in a wind project, whether it will be economically feasible to curtail some energy or to build a new transmission line, so that a more informed decision can be made.

The main control centre (transmission system operator) is responsible for deciding power from which wind farms should be reduced. Depending on the
Grid Code requirement, a utility may not be allowed to trip a wind farm completely but it may have the authority to reduce its power generation, as is the case in Spain. Curtailments often take place by either pitching the blades of wind turbines out of wind or by switching off some of the operating wind turbines. Former is valid for modern pitch control wind turbines whereas latter for stall control wind turbines. If wind turbines are stall controlled it can be difficult to decide which turbines to shut down. This shutting down process can be made more efficient if only those wind turbines are switched off that have a higher chance of suffering from mechanical fatigue damage. This would help improve its lifetime and reduce the preventive maintenance cost of wind turbines.

Another factor that leads to energy loss is the *wake effect*. These are aerodynamic losses that lead to reduced power output and subsequently, a reduced energy yield. The effect is so significant that it can exceed electrical losses, therefore it should not be ignored during pre-feasibility studies and in general modelling of the wind farms. Wake effects explain the difference in power production often observed between wind turbines at the same wind farm. Several complex models have been developed in the past but not all of them are suitable for electrical engineering studies where a fast, yet relatively accurate estimate would be sufficient.

Large wind farm capacities and increasing distances from the shore pose a new challenge in designing offshore wind farms. Development costs of such projects can be significantly high. For instance, if the current cost of production is considered (€3.45m/MW)[3] a 400 MW wind farm will cost around €1.38 bn. Although the final cost depends on a variety of factors, the cost of equipment represents a major portion. Therefore it is absolutely essential that the design and choice of equipment are optimal and justifiable. A better approach would be to analyse several possible network layouts prior deciding on one. With growing dependence on wind energy, reliability and security of power supply can no longer be treated as a secondary concern. A cost-effective layout should balance the costs and provide a certain level of reliability. So far, research in designing large offshore networks is very limited. A methodology to solve this problem will be advantageous for the wind industry.

Apart from offline analysis, real-time online simulations are becoming a need for networks with a larger presence of wind farms. In order to perform
simulations in real-time (using forecasted wind and load demand) the models should provide quick output of results. The calculation process to estimate the instantaneous power output from wind farms should be fast and accurate so that it can be used to quickly simulate change in wind conditions. For this purpose, faster probabilistic methods would suffice rather than deterministic models, due to non-steady flow and stochastic nature of wind.

Real time transient stability simulations are another leap forward in online studies. Data such as protection and control settings can be gathered in real-time from devices installed in the network. Generally, transient stability simulations are time consuming, especially when dealing with networks with a large number of generators. For this reason, these analyses are often carried out offline. In future, bigger wind farms are expected to consist of numerous wind turbines that will lead to very large simulation times if each turbine is to be modelled separately. This problem can be solved by the use of aggregation techniques that can reduce the complexity of a wind farm model. However, this leads to an interesting problem as it requires aggregation of wind turbines facing different levels of wind speed (due to wake effects), thus producing different amounts of power. An array of cabling further complicates this issue since wind turbines producing different amounts of power can be in different strings (as in a radial configuration).

The motivation for this research has been to gain a deeper understanding about wind farms and techniques used for their modelling. Potential growth in the capacity of offshore wind farms require a re-look at existing methods normally applied to smaller wind plants. It is hoped that through this thesis an insight into the current issues will be gained and the models proposed will be useful not only for wind farm designers but also for utilities and consultancy companies in general.

A critical review of existing techniques is carried out in the following sections to identify whether current knowledge is sufficient to tackle the projected issues.
1.2 Overview of Wind Power Generation

1.2.1 Wind farm capacities and turbine sizes in European offshore wind farms

By observing existing offshore operational wind farms and those planned in the future it can be said that their capacity will increase in the near future. To make this analysis clearer, wind farms are classified into four categories:

1) operational
2) under construction
3) approved
4) submitted

All four categories are analysed for 120 offshore wind farms in Europe [9, 11, 12], which includes 46 operational, 9 under construction, 61 approved and 4 submitted in the UK (data for all submitted European wind farms was not available). Wind farms in the planning phase (such as Round 3 in the UK) have been excluded from analysis as their exact capacity is not finalised yet. Wind farms in category 1 and 2 are characterised as present installations, whereas those in category 3 and 4 consists of wind farms likely to be installed in the future. This analysis is aimed to investigate dominant capacities of wind farms in present and future offshore installations.

Figure 1.3: Capacities of wind farms in Europe

1 Data gathered in August 2011
From Figure 1.3 it can be seen that the most popular size of offshore wind farm in present installations is up to 100 MW, this is followed by 100 to 200 MW range. The biggest wind farm under construction (as of September 2011) is London Array Phase 1 in the UK, with a rated capacity of 630 MW. On the other hand, if offshore wind farms in the future are analysed, sizes between 200 and 500 MW are very popular. There will be fewer wind farms smaller than 200 MW in the future compared to the present. Therefore, it can be said that in coming years the capacity of a wind farm is set to increase. New, smaller capacity plants will still be installed but they will be few. Amongst European countries, the UK, Germany and Netherlands have the highest number of future planned offshore wind farms.

Figure 1.4 shows the exact capacity of present and future offshore wind farms along with their approximate distance from the shore. Generally, as can be observed from the figure, some wind farms with a bigger capacity are further away from the shore; however there does not seem to be any direct correlation between the two. For instance, in two capacity ranges 0 to 100 MW and 200 to 300 MW, the distance is mostly up to 15 km in the first range however in the second range the distance varies between 10 and 100 km. If 600 to 700 MW range is considered, i.e. relatively large capacity wind farms, the distance remains between 10 and 40 km. This shows that it is difficult to assume any correlation between wind farm size and distance to the shore.

![Figure 1.4: Wind farm capacity and their distance to shore for present and future wind farm installations](image)
(construction) wind farm in Germany is currently the furthest away from the shore (about 100 km). Amongst future installations, Global Tech 1 in Germany will be up to 115 km away from the shore. It should be noted that distances for future wind farms are only an estimate that has been reported so far and the exact distance will be only established when the actual wind farm is installed. A few wind farms for which distances were not known have been excluded from Figure 1.4.

The majority of large wind farms analysed operate with an internal array MV level of 33 kV. This voltage is then scaled up to typically 132 kV at an offshore platform for electricity transmission to shore.

The average water depth at which wind turbines were installed in 2010 was 18.8 m which is 6 m deep than the average water depth in 2009. The distance to shore also increased from an average of 14.4 km in 2009 to 27.1 km in 2010 [1].

1.2.2 Components of an offshore wind farm

1.2.2.1 Wind turbines

Turbines with a two axis configuration are currently available in the market: i.e. horizontal and vertical. In this thesis, only horizontal-axis turbines are discussed since they are commonly employed in large scale wind farms around the world. Vertical-axis turbines are generally used on roof-tops for small-scale residential or industrial use. The first produced horizontal-axis turbines were fixed-speed with passive stall: the rotor blades were designed for the average site wind speed therefore power generation was not optimum at all wind speeds. Newer variable speed active pitch control turbines can reach their optimum power output at rated speed and maintain this power output for higher wind speeds, enabling extra energy capture.

As well as improvements in aerodynamic components, the generators have also become more efficient; especially with the involvement of power electronics. Wind turbine can be divided into four types, detailed below and shown in Figure 1.5.
1. **Fixed Speed**: Squirrel cage induction generators (SCIG) were the first wind turbine generators used. They are driven by a gearbox and connected directly to the AC offshore grid.

2. **Variable Slip**: The introduction of varying rotor resistance allows for a small (typically 10%) variation in rotor speed. The variable slip induction generators (VSIG) are driven by a gearbox, and are directly connected to the AC offshore grid.

3. **Doubly Fed**: Doubly fed induction generators (DFIG) enable variable speed operation through the use of power electronic converters, typically rated to 30% of the turbine’s power output. Again, these generators are driven by a gearbox. These turbines are the most dominant technology with the greatest market penetration.

4. **Fully Rated Converters**: By utilising power electronic converters rated for the full output of the turbine, the gearbox can be removed from the system if desired, improving reliability and allowing very wide rotor speed variation. Wound rotor induction generators (WRIG), wound rotor synchronous generators (WRSG), and permanent magnet synchronous generators (PMSG) can all be used, with manufacturers currently developing models with large capacities. These are expected to become the leading technology in the future.

Early wind farm installations were limited to 5 or 10 MW total capacities, but this has grown phenomenally, with the biggest wind farms now expecting outputs of over 1000 MW (London Array when completed). This has been realised mainly through development of wind turbine technology, as well as through reduction in transmission limitations. Today, wind turbines with various ratings are in use from 0.6 to 5.0 MW; while a 7.0 MW has been
developed and is currently being tested [14]. Figure 1.6 (data collected from [11, 12]) shows the current prevalence of individual turbine capacities of around 2-3 MW (in European offshore wind farms). However, future wind farms will make use of larger capacity turbines, up to and including 7 MW.

1.2.2.2 Types of foundation

In order to hold a wind turbine in place under high winds and to prevent damage from sea currents, the turbines have to be installed on solid foundations. The base (footing) of a turbine is exposed to immense loads due to the mass of the turbine’s rotor and blades, nacelle and tower. The total mass experienced at the footing can reach several hundred tonnes. For example, considering a Vestas V80 2.0 MW turbine [15] the tower alone is 100 tonnes, the nacelle (carrying the generator, transformer and other control equipment) is 67.5 tonnes, and the rotor and blades (including the gearbox) is 37.2 tonnes, totalling over 200 tonnes.

The foundation must be able to carry such loads, therefore they are designed according to the turbine’s specifications. Their delivery and installation also poses a major challenge, as road infrastructure has to be appropriate to transport them from the manufacturing plant to the shore, then specialised cranes and vessels are needed to erect the wind turbines at sea. Foundation types vary between onshore and offshore turbine installations. On land, steel pile foundations are used that may extend up to two-thirds of the tower height under the ground [16]. The turbine is kept vertically erect through deep drilling.
and insertion of steel piles in the ground. In an offshore environment, this method is not useful due to soil stiffness and other parameters, therefore different types of foundations are commonly employed such as: gravity, monopile, jacket, tripile, and (currently experimental) floating foundations [11, 17].

These offshore foundations have been used in existing European wind farms [11] and may be used in future projects. The selection of foundation type also depends on sea depth, soil formation and the site’s atmospheric conditions. Among the types mentioned above the monopile has so far been used in most offshore wind farms, followed by gravity foundations. In Bard 1, tripile foundations are used [12] in water depths of around 40 m [18]. The floating foundation is still in the experimental phase and is expected to be useful in deep waters.

1.2.2.3 Wind turbine array

Spacing of turbines is an important factor. A large spacing might be ideal to reduce any wake induced power losses, however longer distances imply larger cable lengths which results in higher costs. Normally, wind turbines are connected through AC Cross-Linked Poly Ethylene (XLPE) 3-core submarine cables with a Copper or Aluminium conductor. Cables are specially designed to prevent moisture ingress and therefore have a thicker outer protective layer. The correct choice of voltage level inside an array is important. At a low voltage the current level will be high, leading to greater $I^2R$ losses. On the other hand, if the voltage level is too high then the cost of cables and equipment will increase due to extra insulation.

Newer wind turbines have a built-in transformer located inside the nacelle. This scales up the generator voltage level (usually 690 V) to a MV level at which the turbines are interconnected. Offshore wind farms in Europe typically use a MV level of 22 kV or 30-36 kV (more commonly employed) [12].

1.2.2.4 Array configurations

An array collector system gathers power from all turbines and delivers it to the collector transformer installed at the offshore substation. There are several ways to connect wind turbines inside an offshore wind farm but factors such as the distances between them (influenced by wake effects), voltage level inside
the array, costs of cable lay and bury, reliability of the array and potential electrical losses have to be considered. To prevent damage from strong sea waves, ship anchors and fishing trawler, cables are buried 1 to 4 meters deep inside the sea bed [19]. Smaller wind farms up to 20 MW and with distances less than 8 km [20] have been able to connect with the grid by transferring power over MV cables. In larger wind farms, however, power from all the turbines is collected at an offshore substation and then transmitted to shore at a higher voltage level to reduce $I^2R$ power losses. Four turbine array configurations commonly used inside wind farms and/or commonly discussed in existing literature are presented in the following sections.

**Radial Network**

In this configuration, wind turbines are connected in strings of cables as illustrated in Figure 1.7. The number of wind turbines that can be attached to the same string depends on the amount of current cables can carry. However a drawback with this network is that a fault at the end of a string (connecting the last wind turbine to the MV bus) can prevent power transfer from all the wind turbines in that string. To overcome this difficulty, redundancy can be introduced as shown in Figure 1.8 (a) in dotted lines. This configuration is known as *radial with end loop*. The redundant line can be brought into operation (see Figure 1.8 (b)) to prevent reliability based power losses when a line is disconnected to clear a fault.

![Figure 1.7: Radial connection](image1)

![Figure 1.8: Radial connection with an End loop to provide redundancy (a) no fault (b) fault cleared by line disconnection](image2)

Making the network reliable by adding redundancy may require use of higher capacity cables throughout the strings so that during fault clearance, power can be re-routed from other strings. The *radial* network is used in Horns
Rev 1 and 2 offshore wind farms [21, 22] and is also discussed in existing literature [23], [24]. A radial with end loop connection is used in Greater Gabbard offshore wind farm in the UK [25].

*Starburst Network*

In this network the turbines are connected to a central node by individual cables as illustrated in Figure 1.9. The network is very reliable in case of a single cable fault but implementation can be more expensive due to extra lengths of diagonally laid cables and complex switchgear of the node where all cables meet. Redundancy is not needed, as failure of any cable does not interrupt power from other turbines, however if a fault occurs at the main power carrying cable to the MV bus, then power transfer from all turbines is halted.

![Figure 1.9: Starburst connection with MV bus](image)

Lower capacity cables can be employed throughout, except at the link between the nodal point and platform. The *starburst* connection is discussed in [24], and it was one of the considered options for Middelgrunden offshore wind farm [26].

*Central (Tree) Network*

The *central* network links all turbines in a tree-branch configuration as shown in Figure 1.10.

![Figure 1.10: Central network connected with the MV bus](image)
In this thesis, the central network is also referred as tree configuration. Power from all wind turbines is collected at one turbine from where it is transferred to the MV bus. This type of collector system was used in Middelgrunden offshore wind farm [26]. One of the main disadvantages is that if a cable fault occurs in the cable carrying power to the MV bus, power from many turbines can be stopped. Wind turbines at Thanet offshore wind farm use both radial and tree networks [27].

Single-sided ring design

This network provides more flexibility if used with redundancy, since a fault in any cable cannot stop power transfer from the other wind turbines. Separate cables are laid from the end of each string to the MV bus which increases its cost relatively but also improves reliability. The rating of the redundant cable has to be enough to carry power from all the turbines in the string in case of a worst case contingency.

![Figure 1.11: Single-sided ring system (a) no fault condition (b) after line disconnection to clear the fault](image)

A single-sided ring network is illustrated in Figure 1.11 and discussed in [24]. A detailed investigation, including electrical loss calculations and reliability evaluation of these four configurations is carried out in the following chapters.

1.2.2.5 Offshore substation

Power from the turbine array is collected at offshore AC platforms. For larger wind farms (as expected in most future installations) voltages greater than MV are required for power transmission to shore and so offshore collector transformers are needed. They step up MV to High Voltage (HV) which is typically 130-160 kV and up to 220 kV though 245 and 275 kV are also used. Offshore transformers can be either 2-winding or 3-winding as used in Thanet and Greater Gabbard respectively. If transmission to shore is planned through high voltage AC (HVAC) cables then collector transformers are sufficient, but if
high voltage DC (HVDC) is to be used then the platform should be able to carry converter transformers and converters.

The cables used in wind farm arrays produce reactive power due to shunt capacitance; this can affect the MV level at the offshore busbars. Conversely, collector transformers absorb reactive power. If the link to shore is made through HVAC cables, then they also act as a reactive power source raising the voltage levels. Therefore, a source of reactive power compensation is required on the offshore platform. A compensation device not only improves the voltage quality but also provides the power factor correction to follow the requirements of the Grid Code. If the link to shore is made through HVDC technology, an offshore device for reactive power compensation may not be needed as converters have the ability to regulate reactive power.

Offshore substations are often completely prefabricated on land and installed offshore in one piece. Alternatively, they can be of modular design for easy assemblage at sea. Transformers for offshore use have to be specifically designed for the weight and volume restrictions imposed by the platform. Furthermore, the total weight to be lifted cannot exceed that of the crane to be used; (the current largest sea crane Thialf can haul 14,200 tonnes [28]).

A typical large wind farm offshore AC collection substation will include:

- One or more collector transformers (2- or 3-winding) to step up voltage to transmission levels.
- Devices for reactive power compensation.
- AC switchgear: usually gas insulated (GIS) [25] due its improved reliability, minimal maintenance requirements, resilience to the corrosive environment and a smaller footprint [29].
- Instrumentation and protection systems.
- Neutral earthing resistors.
- Auxiliary backup diesel generator.

1.2.2.6 Platform interconnection

When the capacity of a wind farm is very large, a single platform may not be sufficient to house all the required equipment. Limitations exist not only in terms of the civil works of the platform (the weight it can withstand) but also on the number of cables that can be safely brought in a limited space. For these reasons, as well as for the reliability improvements that interconnection brings
(increasing redundancy), having more than one platform is beneficial. These inter-platform connections are made using HVAC cables. One major disadvantage of this approach is the cost of additional offshore substations; however a full cost-benefit analysis will reveal the optimal configuration.

Many of the European wind farms with authorised consent for development at higher power capacities will have two offshore substations. Amongst wind farms near completion, London Array (currently in development in the UK) will utilise two offshore substations in Phase One (1,250 tonnes each) delivering 630 MW of power to shore [30]. Sheringham Shoal and Greater Gabbard wind farms in the UK will make use of two offshore substations [25, 31].

1.2.2.7 Transmission of electricity to shore

Power transmission to shore in large offshore wind farms can take place by either High-voltage AC (HVAC) or High-voltage DC (HVDC) cables. HVAC line losses are less compared to HVDC for shorter distances whereas, HVDC is more economical for large wind farms when the distance to shore is greater than 90 km [32]. For distances greater than 90 km, power transfer by HVAC is limited due to the capacitive nature of the cables [33] (as they generate reactive current) unless reactive compensation is installed at each end. Generation of reactive current reduces the capacity to carry the active current. In this situation HVDC becomes the preferred option as it offers no technical limitations on the length of submarine cables.

Systems interconnected by HVDC do not need to operate synchronously with each other, thus preventing propagation of cascading system failures which are observable in AC systems. Apart from this, it allows controllability of the magnitude and direction of power flow that can improve the stability of the system.

HVDC can be implemented through two different technologies: Line Commutated Converter (LCC) and Voltage Source Converter (VSC). AC to DC rectifier and DC to AC inverters are needed at offshore and onshore substations respectively.

LCC is a thyristor based HVDC technology; it is a conventional way to transfer power over a HVDC line. ABB sells this technology under the name of HVDC Classic.
The VSC technology is relatively new and is gaining world-wide recognition as it is lightweight, compact and has better control than conventional LCC. So far VSC technology has only been used in projects in Sweden, Denmark, Australia and USA. It offers numerous benefits over LCC but is very expensive. Pulse Width Modulation (PWM) and Insulated Gate Bipolar Transistors (IGBT) are used in this technology. VSC allows flexible control of reactive power. In industry it has been developed by ABB and Siemens with the product names HVDC Light® and HVDC PLUS respectively.

A more detailed comparison between LCC and VSC, as well as between monopole and bipolar configurations is presented in Section 7.2.6.

1.2.2.8 Onshore substations

To accommodate power injection from the wind farms onshore, substations would have to be modified or new ones constructed. The voltage level may have to be adjusted through onshore transformers if power has to be added directly to Distribution or Transmission Lines. Creation or extension of new substations will involve land acquisition and planning permissions will also be required [29]. Onshore reactive power compensation may have to be installed, depending on the VAr creation in the HVAC lines. If an HVDC link is used, then an Inverter will also have to be installed to convert the voltage and current back into AC. Protection and control equipment, Air Insulated Switchgear (AIS) and AIS Disconnectors may also be needed on an onshore substation.

1.3 Wind Farm Costs

Many factors contribute towards the total project cost to build a large wind farm. These include price of the equipment, transport, installation, shipping, labour, planning and construction. With so many potentially volatile costs (including currency and commodity price movements) to incorporate and the fact that specific details of each project play an important role in determining the required level of investment, it is difficult to predict the price of future wind farms.

Despite a general reduction in prices during the 1990s, from the mid-2000s prices have been escalating. Initial projects carried price tags of approximately €2.08 million/MW (Vindeby, 1991), later reducing to €1.20 million/MW (Horns Rev, 2002). However, current costs are now much higher at approximately
€3.45 million/MW [3] (e.g. 300 MW Thanet wind farm completed in 2010 came in at a cost of €3.0 million/MW) [34].

Due to the cost of an offshore platform, cable connection to shore and in general, higher costs of foundations, installation and construction, offshore power per MW costs more than onshore [35]. Not only this, but also operational expenditure (OpEx) for offshore wind farms is higher than onshore since access to the wind farm is dependent on weather conditions and availability of a vessel.

1.4 Review of Relevant Previous Works

1.4.1 Aggregate models for transient stability studies

Increasing use of wind generation requires suitable models of WFs that can be easily deployed in power system studies. Detailed dynamic models of large WFs consisting of tens and even hundreds of wind turbines are not suitable as they can significantly increase the size of the mathematical model of the power system and thus increase the overall simulation time. In spite of significant computer power available and efficient numeric algorithms to handle large mathematical models, it is still desirable to reduce the order of the model of individual system components as much as possible. Although model reduction is entirely preventable by use of a super computer [36] this may prove to be an expensive solution. The studies involving very large power systems (e.g., pan-European system) involving thousands of generators are becoming more and more sought after and every reasonable reduction in mathematical model of individual components is welcomed as long as equivalent/aggregate models retain the required level of accuracy. Several aggregate WF models [37-42] have been proposed over the last decade with the aim of reducing computational effort and simulation time during transient stability analyses to enable very fast, first approximation, assessment of WF performance and consequently WF effect on power system performance.

Wind speed variation (due to wake effects) inside a wind farm, turbine type and wind turbine interconnection in different strings makes the aggregation non-trivial. A single-unit aggregate wind turbine model, proposed in [43] represents the entire wind farm by one equivalent machine. All wind turbines are modelled through simplified wind turbines and variation in wind speed is
taken into account in [44]. The importance of wake effect consideration during wind farm aggregation is highlighted in [45]. A multi-machine model is reported in [37] by clustering wind turbines with similar wind speeds. Aggregation by wind speed (for DFIG) is performed in [46] by summation of mechanical torques from individual turbines which then feed into an equivalent generator. Wind farm behaviour emulative models can represent wind farms as a DC current source [47] however they have been built for full converter machines. An aggregate model for wind farms consisting of fixed-speed turbines is presented in [48]. Variable speed wind turbines can be represented by a transfer function in [49] whereas a complete wind farm model reduction through singular perturbation theory is proposed in [40].

Wind farms are usually built in areas with higher wind speeds and this can eventually lead to a wider geographical gap between generation and demand. In future, when power networks will have a significant amount of large-scale wind farms installed, the centre of power generation will no longer be fixed. In this case, offline analysis may no longer be effective and real time transient stability simulations will have to be performed using short-term forecasted wind speed as input. Wind pattern models for short term forecasts from a few minutes to several hours ahead [50], [51], [52, 53] already exist. Aggregate models of wind farms can be plugged in to real-time simulators to reduce simulation time as proposed in [54].

Problem statement 1:

All aforementioned aggregation methods were designed for offline simulations, however they have not been tested on a real-time simulator. Some of these studies involve simplified wind turbine models leading to lower accuracy of dynamic results while others use simplified wind models, e.g., neglecting wake effects and assuming that every turbine inside the WF receives the same wind speed. Doing so does not accurately estimate the power output from a WF. Some of the above mentioned models are accurate and cause reduction in simulation time, but as a consequence, increased application difficulty. A model that considers wake effects that is fast and practical to be used in an online real-time simulator is needed.
1.4.2 Energy yield estimation and cost-benefit analysis for offshore wind farms

Evaluation of the energy yield analysis of a wind farm is necessary to determine the feasibility of a project. It is a prerequisite for obtaining planning permission and to justify project financing. Therefore it is essential to determine this value as close to reality as possible. However, this can only be achieved once all influential factors have been considered during the analysis. These factors are generally losses that reduce power output and thus energy yield of a wind farm. One such factor is wake effect and several models have been presented in the past [55-59] to take it into consideration, however some models are more complex than others. Although complex models can model wakes very closely and in greater detail, they are computationally very demanding. Simple analytical models exist but they are mostly deterministic. Wake models are covered in greater detail in Chapter 3.

Recording wind speed measurements for a wind farm project for at least one year [60-62] is a common practice as it helps in assessing the energy yield. However, if mast and anemometer installation costs have to be avoided or if a general estimate of wind potential is needed, then a Weibull distribution [63, 64] can be also used.

The energy yield for wind farms is calculated in [65, 66]. Currently existing energy yield evaluation techniques [64, 67] often ignore some or all of the loss factors. Reliability is another important factor because if a component becomes unavailable it can cause power interruption and thus reduction in energy yield.

Models for reliability evaluation of power systems with a large proportion of wind generation already exist [68-70]. Very few models have been established however, that carry out reliability based loss evaluation of wind farm energy [71], yet impact of a wind farm’s internal grid is often neglected [62, 72]. A brief discussion on existing reliability models for wind farms can be found in [73]. Markov models and Monte Carlo simulations have been ubiquitously used in the past.

Several software tools such as IPSA [74, 75], PSS®E [76, 77], DIgSILENT PowerFactory [78], PowerWorld [79] can be used to build up a wind farm network and carry out detailed analysis. Due to growing interest in wind farm studies, dedicated software have been developed for wind farm design and
energy yield evaluation including WindFarmer [80] from GL Garrad Hassan and WAsP (Wind Atlas Analysis and Application Program) [81].

Several techniques exist that can increase the energy yield of a wind farm through optimal placement of wind turbines [82-84] and selection of appropriate turbines [85]. Wind farm designs have been discussed in various studies [86-89] including profit optimisation through Net Present Value (NPV) analysis (with various turbine tower heights and locations) [90, 91]. Investment cost analysis for building an offshore wind farm is provided in [92] (excluding VSC converters and DC line costs). Electrical losses and investment costs of electrical collector systems is investigated in [24]. However, a complete cost-benefit study analysing various possible offshore electrical configurations (from turbine to shore) along with losses and reliability is not available.

Increasing wind farm capacity and distance from shore has raised questions as to whether HVAC or HVDC should be used for electricity transmission to shore. Although an AC link is generally an economical choice, higher charging currents and bigger losses makes it unfeasible for longer distances and this is when the HVDC link appears to be a more suitable solution [19]. Transmission link options from an offshore platform to shore are investigated in [32, 93]. Amongst the new electrical designs, a DC grid has been given serious thought. When considering a complete DC grid based wind farm [88, 89] it was observed that this configuration is suitable for large offshore wind farms, whereas series connected DC wind turbines have the potential to yield lower cost of energy production for distances than 20 km [86].

**Problem statement 2**

An optimisation algorithm is needed that deals with all aspects of wind farm design collectively whether they are the physical placement of turbines, choice of electrical layouts, choice of components or even transmission options to shore. Maximisation of energy yield and minimisation of cost and losses have to be looked at simultaneously. Existing studies lack such holistic optimisation since only parts of the design are dealt with in previous studies.

**Problem statement 3**

Although current studies are very useful for layout design (turbine placement) of an offshore wind farm, there is no comprehensive methodology that provides a complete solution for an optimal electrical layout selection that
is reliable yet cost-efficient. With growing wind farm sizes it gets difficult to choose the right electrical components, voltage levels, type of transmission, turbine capacity, array configuration etc. that satisfy both criteria. Electrical and reliability based losses should also be considered as part of the layout and component selection process.

**Problem statement 4**

Energy yield calculation is essential during pre-feasibility studies as well as during the design process. The methods used in the commercial software that evaluate wind farm energy yield are hardly visible. In fact, several factors contribute towards this final value and therefore this value should be probabilistic and project specific. All loss factors including electrical losses, wake losses and reliability based losses should be modelled. Current studies ignore some, or all of these factors, while others generalise the total losses or represent them by a deterministic value. In reality these losses are project and site dependant, therefore a complete methodology is needed that can be easily followed.

**Problem statement 5**

Analytical wake modelling techniques should be able to predict wind speed probabilistically since wind interaction with a turbine changes the flow of wind. Although complex models can simulate such phenomena, they are mostly used during blade design and are not computationally efficient for electrical engineering studies.

**Problem statement 6**

Reliability studies considering components internal to a wind farm are few and in those studies only single component failures are considered. A multi-component failure is a possibility and hence a methodology to calculate its effect is needed.

**1.4.3 Wind energy curtailments**

In general, rural, open and low population areas are good locations for wind farms. Electrical infrastructure, e.g. the transmission network, in these places may not be sufficiently strong to accommodate integration of large-scale in feed from wind farms. Transmission line reinforcement or network component
upgrade is an expensive option. The transmission corridor may already be reserved for existing conventional generators installed in the area. Furthermore, power imbalances between generation and demand can happen under a high wind low demand situation. In such circumstances, curtailment of wind energy might seem to be a feasible, yet cheaper alternative. Curtailments are carried out in several parts of the world including the US [94], Spain, New Zealand, Ireland, Germany and Canada’s Alberta province [10]. Curtailments were initially suggested in [95] and then widely discussed in the existing literature [96-98]. Although methods for wind farm energy curtailment evaluation have been proposed in the past [99-101] some of them require detailed network parameters to be known, while others require a unit commitment schedule. Such methods are generally applicable when information about the network or generator scheduling is available.

In future, electricity storage devices (e.g. battery) will have the potential to limit curtailment losses by effectively storing excess energy and later using it as a backup reserve [102]. However, such devices are still very expensive or of limited capacity, therefore, in the short to medium term, wind curtailments may prove to be a more economic option. Although curtailments are performed by reducing power output from a wind farm, very few if any studies have been carried out to determine which turbines to shut down first.

**Problem statement 7**

A method is needed to estimate annual energy curtailments for wind farms which consider the influence of realistic factors such as internal wind farm losses, turbine availabilities and correlation between wind power generation and loading of transmission lines (ignored in the previous studies) so that a realistic estimate is obtained.

**Problem statement 8**

During curtailments it is not known which turbines should be given priority to shut down. A procedure should be devised that allows determination of such turbines. This has not been studied so far in the literature.
1.5 Summary of the Past Work

After reviewing the existing body of work, the following areas were identified for potential further improvement.

- Comparatively less research has been carried out in designing large offshore wind farms. Although many issues have been addressed in isolation, e.g., optimal wind turbine placement and type of connection with the shore, a complete methodology to analyse all aspects of wind farm design collectively has not yet been developed.
- The correct choice of electrical components and their connection options should lead to a robust electrical layout that is reliable and cost-efficient. The existing literature does not show a methodology that leads to such a solution.
- A complete and transparent methodology is not available for energy yield evaluation of a wind farm. Existing methods ignore some of the loss factors.
- Reliability based losses inside a wind farm depend on availability of components. Few methods provide single component failures but multi-component failures have not been looked at in a great detail.
- A methodology to estimate wind energy curtailments that considers various factors affecting the energy yield and energy export from a wind farm is not available.
- There is no methodology to identify whether some turbines inside a wind farm are more, or less, critical than others. Turbines that are critical should be kept operational most of the time.
- Existing models that simulate wind flow inside a wind farm are complex and computationally heavy. Analytical models are fast but mostly deterministic; they do not represent wind speed variation inside the farm adequately.
- Aggregation models proposed in the past involve simplified wind turbine models or simplified wind farm models that ignore variation of wind speed inside the wind farm. Models that are sufficiently accurate on the other hand are not easy to setup and use.
1.6 Research Objectives

Several areas that can be further improved have been identified and summarised in the previous section. The main aims of this research are derived from identified areas for further improvement and summarised below:

1. Identify and summarise gaps and areas in need of further improvement based on the existing body of literature.
2. Critically evaluate existing methods for wind farm aggregation and develop a more easy to use yet accurate methodology for wind farm aggregation.
3. Evaluate the developed aggregation approach against full wind farm model and existing aggregate models.
4. Collect and compare existing methods and if required, develop new methodologies for energy loss calculation inside a wind farm to establish complete set of methods that can be followed in different types of studies.
5. Develop curtailment evaluation method which considers various realistic factors and can estimate curtailments for a wind farm in a remote location without detailed network parameter information.
6. Determine and quantify the effects of wake on wind farm power output and energy curtailments.
7. Investigate existing wake effect models and if required, develop a new fast, probabilistic wake model which can be used during online studies.
8. Develop methodology to identify wind turbines that face high wind speeds/remain under wake most of the time, so that more power producing turbines and those under greater mechanical stress can be identified.
9. Develop methodology to identify a robust electrical layout for an offshore wind farm and to choose component ratings effectively using cost-benefit analysis.
10. Develop user friendly software tool with an appropriate Graphical User Interface (GUI) for quick and effortless design of large offshore wind farm electrical systems.
1.7 Major Contributions of the Research

The contributions made during the course of this research are summarised as follows. (Research papers published or submitted for publication to International Journals, and International Conferences based on particular contribution are given in the parenthesis. List of author’s thesis based publications can be found in Appendix F).

1.7.1 Vector based wake calculation program (VebWake)

A software is developed in MATLAB that allows calculation of wind speed at any turbine inside the wind farm. The software uses detailed wake effect models (considering single, partial and multiple wakes) to estimate the wind speeds. A wind farm consisting of any number of turbines arranged in any layout at any location can be simulated for any incoming wind speed and wind direction. Integrated power curve of the turbines allow rapid evaluation of power output of the wind farm. The software estimates the wind speed using the vector intersection method detailed in Chapter 3.

1.7.2 Probabilistic wake effect model

Existing wake effect models used in wind farm studies are mostly deterministic. Detailed and reasonably complex models of wake effect exist, however they are mostly suitable for turbine blade design and add significant and possibly unnecessary computation burden. A new analytical wake model is proposed in this thesis by combining two existing widely adopted models. The model allows probabilistic evaluation of power output from a wind farm, it is efficient and can be used during online analysis. Details about this model can be found in Chapter 3. [F.6]

1.7.3 Probabilistic aggregate model of a wind farm

A novel method is developed through which a large wind farm can be represented by fewer turbines. The concept of aggregation is extended to include wake effects, electrical losses, site wind characteristics and wind farm layout. A dynamic response comparison is also provided with the detailed model. The approach is practical and leads to significant reduction in simulation time.
The probabilistic aggregation method is compared with existing approaches. Factors such as simulation time, ease of setup and use and dynamic stability performance are evaluated. The technique and the comparison are presented in Chapter 4. [F.2] [F.5] [F.8]

1.7.4 Advanced method for wind farm energy yield calculation

A method is proposed for probabilistic calculation of wind farm energy yield. It comprises a new method for reliability evaluation that takes into account availability of wind turbines, turbine cables, transformers and cables to shore. It is developed for four commonly used array collector systems i.e. radial, starburst, tree and single-sided ring configurations. The sensitivity of energy yield calculation to various factors that contribute towards energy losses is also established. The calculation procedure is described in Chapter 5. [F.1] [F.4]

1.7.5 Assessment of wind energy curtailment

A new method is proposed to evaluate energy curtailment losses for wind farms installed in remote areas with transmission bottlenecks. It takes into account correlation between transmission line loading, wind turbine availability and wind speed. It also considers factors such as wake effects and electrical losses inside the wind farm during calculation. The method developed is discussed in Chapter 5. [F.1] [F.9]

1.7.6 Probabilistic identification of critical wind turbines inside the wind farm

A new method is developed to identify turbines that face high and low wind speeds inside a wind farm during a year. Wind farm layout, height and rotor radius of turbines, site’s wind characteristics (wind speed and direction), wake effects and positioning of turbines are all taken into account. The method is applicable to both onshore and offshore wind farm installations. The model is presented in Chapter 6. [F.7]

1.7.7 Methodology for cost-benefit analysis of offshore electrical network design

A novel methodology is proposed to select a robust design option for an offshore wind farm. Several design options are possible for a large offshore wind
farm considering voltage levels, choice of turbines, rating and quantity of components that can be employed. The proposed method short-lists a robust design option from a list of feasible design options. The method considers capital cost, level of redundancy, electrical losses and reliability based losses. The cost of losses is computed and a cost-benefit analysis carried out using the Net Present Value (NPV) calculation for all short-listed options. The method developed and assessment procedure is described in Chapter 7.

1.7.8 Industrial software for offshore wind farm design and loss evaluation

An industrial-grade software tool is developed that allows a user to quickly develop and test large wind farm electrical systems. The tool is based on commercially available power system software PSS®E. Data is entered through a Graphical User Interface (GUI) which is then used for the automated design of the network. Once network development is complete, rapid analysis of electrical losses (compliant with Grid Code) is also possible. Reliability based energy losses can also be evaluated through an automated procedure. The developed software tool significantly reduces the time and effort needed in carrying out such calculations. Details about the software and design methodology are described in Chapter 7. [F.3] [F.10]

1.8 Overview of Thesis

There are nine chapters in this dissertation. An outline of each of them apart from the introduction is presented below:

Chapter 2: Wind Turbine and Power System Components Modelling

Basic models for power system and wind turbine components are given in this chapter. These include line, transformer, doubly-fed induction generator, rotor-side and grid-side converter, power and thrust coefficient, drive train, protection system, pitch and rotor speed controller models.

Chapter 3: Modelling of Wake Effects

Existing wake effect models are critically reviewed and the most suitable model for use is identified in this chapter. The wake calculation program which has been developed is also introduced here and illustrative simulation
screenshots are presented. Models of large and small wind farms used in the analysis throughout the thesis are also shown in this chapter.

A new probabilistic wake model is proposed by combining two analytical wake models to take into account wake induced turbulence in wind speed and its impact on power output. The method is tested on a large wind farm and illustrative results are presented.

Chapter 4: Probabilistic Aggregate Dynamic Model of a Wind Farm

This chapter introduces a novel methodology to establish a probabilistic aggregate model of a wind farm that can be used during the year. The aggregate model can be used for transient stability studies to simulate dynamic response of a large wind farm. Development of the aggregate model considers layout of the wind farm, wake effects and wind characteristics at the site. Support Vector Clustering is performed to cluster wind turbines facing the same wind speed. Groups are then formed out of these clusters; the most probable group is then chosen to represent the wind farm. Aggregation of the collector system is also proposed so that electrical losses can also be taken into account. The method is tested on a large wind farm against a detailed wind farm model to compare transient stability results and simulation time. A comparison with existing aggregate models is also provided to compare accuracy, simulation time, ease of setup and use.

Chapter 5: Probabilistic Assessment of Wind Farm Energy Yield

In the early sections of this chapter likely causes of transmission bottlenecks are discussed, including voltage stability limits and thermal limits of the equipment. This is followed by factors that affect energy yield production from a wind farm such as wake effects, electrical losses and reliability based losses. A methodology is then provided to calculate energy loss due to each factor, looking especially at the reliability calculation where a new method is proposed, based on combinatorial algorithms. A new method to determine curtailments in a region with transmission bottlenecks is also presented. Case studies and sensitivity analysis are performed on a small wind farm. The method is applicable for offline pre-feasibility studies (i.e. prior to wind farm development) to facilitate informed decisions by a wind farm owner.
Chapter 6: Probabilistic Identification of Critical Wind Turbines inside a Wind Farm

The chapter presents a new methodology to identify wind turbines inside a wind farm that are exposed to different winds during the year. The technique is demonstrated on a case study involving a large wind farm.

Chapter 7: Robust Design Methodology for Offshore Wind Farms

A new methodology is proposed in this chapter that allows wind farm designers to select a cost-efficient and reliable electrical network layout for the offshore wind farm. A method for short-listing of options filters out layouts based on investment cost and a reliability level index. The short-listed layouts are then further tested for detailed electrical and reliability based losses. The cost of losses is calculated based on energy price. Feasibility of each layout is tested by NPV analysis. As a case study, a 400 MW offshore wind farm was used to demonstrate the methodology.

A software tool to assist wind farm designers and consultants was developed during an industrial placement. This chapter also describes key features and advantages of this software, along with its design and calculation process. Illustrative screenshots of developed GUI are also provided in this chapter. The software automates electrical losses as well as reliability based losses.

Chapter 8: Conclusions and Future Work

The chapter presents major conclusions of this research as well as proposals for future research and development that could advance the research presented in this thesis.
Chapter 2

Wind Turbine and Power System Components Modelling

2.1 Introduction

This chapter provides models for power system and wind turbine components. Among four types of wind turbine technologies covered in the previous chapter, the variable speed *Doubly Fed Induction Generator* (DFIG) (Type 3) is most widely used commercially. This is because it provides a low cost solution over *Fully Rated Converter* type of turbines [103] yet improved power quality over *Fixed Speed turbines*. It should be pointed however that although DFIG is a popular concept at present, but *Fully Rated Converter* type is rapidly gaining popularity and might be used more commonly in the future. This however will not change the relevance of the research presented in this thesis. However model reduction for dynamic studies (presented in Chapter 4) may have to be done differently.

Initial sections of the chapter discuss the basic energy extraction procedure of a wind turbine, this is followed by aerodynamic, electrical and mechanical component models. Operation and role of each wind turbine component in a DFIG is discussed. Models for power coefficient, thrust coefficient, drive-train, generator, rotor-side converter (RSC), grid-side converter (GSC) and pitch angle controller are provided along with power system component models for cable and transformers (2-winding and 3-winding). Protection system, DC link chopper, rotor speed controller and yaw control of a wind turbine are also briefly discussed.
### 2.2 Wind Turbine Modelling

A wind turbine extracts kinetic energy from the wind and converts it into mechanical and then electrical energy. Two main components inside the turbine enable this conversion process to take place: the turbine rotor and the electrical generator. A rotor extracts the energy from the wind and converts it into mechanical torque while the generator converts this mechanical energy in the torque into electricity which is then fed into the grid. This is a general working principle of a wind turbine, which sounds rather simple. In reality however, a wind turbine is a complex system that can consist of several components, including:

- Aerodynamic rotor (with typically three blades),
- Yaw mechanism,
- Gear box,
- Pitch control for the blades,
- Electrical generator,
- Anemometers,
- Power electronics (Converters) and
- Controllers

#### 2.2.1 Power extraction from a wind turbine

Kinetic energy \((KE)\) in a moving mass \(m_a\) of air travelling at a speed \(v\) is given as [104]:

\[
KE = \frac{1}{2} m_a v^2 \tag{2.1}
\]

Power inside this moving mass of air can be expressed as:

\[
P_w = \frac{1}{2} (\text{Mass flow rate per second}) v^2 \tag{2.2}
\]

If mass flow rate of air \((\rho A v)\) in kilograms per second is added to (2.2), this equation can be re-written as:

\[
P_w = \frac{1}{2} (\rho A v) v^2 \tag{2.3}
\]

where \(P_w\) is the mechanical power in the moving mass of air, \(A\) is swept area by the rotor and \(\rho\) is air density.
Power coefficient ($C_p$) also known as performance coefficient calculates the fraction of power a wind turbine can extract from the wind. The amount of kinetic energy that can be converted into mechanical energy depends on turbine parameters as well as the wind speed. Turbine parameters such as blade pitch angle, radius of the rotor and angular rotor speed determine the fraction of power captured. A higher $C_p$ implies that a turbine is more efficient in extracting power from the wind. Mechanical power that a rotor extracts from the wind is given by:

$$ P_{rot} = C_p P_w $$

(2.4)

Substituting (2.3) into (2.4) gives:

$$ P_{rot} = \frac{1}{2} \rho A v^3 C_p $$

(2.5)

Power coefficient is a non-linear function of tip-speed ratio $\lambda$ and pitch angle $\beta$. It can vary with the type of turbine but has a maximum theoretical limit of 16/27 (59.3%) according to the Betz law [105]. Mechanical torque on aerodynamic rotor shaft can be determined using turbine rotational speed $\omega_{rot}$:

$$ T_{rot} = \frac{P_{rot}}{\omega_{rot}} $$

(2.6)

A tip speed ratio is defined as the ratio of rotor tip speed to free wind speed [105], it can be calculated through the following expression:

$$ \lambda = \frac{\omega_{rot} R}{v} $$

(2.7)

where $R$ is the rotor radius and $v$ is the incoming wind speed. Together $\omega_{rot} R$ make up the blade’s linear speed at the outer tip.

Wind power varies linearly with air density. If air pressure $P_r$ and temperature $T_p$ are known air density at a location can be determined using:

$$ \rho = \frac{P_r}{R_G T_p} $$

(2.8)

where $R_G$ is the gas constant. Under one atmospheric pressure (14.7 psi) and 60° Fahrenheit the air density is 1.225 kg/m³.

Figure 2.1 depicts operation (i.e. mechanical torque extraction from the wind) of an aerodynamic model of a wind turbine.


### 2.2.2 Power coefficient models and look-up table

Power coefficient characteristic of a wind turbine can be calculated through analytical models using non-linear functions if actual measurements from a wind turbine manufacturer are not available. One such model is given [106] as follows:

\[
C_p(\lambda, \beta) = c_1(c_2 - c_3\beta - c_4\beta^{1.5} - c_5)e^{-c_6}
\]  

(2.9)

Coefficients \( c_1 \) to \( c_6 \) can vary with the type of wind turbine, some exemplary values are given below [106], [107]:

<table>
<thead>
<tr>
<th>( c_1 )</th>
<th>( c_2 )</th>
<th>( c_3 )</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.5</td>
<td>( 116/\lambda_i )</td>
<td>0.4</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>( c_4 )</th>
<th>( c_5 )</th>
<th>( c_6 )</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>5</td>
<td>( 21/\lambda_i )</td>
</tr>
</tbody>
</table>

where \( \lambda_i \) can be obtained from the following expression:

\[
\lambda_i = \left[ \frac{1}{\lambda + 0.08\beta} - \frac{0.035}{\beta^{3} + 1} \right]^{-1}
\]  

(2.10)

Another mathematical model that can be used to calculate power coefficient is obtained by curve fitting [108]:

\[
C_p(\lambda, \beta) = \sum_{i=0}^{4} \sum_{j=0}^{4} \alpha_{i,j}\beta^i\lambda^j
\]  

(2.11)

The model is found to be accurate for the range \( 2 < \lambda < 13 \) whereas \( \alpha_{i,j} \) coefficients are tabulated as below:
Table 2.2: Coefficients $a_{i,j}$ for corresponding variables $i$ and $j$

<table>
<thead>
<tr>
<th>$i$</th>
<th>0</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>$-4.19 \times 10^{-1}$</td>
<td>$2.18 \times 10^{-1}$</td>
<td>$-1.24 \times 10^{-2}$</td>
<td>$-1.33 \times 10^{-4}$</td>
<td>$1.15 \times 10^{-5}$</td>
</tr>
<tr>
<td>1</td>
<td>$-6.76 \times 10^{-2}$</td>
<td>$6.04 \times 10^{-2}$</td>
<td>$-1.39 \times 10^{-2}$</td>
<td>$1.06 \times 10^{-3}$</td>
<td>$-2.38 \times 10^{-5}$</td>
</tr>
<tr>
<td>2</td>
<td>$1.57 \times 10^{-2}$</td>
<td>$-1.09 \times 10^{-2}$</td>
<td>$2.14 \times 10^{-3}$</td>
<td>$-1.48 \times 10^{-4}$</td>
<td>$2.79 \times 10^{-6}$</td>
</tr>
<tr>
<td>3</td>
<td>$-8.60 \times 10^{-4}$</td>
<td>$5.70 \times 10^{-4}$</td>
<td>$-1.04 \times 10^{-4}$</td>
<td>$5.99 \times 10^{-6}$</td>
<td>$-8.91 \times 10^{-8}$</td>
</tr>
<tr>
<td>4</td>
<td>$1.47 \times 10^{-5}$</td>
<td>$-9.5 \times 10^{-6}$</td>
<td>$1.61 \times 10^{-6}$</td>
<td>$-7.15 \times 10^{-8}$</td>
<td>$4.96 \times 10^{-10}$</td>
</tr>
</tbody>
</table>

Another source of $C_p$ values is a look-up table which is often provided by the turbine manufacturer. The table gives relevant values of $C_p$ for every wind speed. Both $C_p$ and thrust coefficient ($C_t$) values at each wind speed for Vestas V80-2.0 MW wind turbine are available in [109] and [110] respectively (see Table A.4, Appendix A).

![Figure 2.2: Power coefficient of Vestas V80 wind turbine](image1.png)

![Figure 2.3: A typical $C_p(\lambda, \beta)$ characteristic for pitch angle between 0° and 25°](image2.png)
Typical power coefficient \( (C_p) \) characteristics for different tip-speed ratios and pitch angles are illustrated in Figure 2.3.

### 2.2.3 Thrust coefficient

The amount of thrust (force) generated on the rotor blades by a pressure drop can be characterised by a thrust coefficient \([105]\). Its value changes with the incoming wind speed. Exemplary behaviour of \( C_t \) at different wind speeds in a pitch controlled wind turbine (Vestas V80) is illustrated in Figure 2.4. The data used to produce the plot was obtained from \([110]\).

![Figure 2.4: Thrust coefficient of Vestas V80 wind turbine](image)

Similar to \( C_p \), the data for \( C_t \) should also be obtained from the wind turbine manufacturer, however in case that this data is not available a general estimate given in (2.12) \([111]\) can be used. The formula (2.12) was validated in \([112]\) after comparing \( C_t \) curves for several wind turbines.

\[
C_t = \frac{3.5(2v-3.5)}{v^2} \approx \frac{7}{v} \text{ m/s} \tag{2.12}
\]

### 2.2.4 Operating range of wind turbines

Generally wind turbines operate within a certain range of wind speed that is defined by two thresholds known as the cut-in and cut-out levels. Cut-in is the lowest wind speed at which the turbine starts generating power while cut-out is the highest wind speed when the turbine stops producing power. The cut-out speed is defined to ensure safety of the turbine components, that easily get
damaged in stormy conditions when wind speeds reach excessive levels. Normally, modern turbines have cut-in wind speeds of around 3 to 5 m/s and they cut-out generally at about 25 m/s [15, 113]. A typical power curve of a pitch controlled wind turbine (Vestas V80) is illustrated in Figure 2.5.

![Power curve of Vestas V80](image)

Figure 2.5: Power curve of Vestas V80 a pitch controlled wind turbine (adopted from [15])

### 2.3 Modelling of Doubly Fed Induction Generator

Among wind power generation technologies, DFIG based turbine is the most popular and widely implemented concept. It is better than squirrel cage induction generators in terms of power quality yet less expensive than a full rated converter. Several wind turbine manufacturers have embraced this technology and as a consequence numerous existing wind farms have DFIG based turbines installed. Due to its growing practical use it has been a hot topic in various research studies where new controls and uses are constantly being discovered [114-122].

Table 2.3 is a proof that a number of wind turbine manufacturers adopt this concept in their products. Most of the current installed wind turbines have a rated power of around 2 to 5 MW. The next round of offshore turbines appears to be bigger with rated powers between 5 and 7 MW whereas 6 MW class machines are also in development. It can be seen from the table that DFIG remains a popular choice in the future. (Rated power of the turbine is usually the maximum power the generator can produce).
Table 2.3: Wind turbines with DFIG technology

<table>
<thead>
<tr>
<th>Manufacturer/Type</th>
<th>Rated power (MW)</th>
<th>Rotor diameters (m)</th>
<th>Operational range (m/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>GE Wind Energy 1.5s</td>
<td>1.5</td>
<td>70.5</td>
<td>4 - 25</td>
</tr>
<tr>
<td>Vestas V80</td>
<td>2.0</td>
<td>80</td>
<td>4 - 25</td>
</tr>
<tr>
<td>Suzlon S95</td>
<td>2.1</td>
<td>95</td>
<td>3.5 - 25</td>
</tr>
<tr>
<td>Nordex N100</td>
<td>2.5</td>
<td>100</td>
<td>3.5 - 25</td>
</tr>
<tr>
<td>Vestas V90</td>
<td>3.0</td>
<td>90</td>
<td>3.5 - 25</td>
</tr>
<tr>
<td>Sinovel SL3000</td>
<td>3.0</td>
<td>91.3</td>
<td>3 - 25</td>
</tr>
<tr>
<td>BARD 5.0</td>
<td>5.0</td>
<td>122</td>
<td>3 - 25</td>
</tr>
<tr>
<td>Repower 5M</td>
<td>5.0</td>
<td>126</td>
<td>3 - 25</td>
</tr>
<tr>
<td>Repower 6M</td>
<td>6.15</td>
<td>126</td>
<td>3.5 - 25</td>
</tr>
</tbody>
</table>

In a DFIG configuration, stator of generator is connected directly to the grid, which makes it synchronous with the grid frequency, while the rotor is connected to the grid through a power electronic converter, as visible from Figure 2.6. Active power can be controlled by current in the RSC through variation in electric torque and generator excitation. Reactive power can be independently controlled by adjusting rotor currents in the RSC which determines the stator reactive power and through control settings of a GSC. Interaction between different components of a DFIG with corresponding signal exchange is illustrated in Figure 2.7. A DFIG can be operated in super-synchronous or sub-synchronous modes because of its bi-directional converter.
2.3.1 Drive train

A gearbox connects an aerodynamic rotor with the generator to increase the speed of shaft rotation. Through gear box, low rotational speed (9-21 rpm) is converted to high rotational speed typically in the range between 900-2000 rpm. Shaft characteristics of wind turbine are different from large conventional generators. This is due to lower shaft stiffness resulting in torsional resonant frequencies in the range of 0.5 to 2 Hz [123].

Drive train can be modelled using a three-mass, two-mass model or one-mass model. Using a three-mass model can add towards system complexity which is undesirable for system stability studies whereas a single-mass model removes shaft stiffness and mutual damping. In most circumstances the drive train with a two-mass model provides sufficient accuracy for stability analysis [126]. A
two-mass model has been validated against an actual wind turbine in [127], it has been used in various stability studies [122, 128]. Figure 2.8 shows a two-mass model representing turbine and generator rotor inertias connected by a shaft with damping components. Inertia of the gear-box is not modelled separately and it is included in generator inertia.

The equations (2.13) to (2.15) describe the two-mass model. Typically, an aerodynamic rotor has a large while an electrical generator has a smaller mass [125]:

\[
\frac{d\theta_{\text{rot}}}{dt} = \omega_{\text{rot}} \tag{2.13}
\]

\[
\frac{d\theta_k}{dt} = \omega_{\text{rot}} - \frac{\omega_m}{n_{\text{gear}}} \tag{2.14}
\]

\[
\frac{d\omega_{\text{rot}}}{dt} = \frac{T_{\text{rot}} - T_{\text{shaft}}}{J_{\text{rot}}} \tag{2.15}
\]

where \( J_{\text{rot}} \) corresponds to the rotor inertia, \( \omega_m \) is the rotational speed of the generator rotor, \( T_{\text{shaft}} \) is the torque acting on the low speed shaft, \( J_m \) is the mechanical inertia of the generator rotor, \( \theta_k \) is the angular difference between the rotor and the generator end of shafts, the ratio of an ideal gear box is assumed to be \( 1:n_{\text{gear}} \) and aerodynamic torque is represented by \( T_{\text{rot}} \). The mechanical torque of the low-speed shaft is:

\[
T_{\text{shaft}} = c_d \left( \omega_{\text{rot}} - \frac{\omega_m}{n_{\text{gear}}} \right) + K_s \theta_k \tag{2.16}
\]

where low speed shaft has a stiffness \( K_s \) and it has a damping coefficient of \( c_d \).

The mechanical power at the generator shaft is given by:

\[
P_m = \omega_m \frac{T_{\text{shaft}}}{n_{\text{gear}}} \tag{2.17}
\]

\[
c_d = 2\bar{\zeta} \sqrt{K_s J_{\text{rot}}} \tag{2.18}
\]

\[
\bar{\zeta} = \frac{\delta_s}{\sqrt{\delta_s^2 + 4\pi^2}} \tag{2.19}
\]
\[ \delta_s = \ln \left( \frac{a(t)}{a(t + t_p)} \right) \]  

(2.20)

where \( \zeta \) is the damping ratio, \( \delta_s \) is the logarithmic decrement, \( a \) is the amplitude of the oscillation at the beginning of period \( t \), \( t + t_p \) is the time at end of the next period. Further details about the drive train model can be found in [125].

### 2.3.2 Generator model

Equations used to model DFIG are similar to those used for modelling a squirrel cage induction generator with just one exception, the rotor windings are not shorted, hence rotor voltages \( (V_{dr}, V_{qr}) \) are not equal to zero. The induction generator used in doubly-fed configuration can be modelled through a full 5th order stator and rotor voltage equations in d-q reference frame using generator convention as below [13, 129]:

\[
V_{ds} = -R_s I_{ds} - \omega_s \psi_{qs} + \frac{d\psi_{ds}}{dt} \tag{2.21}
\]

\[
V_{qs} = -R_s I_{qs} + \omega_s \psi_{ds} + \frac{d\psi_{qs}}{dt} \tag{2.22}
\]

\[
V_{dr} = -R_i I_{dr} - s_i \omega_i \psi_{qr} + \frac{d\psi_{dr}}{dt} \tag{2.23}
\]

\[
V_{qr} = -R_i I_{qr} + s_i \omega_i \psi_{dr} + \frac{d\psi_{qr}}{dt} \tag{2.24}
\]

where \( s_i \) is the slip, defined as:

\[
s_i = 1 - \frac{p \omega_m}{2 \omega_s} \tag{2.25}
\]

Stator and rotor flux linkages are given as:

\[
\psi_{ds} = -(L_{sr} + L_m) I_{ds} - L_m I_{dr} \tag{2.26}
\]

\[
\psi_{qs} = -(L_{sr} + L_m) I_{qs} - L_m I_{qr} \tag{2.27}
\]

\[
\psi_{dr} = -(L_{sr} + L_m) I_{dr} - L_m I_{ds} \tag{2.28}
\]

\[
\psi_{qr} = -(L_{sr} + L_m) I_{qr} - L_m I_{qs} \tag{2.29}
\]
The difference between mechanical and electrical torque results in change of generator speed that can be calculated from the following expression:

\[
\frac{d\omega_m}{dt} = \frac{1}{2H_m}(T_m - T_e)
\]  

(2.30)

\[T_e = \psi_{ds}I_{qs} - \psi_{qs}I_{ds} = \psi_{qr}I_{dr} - \psi_{dr}I_{qr}\]  

(2.31)

where \(T_e\) is the electric torque of the generator. The equations for active and reactive power exchange with the grid are similar to that of a squirrel cage induction generator, except the rotor windings can also be accessed in a DFIG hence the rotor component in equations (2.36) and (2.37). Converters can consume or produce reactive power but they cannot produce or consume active power, thus total active power fed into the grid by a DFIG can be expressed by \(P_{\text{total}}\). However, reactive power fed into the grid is not the same as \(Q_{\text{total}}\) in (2.37) because it is affected by the converter. (Total reactive power fed into the grid by a DFIG is explained and calculated in the following section.)

\[P_s = V_{ds}I_{ds} + V_{qs}I_{qs}\]  

(2.32)

\[Q_s = V_{qs}I_{ds} - V_{ds}I_{qs}\]  

(2.33)

\[P_r = V_{dr}I_{dr} + V_{qr}I_{qr}\]  

(2.34)

\[Q_r = V_{qr}I_{dr} - V_{dr}I_{qr}\]  

(2.35)

\[P_{\text{total}} = P_s + P_r = V_{ds}I_{ds} + V_{qs}I_{qs} + V_{dr}I_{dr} + V_{qr}I_{qr}\]  

(2.36)

\[Q_{\text{total}} = Q_s + Q_r = V_{qs}I_{ds} - V_{ds}I_{qs} + V_{dr}I_{dr} - V_{qr}I_{qr}\]  

(2.37)

where \(p\) is the number of poles, \(I\) is the current, \(R\) is the resistance of the corresponding rotor or stator, \(\Psi\) is the flux linkage, \(L_m\) is the mutual inductance, \(L_o\) is the leakage inductance, \(H_m\) is inertia constant of the generator rotor, \(T_m\) is the mechanical torque and \(\omega_m\) is the angular frequency of the generator rotor. Subscripts \(s\) and \(r\) indicate stator or rotor side, \(d\) and \(q\) stand for direct and quadrature components, respectively. \(P_{\text{total}}\) is the active power fed into the grid by a DFIG. If, however, converter efficiency has to be taken into account the terms with rotor subscript in this expression must be multiplied with converter efficiency to access total power injected into the grid, \(Q_{\text{total}}\) is the reactive power but is not necessarily the amount fed into the grid because the
converters can generate or consume reactive power which thus affects the total amount of reactive power fed into the grid.

In generator convention, for modelling electrical machines the current leaving the machine is positive while that entering the machine is negative. The induction generator model presented above is a full 5th order dynamic model that includes both stator and rotor transients. In stability studies, transient phenomena associated with stator transients, e.g., electromagnetic transients are usually ignored. Neglecting stator transients \( \frac{d\psi_s}{dt}, \frac{d\psi_q}{dt} \) converts a 5th order model into a 3rd order model. (This exclusion is equivalent to ignoring the DC component in the stator transient current.) In both models the electrical torque equation remains the same.

More details about modelling of induction machines can be found in [44, 125], [130].

2.3.3 Rotor-side and Grid-side converter

Converters are the key feature of a DFIG machine as they play an important role. They allow variation in generator angular speed which enables a DFIG to operate at variable speeds [37]. This is essential because fluctuating wind speed causes mechanical power to fluctuate and if the converters are missing (as in fixed speed turbines) all the fluctuation will be reflected in the power supplied to the grid. In comparison with the full-scale power converter (used e.g. in Permanent magnet synchronous machines) the DFIG converters are smaller in size, cost less and lead to lower losses. In both types of variable speed turbines (DFIG and full-scale converter connected) behaviour of the generator is controlled by converters and controllers.

The power electronic converter in a DFIG machine is rated to about 30% of turbine’s rated power [131], for this reason it is also known as a partial-scale converter. Both RSC and GSC are self-commutated and made up of six-pulse bridges. These converters allow control over reactive power and power factor. DFIG model built into DIgSILENT PowerFactory has an induction machine joined together with a RSC as illustrated in Figure 2.9 and Figure 2.10. RSC enables variation in generator’s AC voltage magnitude and phase angle (by modifying the pulse-width modulation factor, \( M_f \)) that allows fast and flexible control of the generator.
RSC can be used to control rotor current which makes rotor flux and electric torque of the generator also controllable as seen from (2.26) to (2.31). By controlling the rotor current of this converter both speed of the generator and of the shaft can be controlled. This feature is useful when tracking the optimum tip speed ratio to extract maximum power at varying wind speeds, in other words, for maximum power point tracking [132].

RSC is assumed loss less, however switching losses can be high due to high switching frequency (5 to 10 kHz). These losses can be incorporated into the model by adding shunt resistors between the two DC poles as losses are proportional to $V_{dc}^2$ [133]. The AC-DC voltage relationship of a PWM converter is expressed by (2.38) in per-unit [125]:

$$V_{r,dq} = \frac{\sqrt{3}}{2\sqrt{2}} M_{f,dq} \frac{V_{dc}}{V_{r,nom}}$$

(2.38)

where $V_{r,dq}$ is the rotor voltage affected by RSC, $V_{r,nom}$ is the nominal voltage of the rotor and $M_f$ is the pulse-width modulation factor. The value of $M_f$ usually resides between 0 and 1, for any values larger than 1 lower-order harmonics start to increase as converter saturates [133]. The AC-DC current relationship of RSC assuming a loss-less converter is given by:

$$P_{AC} = \text{Re}(V_{AC}I_{AC}^*) = V_{dc}I_{DC} = P_{dc}$$

(2.39)

where $V_{AC}$ is same as $V_r$ while $I_{AC}$ is the rotor current $I_r$. 

---

**Figure 2.9: Built-in DFIG model in DIgSILENT PowerFactory**
GSC is dedicated to DC-link voltage control (maintaining it to a fixed value) so that RSC can control power. It can be also used to support grid reactive power during a fault [118] and to enhance grid power quality [119] but these abilities require a larger converter rating. The following expressions represent power flow through the GSC [13]:

\[ P_c = V_{dc} I_{dc} + V_{qc} I_{qc} \]  \hspace{1cm} (2.40)

\[ Q_c = V_{qc} I_{dc} - V_{dc} I_{qc} \]  \hspace{1cm} (2.41)

Assuming stator resistance to be negligible [44] \((R_s = 0)\), and assuming that d-axis coincides with maximum stator flux, \(V_{ds} = 0\) and \(V_{qs} = V_{st}\). Recalculating electric torque in (2.31) using (2.21) to (2.29) gives:

\[ T_e = - \frac{L_m V_{st} I_{qr}}{\omega_t (L_{sr} + L_m)} \]  \hspace{1cm} (2.42)

Reactive power at the stator terminals \(Q_s\) can be calculated using (2.32), (2.33), (2.21) to (2.29) as:

\[ Q_s = - \frac{|V_{st}| L_m I_{dr}}{(L_{sr} + L_m)} - \frac{|V_{st}|^2}{\omega_t (L_{sr} + L_m)} \]  \hspace{1cm} (2.43)

the total reactive power exchanged with the grid \(Q_{total}\) can be expressed as

\[ Q_{total} = Q_s + Q_c \]  \hspace{1cm} (2.44)
Both GSC and rotor currents (controlled by RSC) are responsible for the amount of reactive power a DFIG exchanges with the grid as can be seen from (2.41), (2.43) and (2.44).

Since converter active power $P_c$ is equal to the rotor active power $P_r$ calculated in (2.34) i.e. $P_c \sim P_r$ (if however, converter losses have to be included $P_c$ should be multiplied with the converter efficiency), total active power exchange with the grid, $P_{total}$, remains the same as in (2.36)[44]. Therefore, $P_{total}$ in (2.36) and $Q_{total}$ in (2.44) are the total active and reactive power injection into the grid respectively, by a DFIG machine. GSC normally operates at unity power factor therefore $Q_c$ in (2.44) can be set to zero but its value depends on the adopted control policy. In mathematical expressions above the subscript $c$ stands for converter whereas d- and q- are for direct and quadrature axis components respectively.

Terminal voltage control and reactive power exchange with the grid can also be provided through RSC [134, 135], or by using both converters [121], depending on the approach used. GSC has been modelled in detail using a vector control approach in [116] whereas a simplified model is presented in [136]. Various control strategies for RSC and GSC have been proposed in the past, a few can be found in [121, 133]. New controls developed for the converters allow improved fault-ride through capabilities under voltage sags [137] and enhanced control under network unbalances [138].

### 2.3.4 Protection system

Semiconductor switches inside power electronic converters should be protected from over-currents to prevent damage. A fault near the generator can give rise to over-currents in the stator due to direct connection with the grid. Due to electromagnetic coupling between the stator and the rotor this disturbance is transmitted to the rotor which results in high rotor currents and voltages. To protect excessive current inflow entering the RSC from rotor terminals the RSC is blocked and by-passed [123]. This action is performed by a crowbar which short circuits the rotor winding to avoid over-current in the RSC and overvoltage at the DC-link capacitor. During the time the rotor is short-circuited, the DFIG operates as an ordinary induction generator with no control over P or Q [139].
Converters must be protected from over currents whereas generators and DC-link capacitor against over voltages. Therefore protection system constantly monitors both rotor current and DC-link voltage signals to activate the protection system if either of them exceeds a set limit.

A crowbar is effectively a set of resistors that get connected in parallel with the rotor windings in case of an interruption or fault to limit rotor current. The value of resistance is dependant on the generator but it varies with different generators. Generally the protection scheme has a strategy and a criteria to detect whether a wind turbine should be disconnected as well as a strategy and criteria for its reconnection. The reconnection is decided based on the voltage and frequency at the wind turbine terminals [13]. The effect of crowbar impedance and the effect of RSC restart are discussed in [139]. In line with fault ride through requirements (FRT), schemes have been proposed in the past [140] that can allow wind turbines to stay connected with the grid during the fault. Generally a higher crowbar resistance can efficiently damp higher rotor currents and electromagnetic torques [120]. Converter protection schemes using a series dynamic resistor (SDR) [132] can also avoid DFIG control being disabled.

2.3.4.1 DC link chopper

DC-link braking resistor, also known as the DC-link chopper, is also used to dissipate excess energy inside the DC-link capacitor during a grid fault to protect the Insulated Gate Bipolar Transistors (IGBT) from overvoltage. Several units can be installed in parallel to increase the amount of energy that can be dissipated.

2.3.5 Rotor speed controller

The speed of generator rotor is also controlled to make energy capture from the wind optimal. The process begins by measuring the value of rotor speed through sampling techniques. Then, depending on the rotor speed corresponding active power set point is chosen from rotor speed generator power characteristic (shown in Figure 2.12). Next, a torque set point is derived using measured rotor speed and active power set point. Since there is a direct correlation between electric torque and rotor current, the required torque is
achieved by calculating current set point which the controllers then try to achieve.

Reactive power set point can also be established by the RSC. It can be set to a specified value, or to zero, [135] depending on whether a DFIG is required to contribute reactive power. Normally *Terminal voltage controllers* can be used in a DFIG for reactive power regulation and power factor control by controlling the d-axis of the rotor current (as seen in (2.43)). More details about the control schemes for voltage control can be found in [13, 121].

![Figure 2.12: Maximum Power Tracking characteristic for the turbine](image)

Rotor speed power characteristic shown in Figure 2.12 can be investigated in detail by splitting it into four sections (A to D). Between points A and B, the rotational generator speed is set to its minimal value by adjusting the generator torque. This encloses region from cut-in wind speed to a point B which is generally located 2 m/s above the cut-in speed. From point B to C, the speed of the generator is controlled by the RSC to enable maximum power capture. Rotational speed of the turbine is adopted according to the wind speed to maintain optimum tip-speed ratio. With an increase in wind speed, the rotational speed of the generator also increases until $\omega_{max}$ limit is reached. Between points C and D the controller tries to maintain rotor speed to this maximum value $\omega_{max}$. This is carried out until rated power is achieved (at point D). RSC plays a major role in achieving this maximum speed regulation. After reaching the rated power, set points for both power and torque are kept constant. If the rotor speed begins to exceed $\omega_{max}$ the RSC is no longer able to
keep it below maximum. In this case aerodynamic torque is reduced by pitching away the blades from wind using a pitch controller. Reduction in aerodynamic torque \( T_{\text{rot}} \) reduces mechanical torque acting on the generator \( T_m \) and generator rotor speed \( \omega_m \) can be maintained to a constant level [125, 141].

### 2.3.6 Pitch control

In the past, wind turbines did not have the ability to fully utilise wind’s potential at higher wind speeds as blades were fixed at an angle. Modern turbines, however, feature pitch control that allow them to rotate aerodynamic rotor blades according to the incoming wind speed (measured by an anemometer). This mechanism makes full extraction of power possible by adjusting the blades to an optimal pitch angle. At above nominal (rated) wind speeds, the pitch controller tries to maintain power output to its maximum until wind speed rises to cut-out level. The controller is activated above rated wind speed when generator rotor speed is no longer controllable by simply adjusting the torque. By correcting the pitch angle the value of \( C_p \) can be varied and hence thrust produced and power generation can be controlled. For wind speeds below nominal the pitch angle is set to minimum (close to zero degrees) whereas \( C_p \) is maximised (to extract maximum power from the wind) by setting tip-speed ratio to its optimal value through variation in rotor speed \( \omega_m \).

A generic pitch control model is presented in Figure 2.13. It can be easily modified for use in other wind turbines. The difference between the maximum rotor speed \( \omega_{\text{max}} \) and the current angular speed of the generator \( \omega_m \) is fed into the PID controller which generates a reference pitch angle \( \beta_{\text{ref}} \). This signal is then sent to the actuator (servo) which sets the final pitch angle \( \beta \) of the blades. The rate of change of pitch angle is limited by the speed of the servo motor (± 10 deg/s) [142, 143]. Therefore the process of setting the new pitch angle on the blades can take some time depending how fast the servo motor can operate. Limitations on the angle exists hence blade angle can be set between a minimum and a maximum value (0 to 30 deg) [143]. The model presented also accounts for time constant of the servo motor \( T_{\text{servo}} \).
The effect of $\beta$ (pitch angle) on $C_p$ can be evaluated by inserting the output from pitch controller into (2.9) and (2.10), mechanical power can then be obtained by feeding the $C_p$ into (2.5).

There has been a rapid development over the past few years that has resulted in numerous types of pitch control strategies [144]. To avoid complexity of the overall wind generator model simplified models have also been proposed [145]. Pitch angle control can have other uses, for instance, levelling out (removing fluctuation) wind turbine power output [146], maintaining reserve wind power [147] and automatic generation control [148].

2.3.7 Yaw control

As observed from measurements, speed and direction of wind at a site are never static. They can change rapidly with time. In order to extract maximum power from wind from all directions the wind turbines now feature a yaw control that rotates the turbine’s aerodynamic rotor so that it always faces the wind. Sensors installed at the nacelle monitor the wind direction so if a permissible deviation in wind direction angle is exceeded installed geared motors perform the yaw operation. The same mechanism allows turbine to be moved out of the wind (in case of very strong gusts) and to limit the power output [105]. Control mechanism for yaw is studied in detail in [149].

2.4 Power Transmission Line Modelling

Transmission lines and cables are modelled using the well known $\pi$ equivalent circuit as shown in Figure 2.14. Both underground cables and overhead lines have the same basic parameters such as series resistance and inductance; shunt capacitance and conductance. However, underground cables generally have a very high shunt capacitance [130].
In Figure 2.14 below, current $I$ is flowing from the sending end (at the left) to the receiving end (at the right). $Z_L$ represents series impedance of the line ($R_L + jX_L$) and $\frac{Y_L}{2}$ represents half the shunt admittance of the line at each end node. Since typical conductance $G$ for a power line is zero, the shunt admittance is often represented simply by the charging susceptance $\frac{jB_L}{2}$ where $B_L = \omega C$.

Typical electrical parameters (resistance, inductance and susceptance) of submarine cables used in offshore wind farms can be found in [150].

![Figure 2.14: Equivalent π circuit of a transmission line](image)

2.5 Transformer Modelling

Models of two and three winding transformers are used in simulations presented in this thesis. Models given in DlgSILENT PowerFactory [151] are briefly described below.

**2-winding transformer**

![Figure 2.15: Positive sequence model of a 2-winding transformer (in Ohms)](image)

A positive sequence 2-winding transformer model consists of leakage reactances ($X_\sigma$) and winding resistances ($R_{Cu}$) of high voltage (HV) and low
voltage (LV) side, magnetizing reactance ($X_M$) and iron loss resistance ($R_{FE}$) calculated as below:

$$X_M = \frac{1}{\sqrt{\frac{1}{Z_M^2} - \frac{1}{R_{FE}^2}}}$$  \hspace{1cm} (2.45)

$$R_{FE} = \frac{S_{\text{rot}}}{P_{\text{FE}}/1000}$$ \hspace{1cm} (2.46)

$$Z_M = \frac{1}{i_o/100}$$  \hspace{1cm} (2.47)

where $i_o$ is the no-load current, $Z_M$ is the magnetising impedance of the core $S_{\text{rot}}$ is the rated power and $P_{\text{FE}}$ is the measured no-load losses.

3-winding transformer

![Figure 2.16: Positive sequence model of a 3-winding transformer with a short-circuit at medium voltage (MV) side, open-circuit on LV side (for HV-MV measurement)](image)

In the following calculations only a pair of windings (HV-MV) is considered to illustrate the parameters. Similar procedure applies for the other two pairs i.e. LV-HV and MV-LV.

The 3-windings can have three different voltages (e.g. 132/22/11 kV) and rated powers (e.g. 60/60/10 MVA). Positive sequence short circuit voltages ($V_{SC,HV-MV}$) between the two windings is calculated in reference to the lowest MVA rating of the two. Impedance between HV and MV side is calculated as follows (when MV is shorted) as seen from HV-side:
\[ Z_{HV-MV} = \frac{V_{SC,HV-MV}}{100 \min(S_{rat,HV}, S_{rat,MV})} \]  

(2.48)

where positive sequence short circuit voltage is found as:

\[ V_{SC,HV-MV} = \frac{V_{SC,HV}}{V_{rat,HV}} \times 100\% \]  

(2.49)

The short circuit nominal current through MV side (when shorted) is:

\[ I_{N,MV} = \frac{\min(S_{rat,HV}, S_{rat,MV})}{\sqrt{3}V_{rat,MV}} \]  

(2.50)

Real part of short-circuit voltage (%):

\[ V_{rat,SC,HV-MV} = \frac{P_{Ch,HV-MV}}{\min(S_{rat,HV}, S_{rat,MV})} \times 1000 \times 100\% \]  

(2.51)

No-load current \( i_o \) (%) is calculated at the LV side but it depends on the measured no-load current \( I_o \):

\[ i_o = \frac{I_o}{I_{rat,LV}} \times \frac{S_{rat,LV}}{S_{ref}} \times 100\% \]  

(2.52)

\[ I_{rat,LV} = \frac{S_{rat,LV}}{\sqrt{3}V_{rat,LV}} \]  

(2.53)

Magnetization reactance and iron losses are calculated as follows:

\[ X_m = \frac{100\%}{i_o} \]  

(2.54)

\[ R_{FE} = \frac{S_{ref}}{P_{FE} \times 1000} \]  

(2.55)

where \( V_{rat} \) is the rated voltage and \( S_{rat} \) is the rated power for a winding mentioned next to it in the subscript, \( I_{rat,LV} \) is the rated current at the LV side,
$S_{ref}$ is the reference power equal to HV side rated power, $P_{Cu,HV-MV}$ is copper losses of path HV-MV, $P_{FE}$ is measured iron losses.

Further details about transformer models and related parameters can be found in [151].

2.6 Summary

A variable speed turbine consists of several components including generator, converter and controllers. This chapter briefly discussed models for various components that are required to model a wind turbine with a DFIG. Apart from this, models for power system transmission lines and transformers are also presented.

In this research, built-in models of wind turbine in a commercially available software tool DIgSILENT PowerFactory are used for stability studies. Other commercial software including PSS®E and IPSA+ are used for steady-state analysis such as load flow and loss evaluation.
Chapter 3

Modelling of Wake Effects

3.1 Introduction

Wind is a highly variable energy resource. Generally, it varies according to the season, time of the year and time of the day. Changes that occur over period of days are called Synoptic variations while variations according to the time of the day are called Diurnal variations. A third type of variation which is more random and has a much shorter timescale (minutes to seconds) is called the Turbulence [105]. Others factors such as wind shear, type of terrain and thermal effects will also influence its characteristics [152, 153]. Several wind speed simulation and forecasting models [44, 50, 154-157] have been proposed in the past.

Wind interaction with objects makes its behaviour hard to predict as the objects distort wind flow. The change in wind flow is the reason why modelling techniques are required. Although complex models can estimate and simulate wind interaction with high accuracy, for electrical engineering applications a simpler model is needed. Existing models used for the prediction of wind speed inside a wind farm (wake models) are briefly discussed along with a wake calculation program developed during the research.

Wind speed characteristics at a site can often be defined by a probability distribution called a Weibull distribution. This distribution can be created for any site if measured data is not available. However if internal flow of wind within wind farm is to be modelled correctly, the wind direction is also needed. Recordings of wind speed and direction at a site in North Sweden were available and are presented in this chapter. The effects of wind shear and surface roughness on wind speed are also explored.

In order to consider the effect of wake on the power output the system operators may have to use existing wake models. However, the majority of
existing analytical wake models are deterministic, therefore at a given wind condition they give a deterministic output. In reality, the flow of wind changes as it enters the wind farm due to interaction with the wind turbines. This is evident from the behaviour of wind in the wake of a turbine. The wind inside the wake is both reduced in speed and highly turbulent. A few of the existing analytical wake models predict the reduction in wind speed but neglect the turbulence. It was observed in [158] and [159] that turbulence can affect the power output of a wind turbine.

Simulation techniques such as Finite Element Modelling [160], Navier Stokes equations [55] and Computational Fluid Dynamics (CFD) [161] can be used for simulating the wind inside a wind farm. These models can lead to reliable results, but they are often complex and cumbersome to implement. Most of these models can significantly increase the simulation time depending on the computing power available.

This chapter also presents a new probabilistic wake effect model that considers the effect of turbulence inside a wind farm. The model enables network operators to estimate wind power output probabilistically for a forecasted wind condition (few minutes or hours ahead). The probabilistic output from the wind farm can indicate to the operator that the power output may vary within certain limits as opposed to a deterministic output. This information is useful for the network operator while carrying out generation dispatch or reserve allocation. Furthermore, this chapter also compares the wind power output and energy output results from the proposed probabilistic wake model with a deterministic wake model. The model developed is efficient and easy to use which makes it suitable for use in online simulations. It is also computationally less demanding than the simulation techniques mentioned above.

3.2 Wake Effects

The law of the conservation of energy dictates that energy can neither be created nor destroyed, but it can be transformed. Based on this statement a wind turbine can be said to be a converter as it converts kinetic energy present in the wind into mechanical and then electrical energy. However, this process of extraction is not 100% efficient. Extracting kinetic energy from the wind causes the wind speed behind the rotor to slow down in a turbulent manner, known as
the *wake*. The mass of air that passes through the turbine is reduced in speed compared to the free-stream wind that entered the disc. A wake can be visualised through Figure 3.1 [105].

The stream tube (wake affected region of wind) expands behind the turbine because of the reduced wind speed and a drop in static pressure [105]. Generally, wake has two components, a near-wake region and a far-wake region. The near wake region is the area within a few meters downstream of the turbine which requires detailed model of the actual rotor. This region is of concern when researching the physical process of power extraction [162]. The far wake region is the point of focus when determining the effect of turbines on other turbines when they are placed in clusters such as wind farms. This is the area of concern for this research, when the turbines are placed at least a few hundred meters apart. Very far downstream, if the flow of wake is not interrupted then the stream tube further expands and the wake begins to recover to free-stream wind conditions.

In the far wake region, the effects of wake can be significant as reduction in wind speed can lead to a reduction in power generation from the turbines (as depicted from the power curve in Figure 2.5). If, however, the turbines are placed far apart (greater than ten turbine rotor diameters) to avoid the influence of wakes on power output, then the cost of internal wind farm cabling goes up. Existing models such as Ainslie [55], Frandsen [59], Larsen [58] and Jensen [56, 57] can be used to simulate wake effects. A survey of several near and far wake models is presented in [162].
Ainslie’s wake model determines the total momentum deficit inside a wake by using the thrust coefficient of the turbine. It takes into account all relevant meteorological effects and the description of flow structure is also very accurate. Navier Stokes equations and the concept of turbulent viscosity is applied. This model is best used if a detailed study on wakes is required [55].

Frandsen’s model is an analytical model applicable to both small and large wind farms. It takes into account the complex interaction of wakes when merging downstream from neighbouring rows. It assumes an asymptotic flow deficit inside the wake.

Larsen’s model is a semi analytical model that uses Prandtl’s turbulent boundary layer equations. The model calculates the width of wake at a given distance as well as the mean wind profile in the wake. The wake flow is assumed to be incompressible and stationary.

Some of these models are more complicated than others with extra computational burden leading to higher simulation times. Blade element momentum is another way of modelling turbine blades and wind flow. In this method a turbine blade is divided into several smaller cross-sections and the total force on the blade is calculated by summing the forces on each section [163]. This method is normally used for design of wind turbines [164]. Some of the other models apply Computational Fluid Dynamic (CFD) [161] schemes, however these schemes are not computationally feasible when faster simulations are needed.

The models described above are dedicated for near-field and far-field wake effects. They are useful for detailed modelling of wakes often required during the design and manufacturing of wind turbines. Some of them are made to model wind flow over complex terrains in case of a flow separation, though these are more intricate. For electrical engineering purposes a moderately simple model that can estimate the wind speed in a wake at a certain distance should be sufficient.

The wake model postulated by Jensen [56], [57] is a mathematical model designed to minimise input parameters and reduce computation burden. In this model, a wake expands linearly with distance $x_o$ while the spread of the wake has a Gaussian distribution often referred as a top-hat distribution. The entrainment constant $k$ controls the development of the wake and a value of this constant has been found to be 0.075 for onshore sites and 0.04 for offshore
sites [57]. In general, the model seems to fit well when compared with actual wake measurements [56]. Moreover, it is simple to implement and fast during simulation, however it should not be used to model flow in complex terrains such as hills and mountains where the other models described above would be more useful. In this research, only onshore plains and sea are considered, therefore, Jensen’s wake model is perfectly applicable as it leads to shorter simulation times.

The model is commercially used in softwares such as WAsP [165] and WindPro [166] to simulate wake effects and calculate wind farm production. The choice of a simple model is further validated through a comparison between wake models carried out in [167] revealing that sophisticated models do not predict momentum deficit significantly better than simplified wake models.

Wake models using CFD techniques, Blade Element Momentum and Navier Stokes equations are useful for simulating wind flow in a near wake region and are more suitable during design of wind turbine blades. For far wake region (to calculate wake effect on other turbines) Jensen’s model is commonly used in electrical engineering studies to estimate effect of wake on power output of turbines. This model is efficient and leads to reduced simulation times yet provides sufficient level of accuracy. Furthermore, Jensen’s model has also been implemented by various commercial software to calculate power output and energy yield of a wind farm. Due to these reasons, Jensen’s wake model has been used in this thesis and is often referred as deterministic wake model in this chapter.

3.3 Detailed Wake Effect Modelling

Wake effect is dependant not only on the incoming wind speed and direction but also on the wind farm layout, therefore the distance between the turbines also plays an important role. A detailed wake effect model is implemented considering single, partial and multiple wakes inside a farm which takes into account rotor radius, thrust coefficient and expansion of stream tube. The effects of the turbine hub height and surface roughness can be also simulated by considering wind shear.
3.3.1 Single wakes

A single wake occurs when rotor disc of a turbine downwind is under full shadow of only one turbine. The single wakes are computed using Jensen’s kinematic wake model. Expansion of the wake radius behind a single turbine is described by:

\[ r_w = r_o + kx_o \]  \hspace{1cm} (3.1)

In Jensen’s model the wind speed immediately behind the turbine, \( v_o \), is assumed to be \( u/3 \). This assumption is replaced to make the analysis more realistic by including the turbine’s thrust coefficient.

The wind behind the turbine can then be computed as \( u\sqrt{1-C_t} \). Mean wind speed in the wake of a single turbine under free-stream wind \( u \) at a distance \( x_o \) is dependant on the \( C_t \) of the turbine:

\[ v_i = u \left[ 1 - \left( \frac{r_w}{r_o + kx_o} \right)^2 \left( 1 - \sqrt{1-C_t} \right) \right] \]  \hspace{1cm} (3.2)

where \( k \) is the entrainment constant or opening angle which represents the effects of atmospheric stability, \( r_o \) is the radius of wind turbine rotor, \( r_w \) is the radius of the wake and \( u \) is the wind speed entering the upstream turbine. The expansion of wake behind a wind turbine is represented in Figure 3.2.

![Figure 3.2: Wake structure by using Jensen model (symbols defined in the text)](image)

3.3.2 Partial wakes

A partial wake is a phenomenon which occurs when one or more upwind turbines cast a single shadow on a downwind turbine partially covering its rotor disk (as illustrated in Figure 3.3).
The wind speed entering into the turbine is then given by [147]:

\[
v_m = u \left[ 1 - \sqrt{ \sum \beta_{m,l} \left( 1 - \frac{v_{p0,l}}{u} \right)^2 } \right] \quad (3.3)
\]

where \( \beta_{m,l} \) is the ratio (the weighting factor) of the rotor area in wake to the total rotor area, \( m \) is the turbine under wake, \( l \) is the upwind turbine, \( u \) is the initial wind speed entering into the wind turbine \( l \), and \( v_{p0,l} \) is the wind speed in the wake of \( l \) falling on \( m \). The expression also works if more than one upwind turbine places a single shadow on a turbine downwind.

### 3.3.3 Multiple wakes

Multiple wakes occur when two or more upwind turbines slow down the wind approaching the turbine in the same row. Figure 3.4 illustrates the effect of multiple wakes on the third turbine, since it is under wake of the second turbine which in turn is under wake of the first one. It is seen through measurements in [168] that effect of wake behind the first turbine is the strongest and causes the most significant reduction in wind speed.
As the distance between the turbines increases the effect of wake reduces, thus wake from the first turbine will not significantly affect the third turbine i.e. not as much as the wake of the second turbine. Based on Jensen’s model for multiple wakes while considering wind turbine characteristics (dynamically changing $C_t$ values based on wind speed) the speed of wind entering the third turbine is given by:

$$v_2 = u \left[ \frac{r_n}{r_n + kx_n} \right] \left( \frac{v_1 \sqrt{1 - C_{t1}}}{u} - 1 \right) + 1 \quad (3.4)$$

Through this a general expression can be deduced to calculate the mean wind speed at the $n^{th}$ turbine under multiple wakes:

$$v_n = u \left[ \frac{r_n}{r_n + kx_n} \right] \left( \frac{v_n \sqrt{1 - C_{tn}}}{u} - 1 \right) + 1 \quad (3.5)$$

$C_t$ values are dependant on the type of turbine used; they also change with the incoming wind speed. For implementation of the above mentioned wake models $C_t$ values are taken from a look-up table (see Figure 2.4).

### 3.4 Development of Vector Based Wake Calculation Program

To rapidly simulate wake effects and to quantify its impact on power output, a vector based wake calculation program (VeBWake) is developed in MATLAB using the detailed wake models presented above. First, turbines in shadow of other turbines are identified and then their respective incoming wind speeds are evaluated. If a turbine is under multiple wakes, the locations of all upwind turbines are determined first along with their corresponding wind speeds. The wind speed at the relevant turbine is then evaluated. A similar procedure is adopted if the rotor is under a partial wake. The wind speed in this case is evaluated according to the ratio of rotor disc under wake. This ratio is determined by first finding the intersection between the two vectors (red and blue line in Figure 3.5) and then plotting two circles at corresponding location to find the area of overlap. The ratio of turbine rotor under wake is calculated by dividing rotor swept area by the area of overlap. The final effective wind speed at the turbine is calculated using this ratio. A visualisation of the
calculation process is presented in Figure 3.5 on four symmetrically arranged turbines.

Figure 3.5: Wakes (in blue lines) of wind turbines (red lines) 400 m apart facing wind from \( \theta \) degrees

Through this program wind speed magnitude at any turbine can be evaluated. The layout of the wind farm can be setup quickly by entering the coordinates (position of the turbines) and relevant parameters. The nacelle of a turbine will move (yaw) so that it faces the wind perpendicular to its axis as shown in Figure 3.6.

Figure 3.6: Nacelle moves to be directed into the wind (yaw control)

The program allows the testing of wind farms of any size, at any location (onshore or offshore), with turbines of any height, rotor radius, \( C_t \) curve, at any air density or temperature. For the case studies presented in the following
chapters, just two sizes of wind farms (see Section 3.9) are used wherever wake modelling is performed. The VeBWake program is given in a CD in Appendix G.

![Figure 3.7: Simulated mean wind speed at turbines in the same row placed 400 m apart](image)

Results from the model show great similarities when compared with recorded wind speed and power data [168, 169]. The highest drop in the speed, and hence power, occurs between the first and the second turbine in the same row. After the second turbine, wind speed starts to settle to a constant value as shown in Figure 3.7.

### 3.5 Impact of Wind Speed and Direction on Wind Turbine Power Output

It is commonly known that the wind speed faced by a wind farm affects its power production. In reality, the direction of the wind also has a significant impact because the flow of wind can be interrupted based on location of the turbines. To show the impact of wind direction on power output and to illustrate the mutual interaction of wakes, a symmetrical wind farm with nine Vestas-V80 2 MW wind turbines (rotor radius of 40 m and hub height of 80 m) is simulated at a fixed incoming wind speed of 10 m/s but with varying incoming wind direction from $0^\circ$ to $360^\circ$. The results calculated using the VeBWake program are shown in Figure 3.8. Wind speed magnitude at each turbine can be mapped at any direction. In general, it is observed that the biggest velocity drop occurs for turbines under multiple wakes.
Figure 3.8: Wind speed at each turbine in an exemplary wind farm, incoming wind speed = 10 m/s, wind direction = 0° to 360° (1° direction interval)

Figure 3.9: Total power generation (MW) from a wind farm at 10 m/s for wind directions from 0° to 360°
Figure 3.10: Wind power (MW) production from the wind farm at various wind speeds and directions

Power curves (as shown in Figure 2.5) are used to convert wind speed into power and then total production in MW is calculated by summation of power from individual turbines. Total wind farm power generation for winds entering from various directions but at a fixed incoming speed of 10 m/s is shown in Figure 3.9.

The overall effect of increasing wind speed and variation of wind direction on power generation from the sample nine turbine wind farm is illustrated in Figure 3.10. It can be seen that the impact of wake diminishes at higher winds speeds (when $C_t$ gets smaller) as turbines achieve rated power, therefore power losses due to wakes are minimum at higher wind speeds. At 16 m/s and above all turbines produce 2 MW (summing to 18 MW, the wind farm rated power) from nine wind turbines. Although operational wind speed of the turbine (Vestas V80) is between 4 m/s and 25 m/s, only plots up to 16 m/s are shown in Figure 3.10 as it is hard to differentiate plots for wind speeds above 16 m/s. It
can be concluded that the effects of wake diminish above a certain threshold wind speed, depending on the type of turbines and layout of the wind farm.

### 3.6 Effect of Height on Wind Speed

The increase in mean wind speed with altitude is called the *wind shear*. It is important to measure the velocity as near as possible to the hub height of the turbine, but in cases where measurements at hub height are not available a good estimate of the wind shear profile is required. Generally, the higher a meteorological mast is placed the more costly it is \[2\], therefore measurements can be made using a shorter mast but then scaled up using the log law \[170\] expressed below:

\[
U(z) = U(z_{\text{ref}}) \frac{\ln \left( \frac{z}{z_o} \right)}{\ln \left( \frac{z_{\text{ref}}}{z_o} \right)}
\]

(3.6)

where \(z\) is the hub height of the turbine, \(z_o\) is the surface roughness, and \(U(z_{\text{ref}})\) is the wind speed measured at the met mast height \(z_{\text{ref}}\). Surface roughness varies with the type of terrain at the site. Values for different types of terrain are given in Table 3.1 [170].

<table>
<thead>
<tr>
<th>Terrain</th>
<th>Surface roughness length (z_o) (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Calm open sea</td>
<td>0.0002</td>
</tr>
<tr>
<td>Blown sea</td>
<td>0.0005</td>
</tr>
<tr>
<td>Snow surface</td>
<td>0.003</td>
</tr>
<tr>
<td>Lawn grass</td>
<td>0.008</td>
</tr>
<tr>
<td>Rough pasture</td>
<td>0.01</td>
</tr>
<tr>
<td>Fallow field</td>
<td>0.03</td>
</tr>
<tr>
<td>Crops</td>
<td>0.05</td>
</tr>
<tr>
<td>Few trees</td>
<td>0.1</td>
</tr>
</tbody>
</table>

### 3.7 Weibull Distribution

Wind speed variations in a year can be characterised by probability distribution known as the Weibull distribution \(f(v)\). The Weibull distribution is a two parameter distribution which makes it more versatile than the one
parameter Rayleigh distribution [171] which is also often used. The two parameters are namely the shape \( k_s \) and the scale parameter \( s_c \) that describe its variability about the mean. As \( k_s \) gets larger, for a fixed \( s_c \), the distribution gets narrower and more peaked, alternatively if \( k_s \) decreases then the distribution becomes wider and more spread out. The probability density function of a wind speed \( v \) can be calculated as:

\[
f(v) = \frac{k_s}{s_c} \left( \frac{v}{s_c} \right)^{k_s-1} e^{-\left( \frac{v}{s_c} \right)^{k_s}} \quad (k_s > 0, \; v > 0, \; s_c > 1)
\]  

(3.7)

The area under the curve always remains unity implying that if the curve is compressed vertically it will spread horizontally. As observed in [171] the distribution can reasonably fit wind speed pattern at several locations around the world provided the time period of measurements available is from several weeks to a year. For this reason, if wind speed measurements at a site are not available, a Weibull distribution can be used along with a wind turbine power curve to obtain the wind power frequency curve for the wind farm. The shape and mean value of the distribution may vary from site to site depending on local climate conditions, the landscape, and its surface roughness.

### 3.8 Wind Measurements

A meteorological mast must often be installed on potential wind farm sites in order to convince the investment bodies involved that enough power will be generated. Wind speed and direction measurements from a site in North Sweden were available for the year 2000.

![Figure 3.11: Probability density curve (Weibull) for wind speed data in year 2000](image)
The recordings were made at 10 minute intervals using an anemometer and a wind vane stationed at a meteorological mast 35 meters high. A probability density plot of this data is evaluated as shown in Figure 3.11 and Figure 3.12. In the UK, a general estimate about the wind speed at a site can be obtained from [172, 173].

It is visible from Figure 3.11 that the measurements form the shape of a Weibull distribution; therefore if $k_s$ and $s_c$ parameters are accurately estimated, equation (3.7) can be made to fit this curve. Wind speeds between 5 and 8 m/s are most probable whereas higher wind speeds above 20 m/s are the least probable as seen from Figure 3.11. It can be seen from Figure 3.12 that wind is more probable from two directions i.e. between $100^\circ$ and $180^\circ$ and between $280^\circ$ and $360^\circ$.

In cases where recorded data is not available, wind speed models [44] can be used to simulate average value, ramp, gust and turbulence. If past wind speed time series and averages are available then the Markov chain method can be used to obtain hourly mean wind speed predictions [174].

### 3.9 Wind Farm Layouts

Two sizes of wind farms are used in the following chapters as case studies; they are illustrated in Figure 3.13 and Figure 3.14. Both wind farms have a symmetrical layout; the larger one has 49 turbines while the smaller one has 9
turbines with 7 and 3 turbines in each row and column, respectively. The distance between the turbines in a row and column is 400 m.

Figure 3.13: Layout of the large 49 turbine wind farm

Figure 3.14: Layout of a small 9 turbine wind farm

Figure 3.15: Bird’s eye view of a 49 turbine wind farm receiving wind from 315°

Wind farms have been designed with symmetrical and non-symmetrical turbine layouts. A symmetrical layout is visually appealing in landscapes with
orderly cultivated structures [175] and has been used in wind farms such as Horns Rev [176] and Nysted [177]. A non symmetrical design may have non-regularly spaced wind turbines with a random layout. Non-symmetrical layouts may often be a result of turbine location optimisation. However, for studies carried out in this thesis symmetrical layouts have been considered.

Visual representation of wakes in a 49 turbine wind farm is shown in Figure 3.15. This figure is plotted using the VeBWake program and it demonstrates that the program is effective for large wind farms.

### 3.10 Capacity Factor

Percentage of actual power produced over a period of time against power that could have been produced given the plant was operating at full capacity for the same period, is known as the capacity factor of a power plant. Since wind is a variable resource it is impossible for a wind farm to operate at its full capacity throughout the year. For example a 2 MW wind turbine can theoretically generate $2 \text{ MW} \times 8760 \text{ hours} = 17520 \text{ MWh}$ in a year if running at full capacity, however due to variation in wind speed over time it only generates, for instance $6132 \text{ MWh}$. In this case the capacity factor of the wind turbine will be $35\%$.

Similarly, using the statistical wind speed data for the site in North Sweden (presented in Section 3.8) capacity factor of two wind farm layouts studied in this thesis is calculated. For both 9 turbine wind farm shown in Figure 3.14 and for 49 turbine wind farm shown in Figure 3.13 the capacity factor is $39.8\%$. It is the same for both wind farms because the ratio of actual energy produced to theoretical maximum has not changed because same statistical wind speed data is being used for both wind farms.

### 3.11 Wind and Wake Turbulence

Turbulence refers to variation in wind speed on a relatively fast time-scale (seconds to several minutes) [105]. Turbulence in free-stream wind is known as the *ambient turbulence* whereas turbulence added by the turbine after extraction of energy is known as the *wake added turbulence*. 
The need for the probabilistic wake model is described by a simple scenario illustrated in Figure 3.16. In this scenario, the wind conditions forecasted for the next hour \( t = t_1 \) predicts that a wind farm will receive free-stream wind at \( u \) m/s (from \( y \) degrees). If a deterministic wake model (such as Jensen’s wake model) is used, it will predict that the free-stream wind \( u \) m/s will interact with the first wind turbine, WT1. The second wind turbine WT2, directly under the wake of WT1 will receive a reduced wind speed \( v_1 \). The third wind turbine, WT3 that is in wake of WT1 and WT2 will receive an even further reduced wind speed \( v_2 \) and so on. But in reality, the wind speed \( v_1 \) arriving at the WT2 cannot be described by a deterministic value because the wake of WT1 will introduce some level of wake added turbulence. Therefore the wind speed entering WT2 will be any value between \( v_1 + \delta_1 \) and \( v_1 - \delta_1 \). Similarly the wind speed arriving at the WT3 will be any value between \( v_2 + \delta_2 \) and \( v_2 - \delta_2 \) where \( \delta \) indicates a variation around the mean.

To analyse the wind speed and its effect on the power production from each turbine, a sample of turbulent wind for 1 minute interval is analysed. The wind speed of the turbulent wind will either be varying very rapidly or slowly. If the turbulent wind in the wake is varying very rapidly at a time scale of seconds e.g. in the first second \( v_1 \) is 12 m/s, in the fifth second it falls to \( v_1 = 8 \) m/s, while at the tenth second it gets back to 12 m/s then the effect of this variation on the wind turbine power will be minimum, because the inertia of the aerodynamic rotor will not let the rotational speed reduce. In that case a mean wind power output will be sufficient. However, if the turbulent wind in the wake is not varying rapidly e.g. in the first second it is 12 m/s then it goes down slowly such that in the tenth second it is 8 m/s and then it ramps up by the same rate such that after another ten seconds it is back to 12 m/s, then the effect on the power output will be noticeable. This is because the aerodynamic rotor will slow down,
which in effect will reduce the power output of the turbine, later it will speed up and the power output will increase gradually. The turbulent nature of the wind depends on the internal dynamics of the wind farm. Overlapping of wakes, surface roughness, mixing of free-stream wind into the wakes, effects of wind shear etc. can affect the way wind speed is varied either rapidly or slowly.

The model developed assumes the second scenario where the power of a turbine will increase and decrease noticeably within a sample period of 1 minute for a fixed incoming wind speed. (It should be noted however, that for the sake of simplicity the turbulence in the free-stream wind \textit{(ambient turbulence)} is ignored.) This will lead to wind turbine WT1 power output to vary between $P_1 + \delta p_1$ and $P_1 - \delta p_1$. Using the same analogy, all wind turbines in the wind farm under wake can be considered and hence variation in total power output of the wind farm can be calculated. This variation in wind speed internal to the wind farm is normally ignored by the deterministic wake model which leads to a mean wind speed and thus a mean power output.

It might be argued though that a mean value of power output from the wind farm will be sufficient rather than a variable output in all cases, but the model developed prepares the network operator to keep a spinning reserve ready in case the wind power varies due to turbulence. The model allows calculation of variance in wind power output of the wind farm. This information is very useful beforehand when several GW capacity of wind farms are installed in the network because a small variation from the expected mean power output can result in deviation of a few MWs. Besides, the output from the probabilistic wake model covers the mean value which is otherwise estimated by the deterministic wake model.

### 3.12 Probabilistic Wake Model

The probabilistic wake model is developed by combining two existing wake models. At first, Jensen’s wake model calculates the mean wind speed e.g. $v_1$ and $v_2$, arriving at the turbines under wake then the turbulence model calculates the deviation in the wind speeds e.g. $\delta_1$ and $\delta_2$.

In the wake model developed, the \textit{ambient turbulence} in the free-stream wind is considered, however for the sake of simplicity its value is assumed to be negligible in the case study.
3.12.1 Jensen’s wake model (deterministic)

The detail wake effect model discussed in Section 3.3 is used to calculate the mean wind speed at each turbine (the top-hat distribution is ignored). Single, partial and multiple wakes are modelled to consider wind entering the wind farm from any direction.

3.12.2 Turbulence model

Generally, turbulence intensity is defined as a measure of the overall level of turbulence and is expressed as follows [105]:

\[ I = \frac{\sigma}{\bar{U}} \]  \hspace{1cm} (3.8)

where \( \sigma \) is the standard deviation of wind speed over a short period of time and \( \bar{U} \) is the mean wind speed.

The model employed for wake added turbulence calculation in this chapter can be used with single, partial and multiple wakes. The turbulence model is given in [111], [178] and expressed as follows:

\[ I = I_o(1 + \alpha_w) \exp \left( -\frac{\beta_w^2}{\beta_w^2} \right) \]  \hspace{1cm} (3.9)

\[ \beta_w \approx \frac{1}{2} \left( \frac{180}{\pi} \tan^{-1} \left( \frac{1}{s} \right) + 10^9 \right) \approx \frac{25}{s} [\text{deg}] \]  \hspace{1cm} (3.10)

where \( \beta_i \) is the angle between line connecting two turbines and the wind direction as shown in Figure 3.17, \( \beta_w \) is the characteristic width of the wake, \( s \) is the distance between the turbines in separate rows, \( \alpha_w \) is a constant expressed by the ambient turbulence \( I_o \), and the wake added turbulence (at hub height in the centre of the wake) \( I_w \): \n
\[ \alpha_w = \sqrt{\left( \frac{I_w}{I_o} \right)^2 + 1} - 1 \]  \hspace{1cm} (3.11)

The wake added turbulence \( I_w \) is the turbulence introduced by the wake of a turbine. It is expressed as [178]:

\[ I_w = \frac{1}{1.5 + 0.3s \sqrt{u}} \]  \hspace{1cm} (3.12)
If thrust coefficient, $C_t$ of a turbine is known for every wind speed then the following expression can be used instead:

$$I_w = \frac{1}{1.5 + 0.1s/\sqrt{C_t}}$$  \hspace{1cm} (3.13)

where $s$ is the distance between two turbines which wake one or the other, $u$ is the mean wind speed.

![Figure 3.17: Wake turbulence as faced by a downwind turbine (adopted from [178])](image)

In probabilistic wake model proposed the mean wind speed at a turbine is calculated using (3.2) to (3.5) while the range of speed variation is calculated using (3.8), (3.9) to (3.13) where $\sigma$ defines the width of this range.

### 3.13 Case Study

The distribution of wind speed faced by turbine/s downwind is computed using the above mentioned approach. A 49 turbine wind farm shown in Figure 3.13 is used for simulation purposes. Each turbine has a rated power of 2 MW with hub height of 80 m and rotor radius of 40 m. Rated power of the wind farm is 98 MW. The wind farm is located at sea with surface roughness of 0.0002. Distance between two turbines in the same row is 400 m while the diagonal distance is 565 m. Ambient turbulence $L_o$ is assumed to be negligible.

Once the mean wind speed and the variance at each turbine are obtained, Monte Carlo simulations are performed to obtain wind speed distribution. For turbines arranged in the same row, the wind speed distribution is plotted in Figure 3.18. The distribution is assumed to be Gaussian as shown for wind turbine 21 in Figure 3.19.
In Figure 3.20 probabilistic wind speed received by turbine 13 inside a wind farm (shown in Figure 3.13) from all directions (0° to 360°) is illustrated. It shows that using a deterministic model fixed wind speeds are obtained whereas if probabilistic method is used a spread of wind speed is observed since internal wind farm dynamics are considered.

![Wind Speed Distribution](image1)

Figure 3.18: Distribution of wind speeds at each wind turbine (dots) and result from deterministic wake model (line) at incoming wind speed of 10 m/s from wind direction = 270° ± 3°

![Gaussian Wind Speed Distribution](image2)

Figure 3.19: Gaussian wind speed distribution at wind turbine (WT) 21 for wind entering the wind farm at 10 m/s from wind direction = 270° ± 3°

This figure is plotted for a wind speed of 10 m/s entering the wind farm at a particular direction range. (The results will be different for other wind speeds and wind directions). The wind plot shown in Figure 3.20 is part symmetrical (top and right side) and part non-symmetrical (bottom and left side). The symmetrical part is due to single wake by wind turbines 21, 14, 7, 6 and 5 when wind is entering the wind farm from between 315° to 135°, whereas the non-symmetrical part is due to complex interaction of multiple wakes by several
wind turbines at the bottom left side of turbine 13 when wind is entering the wind farm from between 135° to about 315°.

Figure 3.20: Wind plot of wind turbine 13 for incoming wind speed of 10 m/s showing results of deterministic wake model (black line) and probabilistic model (red crosses). Circles indicate wind speed magnitude (m/s) from each wind direction.

3.14 Power Output Analysis

Power curves are used to trace the power at the corresponding wind speed. The total power output of the wind farm is obtained by summing up the power from individual wind turbines. Applying the probabilistic wake model gives a range of power output for each turbine. The test was performed for wind entering the wind farm at 10 m/s but from various directions. The results are compared with those obtained using the deterministic wake model, as shown in Figure 3.21.

The difference between wind power output obtained using the probabilistic and the deterministic wake model is illustrated in Figure 3.22. It can be seen that the difference varies from several kilowatts to Megawatts. For example, at wind speed 10 m/s and wind direction of 91° the difference in power output can be seen as large as 7 MW, implying that total power production can be as much as 7 MW different to that predicted by the deterministic model. However on average this difference is plus or minus 2 MW. Although only one wind speed is simulated in this case study, the probabilistic wake model can be used for any speed and direction of wind entering the wind farm. The variation in power
output will decrease at higher wind speeds (above rated wind speed) as the turbine aims to produce the rated power.

The results of the model can be only verified if wind speed measurements at each turbine inside the wind farm are available. However, this data was not available. But, the turbulence model used has been previously verified against the measurement data therefore the results obtained should be realistic.

Figure 3.21: Total wind power output in MW from the wind farm at each wind direction for fixed wind speed of 10 m/s, with deterministic (black line) and probabilistic wake model (red cross)

Figure 3.22: Difference in power output for wind entering from all directions in the WF at wind speed of 10 m/s
3.15 Energy Yield Analysis

Traditionally energy yield is calculated using wind speed data from a Weibull distribution and the power curves of wind turbines; or if wind measurements at the site are available, the power of a turbine is calculated for every wind speed and then multiplied by the total number of turbines. Both techniques overestimate energy yield because wake losses are ignored. In this chapter, energy yield is calculated using deterministic and probabilistic wake models, the results are given in Table 3.2.

Wind speed and direction measurements (see Section 3.8) recorded at a site in North Sweden are used for the analysis. When using probabilistic wake model, some power outputs in the year were higher while some were lower than the mean power, equalling out the rise and fall in energy yield. However, the difference observed after several simulations is shown below.

Table 3.2: Energy yield comparison using deterministic and probabilistic wake model

<table>
<thead>
<tr>
<th>Energy yield ignoring wake effects</th>
<th>Energy yield with deterministic wake model</th>
<th>Energy yield with probabilistic wake model</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference</td>
<td>-15.41%</td>
<td>-15.41% ± 0.2%</td>
</tr>
</tbody>
</table>

It can be seen that deterministic model results in energy yield losses of about 15.41% (compared to the case when wake is completely ignored) while inclusion of probabilistic nature of wind converts these losses into a range of (15.41 ± 0.2%). The capacity factor is also calculated using the deterministic wake model. It was found that the capacity factor reduced from 39.8% to 33.7% due to 15.41% reduction in energy yield. It should be noted however that results presented in Table 3.2 are valid for this case study, i.e. for wind farm with layout shown in Figure 3.13, with turbines 80 m high installed at a site with wind characteristics shown in Figure 3.11 and Figure 3.12. If either wind farm layout, wind turbine type or wind site characteristics changes these results will vary accordingly.

From Table 3.2 it can be seen that the difference in energy yield by using the probabilistic wake model is not significant which makes it more applicable for online usage rather than for offline use.
3.16 Summary

The power production from a turbine is sensitive to the wind speed it receives. It was shown in this chapter that wake effects can significantly reduce the power output below rated wind speeds. Wake effect models presented in the past were briefly discussed while Jensen’s model is chosen for detailed wake modelling. A program (VeBWake) is developed in which a wind farm of any layout consisting of turbines of any rotor radius and height can be simulated to calculate the wind speed experienced at each individual turbine. Jensen’s wake model is commonly adopted for electrical engineering related research studies as well as in commercially available software. The MATLAB software environment was chosen for development of this program to allow modelling flexibility and parameter accessibility.

It was also noticed that terrain roughness, wind shear and the direction of the incoming wind can affect the power generation from a turbine inside a wind farm. Therefore it is essential to take these factors into account when modelling wake effects. Wind speed measurements at a site and the Weibull distribution are also presented. Two wind farm layouts consistently used in the case studies throughout this thesis were also presented within this chapter.

A new probabilistic wake model to account for wind farm power output variation due to the stochastic nature of wind (inside the wind farm) is also presented in this chapter. This model is different from Jensen’s wake model that always provides a deterministic output at a given incoming wind speed. Using this method, the range of power output and energy yield can be estimated. It is an attempt to include turbulence of wind in an analytical wake model. Deterministic wake models do not take into account dynamic characteristics of wind inside a wind farm. The presented approach is computationally efficient in comparison to the complex modelling techniques available. The main advantage includes estimating a range of possible wind farm power output for an available forecast of wind speed and wind direction a few minutes ahead. This method is beneficial for online simulations as many large wind farms are expected to be installed in the network, a range of power output from each WF can enable the network operator to allocate spinning reserve and generator dispatch. The results of the model are dependent on the location, layout and the type of wind turbines installed in a wind farm. Other
factors that can influence the results are the distance between the wind turbines, the thrust coefficient, the speed and direction of the wind entering the wind farm.

It is also shown by the analysis that the probabilistic wake model does not significantly affect the energy yield of the wind farm because of the zero mean effect. These results support the fact that the turbulence can be ignored for offline studies such as for energy yield analysis. For this reason, deterministic wake models are used in the following chapters.
Chapter 4

Probabilistic Aggregate Dynamic Model of a Wind Farm

4.1 Introduction

Increased wind penetration in the network has led to major challenges but simultaneously, advancement in communication technologies has provided some solutions. Utilities are now implementing real-time monitoring techniques to enable them to obtain wind power outputs from wind farms connected with the system. With large scale wind penetration, instantaneous regional shift in power generation will be common as wind flow changes. This requires modelling tools that are fast and accurate so that stability of the system within the following few hours can be simulated by testing faults in critical areas. Using wind speed and direction measurements along with a forecasting tool, wind conditions from a few minutes to hours ahead can be predicted. Although dramatic increases in computational power over the recent years has led to faster simulation times, handling large numbers of nodes and solving hundreds (if not thousands) of differential equations still leads to long simulation times.

Since wind is a variable energy resource, deterministic models often do not lead to a reliable solution so for this purpose probabilistic techniques are often more suitable. This can mean testing multiple scenarios with variable parameters. If each wind farm in the system is modelled with all its turbines, this will not only increase the computation burden during transient stability simulations but it will also be cumbersome for the system operator to reset the parameters to model the wind farm when wind conditions change.
Although detailed modelling of wind farms is reasonable during the design stage, where faults internal to the wind farm have to be tested, when analysing several wind farms as part of a network, this type of study is not suitable [43]. To solve this issue, wind farm aggregation models have been introduced in the past (as discussed in Section 1.4.1). They enable a large wind farm to be simulated by fewer turbines. Some of the existing models have already been explored in the literature review.

An innovative probabilistic clustering approach is proposed in this chapter which determines the equivalent number of wind turbines (and their corresponding parameters) that can be used most frequently throughout the year to model a WF accurately. The quantity and rated power of each equivalent turbine is dependent on a variety of factors such as the statistical analysis of the site and the wind farm layout. The number of equivalent turbines is determined only once using the probabilistic clustering approach, then the same set of turbines are used to represent the wind farm in any wind condition.

The approach is applicable to wind farms with symmetrical or arbitrary layouts as it takes into account wind speed variation inside the WF due to wakes. The only information needed for model development apart from the electrical and mechanical parameters of individual wind turbines, cable parameters and WF topology is the wind data at the site, i.e., wind speed and wind direction. The availability of wind data at each wind turbine inside the WF (which is still not something that most of the WF operators would have) will simplify and speed up the computational process. If this data is unavailable, wind speed at each wind turbine can be calculated through the wake effect model (VeBWake).

Accuracy of dynamic simulation is compared against results from the detailed model. It is assumed that all turbines inside the wind farm are of the same type. The model is useful in real-time simulators where modelling individual wind turbines requires multiple computer processors [179]. The model proposed is equally useful for offline studies. A comparison with popular existing aggregation models is also performed to test simulation time, dynamic response, ease of setup and use.
4.2 Aggregation by Wind Speed

It is argued in [37] that irregularity of wind distribution inside the wind farm (due to wakes) will lead to wind turbines running at different operating points from one another. Dynamic behaviour of a wind turbine during a fault in the system is influenced by the controller’s actions, which depends on the wind speed faced by the turbine. At low wind speed, the controller would try to track the optimal point of operation, whereas at higher wind speed the controller would attempt to keep the angular speed inside an acceptable range to maintain power production.

Furthermore, the stiffness of the shaft also affects the dynamic behaviour of the turbines [77]. A wind turbine has a soft shaft system which accumulates potential energy when twisted during normal operation and some of this energy is released when a short circuit fault occurs in the network. Potential energy stored in all the turbine shafts at a point of fault can in some instances, be larger than that predicted by a single-unit model [77] because it assumes the same operating point for all turbines. For this reason, a single-unit model will also predict less acceleration of the turbines at faults, such influencing their overall dynamic behaviour. Dynamic results in [180] show that a single-unit equivalent is only suitable when the wind profile at each turbine is similar. This model is no longer suitable when profiles differ between turbines. Multi-machine models however can predict this accumulation of potential energy more accurately as described in [37, 77].

To test the claims which say that turbines facing different wind speed will be operating at different operating point, the dynamic behaviour of a DFIG machine is simulated at two different wind speeds i.e. at below rated wind speed and at rated wind speed. A 3-phase fault is applied at the cable connecting the wind turbine with the grid (infinite bus) at 1 second and cleared after 200 ms. Results in Figure 4.1 shows the difference in dynamic response of a wind turbine operating at two different operating points when it receives two different wind speeds. In steady state condition, the per unit generator rotor speed is slightly higher for the turbine facing the rated wind speed because it is operating at $\omega_{max}$ (see Figure 2.12) whereas at lower wind speed the rotor speed is below $\omega_{max}$. It can be seen from Figure 4.1 that the rotor speed, active power and reactive power dynamic response take longer to stabilise when the turbine
is facing rated wind speed as compared to when it is facing below rated wind speed.

This example illustrates that two wind turbines inside a wind farm facing different wind speeds will operate at different operating points, this will affect their generator rotor speed, active and reactive power magnitude as well as the dynamic response in case of a disturbance.

The single-unit equivalent model assumes that all turbines receive the same wind speed, therefore it may predict an inaccurate dynamic response. A multi-machine aggregate model might be more suitable for equivalent wind farm representation. This is further validated when aggregation methods are compared in Section 4.7.

Figure 4.1: Response of a DFIG machine under two wind speeds (a) Generator rotor speed (b) Active power (c) Reactive power
4.3 Support Vector Clustering

In order to consider irregularity of wind speed inside a wind farm due to wakes, the wake effect program VeBWake is used. Wind speed at each turbine is calculated for wind entering the farm at various speeds from various directions. Since wind turbines that face similar wind speeds operate at the same operating point they can be clustered together [37]. The clustering is performed using a Support Vector Clustering (SVC) method.

The SVC has been introduced as a further step to the support vector machine concept introduced in [181]. It consists of determining the support vectors and cluster labelling characterised by the identification of the final clusters. The clustering procedure is carried out following two major steps:

1) **Determinination of the support vectors:** a data set with \( N \) multi-dimensional features is transformed from the original data space \( D \) to a high-dimensional feature space \( T \) through a nonlinear transformation. Then, an optimization procedure is applied to minimize the radius of the sphere enclosing the image of the features mapped into the \( T \)-space [182]. Three types of features are defined according to the location of their image in the transformed space inside the enclosing sphere (internal vectors, IVs), on the boundary of the enclosing sphere (support vectors), and outside the sphere (bounded support vectors).

2) **Cluster labelling:** the support vector computation only refers to the distances in the \( T \)-space between the features and the centre of the enclosing sphere, and no information is provided on the directional coordinates of the features. Thus, a second step is needed to form the final clusters [182]. The full procedure for the SVC is described in [183], in which the data points corresponding to bounded support vectors are considered as outliers and are assigned to individual clusters, while the data points corresponding to the non-bounded support vectors are grouped into clusters through a deterministic algorithm.

In the SVC-based algorithm [183], the number of final clusters depends only on a single, user-defined, threshold parameter, thus avoiding settings of additional parameter learning heuristics as in [184]. The main goal of the SVC algorithm is to assign multidimensional data features to groups and obtain accurate and non-overlapped clusters.
Various clustering methods including *follow-the-leader, k-means, fuzzy k-means, hierarchical clustering* (average linkage criterion, Ward linkage criterion) and *Kohonen’s self organizing map* are tested against the SVC in [183]. The SVC is found to have better clustering validity than other listed methods and it performs well when number of clusters is relatively small. For these reasons, this algorithm was chosen for clustering of turbines based on their wind speeds.

### 4.4 Wind Turbine Clustering

As mentioned above, wind turbine clustering is addressed by applying the SVC algorithm. All wind speeds within the turbine’s operating range are tested from 0° to 360° and then VeBWake program (mentioned in Section 3.4) is used to obtain the proper wind speed received by each wind turbine within the plant. Wind turbine clusters are then created based on their wind speed and direction profiles using the SVC algorithm.

#### 4.4.1 Wind farm layout

A test WF consisting of 49 identical offshore wind turbines with the rated power of $S_{WF} = 98$ MW is used in the case study. Variable speed, pitch controlled and yaw enabled turbines with a 2 MW DFIG are used. They have an operating range between 4 m/s and 25 m/s with a rated wind speed of 15 m/s [15]. Distance between adjacent wind turbines is 400 m. A symmetrical WF layout is chosen for the case study, the layout is shown in Figure 3.13; however, the methodology developed is applicable to a wind farm of any size and layout. All steady state and dynamic simulations are performed using DlgsILENT PowerFactory [151].

#### 4.4.2 Clustering

The test WF is used to illustrate the way wind turbine clustering is performed. At a given time in the future, the speed and direction of the wind impacting on the WF is assumed to be known from wind forecasting. The wind speed patterns at each wind turbine (obtained through wake effect program, VeBWake) are the inputs of the SVC algorithm used to establish distinct and non-overlapped clusters. This corresponds in particular to a target wind speed.
used as a parameter in the analysis. The effective wind speed received by each wind turbine depends on the speed of wind entering the WF, its direction and the effects of wakes inside the WF. For each target wind speed, clusters are formed by running the SVC algorithm for a set of wind directions with one-degree resolution.

The clustering results will differ with both, the speed and the direction of the wind arriving at the wind farm. Two characteristic cases affecting clustering results can be discerned as:

a) Constant incoming wind speed but variable direction: Wind speeds inside the WF are to a large extent, affected by wakes of other turbines. Therefore, even if the incoming wind speed into the wind farm is kept constant, direction changes would cause turbines to face that wind direction (assuming turbines have yaw control) and this would, in effect, alter the wind speed that a downwind turbine(s) receives due to wake effects. This change in wind speed received by the turbine will influence the clustering results, i.e., the turbines will be clustered differently as can be seen from Table 4.1.

b) Constant incoming wind direction but variable wind speed: a change in wind speed would also alter the magnitude of wind speed at each turbine inside the WF.

### Table 4.1: Cluster components at 15 m/s for various wind directions

<table>
<thead>
<tr>
<th>Direction (degrees)</th>
<th>Number of Clusters</th>
<th>Cluster 1</th>
<th>Cluster 2</th>
<th>Cluster 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>105</td>
<td>2</td>
<td>-</td>
<td>22-27, 29-34, 36-41, 43-48</td>
<td>1-21, 28, 35, 42, 49</td>
</tr>
<tr>
<td>322</td>
<td>3</td>
<td>3-7, 10-14, 17-21, 2, 9, 16, 23, 30, 37-42, 24-28, 31-35</td>
<td>42</td>
<td>36, 43-49</td>
</tr>
<tr>
<td>280</td>
<td>3</td>
<td>(1-35)</td>
<td>36-42</td>
<td>43-49</td>
</tr>
</tbody>
</table>

Table 4.1 shows clusters of turbines obtained for a fixed incoming wind speed entering the WF at 15 m/s at given wind directions. Wind turbines are clustered according to the wind speed they receive individually inside the WF. For instance, Cluster 1 represents turbines facing lower wind speeds and Cluster 3, those that face higher wind speeds. Turbines in Cluster 1 are under
Chapter 4: Probabilistic Aggregate Dynamic Model of a Wind Farm

the wake of those in Clusters 2 and 3, while turbines in Cluster 2 are only under the wake of turbines in Cluster 3. An illustration of wind speed variation and thus clustering for wind entering the wind farm from 322° is presented in Figure 4.2. The darker circles indicate wind turbines facing higher wind speeds, Cluster 3, a gradual progression towards the inside shows turbines facing reduced wind speeds, Clusters 2 and Cluster 1 respectively.

Analysis of clustering results shows that not only the number of turbines inside a cluster, but also the number of clusters vary with the incoming wind direction. For instance, number of turbines inside Cluster 2 is different at each wind direction and number of clusters is different between 105° (two clusters) and 322° (three clusters). Similarly, number of turbines inside a cluster and number of clusters also vary with the magnitude of the incoming wind speed. Nonetheless, for wind speeds greater than 18 m/s, the wake effect is reduced and also wind turbines operate at rated power, therefore they can be represented by a single cluster (consisting of 49 wind turbines).

![Figure 4.2: Wind speed variation inside a wind farm at 15 m/s, 322°](image)

If the system, or a WF operator would want to perform either static or dynamic simulations using equivalent models developed based on these clusters he/she would need to readjust several parameters of the model whenever wind speed or direction changes. This is because, a change in wind condition would influence the number of clusters and the number of wind turbines inside individual clusters (see Cluster Representation in Section 4.7.2). This frequent readjustment of model parameters is avoided through a probabilistic approach, by grouping clusters together, and determining the most probable set of groups
that would work for most wind conditions throughout the year (or any time period).

4.5 Probabilistic Clustering of Wind Turbines

The probabilistic model provides a unique representation of the wind plant that could be used throughout the year. The clusters established for each wind condition are further arranged into groups. Through probabilistic analysis of wind conditions at the site, the most probable group is established. This most probable group defines the number of equivalent turbines that will represent the wind farm throughout the year. The following sections provide detail description of each step of the process.

4.5.1 Formation of groups

Once clustering of wind turbines is achieved according to the wind speed they receive, these clusters are further arranged into groups. An example is shown in Table 4.2. Sometimes the same group can occur for more than one wind condition. Groups are classified as different (i.e., unique groups), if either or both the criterion is met:

1) Number of clusters in any two groups is different.
2) Number of clusters in any two groups is the same, but the number of turbines in the clusters are different.

The number of clusters represents the number of equivalent turbine(s) needed for WF representation, while the number of turbines inside each cluster allows calculation of rated power of the equivalent turbine(s). The total number of unique groups that exist for all wind speeds and directions are identified first. Probabilities for each of these unique groups are then calculated using the wind information at the site (this will be shown in the next section).

A change in wind speed or direction can affect the way wind turbines are clustered (as seen in previous section), which in turn can alter the number of groups and the probability of group occurrences.

An illustration of group formation for various wind conditions is shown in Table 4.2. For instance when wind speed is 15 m/s and wind direction is 105°, two clusters of wind turbines are identified by the SVC algorithm (as shown in Table 4.1), and these clusters are assembled into a group G1. Group G1 can...
represent the entire WF by 2 equivalent turbines. Similarly, for the same wind speed but with wind directions, 322° and 280°, 3 clusters of wind turbines are formed, Group G2 and Group G3, respectively. Although G2 and G3 have the same number of clusters, the number of turbines within a cluster is different (see Table 4.1). For wind speeds above rated, e.g. at 24 m/s, when turbines produce similar power, a single cluster can model the entire WF. Groups are formed for all wind speeds and wind directions considered.

Table 4.2: Formation of Groups at different wind conditions

<table>
<thead>
<tr>
<th>Speed (m/s)</th>
<th>Direction (deg)</th>
<th>Groups</th>
<th>No. of Clusters</th>
</tr>
</thead>
<tbody>
<tr>
<td>15</td>
<td>105</td>
<td>G1</td>
<td>2</td>
</tr>
<tr>
<td>15</td>
<td>322</td>
<td>G2</td>
<td>3</td>
</tr>
<tr>
<td>15</td>
<td>280</td>
<td>G3</td>
<td>3</td>
</tr>
<tr>
<td>24</td>
<td>160</td>
<td>G4</td>
<td>1</td>
</tr>
<tr>
<td>10</td>
<td>100</td>
<td>G5</td>
<td>8</td>
</tr>
<tr>
<td>10</td>
<td>352</td>
<td>G6</td>
<td>6</td>
</tr>
</tbody>
</table>

4.5.2 Probability of groups

To find the probability of occurrence of a group during the year, the probability of wind speed and wind direction when that group should be used, needs to be determined first.

Assume that for an assigned wind direction range \(d\) the group \(X\) is used for the subset of \(N^{(x)}\) discrete wind speed bins \(W^{(x)} = \{w^{(x)}_i, i = 1, ..., N^{(x)}\}\). (Group \(X\), in general, could appear for the wind speeds belonging to the subset \(W^{(x)}\), and for each wind speed bin \(w_k \in W^{(x)}\) it could appear with \(J^{(x)}_k\) occurrences in the subset \(D^{(x)}_{w_k} = \{d^{(x)}_{kj}, j = 1, ..., J^{(x)}_k\}\) of wind direction ranges). Let us denote with \(P_{w_k,d}\) the joint probability of wind speed and direction. Each wind speed occurrence is independent of the other wind speeds, and the occurrences of the wind direction ranges are independent of each other as well. As such, the probability of occurrence of group \(X\) during the year becomes:

\[
p^{(x)} = \sum_{w_k \in W^{(x)}} \sum_{d \in D^{(x)}_{w_k}} P_{w_k,d}
\]  

(4.1)
For example, if group $X$ occurs with a different combination of wind speed and direction, i.e., once for $w = 4$ m/s and directions 100° to 120°, then for $w = 6$ m/s and directions 120° to 140°, (4.1) is used with $W^{(x)} = \{4, 6\}$, $D^{(x)}_4 = \{100°, 101°, ..., 120°\}$, and $D^{(x)}_6 = \{120°, 121°, ..., 140°\}$.

By using (4.1), the probability of any group during the year can be determined for any site. The number of groups can vary based on size and layout of the WF, wind characteristics at a site during the year, wind speed and direction step used.

### 4.5.3 Information of wind at a site

It is assumed that the 49 turbine wind farm is placed at a site in North Sweden for which wind speed measurements are given in Section 3.8. It can be seen from Figure 3.12 that there are two dominant ranges of wind directions during the year, i.e., 100° to 180° and 280° to 360° so for this reason only these direction ranges were analysed with a step of 1°. Although the most probable wind speeds (in Figure 3.11) are in the range from 4 m/s to 15 m/s, all wind speeds within the entire wind turbine operating range are considered (with a step of 1 m/s) for wind turbine clustering.

### 4.5.4 Probabilistic group identification

A total of about 3500 groups were identified after testing all wind conditions, out of these there were 321 unique groups.

![Figure 4.3: Probability of every unique group found](image)
In order to establish a single group, out of 321, the probability of each of them is calculated using (4.1), i.e. site analysis is brought in to see the probability of usage of each group during the year. Figure 4.3 shows that only four groups (Groups A, B, C and D) have noticeable probabilities, whereas the rest of them have probabilities less than 0.01. Cluster information of these four most probable groups is given in Table 4.3. From this table it is obvious that representation of the WF by 3 equivalent turbines is the best choice. Although both Groups A and B have 3 clusters, they differ in terms of wind turbine clustering. Since the probability of occurrence of Group A is the highest, it is used to represent the WF throughout the year. The high probability of Group A indicates that the equivalent turbines in this group will be most highly employed throughout the year to represent the wind farm of the described layout at the given site.

<table>
<thead>
<tr>
<th>Groups</th>
<th>Number of Equivalent turbines</th>
<th>Rated powers (MW)</th>
<th>Probability</th>
<th>Wind turbines clustered</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>3</td>
<td>26; 22; 50</td>
<td>0.1028</td>
<td>13; 11; 25</td>
</tr>
<tr>
<td>B</td>
<td>3</td>
<td>38; 30; 30</td>
<td>0.089</td>
<td>19; 15; 15</td>
</tr>
<tr>
<td>C</td>
<td>2</td>
<td>38; 60</td>
<td>0.062</td>
<td>19; 30</td>
</tr>
<tr>
<td>D</td>
<td>1</td>
<td>98</td>
<td>0.0244</td>
<td>49</td>
</tr>
</tbody>
</table>

By analysing unique groups in this case study, it was found that the maximum number of clusters that any group has is 10. This implies that the 49
WT wind farm, considered here, can be represented by a maximum of 10 equivalent turbines.

The probability to represent the wind farm by 1 equivalent turbine is found to be very low as seen from Figure 4.4. This shows that if a *single-unit equivalent model* (which represents a wind farm by a single turbine) is used it will not accurately represent the wind farm throughout the year. This is because the probability when a single turbine could be used to accurately represent the wind farm is extremely low. The selection of Group A with 3 equivalent turbines is justified as the probability of representing the wind farm with 3 equivalent turbines is the highest (as seen from this figure).

![Figure 4.5](image)

Figure 4.5: Number of equivalent turbines that can represent a WF and number of possible ways to model them

It was seen in Table 4.3 that Groups A and B have the highest probability of usage throughout the year, both represent the wind farm by 3 equivalent turbines but they differ in their rated capacity. This showed that there is more than one way to setup the equivalent turbines. Possible ways to setup equivalent turbines in all unique groups are further explored. Figure 4.5 shows that there are about 48 different ways to setup 3 equivalent turbines, whereas there are 82 different ways to setup 5 equivalent turbines. The difference occurs due to the number of turbines in each cluster (in a group) which affects the rating of an equivalent turbine.
4.6 Dynamic Simulations

The probabilistic aggregate model of the WF developed in the previous section is further tested by comparing its transient response with the detailed WF model under various wind conditions. This test is carried out to confirm that the aggregate model will be able to accurately represent the dynamic behaviour of the detailed WF throughout the year.

4.6.1 Wind plant description

For this particular case study, a wind farm with turbines connected in a radial manner, as shown in Figure 4.6, is considered. The layout of the wind farm is described previously in Section 4.4.1. The wind turbines are connected in an array at a voltage level of 30 kV. This level is stepped up to 132 kV by a 30/132 kV collector transformer. The voltage at the point of common coupling (PCC) (slack bus) is fixed at 1 p.u as the grid is represented by an ideal voltage source. A built-in model of DFIG in DIgSILENT PowerFactory™ is scaled to represent the 2 MW machine. Each turbine is connected to the array collector system by a tertiary 0.69/3.3/30 kV transformer (shown in Figure 2.9). A 3-phase, 200 ms, self clearing fault is applied to one of the transmission lines connecting the WF to the PCC. It is assumed that all turbines in the wind farm are of the same type, having the same mechanical and electrical parameters.

![Electrical layout of the detailed wind farm](image)

Figure 4.6: Electrical layout of the detailed wind farm

4.6.2 Impact of wind turbines in different strings on WF aggregation

The wind turbines are connected in strings, as can be seen in Figure 4.6, this array layout is the radial array configuration. The impact of wind turbine location on dynamic behaviour is investigated in this section.
The dynamic response of three wind turbines, 1, 5 and 8 (in the network shown in Figure 4.6) receiving the same wind speed is compared. Wind turbines 1 and 5 are in the same string (String 1), whereas wind turbine 8 is in another string (String 2). The dynamic responses are shown in Figure 4.7. It can be seen from this figure that the dynamic behaviour of all three generators is the same; therefore it can be said that wind turbines in different strings can be aggregated into a single machine, if they receive the same wind speed.

In studies such as [44] the impact of internal wind farm cabling on dynamic response of the wind farm is ignored, however this is not entirely accurate. A difference in power may occur because of cable losses inside the wind turbine array. A model that accounts for line resistance, reactance and capacitance is proposed in the following sections to improve the equivalent modelling of a WF for dynamic studies.

![Figure 4.7: Dynamic response of three DFIG machines arranged in a radial configuration](image)

(a) Active power (b) Reactive power

### 4.6.3 Setting up equivalent wind turbines

The method of reducing the complexity of the system by representing several wind turbines by fewer equivalent turbines is known as *wind turbine*
aggregation. This type of aggregation has been performed in [37, 46, 77, 180]. An aggregate model of the wind farm is required to fulfill two conditions:

1) The pre-fault active and reactive power output from the aggregate model should be the same as that from a detailed wind farm model

2) The dynamic response of the aggregate model should be the same as that of a detail wind farm model response

In this case study, the number of the equivalent turbines and the number of wind turbines the equivalent turbine represents is given by Group A. From Table 4.3 it can be seen that there will be 3 equivalent turbines of capacity 26 MW, 22 MW, 50 MW, i.e., each equivalent turbine represents 13, 11 and 25 wind turbines respectively. Although wind turbine aggregation had been performed in several previous studies, no research study described in detail which internal parameters of the machine should be adjusted.

Setting up an equivalent turbine requires adjusting of mechanical as well as electrical parameters. As a starting point, pre-fault mechanical power should be the same as electrical power which implies that if a large induction machine is used it will require an equally sized mechanical rotor. Thus, when bigger turbine rotor is used, the inertia constant and damping coefficients should be adjusted (increased) accordingly. Also, wind turbines usually have softer shafts than conventional generators, therefore, stiffness of the shaft needs to be adjusted appropriately.

On the electrical side, transformer, converter, capacitor and inductor which will be handling larger current than before will need to be rescaled. The amount of current inside the induction machine will increase with an upscale of the MVA power rating in a linear fashion since voltages are assumed to remain static. When generator will have larger MVA ratings they will be physically larger, therefore the inertia of its rotor will also be larger. All these parameters are scaled up in the DIgSILENT PowerFactory to simulate an equivalent turbine model. Table 4.4 shows in a summarised form the parameters that need to be scaled in order to setup aggregate wind turbines. The scaling factor mentioned in this table is the number of turbines an equivalent turbine will represent. For instance, if the 2 MW machine is being scaled up to represent 13 (26 MW) such machines then the scaling factor is 13.

The rated apparent power of an equivalent turbine is calculated as the sum of rated apparent powers of individual turbines in a cluster:
\[ S_{eq\_WT} = \sum_{i=1}^{n} S_{individual\_WTs} \] (4.2)

where \( n \) is the number of aggregated turbines in a cluster, \( S_{individual\_WTs} \) is the rated apparent power of each wind turbine in the cluster and \( S_{eq\_WT} \) is the rated apparent power of the equivalent wind turbine.

It is assumed that the rated voltage at the terminal of an equivalent wind turbine is the same as that of a single turbine (in a detail wind farm).

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Scale factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated Mechanical Power</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Active Power (initial conditions)</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Reactive Power (initial conditions)</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Converter Rating</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Reactive Power set-point</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>DC-Link Capacitor size</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Rotor side converter rating (PQ measurement)</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Rated Power of Generator</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Rotor Inertia (without generator)</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Shaft Stiffness</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Torsional Damping</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Series Inductor Rated Power</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Rated power of transformer at HV, MV and LV side</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Positive-seq short-circuit voltage at HV-MV</td>
<td>Adjust manually</td>
</tr>
<tr>
<td>Positive-seq short-circuit voltage at MV-LV</td>
<td>Adjust manually</td>
</tr>
<tr>
<td>Positive-seq short-circuit voltage at LV-HV</td>
<td>Adjust manually</td>
</tr>
<tr>
<td>Inertia of Generator</td>
<td>Multiply by scaling factor</td>
</tr>
<tr>
<td>Acceleration time constant</td>
<td>Automatically adjusted according to inertia</td>
</tr>
<tr>
<td>Mechanical Power of Turbine</td>
<td>Multiply by scaling factor</td>
</tr>
</tbody>
</table>

Those parameters of the generator, rotor-side converter, crow-bar protection, current control, grid-side converter, 3-winding transformer and reactor (inductor) that are in per-units are not modified as they will be adjusted according to the rated apparent power and rated voltage base. No parameter of
Chapter 4: Probabilistic Aggregate Dynamic Model of a Wind Farm

Pitch control is changed as it is assumed that scaling up would not affect the pitch control of the equivalent turbine.

The inertia, MVA power rating of the generator, MVA converter rating, DC-link capacitor size, rotor inertia, shaft stiffness, torsional damping, size of the inductor and mechanical power of turbine are manually scaled up. The equivalent transformers connecting the equivalent wind turbines are also set appropriately allowing rated power transfer.

Figure 4.8 shows 3 equivalent turbines from Group A connected with a bus at 30 kV through lines (with equivalent cable parameters). The equivalent resistance and reactance of these lines is calculated in the following section.

\[ P_{loss} = 3 \left( I_1^2 R_1 + (I_1 + I_2)^2 R_2 + ... + (I_1 + I_2 + ... + I_n)^2 R_n \right) \]  
(4.3)

\[ Q_{loss} = 3 \left( I_1^2 X_1 + (I_1 + I_2)^2 X_2 + ... + (I_1 + I_2 + ... + I_n)^2 X_n \right) \]  
(4.4)

where \( R_i \) and \( X_i \) are respectively the resistance and the reactance of the \( i \)th portion of the string containing \( n \) wind turbines, and \( I_i \) is the rated current of
the \(i\)th wind turbine in the string, for \(i = 1,\ldots, n\). Total electrical losses \((P_{loss,WF}, Q_{loss,WF})\) inside the WF are calculated as a sum of losses inside each string (in the detailed wind farm model). Considering the WF rated voltage \(V\), the total current flowing out of the WF is evaluated as:

\[
I_{WF} = S_{WF} / \sqrt{3}V
\]  

(4.5)

In the aggregate model, as shown in Figure 4.8, for a total of \(p\) equivalent turbines, the current from each can be evaluated as:

\[
I_{\text{eqWT}j} = S_{\text{eqWT}j} / \sqrt{3}V
\]  

(4.6)

where \(j = 1, 2, 3, \ldots, p\) and \(S_{\text{eqWT}j}\) is the rated capacity of the \(j\)th equivalent turbine. Sum of total losses from all equivalent wind turbines should be equal to total power losses in the detailed WF:

\[
\sum_{j=1}^{p} (P_{loss,eqWTj}) = P_{loss,WF} \times \sum_{j=1}^{p} (Q_{loss,eqWTj}) = Q_{loss,WF}
\]  

(4.7)

In the case studied and for any set of clustered wind turbines the following expression is valid:

\[
\frac{P_{loss,eqWT1}}{M_1} = \frac{P_{loss,eqWT2}}{M_2} = \frac{P_{loss,eqWT3}}{M_3} = \cdots = \frac{P_{loss,eqWTp}}{M_p}
\]

(4.8)

\[
\frac{3I_{eqWT1}^2R_{eq,1}}{M_1} = \frac{3I_{eqWT2}^2R_{eq,2}}{M_2} = \frac{3I_{eqWT3}^2R_{eq,3}}{M_3} = \cdots = \frac{3I_{eqWTp}^2R_{eq,p}}{M_p}
\]

(4.9)

By solving these equations simultaneously, equivalent resistance of each line connecting the equivalent wind turbines \((R_{eq,j})\) with the 30 kV bus can be determined. The value for the first equivalent line, for instance, is evaluated as below:

\[
R_{eq,1} = \frac{P_{loss,WF} M_1}{3I_{eqWT1}^2 [M_1 + M_2 + M_3]}
\]

(4.10)

Equivalent reactance \((X_{eq,j})\) can be evaluated in the same way by replacing \(R\) with \(X\):

\[
X_{eq,1} = \frac{Q_{loss,WF} M_1}{3I_{eqWT1}^2 [M_1 + M_2 + M_3]}
\]

(4.11)
where $M_j$ is the number of turbines clustered into an equivalent wind turbine $j$. Since a $n$-equivalent line model is considered, capacitance also needs to be calculated. It is assumed that the shunt capacitance of the line connecting the equivalent turbines is the sum of the individual capacitances of number of lines aggregated (the number is the same as the number of turbines aggregated in a cluster).

4.6.5 Adjustment of turbine powers for any wind speed and direction

Determination of the most probable group allows setting up of an equivalent WF model with adjusted parameters. Although this model will be set up once, the initial conditions should be calculated every time wind speed or direction changes.

So for a forecasted wind condition (wind speed and direction) the wake effects are simulated first and then power production of each wind turbine is evaluated through a power curve. During most wind conditions throughout the year, Group A (containing sets of 25, 13 and 11 wind turbines) would represent the WF accurately, as shown through probabilistic analysis in the previous section. Even for wind conditions at particular time of the year when another group (other than Group A) might be more suitable for representing the WF, the WF can still be modelled accurately using the same group, i.e., Group A. In wind conditions when other group will be more suitable the following procedure should be adopted. First, power from all the 49 wind turbines should be calculated after wake effects; Second, these powers should be summed up to calculate the total power that will be transferred to the grid; Third, based on wind turbine cluster ratios, the total power calculated should be divided among the equivalent turbines. This is also explained by an example below.

For example, at a wind speed of 10 m/s and wind direction of $100^\circ$, the best group to represent the WF consists of 8 clusters (see Table 4.2). In these wind conditions, the total power produced by a WF (after considering wake effects) is calculated to be 32.12 MW. Three equivalent turbines in Group A form a ratio of 13:11:25 based on the number of individual turbines each equivalent turbine clusters. In this wind condition, the power output of three equivalent turbines in Group A is calculated based on this ratio 8.52 MW; 7.21 MW; and 16.39 MW,
respectively. A similar procedure should be performed for reactive power output evaluation.

4.6.6 Dynamic response comparison between probabilistic aggregate model and the detailed model

The transient stability behaviour of the probabilistic aggregate model is compared with the detailed WF model at two different wind conditions. This should establish that the probabilistic aggregate model can accurately represent the dynamic response of the wind farm. The two wind conditions simulated are the following:

i) The wind entering the WF at 10 m/s from 100°, this models partial load operation of the turbines;

ii) The wind entering WF at 24 m/s from 0°, this models full load operation of the turbines.

When the wind speed entering the farm is low i.e. 10 m/s, wake effects have a major influence as turbines can receive completely different magnitudes of wind speed and operate at different operating points, producing different amounts of power, whereas at higher wind speeds (usually above rated) they produce similar power and run at nominal operating points. Results for these simulations are illustrated in Figure 4.9 to Figure 4.12. During the time frame of dynamic simulations the incoming wind speed is kept constant.

![Figure 4.9: Active power response for Detailed and Probabilistic model at wind speed = 10 m/s, wind direction = 100°](image)

Figure 4.9: Active power response for Detailed and Probabilistic model at wind speed = 10 m/s, wind direction = 100°
Figure 4.10: Reactive power response for Detailed and Probabilistic model at wind speed = 10 m/s, wind direction = 100°

It can be seen from the figures that in both wind scenarios simulated, 3 equivalent turbines, determined from the proposed method, gives similar results to the detailed 49 turbine WF model. Although the best representation of a WF at 10 m/s and 100° would be by 8 equivalent turbines, Group A has represented the dynamic behaviour of the WF in this case accurately (see Figure 4.9 and Figure 4.10).

It should be noted though that winds at 24 m/s from 0° direction are not very probable, as observed from Figure 3.11 and Figure 3.12, and that in such situations an adequate WF representation would be with a single-unit equivalent turbine [43]. The Group A however, still represented the WF in this case accurately as shown in Figure 4.11 and Figure 4.12.

The comparison proves that the probabilistic aggregate model (Group A) can accurately represent the 49 turbine wind farm with just 3 equivalent turbines under any wind condition. The use of aggregate model will save simulation time while carrying out the transient stability studies. (Peaks in real and reactive power responses observable at 2.2 sec are due to WF reconnection and then the operation of crowbar protection to reconnect the rotor-side converter. The high peak value in reactive power response is due to the small integration time step used and due to the internal simulation software settings.)
4.6.7 Simulation time

A comparison of simulation time required to perform the dynamic simulation of the WF for 10 seconds is given in Table 4.5. The time reduction through the probabilistic aggregate model is compared against the time taken using the full WF model for two wind conditions. It can be seen that the simulation time for dynamic response using the aggregate model was significantly reduced.
compared to the full WF model. For the cases studied, modelling 3 instead of 49 turbines led to a significant reduction in simulation time.

<table>
<thead>
<tr>
<th>Model</th>
<th>Wind Speed (m/s)</th>
<th>Wind Direction (deg)</th>
<th>Simulation Time (s)</th>
<th>Number of wind turbines</th>
</tr>
</thead>
<tbody>
<tr>
<td>Detail</td>
<td>10</td>
<td>100</td>
<td>925</td>
<td>49</td>
</tr>
<tr>
<td></td>
<td>24</td>
<td>0</td>
<td>925</td>
<td>49</td>
</tr>
<tr>
<td>Probabilistic (Aggregate)</td>
<td>10</td>
<td>100</td>
<td>44.9</td>
<td>3</td>
</tr>
<tr>
<td></td>
<td>24</td>
<td>0</td>
<td>34.8</td>
<td>3</td>
</tr>
</tbody>
</table>

In all simulations a constant step size of 0.75 milliseconds was used to make the time comparisons adequate.

Table 4.5 shows that the detail model takes 925 seconds to complete the simulation in Figure 4.9 and Figure 4.10, whereas the probabilistic model takes only 45 seconds. This shows a simulation time reduction of about 95.14%, but the largest reduction in simulation time occurs for the 24 m/s, 0° case i.e. a reduction of 96.23%.

4.6.8 Smaller wind farm test

The probabilistic aggregate model was also tested on a smaller wind farm consisting of only 9 wind turbines arranged in a symmetrical manner shown in Figure 3.14. The same wind speed measurements were used and clustering was performed using the SVC method. It was found that the proposed method is equally applicable to smaller wind farms. The full results of this study can be found in Appendix B.

4.7 Comparison with Existing Aggregate Models

The choice of an aggregation technique depends on the type of study it will be used for. Various existing aggregate models have been critically examined in the literature review in Chapter 1. Generally, the main requirement for a WF aggregate model is that the active and reactive power output at the PCC should be the same as that from the detailed model. Another requirement is that the aggregate model should be able to adequately represent the dynamic behaviour
of a WF in case of a disturbance. Accuracy of aggregation methods is verified by comparing the resulting active and reactive power exchanges and responses with those obtained with a full WF model. Apart from this, an aggregate model should lead to a reduction in simulation time without sacrificing the accuracy of the results. To implement an aggregate model in an online real-time simulator the model should also be easy to setup and use.

An overview of two common aggregation methods, *single-unit equivalent* and *cluster representation*, is provided below, followed by a comparison with the detailed model and probabilistic model proposed in this chapter. The same 49 turbine wind farm used earlier (shown in Section 4.6.1) is used here as a case study.

### 4.7.1 Single-unit equivalent

This method assumes that all wind turbines inside the wind farm receive the same magnitude of wind speed (normally wind speed coming to the WF or an average value), hence they can be replaced by a *single* equivalent wind turbine [43, 185]. Rated apparent power of this equivalent machine is the same as rated apparent power of the wind farm i.e. the sum of rated apparent powers of all individual turbines. At a particular wind speed, the load flow power is the sum of power outputs of individual turbines.

The transformer connecting the equivalent turbine to the grid is also scaled appropriately to allow power transfer of the aggregate generator. The equivalent WF model has all mechanical and electrical components and controllers scaled appropriately (according to parameter scaling in Table 4.4).

#### 4.7.1.1 Case study

In this case, all 49 wind turbines are represented by a single equivalent turbine. Cables with equivalent parameters are used to ensure that losses are similar and that power flowing out of the aggregated WF is the same as in the detailed WF model.

### 4.7.2 Cluster representation

This method considers the wake effect, therefore wind turbines receiving similar wind speeds are clustered into an equivalent turbine. This is based on
the assumption that turbines receiving similar wind speeds operate at the same operating point (see Section 4.2).

Rated terminal voltage of the equivalent turbines should be the same as that of individual turbines. Rated apparent power of an equivalent unit is the sum of rated apparent powers of the turbines that it replaced. The number of equivalent turbines used to represent a WF at a particular time depends on the incoming wind speed, wind direction, WF layout and the level of accuracy required during clustering. The use of a multi-machine equivalent model provides the ability to account for different acceleration of individual turbines in the farm based on their actual operating points.

A drawback of this approach is that it requires modelling a new set of equivalent turbines every time either wind speed or direction changes. Therefore a constant update of the equivalent model is needed which can be cumbersome for the operator, as parameters of the equivalent turbines and equivalent cable circuits will have to be calculated every time the wind direction or speed changes. Also in some cases this aggregation method can result in several equivalent turbines that can lead to longer simulation times and extra effort in setting up the model. When several wind farms are collectively modelled in a power network, the operator will have to re-evaluate and re-setup equivalent turbines for all wind farms whenever wind conditions change.

A coherency matrix stores the number of equivalent turbines needed in each wind speed or wind direction. The size of this matrix is calculated using the following expression [37]:

$$S_{coh\_mat} = n_{WDi} \cdot n_{WTs} \cdot n_{WSi}$$  \hspace{1cm} (4.12)

where $n_{WDi}$ is the number of wind directions, $n_{WTs}$ is the number of turbines inside a wind farm, $n_{WSi}$ is the number of wind speeds. The number of wind directions and speeds are dictated by a step size.

4.7.2.1 Case study

This approach will require the creation of a $360 \times 49 \times 22 = 388,080$ entry matrix from which relevant clustered information will have to be used every time wind speed and wind direction changes. This will require a new set of equivalent turbines to be selected from $7920 \ (22 \times 360)$ possible combinations.
In this case study the clustering algorithm is used with an accuracy of 0.1 m/s at 1° direction intervals to identify turbines receiving similar wind speeds.

### 4.7.3 Results of comparison of different aggregate models

Time domain simulations are performed comparing active and reactive power behaviour of different aggregate models. The test is performed under two wind conditions and performance of each aggregation method is summarised in Table 4.6 and Table 4.7. In the first scenario, partial load operation is considered for wind entering the wind farm from 349° at 12 m/s. In the second scenario, full load operation is considered simulating wind from 0° at 24 m/s.

<table>
<thead>
<tr>
<th>Model</th>
<th>Simulation Time (s)</th>
<th>Time Reduction</th>
<th>No. of wind turbines</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Detailed</strong></td>
<td>925</td>
<td>-</td>
<td>49</td>
</tr>
<tr>
<td><strong>Single-Unit Equivalent</strong></td>
<td>15.2</td>
<td>98.4%</td>
<td>1</td>
</tr>
<tr>
<td><strong>Cluster Representation</strong></td>
<td>58.5</td>
<td>93.7%</td>
<td>5</td>
</tr>
<tr>
<td><strong>Probabilistic Clustering</strong></td>
<td>34.2</td>
<td>96.3%</td>
<td>3</td>
</tr>
</tbody>
</table>

Table 4.7: WF modelling with incoming wind speed = 24 m/s, wind direction = 0°. Using constant step size of 0.75 ms

<table>
<thead>
<tr>
<th>Model</th>
<th>Simulation Time (s)</th>
<th>Time Reduction</th>
<th>No. of wind turbines</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Detailed</strong></td>
<td>925</td>
<td>-</td>
<td>49</td>
</tr>
<tr>
<td><strong>Single-Unit Equivalent</strong></td>
<td>18.9</td>
<td>97.9%</td>
<td>1</td>
</tr>
<tr>
<td><strong>Cluster Representation</strong></td>
<td>18.9</td>
<td>97.9%</td>
<td>1</td>
</tr>
<tr>
<td><strong>Probabilistic Clustering</strong></td>
<td>34.8</td>
<td>96.2%</td>
<td>3</td>
</tr>
</tbody>
</table>

At 12 m/s, the effect of the wake is strong therefore turbines receive different wind speeds, thus the cluster representation approach leads to wind farm representation by 5 equivalent units. At higher wind speeds (usually above
rated) however, turbines reach rated wind speeds which makes their operating points similar. For this reason, *cluster representation* and *single-unit equivalent*, both model the WF by a single turbine at 24 m/s. The proposed probabilistic clustering however, uses 3 equivalent turbines (most probable Group A from Table 4.3) in all wind conditions.

In both wind scenarios, the *single-unit equivalent* results in shortest simulation time as is observable from Table 4.6 and Table 4.7. At a lower wind speed, the *cluster representation* approach takes longer than the probabilistic approach. At higher wind speeds, both *cluster representation* and *single-unit equivalent* lead to similar results. For probabilistic clustering, the simulation time in the second case (24 m/s) is longer compared to the other methods.

The simulations were carried out on a PC with Intel Core 2 Quad CPU Q9400 at 2.66 Ghz and 3.25 GB of RAM. The DIgSILENT PowerFactory version 14.0.513 was being used.

It can be seen from Table 4.6 and Table 4.7 that the proposed method always represents the wind farm by a static number of equivalent turbines (3 in this case) in all wind conditions, whereas *cluster representation* requires a change in number of equivalent turbines if either wind speed or direction changes.

### 4.7.3.1 Dynamic response analysis

Results of transient simulations for two wind scenarios discussed above are illustrated in Figure 4.13 to Figure 4.16. The wind farm regains stability after fault clearance in both scenarios considered. (Peaks in real and reactive power responses observable at 2.2 sec are due to WF reconnection and then the operation of crowbar protection to reconnect the rotor-side converter.)

It can be seen that for below rated wind speed (12 m/s), the *single-unit equivalent* over-estimates the power produced (since wake effects are ignored) thus power response is offset as compared to the detailed model. The probability of representing a wind farm by a single equivalent turbine is very low as can be seen from Figure 4.4. Therefore, the use of this model for all wind conditions may not be suitable. Probabilistic clustering and *cluster representation* on the other hand accurately capture the WF responses. At higher wind speed (24 m/s) when turbines operate at rated power, all aggregation methods model the response of the WF with sufficient accuracy.
Chapter 4: Probabilistic Aggregate Dynamic Model of a Wind Farm

Figure 4.13: Active power response for all three aggregation methods and detailed model at wind speed = 12 m/s, wind direction = 349°.

Figure 4.14: Reactive power response for all three aggregation methods and detailed model at wind speed = 12 m/s, wind direction = 349°.

Although single-unit model requires setting up only one equivalent turbine, the accuracy of dynamic responses may be compromised. The number of equivalent turbines in a cluster representation varies with the wind condition.
In some cases it can lead to several equivalent turbines that can increase both the simulation time and effort required for model implementation.

Figure 4.15: Active power response for all three aggregation methods and detailed model at wind speed = 24 m/s, wind direction = 0°

Figure 4.16: Reactive power response for all three aggregation methods and detailed model at wind speed = 24 m/s, wind direction = 0°

Probabilistic clustering on the other hand requires initial offline analysis but leads to a fixed set of equivalent turbines. Once setup it can easily be used by
simply adjusting the load flow parameters when wind conditions change. The proposed method provides results with a good level of accuracy and leads to significant reduction in simulation time. The proposed method is easier to use under any wind condition. These features make it suitable for on-line (real time) studies.

4.8 Summary

Aggregate WF models are required to reduce both complexity of the WF network and the simulation time. This chapter presented a probabilistic clustering method which can be applied to a WF of any size and layout consisting of variable speed DFIG machines. It allows determination of a static number of equivalent wind turbines and their corresponding rated powers that will most accurately represent the WF during the year. It led to development of probabilistic aggregate model of the WF.

Accuracy and reduction in simulation time of different aggregation methods has been compared through dynamic response analysis. Performance of detailed model of the WF was compared against two popular aggregation methods, single-unit equivalent and cluster representation, as well as against proposed probabilistic aggregate model. Comparison was made using a large 49 turbine wind farm connected to the grid through a collector transformer and two transmission lines. A 3-phase fault was applied to one of the lines and cleared after 200 ms.

The proposed probabilistic aggregation technique requires initial off-line analysis of wind data to determine the most probable equivalent model of the WF but subsequently leads to a simple aggregate model and shorter simulation times. In the case studied, simulation time was reduced by 96%. It has been demonstrated through dynamic simulations that the most probable group (Group A) determined using the proposed technique can represent the WF for any wind condition during the year, although it works best if the most probable wind speeds and directions are used. To prove this point, two distinct cases were tested that cover probable and least probable wind scenarios, but the technique can be further validated by testing it at all wind speeds (within wind turbine operating range) and wind directions (0° to 360°).

The method takes into account wind farm layout, wake effects and location yet does not require, as in previously proposed methods, changes in an
equivalent model every time the wind speed or direction changes. This makes the method very practical and easy to use. In previous method that considered wake effect a different set of equivalent turbines had to be used if wind conditions changed. The proposed technique leads to a static number of equivalent turbines for any wind condition saving operator time and effort readjusting the equivalent model. The probabilistic aggregate model also provides much more accurate results than the single-unit equivalent model (commonly applied to model WFs) at low wind speeds.

It has been demonstrated that the model is very useful for on-line and offline studies as it can significantly reduce simulation time in modelling power networks with large-scale penetration of wind power generation.
Chapter 5

Probabilistic Assessment of Wind Farm Energy Yield

5.1 Introduction

Energy output is the main factor that contributes towards the feasibility of a wind project. Its evaluation is essential for profit estimation and such analyses are usually part of the pre-feasibility study for any wind farm (WF). Energy output can vary due to several factors including site location and the WF layout. Other factors such as availability of the wind resource at the site, terrain characteristics of the site, wake losses in the WF, wind turbine and cable availability in a WF collector system and electrical power losses occurring inside the WF are also some of the influential factors that affect the energy yield. Therefore, a reasonably realistic estimate of the energy output can be only obtained once all important factors have been taken into account. This chapter provides detailed methodologies to calculate the influence of these factors on the energy output. A novel method to account for losses due to unavailability of wind turbines and cables within a WF for four collector systems is also proposed in this chapter.

The aim is to provide a complete methodology to perform energy yield study for a new wind farm. A complete methodology should not only take into account all influential factors that affect the energy output from a wind farm but also the energy delivered to the grid. Transmission of energy to the grid is an important consideration because the profits from a wind farm depend on the energy sold. Therefore, prior to building the wind farm the owner of the wind farm should have a complete picture of how much energy will be produced and how much of this energy can be sold to the grid. In case a wind farm is planned
to be built in an area with transmission bottlenecks it is likely that some of its energy will be curtailed. For this reason, a new method to estimate the wind energy curtailments is proposed. This method allows energy curtailment evaluation in various possible scenarios, through use of correlation coefficients between the wind power produced and the transmission line loading.

The impact of wind resource variation on the energy output and the energy curtailed is also investigated. Furthermore, a sensitivity analysis is performed to quantify the effect of different parameters on the energy yield.

5.2 Power Transmission Limitations

Wind farms are usually installed in open areas where wind speeds are high and less disturbed. Such areas are often not very close to the load centres or transmission lines [186]. An ideal location (a relatively windy site) for a WF in terms of wind speeds may be a remote area, but the network in that area might not be too strong. The wind power that can be transmitted to the grid may be limited due to the capacity of the transmission lines.

Therefore, along with a good estimation of energy yield (considering all influencing factors) it is also beneficial to determine the amount of energy that can be transferred into the network. A complete study can enable a WF owner to know the amount of energy that will be produced and the amount that will be transferred into the grid.

Several factors can limit the power transmission in a network. The following sections explore these factors briefly and provide potential measures to overcome this bottleneck.

5.2.1 Bus Voltage limit

Voltage stability indicates the ability of a power system to maintain steady voltages at all buses in the system under normal conditions and after being subjected to a disturbance. Voltage instability commonly occurs due to voltage drop but it has an equal chance of occurring due to over-voltages. Voltage drop instability happens when reactive power demand increases beyond reactive power support the system can provide, leading to loss of regional load. Over-voltage instability is related to the capacitive behaviour of the network as well as inability of synchronous compensators and generators to absorb the excess
reactive power [187]. Typically, power system networks all over the world define a range of acceptable voltages at the buses.

5.2.2 Thermal limit

Current flowing through a conductor can increase its temperature due to $I^2R$ load losses caused by resistance of the conductor. To prevent a transmission line from sagging and losing tensile strength, thermal power flow limits are imposed. Generally, transmission components age with time and temperature. To prevent putting at risk the integrity of the physical components and to ensure a reliable operation, it is essential to identify safe thermal operating limits for the network components. This is often performed based on regional climate.

Meteorological factors such as solar radiation, speed of the wind and ambient temperature affects the temperature of an overhead line [188]. The temperature of the line conductor can be calculated using (5.1) and (5.2), more details can be found in [189].

\[
\text{Heat Gain} = \text{Heat Loss}
\]

\[
P_J + P_M + P_S + (k_i P_i) = P_{\text{con}} + P_R + P_W
\]

where $P_J$ is heat gain due to Joule heating, $P_M$ is heat gain due to ferromagnetic heating, $P_S$ is heat gain due to the solar heating, $P_i$ heat gain due to ionization heating, $(P_J, P_M, P_S$ and $P_i$ are given in per unit length per unit time,) factor $k_i$ takes into account thermal diffusion, $P_{\text{con}}$ is heat loss by convection, $P_R$ is heat loss by radiation and $P_W$ is heat loss by evaporation respectively.

5.2.3 Methods to overcome power transmission bottlenecks

Thermal limit constraints can be relaxed by optimising the distribution of power flow to minimise the current at critical branches, or by increasing the current handling capacity of the lines, breakers and transformers. A few possible solutions to remove thermal limit concerns are discussed below [190]:

- Replace substation equipment to handle more current.
- Introduce dynamic line rating; it works by determining the dynamic current carrying capacity of the lines through real-time monitoring of line tension, sag, temperature and current flow. The network operator can decide on the line loading based on the online temperature readings.
Re-tension and re-conductor the existing lines [191] e.g. replace a conductor rated at 500 A at 75 degrees with a thicker conductor to allow higher current flow or with a high temperature low sag conductor to double the original line rating (1000 A at 200 degrees).

- Control the power flow through Flexible Alternating Current Transmission System (FACTS) devices, Phase Angle Regulars (PARs), capacitors and Static Var Compensators.
- Use phase shifting transformers.
- Re-calculate thermal line ratings using more realistic weather conditions (measurements made on the site).

Voltage stability limit problems can be solved with the use of shunt reactors and tap-changing transformers. If power generated by a WF has to be transmitted far away then series capacitors can be installed to maintain the voltages at the line terminals.

Building an overhead transmission line can solve power flow problems, however, it is getting increasingly difficult to obtain planning permissions to build new lines as they affect the landscape and lead to public and political resistance [192]. Apart from this, new lines are very expensive to build especially when new towers have to be put in place. Generally, installation of a new line is accompanied with modifications to the substation components such as switchgears and reactors. All of these factors can offset the cost of the project [191]. In the UK, a WF developer has to bear the cost for building a new infrastructure needed for WF installation [20]. Estimated cost (per mile) to build a new overhead line [193] is illustrated in Table C.1 in Appendix C. It can be seen from Table C.1 that the cost per mile of a new transmission line can be as high as €1.15 Million (£1 Million).

One possible way to relax power transfer limitation is to convert high voltage AC (HVAC) lines to high voltage DC (HVDC) lines as this allows increase in power transmission rating and reduces transmission losses. The costs of HVDC converter stations are however very high and they significantly increase the cost of the overall HVDC transmission link.

Another possible option is to curtail (prevent injection into the line) excess power from the WF at times when loading of the line is high and wind power generation is also high. Depending on the capacity and flexibility of the generators present the utilities may prefer to keep supply from more reliable
generators which might lead to temporary wind power curtailments. When curtailments are needed system operators request wind generators to reduce their power output (by pitching the blades out of wind or by completely shutting down the turbines). This practise is common in countries such as the UK, parts of USA [194] and Spain. It prevents making changes to the transmission network, but on the other hand, WF owner might lose money for not selling the available energy to the grid. If potential energy loss due to possible future curtailments can be estimated by the WF owner in advance then a correct economic decision could be made.

All measures discussed above will increase costs either to the utility or to the WF owner (depending on the country policy), therefore, wind power curtailment might be a cheaper option. The following sections present a methodology to estimate as accurately as possible the energy yield from a WF considering all important factors and energy curtailments.

5.3 Estimation of Wind Energy Yield

This section provides complete methodology for estimation of wind farm energy yield. The impact of various factors including wake effects, electrical losses, availability of wind farm components and variation in wind resource is tested on the overall energy yield output.

A wind farm installed at two different locations (onshore and offshore), with wind turbines of different heights and at different distances from each other is simulated to determine the wake induced power losses in different scenarios. A new methodology to study the impact of wind farm component availability on annual energy production is developed. The impact of annual variation in wind speed (at a site) on annual energy output is also tested considering internal wind farm losses.

As a case study a hypothetical wind farm is assumed to be installed at an area with a transmission bottleneck. A new methodology developed to estimate the curtailment losses from a wind farm. The method is based on an existing technique proposed in [96]. The factors that affect the energy yield of a wind farm were, however, largely ignored there. In the method proposed here, the effect of wake losses, electrical losses, impact of component availability, impact of variation in wind resource at a site and correlation coefficients between wind speed, turbine availability and transmission line loading are all included.
Therefore, the new methodology provides a more realistic solution as all influential factors are now considered.

5.3.1 Wind potential availability

In order to evaluate wind potential at a site, the wind speed is measured for at least one year. Wind turbine generates power only if the incoming wind speed is between its operating range, i.e. between the cut-in and the cut-out wind speed. For a general estimate of the energy yield a Weibull distribution is sufficient, but for pre-feasibility studies of the wind farms the wind measurement data is usually essential. In this study, the power output from a wind turbine is calculated by tracing the wind speed on the power curve.

Using the recorded wind data a wind speed distribution can be obtained. Once wind speed distribution is known, the wind power production distribution function (WPPDF) can be calculated.

For simplicity, let $Y$ be the expected wind power production in MW. Using wind speed distribution function, the power production state $Y$ of the planned WF can be obtained multiplying (2.5) with number of wind turbines $K$ in a WF.

Then discrete probability mass function and distribution functions of $Y$ can be calculated as follows [96]:

$$f_Y(y) = P(Y = y) = \frac{h_Y(y)}{N}$$

$$F_Y(y) = P(Y \leq y) = \sum_{i:y_i \leq y} f_Y(y_i)$$

where $P(Y = y)$ is the probability that wind power production $Y$ is equal to $y$ (MW), $h_Y(y)$ is frequency of $y$, $N$ is number of wind speed measurements.

Finally, energy yield of a WF can be calculated as:

$$E = \sum_{y=0}^{y_{max}} F_Y(y) \cdot \Delta y$$

where $\Delta y$ is a step at which WPPDF $F_Y(y)$ is discretised. This method to obtain an initial estimate of energy yield was used in [63] and [64]. Wake losses and electrical losses inside a WF are then subtracted using very general loss estimates. Those losses however are case specific and in reality can vary significantly with size and layout of the WF.
5.3.2 Wind farm layout

A small 9 turbine WF consisting of 2 MW Vestas V80 wind turbines is used for the analysis (see Figure 3.14). Each wind turbine has a built-in 0.69/33 kV transformer in the nacelle that steps up the voltage level from the generator voltage to 33 kV. This voltage level is used inside the collector system connecting the turbines. Based on the available data from existing WFs of similar size [21, 26] as the one studied here it is assumed that the studied WF does not have an offshore transformer. The WF is assumed to be 8 km away from the shore and is connected with the grid through AC XLPE cables. Four different electrical layouts presented in Section 1.2.2.4 are studied for losses. One year of wind measurement data measured at the height of 35 meters (given in Section 3.8) are scaled up to the turbine height using (3.6).

5.3.3 Wake effects

Detailed models are used for wake effect calculation considering single, partial and multiple shadowing of wind turbines as discussed in Section 3.3. Applying wake models to the up scaled wind measurements, wind speed at each turbine within a WF is estimated for the given WF layout. Since wake effect depends on both, the speed and direction of the incoming wind, the power production from each wind turbine is calculated after modelling wakes for every incoming wind speed and wind direction. Total energy yield of the WF is then estimated by summing the individual wind turbine power production for the whole year.

There are many site specific factors which influence the wake effects and hence the energy yield. These include wind characteristics at a site, size and layout of the WF, height of the wind turbines, distance between the turbines, terrain of the site, radius of the wind turbine rotor, thrust coefficient curve and power curve of the wind turbine. Impact of some of these factors on the energy yield are briefly discussed below. Wake effects are simulated for a wind farm in two terrain conditions i.e. onshore and offshore, with standard terrain roughness lengths of 0.0002 m and 0.1 m respectively (see Table 3.1).

Highest wake losses are observed to occur for wind speeds between 6 and 10 m/s when the thrust coefficient C\textsubscript{t} is relatively high.
5.3.4 Electrical power losses

Energy yield from a WF is further reduced due to electrical losses in the collector system. These losses vary with the type of the collector system, cable and transformers parameters. Four typical collector systems namely radial, starburst, single-sided ring and central are analysed for electrical losses. These collector systems are discussed in Section 1.2.2.4 in detail. In a radial collector system shown in Figure 5.1, the electrical power loss in a string can be found as:

\[ P_{\text{loss}}^{\text{string}} = 3 \left[ R_n I_n^2 + R_{n-1} (I_n + I_{n-1})^2 + \ldots + R_1 (I_n + I_{n-1} + \ldots + I_1)^2 \right] \tag{5.5} \]

where \( R \) is line resistance, \( I \) is the current flowing in the lines. Once power loss from each string is evaluated, the total power loss in the WF can be calculated as the sum of power loss in \( m \) strings along with power loss in the main cable carrying current from all \( m \) strings to the shore.

\[ P_{\text{loss}}^{\text{cable\_to\_shore}} = 3 \left[ R_T \left( \sum_{i=1}^{m} I_i \right)^2 \right] \tag{5.6} \]

\[ P_{\text{loss}}^{\text{total}} = \sum_{i=1}^{m} P_{\text{loss}}^{\text{string}} + P_{\text{loss}}^{\text{cable\_to\_shore}} \tag{5.7} \]

In central collector system configuration, Figure 5.2, power losses can be calculated as in radial configuration with only two strings using (5.5), (5.6) and (5.7). Current from two strings is collected at one central wind turbine from where it is passed on to the shore through a main cable.

In single-sided ring system shown in Figure 5.3, the power loss is computed for each string in a similar way to that of the radial configuration (5.5), however in this case each string is carrying power directly to the shore. Total losses are equal to the sum of losses in the individual strings. Each string is equipped with a redundant cable (shown in grey colour) capable of transferring power in case of a fault in the main cable or in any cable within the string. Increased security comes however at extra cost for redundant lines.

The power loss calculation for the starburst collector system shown in Figure 5.4 is slightly different. There are different ways to set-up a starburst network as discussed in [24] and [26]. The configuration analysed here is based on [24], where the total power loss is calculated using (5.8) to (5.11) for \( m \) clusters.
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\[ P_{\text{loss}}^{\text{total star}} = 3 \left[ R_1 I_1^2 + R_2 I_2^2 + \ldots + R_7 I_7^2 \right] + P_8 + P_9 \]  \hspace{1cm} (5.8)

\[ P_8 = 3 \left[ (I_8 + I_7 + I_6 + \ldots + I_1)^2 \right] R_8 \]  \hspace{1cm} (5.9)

\[ P_9 = 3 \left[ (I_9 + I_8 + I_7 + \ldots + I_1)^2 \right] R_9 \]  \hspace{1cm} (5.10)

\[ P_{\text{loss}}^{\text{total}} = \sum_{i=1}^{m} P_{\text{loss}}^{\text{total star}} \]  \hspace{1cm} (5.11)
In general, losses inside the transformers are divided into two types, no-load losses and load losses. No-losses arise due to energisation of the core of the transformer and remain unaffected by the loading of the transformer. Load losses vary depending on the amount of power transferred through the windings (copper losses). Load losses are simply \( P_R \) losses and can increase as the amount of current increases through the winding coils. Therefore if current and resistance of the winding coils are known they can be easily computed. No-load losses on the other hand remain constant; and are generally a small percentage of the MVA of a transformer.

5.3.5 Wind farm losses due to reliability considerations

With development of wind turbine technology and increase of WF size, reliability is becoming more important as it influences the energy delivered. Analysis of reliability indices of different wind turbine components based on cumulative statistics is given in [195]. Reference [196] provides a more detailed analysis from a group of 3 adjacent WFs. It is shown that there is significant variability in occurrence and duration of tripping of WTs depending on their location within a WF. In [197] reliability indices of a WF are calculated based on component failure rates, repair times and duration of switching operation. However wind speed duration curve is approximated by several characteristic regions weighted by corresponding probability of occurrence. Single component failures and some multi-component failures (only those with highest probabilities) are simulated.

In this chapter, single and all multi-component failures are considered. Wind speed duration curve is discretised to integer values and all wind speeds within wind turbine operating range are taken into account.

5.3.5.1 Wind farm availability distribution function

5.3.5.1.1 Wind farm configurations (without redundancy)

A step-by-step procedure is developed for calculation of WF availability using combinatorial algorithms. These steps are described below:

Step 1: Obtain failure rates and repair rates of involved components (wind turbines, transformers, cables);
Step 2: Calculate overall availability of wind turbines excluding cabling within a WF;

Step 3: Use combinatorial algorithms to account for dependency of overall wind turbine availability on cable availability;

Step 4: Calculate Availability Density Function (ADF) of the WF.

In Step 1, failure rates and repair times of the involved components are included. The availability of each WF component is then calculated as:

\[
p = \frac{1}{\lambda} = \frac{1 - \lambda r}{1 - \lambda^2 r^2} = (\lambda^2 r^2 << 1) \approx 1 - \lambda r \tag{5.12}
\]

where \( \lambda \) is failure rate (failures/year) and \( r \) is repair time, (h/failure). Unavailability of each component is calculated as \( q = 1 - p \). Cable failure rate is usually given per unit length, thus knowing the length of the cable, \( l \), the availability of the cable is calculated as:

\[
p_c = (1 - \lambda_c r_c)^l \tag{5.13}
\]

where \( \lambda_c \) is the failure rate of the cable and \( r_c \) is the repair rate of the cable. The impact of cabling within a WF is initially excluded from calculations in this step. Given that wind speed is within turbine’s operation range i.e. \( v_{\text{cut-in}} \leq v \leq v_{\text{cut-out}} \), the wind turbine is considered overall available if it is producing power and if that power can be transferred to the point of common coupling (PCC).

In Step 2, overall availability of the wind turbine \( p_{\text{wt}} \) is thus calculated as:

\[
p_{\text{wt}} = p_{\text{wt}} \cdot p_{\text{mc}} \cdot p_{\text{tr}} \tag{5.14}
\]

where \( p_{\text{wt}} \), \( p_{\text{mc}} \) and \( p_{\text{tr}} \) are availabilities of wind turbine, main cable (from last turbine to MV bus) and transformer of the respective wind turbine.

In Step 3, WF collector system configuration is taken into account. For configurations shown in Figure 5.1 to Figure 5.3, failure of some cables will only affect the availability of the associated wind turbine, whereas failure of others can take the whole row of wind turbines out of operation.

Figure 5.5: One row of wind turbines and cables within a WF
Calculation of WF availability for radial, single-sided ring and central configurations are discussed below. Consider just one row of the wind turbines first, as shown in Figure 5.5. For $l_c$ components in a row, all possible combinations of component statuses, $c_s$, are generated using a combinatorial algorithm [198]. The component status is assumed to be 1 if in operation and 0 otherwise. Thus $2^{l_c} \times l_c$ matrix is obtained. Each row of the matrix contains a unique combination of component statuses. For each combination the number of overall available wind turbines is calculated:

$$N_{cs} = C_1(T_1 + C_2(T_2 + \ldots + C_{K_r}T_{K_r}) \ldots)$$

where $C_i$ is a status of cable $i$, $T_i$ is status of wind turbine and its transformer, $K_r$ is the number of wind turbines in a row. If instead of component statuses $T_i$ and $C_i$, respective component availabilities $p'_{WT}$ and $p_c$ (if status=1) or unavailabilities $q'_{WT}$ and $q_c$ (if status=0) are substituted in the matrix and then (5.15) is applied, the result is probability of certain combination of component statuses, $p_{cs}$. Summing probabilities of combinations $c_s$ that yield the same number of available wind turbines (i.e. equal values of $N_{cs}$) overall availability of WTs in a row is obtained, Availability Density Function of a row is then:

$$P_{row}(k) = \sum_{\forall c_s: N_{cs} = k} p_{c_s}, \quad \forall k \in [0, K_r]$$

where $P_{row}(k)$ is probability that in one row $k$ wind turbines are available and able to deliver power to the PCC.

In Step 4, availability density of the entire WF is calculated. Assuming WF consists of $m$ rows of wind turbines. In each row 0 to $K_r$ wind turbines can be available. Let $k \in (0, K_r)$ denote the row status. Using combinatorial algorithm $(K_r+1)^m \times m$ matrix is generated. Each row of the matrix contains a unique combination of WF row statuses. If each element of the matrix is substituted with respective probability, $P_{row}(k)$, then product of the elements in each row of the matrix will yield probability of the combination. Summing probabilities of combinations yielding same number of available wind turbines in the WF, similarly to (5.16), ADF of the entire WF can be obtained.

For starburst WF configuration, the availability of the interconnecting cable, $c$, within a WF will only affect the overall availability of the associated wind turbine:
For $K$ identical wind turbines within a WF each of which may fail, there are $K + 1$ wind turbine availability statuses. The probability of each status depends on total number of wind turbines and overall availability of a single turbine. Availability density of the *starburst* configured WF system [199]:

$$p_{WF}(k) = \frac{K!}{[k!(K-k)!]} \cdot p_w^{k} \cdot (1-p_w)^{K-k}$$

(5.18)

where $p_{WT}'$ is the overall wind turbine availability, calculated by (5.17).

### 5.3.5.2 Wind power production distribution

All the above factors, i.e., wake effect, electrical losses and WF availability should be accounted for in the WPPDF, in order to calculate realistic WF energy yield. Because of wake effects, power production of each wind turbine depends on its location within a WF, wind speed and wind direction. Thus to calculate WF power production state, wake effect model presented above should be used, rather than just (2.5) multiplied by number of wind turbines in a WF over a year. Respective electrical losses based on collector system should be subtracted and then discrete probability density and distribution functions of WF power production calculated from (5.3). Each power production state then accounts for wake and electrical losses, and probability of each state depends on probability of the corresponding wind speed and wind direction.

Next factor to account for is the availability of wind turbines, associated transformers and cables. However, location of unavailable wind turbines will affect the wake that neighbouring turbines are experiencing. This leads to a very high number of availability states that need to be taken into account. In order to resolve the trade-off between dimensionality and accuracy a simplification is introduced. Power production of each wind turbine within a WF is calculated for each wind speed and direction considering the wake effects and electrical losses. Sum of individual wind turbine productions is then divided by a number of wind turbines in a WF, yielding equivalent power curve of wind turbine, $S_{WT,eq}(v)$. The individual impact of wake and electrical losses at turbine level is thus effectively averaged amongst all wind turbines in a WF.
Change in wake effect and electrical losses due to wind turbines being out of service are neglected. Location of unavailable wind turbines in this way becomes irrelevant.

All possible WF power production states can now be obtained multiplying $S_{WT_{eq}}(v)$ by number of available wind turbines $k_n$, $\forall k_n \in \{0, K\}$, where $K$ is a total number of wind turbines in a WF. Note that WF power production states do not uniquely correspond to certain wind speed as the same power production states can occur at several $(k_n, v)$ combinations, where $v$ is the wind speed.

### 5.3.5.3 Correlation between wind speed and wind turbine availability

To account for overall wind turbine availability in WPPDF an assumption should be made about correlation between wind speed and wind turbine failure. If there is a strong negative correlation between wind speed and overall wind turbine availability then more energy is lost. So far, there have been no publicly available reports addressing this problem. Data from [200] from 3 adjacent onshore WFs were used to analyze correlation between failures of wind turbines and wind speed within operating range of wind turbine. For each wind turbine in the WFs the time series of wind speed measurements and simultaneous time series of wind turbine statuses (1 if in operation, 0 otherwise) were used to obtain correlation coefficients between wind turbine status and wind speed. For the studied WFs the correlation between wind turbine failures and wind speed conditions proved to be very weak (close to 0).

It is difficult to draw general conclusions based on just one study, in particular as WFs in [200] were onshore. It is possible though that offshore weather conditions have more impact on the availability of wind turbines. Thus, the method for evaluation of all extreme correlation combinations between wind speed and overall wind turbine availability, i.e., 1, 0, -1, is presented in this chapter.

If correlation between wind speed and wind turbine availability is 1, meaning wind turbines are in operation when wind speed is high, Wind Production Duration Curve (WPDC) is constructed from wind power production distribution function calculated in Section 5.3.5.2. The WPDC already includes the effect of wake and electrical losses. Availability density calculated as in Section 5.3.5.1 is then multiplied by number of hours in studied period $T$ and
sorted in the descending order by the number of available wind turbines yielding availability duration curve (ADC). New Wind Production Duration Curve (WPDC') including the impact of wind turbine availability is then obtained as follows:

\[
WPDC'(t) = \frac{WPDC(t)}{K} \cdot ADC(t)
\]  

(5.19)

where \( t \) is a discretisation step of the duration curves, (e.g. 1 hour) and \( K \) is total number of wind turbines in a WF.

Similar calculations are performed if correlation is -1 between wind speed conditions and overall wind turbine availability, i.e., fewer wind turbines are available when the wind speed is high. Discrete Availability Distribution is then sorted in the ascending order by the number of available wind turbines to obtain discrete Unavailability Distribution Curve (UDC). The UDC is then substituted in (5.19), instead of ADC.

For both cases, i.e., correlation 1 and -1, the WF production discrete probability distribution function (WPPDF) \( F_Y(y) \), with wind turbine availability included, is obtained as inverted \( WPDC' \) divided by period \( T \).

If correlation between wind turbine failures and wind speed is 0, WF production discrete probability distribution function \( F_Y(y) \) can be obtained by combining WF discrete Availability Distribution Function and discrete Distribution Function of WF power production states from Section 5.3.5.1 (see [201] for details).

### 5.3.5.4 Losses due to unavailability of WF components

According to statistics in [202], [203] availability of the wind turbine varies approximately between 95% and 100% on yearly basis depending on the weather conditions, age of wind turbine, etc. Results from [200] however show that wind turbine availability can diverge significantly from these values depending on wind turbine location within a WF. Comparing \( F_Y(y) \) calculated with different correlation assumptions, (Section 5.3.5.3), with \( F_Y(y) \) where reliability is disregarded (Section 5.3.1) the range of losses due to unavailability of WF components is obtained:
where $\Delta y$ is a step at which Wind Production Probability Distribution Function $F_Y(y)$ is discretised

### 5.3.6 Losses due to wind energy curtailment

If total power produced by a WF cannot be injected into the system, i.e., if there is congestion; additional losses might be introduced in form of wind energy curtailments. Alternatively, transmission system may need reinforcement.

Under deregulated market conditions it is not always clear how the investment costs should be divided between the network operators and the production utilities. Different countries use different approaches (Deep, Shallowish, Shallow) [13] when determining network connection costs. An optimal balance therefore, should be found between extra benefits arising from increased transmission capacity and costs of respective network reinforcements. Findings in [96] confirmed that in some cases it is more economical to curtail some wind energy during transmission congestion situations than to build a new transmission line. This alternative is currently used, e.g. in Spain where significant number of WFs located between Galicia and Madrid produce power below their full capacity since the necessary reinforcements of the transmission grid have not been realized yet [204].

Wind energy curtailment at each hour depends on wind speed, wake losses, electrical losses, availability of wind turbines and already committed transmission over the line, i.e., Transmission Line Loading (TLL). In order to estimate potential wind energy curtailments accurately, realistic assumption needs to be made regarding correlation between wind speed and wind turbine availability and between TLL and WF power production. In this study, it is assumed that there is a single transmission corridor between the load centre and the WF connection point and that curtailment is a cheaper option as WF capacity is not significantly large. This method is particularly useful when less information about the network is available i.e. only Transmission Duration Curve (TDC) and Line Capacity (C) are known.
5.3.6.1 Correlation between wind power production and transmission line loading

Only two extreme cases of correlation will be addressed here in order to bound the area of uncertainty. In case of correlation equal to 1, wind energy losses due to curtailments are obtained using new Wind Production Duration Curve (WPDC') and Transmission Duration Curve (TDC), see area (highlighted) between WPDC' + TDC and C in Figure 5.6 for the amount of curtailment.

![Figure 5.6](image)

Figure 5.6: Dashed line (C) denotes the transmission limit over the line. The area (highlighted) between (WPDC’+TDC) and C corresponds to energy curtailed. Correlation between wind speed and wind turbine availability is 1.

The figure shows TDC before wind farm is installed in the area, and WPDC’ + TDC after the wind farm has been installed. The highlighted area shows that the peak power will exceed the Transmission Limit (C) for almost 1000 hours in a year. WPDC’ is calculated including electrical losses, wake losses, and losses due to overall wind turbine unavailability, assuming different correlation coefficients between wind speed and overall wind turbine availability as described in Section 5.3.5.2. The curtailment losses are:

\[
L_{\text{curtail}} = \frac{\sum_{t=0}^{t=T} \text{WPDC}'(t) \cdot \Delta t + \text{TDC}(t) \cdot \Delta t - C}{\sum_{t=0}^{t=T} \text{WPDC}'(t) \cdot \Delta t}
\]  

(5.21)
where $C$ is transmission limit, $T_C$ is a number of hours with transmission congestion, $\Delta t$ is a time step, $T$ is time period. If correlation between wind power production and transmission over the line is -1, i.e. wind power production is the highest when TLL is minimal, TDC should be sorted in the ascending order. Curtailment losses are then calculated by (5.21) as before.

5.3.6.2 No correlation between wind power production and transmission line loading

If there is no correlation between wind power production and TLL, then discrete probabilistic estimation method for wind energy curtailments should be used [96]. Let $X$ be the amount of power in MW transmitted through the bottleneck before wind power is installed. The distribution function for transmitted power and corresponding discrete probability density function are calculated, by analogy to (5.3). Discrete distribution function and probability density function for wind power production states $Y$ are calculated as described in Section 5.3.5.2.

The desired transmission after installation of wind power in the area (with transmission limitations) can be represented through a discrete variable $Z$. $Z$ can be expressed as $Z = X + Y$. Its discrete probability mass function $f_Z(z)$ and the new probability distribution function $F_Z(z)$ can be expressed as below [96]:

$$
f_Z(z) = \sum_x f_X(x) f_Y(z-x)$$

$$
F_Z(z) = \sum_{z_i \leq z} f_Z(z_i)
$$

5.4 Case Study

Failure rate of the main cable and cabling within the WF is assumed 0.1 failure/year/100 km [46, 95]. Repair rates for main cable (might take up to 3 months for repair) and cabling within WF are assumed 2160 h/failure [23] and 5 h/failure [197] respectively. Failure rate of 0.007712 failure/year and repair rate of 144 h/failure is assumed for wind turbine transformer [197].
5.4.1 Wake losses

Wind turbines with same rated power are usually available in different heights, e.g., Vestas V80 is available in five different heights 60 m, 67 m, 78 m, 80 m and 100 m [15]. Wind speed measurements are scaled up to the height of the wind turbine and used for power and energy yield calculation of the WF, for both cases without wake losses using (2.5), (5.3) and (5.4) and with wake losses. The results showing effects of different factors, e.g., WF location, wind turbine height and distance on energy yield are summarised in Table 5.1. The table shows that energy yield reduction due to wakes is variable and different factors contribute to it differently.

Both, wind speed and wind direction measurement data recorded at 10 minute intervals over a period of one year were used to calculate energy losses due to wakes. Variation in power output due to change in wind direction entering the WF is illustrated in Figure 5.7 and Figure 5.8. The figures illustrate the effect of variable wind direction (for fixed wind speed and for ‘offshore’ and ‘onshore’ scenarios shown in Table 5.1) on WF energy yield.

<table>
<thead>
<tr>
<th>Case</th>
<th>Location of WF</th>
<th>Distance between wind turbines (m)</th>
<th>Wind turbine Height (m)</th>
<th>Energy yield (GWh) No wake</th>
<th>Energy yield (GWh) With wake</th>
<th>Wake loss (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Offshore</td>
<td>x = 5D</td>
<td>80</td>
<td>62.74</td>
<td>58.39</td>
<td>6.94</td>
</tr>
<tr>
<td>2</td>
<td>Offshore</td>
<td>x = 5D</td>
<td>60</td>
<td>60.57</td>
<td>56.27</td>
<td>7.11</td>
</tr>
<tr>
<td>3</td>
<td>Offshore</td>
<td>x = 9D</td>
<td>80</td>
<td>62.74</td>
<td>60.88</td>
<td>2.97</td>
</tr>
<tr>
<td>4</td>
<td>Offshore</td>
<td>x = 9D</td>
<td>60</td>
<td>60.57</td>
<td>58.74</td>
<td>3.03</td>
</tr>
<tr>
<td>5</td>
<td>Onshore</td>
<td>x = 5D</td>
<td>80</td>
<td>67.43</td>
<td>63.01</td>
<td>6.55</td>
</tr>
<tr>
<td>6</td>
<td>Onshore</td>
<td>x = 5D</td>
<td>60</td>
<td>63.72</td>
<td>59.35</td>
<td>6.85</td>
</tr>
<tr>
<td>7</td>
<td>Onshore</td>
<td>x = 9D</td>
<td>80</td>
<td>67.43</td>
<td>65.54</td>
<td>2.80</td>
</tr>
<tr>
<td>8</td>
<td>Onshore</td>
<td>x = 9D</td>
<td>60</td>
<td>63.72</td>
<td>61.85</td>
<td>2.93</td>
</tr>
</tbody>
</table>

Considering wake effects alone it was observed that the annual energy loss can vary between 2% and 7% depending on the location and parameters of the WF (Table 5.1). The energy yield reduction due to wakes is variable hence it should not be generalised for all WFs as it was done in [64] and [205], rather it should be calculated based on actual WF parameters.
5.4.2 Electrical power losses

Power loss calculations are performed using power flow but with different cable types and lengths for each WF collector system. The WF is connected to a slack bus such that the voltage at PCC is always set to 1 p.u. Cables of cross-sectional area 25 mm$^2$, 50 mm$^2$, 70 mm$^2$, 95 mm$^2$ and 120 mm$^2$ [206] within the WF and 150 mm$^2$ for the main cable connecting WF to the network were used. Turbine transformers are assumed to have 0.22% resistance and 6% reactance at 100 MVA base while grid transformer is assumed to have 1.5% resistance and 15% reactance at 100 MVA base. No-load losses are taken to be 0.11% of the capacity of the transformer [207]. As the rating of the wind turbines is 2.0 MW, turbine transformers rated at 2.2 MVA are used. The rating of grid transformer is 25 MVA.
For energy yield evaluation, only cables with sufficient MVA rating to carry the power that is to be transferred were chosen. Energy loss for any collector system varied between 1.40% and 2.08% for the parameters mentioned in the case study (without no-load losses of wind turbine and grid transformers). If however, no-load losses for all transformers were included then collector network energy losses varied between 2.16% and 2.84%. Losses with central configuration collector system were the highest while with the single-sided ring were the lowest compared to other configurations.

Figure 5.9: Electrical losses inside Radial network for various cable sizes inside the array (connecting turbines) and for cable connecting to shore

Figure 5.10: Electrical losses inside Central network for various cable sizes inside the array (connecting turbines) and for cable connecting to shore
To test the impact of cables sizes and impact of change in distance between WF and shore on losses, the length of the cable connecting the WF with shore was varied between 8 km and 20 km (in all configurations). Figure 5.9 to Figure 5.12 show that as WF real power generation increased the amount of losses also increased (at unity power factor). The effect of variation in power losses due to cable parameters, distance and the type of WF collector system are also observable in the figures. It was noticed that for radial, starburst and central configurations power losses were very similar for similar types of cables and lengths used whereas for single-sided ring configuration these losses were slightly different, smaller for some cases. Maximum losses resulted, as expected, when cables of smallest cross-sectional area were used and vice versa. The range of losses can be used as an indicator of energy yield sensitivity to collector system configuration and cabling parameters.
5.4.3 Wind resource availability

Table 5.2 shows wind resource availability per wind turbine within the studied WF for one year. For 81% of the year wind potential is sufficient to generate power, i.e. wind speed within the wind turbine operating range. However, due to location of wind turbines inside the WF and corresponding wake effects this value is different for each wind turbine. Wind turbines under wake receive reduced wind speed (less than 4m/s in some cases) and hence potential power production for those wind turbines is lower. It should be also taken into account that wind resource can vary between 5% [2] and 10% [208] annually.

<table>
<thead>
<tr>
<th>Wind Resource</th>
<th>WT1</th>
<th>WT2</th>
<th>WT3</th>
<th>WT4</th>
<th>WT5</th>
<th>WT6</th>
<th>WT7</th>
<th>WT8</th>
<th>WT9</th>
<th>Incoming wind speed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reference</td>
<td>77%</td>
<td>78%</td>
<td>80%</td>
<td>79%</td>
<td>76%</td>
<td>77%</td>
<td>80%</td>
<td>77%</td>
<td>76%</td>
<td>81%</td>
</tr>
<tr>
<td>5% increase</td>
<td>79%</td>
<td>80%</td>
<td>81%</td>
<td>80%</td>
<td>78%</td>
<td>78%</td>
<td>82%</td>
<td>79%</td>
<td>77%</td>
<td>82%</td>
</tr>
<tr>
<td>10% increase</td>
<td>80%</td>
<td>81%</td>
<td>83%</td>
<td>82%</td>
<td>79%</td>
<td>80%</td>
<td>83%</td>
<td>80%</td>
<td>79%</td>
<td>83%</td>
</tr>
</tbody>
</table>

Table 5.2 shows that increase of wind resource by 10% leads to 83% of wind becoming usable for production of electricity compared to 81% at reference wind resource. This is because increase in wind speed would place some wind turbines into operating range while others out of their operating range. It was observed that wake losses reduce slightly (by 0.7%) from 6.67% to 5.97% when wind resource increased from 0% (reference) to 10% which implies lower wind speeds causes more wake losses than higher wind speed. (Note: Increase in wind resource was simulated by increasing each wind speed measurement (reference value) by 10% while using the same wind direction associated with it. Overall energy yield increased by about 13.15% due to 10% rise in wind resource (considering wake with maximum electrical losses).

5.4.4 Wind farm component availability

To evaluate the impact of component availability in this case study, the availability of one component was set to its typical value (see above) while keeping availability of other components equal to 100%. It is assumed for this
test that there is no correlation between component availability and wind power production. Annual energy yield is then calculated for each of the four collector system designs and percentage of energy loss due to component unavailability calculated relative to ‘all available’ case. The results show that wind turbine transformer availability (99.998%) and inter-array cable availability have negligible impact on the annual energy production. As expected availability of the wind turbines (95%) and availability of the main cable (99.8%) has the highest impact, see Table 5.3. While wind turbine availability has the same effect on energy losses for all four collector system configurations, main cable unavailability causes the least energy losses in single-sided configuration.

Table 5.3: Impact of WF component availability on annual energy losses

<table>
<thead>
<tr>
<th></th>
<th>Radial</th>
<th>Starburst</th>
<th>Central</th>
<th>Single-sided</th>
</tr>
</thead>
<tbody>
<tr>
<td>$P_{wt} = 95%$</td>
<td>3.26%</td>
<td>3.26%</td>
<td>3.26%</td>
<td>3.26%</td>
</tr>
<tr>
<td>$P_m = 99.8%$</td>
<td>0.39%</td>
<td>0.26%</td>
<td>0.65%</td>
<td>0.17%</td>
</tr>
</tbody>
</table>

The impact of the correlation between wind power production and component availability (all components with assumed typical availabilities) on the annual energy losses relative to all available case is illustrated in Table 5.4. Much higher losses due to component unavailability are expected if component availability is positively correlated with wind energy production.

Table 5.4: Impact of correlation between component availability and wind power production on annual energy losses

<table>
<thead>
<tr>
<th>Correlation between component availability and wind power production</th>
<th>Radial</th>
<th>Starburst</th>
<th>Central</th>
<th>Single-sided</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum wind/Minimum availability</td>
<td>12.52%</td>
<td>12.01%</td>
<td>13.04%</td>
<td>11.85%</td>
</tr>
<tr>
<td>No Correlation</td>
<td>3.66%</td>
<td>3.50%</td>
<td>3.89%</td>
<td>3.41%</td>
</tr>
</tbody>
</table>

5.4.5 Wind energy curtailments

It is assumed that there are other generators (such as Hydro power) situated in the same area as the WF (see Figure 5.13) and that the available
transmission capacity from the area is limited to 70 MW. Existing generators were supplying load in that area and across the transmission line therefore a transmission line of that rating had been installed based on the existing level of power transfer. But with installation of new wind power priority will still be given to the existing generators (such as hydro power) to transfer their power and any excess wind power will be curtailed. Power transmission measurements were available for a transmission line and they are assumed to be representative for the case studied.

![Flowchart](image)

Figure 5.13: A congested system with a transmission bottleneck

Power transmission from the WF through the transmission corridor may not be possible at all times. Wind energy curtailment during the periods of transmission congestion is considered as an alternative to transmission line reinforcement. The method for estimation of wind energy curtailment presented in Section 5.3.6 is applied in this case study. When correlation between wind power production and TLL is 1 then Section 5.3.6.1 (5.21) is used as illustrated in Figure 5.6 to determine curtailed energy. Similarly for correlation of -1, curtailment losses are calculated as described in Section 5.3.6.1. When there is no correlation between wind power production and TLL then method defined in Section 5.3.6.2 is used and results are shown in Figure 5.14. The figure illustrates results of the discrete probabilistic estimation. Figure 5.14 shows the probability of production from the wind farm \(1-F_1(x)\), transmission of power from the line without wind power \(1-F_3(y)\), transmission of power from the line with wind power \(1-F_2(z)\) and transmission line limit \(TL\). As \(F_z(z) = P(Z \leq z)\), the value \(1-F_z(C)\), in Figure 5.14 corresponds to the probability that the transmission limit \(C\) is exceeded. The area under \(1-F_z(C \leq z < \infty)\) in Figure 5.14 is equal to wind energy that would be curtailed. Availability of wind turbines is considered to be between 95% and 100% [209]. More possible correlation scenarios are depicted in Table 5.5.

![Flowchart](image)
Figure 5.14: WF Production Probability Distribution Function (WDF) $1-F_X(x)$, actual Transmission Probability Distribution Function (TDF) $1-F_Y(y)$, New Transmission Probability Distribution Functions (NTDF) $1-F_Z(z)$ and Transmission Limit (TL) of the case study line.

Figure 5.15: Effect of WF cabling configuration and correlation coefficient combinations on energy yield for one year.

Figure 5.15 shows effects of these different correlation combinations on energy yield from the WF considering 95% wind turbine availability for different collector systems. Both wake effects and electrical losses are included in the results. The influence of latter is very small and therefore hardly visible in the figure. For scenario when wind speed is the highest, TLL is lowest and wind turbines are fully available, delivered energy is very high as shown in Figure 5.15 (third combination of correlation coefficient from Table 5.5). The range of energy yield depends on wake effect, WF component availability,
curtailment losses and electrical losses in each cabling structure. For any electrical collector system, when correlations between wind speed, wind turbine availability and TLL were 1 (wind speed is high and TLL is highest, wind turbines are fully available) maximum curtailment was required. This amounted to 14.04% (at reference wind resource) at 100% wind turbine availability. Conversely, no curtailment was needed when correlation between wind speed and TLL was -1. The amount of curtailment depends on the combination of correlation coefficient which varies with WF location, site measurements and TLL profile. Increase in wind resource implies rise in power generation hence increase in energy yield. Since capacity of the line is fixed this yields more energy curtailments. It was observed that for fixed wind turbine availability in radial collector system when wind resource increased by 5% the amount of energy curtailment rose by 4.41%. The curtailment increased by 6.46% in case of 10% rise in wind resource.

Table 5.5: Combinations for correlation between wind speed and TLL as well as between wind speed and wind turbine availability

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Correlation between wind speed and TLL</th>
<th>Correlation between wind speed and wind turbine availability</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1</td>
<td>-1</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>3</td>
<td>-1</td>
<td>1</td>
</tr>
<tr>
<td>4</td>
<td>-1</td>
<td>-1</td>
</tr>
<tr>
<td>5</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>6</td>
<td>-1</td>
<td>0</td>
</tr>
<tr>
<td>7</td>
<td>0</td>
<td>-1</td>
</tr>
<tr>
<td>8</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>9</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

5.4.6 Overall Losses and Capacity Factor

Losses due to various factors given above can also be summarized through Figure 5.16.
For 9 turbine wind farm installed offshore (with 2 MW turbines, 80m high and 5D apart) using statistical site wind characteristic, the capacity factor was found to be 39.8%. This value is prior inclusion of any of losses. Capacity factor was recalculated after inclusion of all losses.

When wake losses are considered the capacity factor varied according to the case considered in Table 5.1. The capacity factor calculation for each case is provided in Table 5.6.

<table>
<thead>
<tr>
<th>Case</th>
<th>Capacity Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>No Wake</td>
</tr>
<tr>
<td>1</td>
<td>39.8%</td>
</tr>
<tr>
<td>2</td>
<td>38.4%</td>
</tr>
<tr>
<td>3</td>
<td>39.8%</td>
</tr>
<tr>
<td>4</td>
<td>38.4%</td>
</tr>
<tr>
<td>5</td>
<td>42.8%</td>
</tr>
<tr>
<td>6</td>
<td>40.4%</td>
</tr>
<tr>
<td>7</td>
<td>42.8%</td>
</tr>
<tr>
<td>8</td>
<td>40.4%</td>
</tr>
</tbody>
</table>

The electrical and reliability based losses due to WF component unavailability were calculated using the base case (Case 1 with wake losses).
The impact of various internal wind farm losses and network related curtailment losses on capacity factor are summarised in Table 5.7.

<table>
<thead>
<tr>
<th>Factors that affect the Energy Yield</th>
<th>Capacity Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electrical losses (2.16% to 2.84%)</td>
<td>36.23% to 35.98%</td>
</tr>
<tr>
<td>WF component unavailability (0% to 13.04%)</td>
<td>36.23% to 31.3%</td>
</tr>
<tr>
<td>Curtailment losses (0% to 14.04%)</td>
<td>36.23% to 26.9%</td>
</tr>
<tr>
<td>Impact of wind resource (10% rise)</td>
<td>35.4%</td>
</tr>
<tr>
<td>Impact of wind resource (10% rise) and curtailment</td>
<td>28.1%</td>
</tr>
</tbody>
</table>

It can be seen from Table 5.7 that capacity factor reduced to a maximum of 35.98% when electrical losses of 2.84% are considered. It reduced further to 31.3% when WF component unavailability of 13.04% is considered. The effect of energy curtailment due to network constraints is also included in capacity factor calculation. It can be seen from the table that 14.4% curtailments will further reduce the capacity factor to 26.9%.

When a 10% increase in wind resource is considered the overall energy yield (including wake, electrical and WF component unavailability losses) increased by 13.15% which increased the capacity factor to 35.4%. But this also increased the curtailment losses as wind energy export increased. Overall, the minimum capacity factor after all losses was found to be 26.9% whereas without any losses it was 39.8%. Thus inclusion of losses reduced the capacity factor by 12.9%.

The capacity factors calculated are valid for the wind turbines, wind farm layout and wind conditions used in this case study. The results will differ if either of the parameters is different.

5.5 Summary

This chapter presented a comprehensive methodology for probabilistic assessment of WF energy yield. A new method to calculate losses due to reliability of WF components was presented for four collector systems. Also, a technique to determine amount of energy curtailments considering all internal WF losses was given. Correlation combinations covering all extreme scenarios
were computed to assess the impact of wind power production, TLL and wind turbine availability on the amount of curtailments.

In the case studied, energy losses due to wake varied between 2% and 7%, electrical losses inside the WF between 2.16% and 2.84%. Losses due to unavailability of wind turbine and other components within the WF were between 0% and 13.05% during a year depending on component availability, WF collector system configuration and correlation between wind turbine availability and wind power production. Impact of variation in wind resource on energy yield, losses and curtailments were also analysed by increasing wind resource by 5% and 10%. A 10% increase in wind resource led to 13.15% rise in energy yield (including losses, wind turbine availability 100%, excluding network constraints). Losses due to wind energy curtailments were found to be between 0% and 14.04% (at reference wind resource), however, energy curtailments rose by further 6.46% when wind resource increased by 10%. The highest curtailment losses occurred for correlation coefficient equal to 1 between wind power, TLL and wind turbine availability, whereas lowest wind energy curtailment occurred for correlation coefficient of -1 between wind power production and TLL. Impact of losses on capacity factor of a wind farm was also analysed. It was found that consideration of all losses (internal to wind farm and due to curtailments) reduced the capacity factor by 12.9%. It should be noted that the values for energy losses computed are valid for this particular case study. If parameters of a wind farm are different the results will vary accordingly. Therefore, these losses should be computed using actual wind farm data during a prefeasibility study. Based on sensitivity analysis, it can be concluded that energy yield should not be computed as a single deterministic value but rather as a range, or as a probability density function. Methodologies presented can help WF developers make more reliable decisions regarding collector system design, cross-section of cables, height of wind turbines, location of the WF and connection with the grid. It can also contribute to assess more accurately the option of wind energy curtailment against the option of transmission line reinforcement in areas with transmission corridor congestion.
Chapter 6

Probabilistic Identification of Critical Wind Turbines inside a Wind Farm

6.1 Introduction

Preventive maintenance is carried out to avoid component failures by replacing worn components before they fail. A sub category of preventive maintenance is the scheduled preventive maintenance which is generally cheaper than the corrective maintenance [210], therefore it is popular amongst wind farms today [211]. Scheduled preventive maintenance is performed on an established time schedule [211, 212], its frequency however depends on the age of the wind turbines in the wind farm. The process of scheduling can be made more efficient if wind turbines that produce large amount of power are scheduled for maintenance on less windy days.

Apart from this, the process of wind energy curtailment can be also made more efficient by prioritising shut down of wind turbines. This chapter proposes methodology for probabilistic identification of critical wind turbines that could yield better scheduling of preventive maintenance of wind turbines and also result in developing better wind energy curtailment strategy.

Wind turbines inside a wind farm do not produce the same amount of power at any given time because the wind speed incident on each turbine is different. The wind speed incident on a turbine is influenced by the physical location of the turbine along with wake effects caused by the local topology and other wind turbines. Another factor influencing wind speed is turbulence within the wakes, which negatively impacts on the WFs operation by causing turbine fatigue damage [111]. Turbines under wake suffer greater fatigue load compared to turbines in free-stream wind [213]. It is assumed that this consequently affects
the wind turbine component reliability and therefore adds towards operation and maintenance costs.

In this chapter, a novel probabilistic methodology is presented to identify wind turbines in the WF that face higher and lower wind speeds during the year. The methodology takes into account WF layout, WF location and wind turbine positions. Probabilistic site analysis is performed along with turbine clustering, after determining the wind speed approaching each turbine by using a detailed wake effect model. The developed approach can help to identify those turbines which are mostly under wake and consequently facing reduced wind speeds. The approach presented in this chapter can be applied to a generic wind farm of any size, layout or location.

The wind turbines in a WF can be broadly split into two groups, \textit{Important wind turbines} and \textit{Less Important wind turbines}. Wind turbines that face higher wind speeds can be defined as \textit{Important wind turbines} while those that face reduced wind speed due to wakes can be defined as \textit{Less Important wind turbines}. Outages on \textit{Important wind turbines} cause greater losses in WF total power production compared with outages in \textit{Less Important wind turbines}. Identifying \textit{Important wind turbines} and \textit{Less Important wind turbines} requires information on the wind characteristics at the site of interest, including wind speed and wind direction measurements data for at least one year, so that most probable wind directions and speeds can be determined.

Once the \textit{Important wind turbines} and \textit{Less Important wind turbines} have been identified, the turbines under the greatest stress can be pro-actively shut down first during wind energy curtailments. Shutting down these turbines is advantageous because it prevents fatigue damage to a wind turbine’s mechanical components. During preventive maintenance it can be profitable to schedule turbines producing higher energy on days with less wind speed to avoid loss of extra energy capture.

The methodology presented in this chapter is tested on a large WF but it is equally applicable to a WF of any size and layout. All quantitative results are dependent on the layout and location of a WF as well as on wind characteristic at the site. The method is applicable for carrying out offline studies on existing wind farms. At present, there are no reports in open literature presenting methodology for identifying wind turbines facing high and low wind speeds within a WF. The methodology presented here uses data from only one
anemometer for the whole wind farm. It thus saves significant wind measurement effort.

6.2 Wind Flow Modelling and Data Clustering

6.2.1 Site information

In order to determine the most probable wind speeds and directions at a site, it is necessary to have a site’s wind measurements available for at least one year. Based on this information the frequency of wind direction for the whole year can be determined. By analysing wind speed measurement data (given in Section 3.8) of a site in the north of Sweden for year 2000, it is evident that the wind during the year is prevailing from two directions: one ranging between 100° and 180°, and one ranging between 280° and 360°. This can be seen from Figure 3.12.

The probability distribution of different wind speeds at a site can be found from wind measurements and represented through Weibull distribution. Figure 3.11 shows that prevalent wind speeds occur between 4 m/s and 15 m/s. Wind speeds greater than 15 m/s were not analysed because their probability of occurrence is low. The most probable wind speed and directions are then used in further calculations whereas low probability wind speeds and wind directions were ignored. A large 49 turbine wind farm shown in Figure 3.13 is used for the analysis.

6.2.2 Wind speed variation due to wake effects

To be able to identify wind turbines receiving high and low wind speeds it is essential to consider the WF layout, incoming wind speed and direction as well as wake effects. Once wind speed approaching each turbine for every incoming wind speed and wind direction is obtained, a power curve for the turbine can be used to determine its power production. The amount of wind speed each turbine receives inside a WF is dependent on the layout of the WF, the number of turbines, their position in WF and the wind speed and direction entering the farm. It was observed that both incoming wind speed and wind direction (even when treated independently) affect the wind speed incident on a turbine. Therefore, both of these factors should be considered whenever the assessment of total WF power production is needed. Wake effect models and VeBWake
program described in Section 3.3 and 3.4 respectively, are used to estimate wind speed at each turbine.

### 6.2.3 Clustering data

Once essential wind speed data at each turbine is obtained through wake effect modelling, the Support Vector Clustering (SVC) method [183] (given in Section 4.3) is applied to cluster wind turbines according to their wind speed with a direction interval (DI) of $20^\circ$. A Direction Interval is used to collectively consider and cluster wind turbines inside 20 directions (e.g. from $100^\circ$ to $120^\circ$ and from $120^\circ$ to $140^\circ$ and so on). A cluster DI of $20^\circ$ was selected due to similarities in wind patterns within this range and to reduce computational effort, without any loss of generality. If increased accuracy is needed, or if there is dissimilarity in the wind patterns within the considered range, a smaller DI (e.g., $10^\circ$, $5^\circ$ or even $1^\circ$), should be used. It should be pointed out that clustering of wind turbines based on wind speeds is not new. References [38] and [214], for example, presented methods which clustered wind turbines based on their wind speeds.

Turbines are then arranged in clusters based on magnitude of wind speeds they face, i.e., those facing higher wind speeds are arranged in one cluster, whereas those facing slightly lower wind speed in another, and so on. Those turbines that appear most frequently in the cluster of high wind speeds are the ones that face the highest wind speeds during the year. On the other hand, those turbines that appear most frequently in the lower wind speed cluster are the ones that are under wake most of the time during the year. A more detailed description of the process is given in the following sections.

### 6.3 Probabilistic Power Output of Wind Farm

The probability mass function for wind power output can be expressed as:

$$f_r(y) = P(Y = y) = \frac{\text{freq}_r(y)}{N}$$

(6.1)

where $Y$ corresponds to wind power production in MW. $P(Y = y)$ is the probability that wind power $Y$ is the same as a level $y$, $\text{freq}_r(y)$ is the frequency of level $y$ and $N$ is the total number of measurements in a year.

The distribution function for wind power production is then:
where \( P(Y \leq y) \) is the probability that wind power output \( Y \) is less than or equal to level \( y \). Finally, the probability to produce \( Y \) amount of wind power during the year by the WF can be obtained as \( 1 - F_y(y) \) [215].

### 6.4 Case Study

For all selected wind speeds (4 m/s to 15 m/s) and directions (100°, 101°, 102°, ... 180° and 280°, 281°, 282°, ... 360°) wind flow and wake effects inside the farm are simulated. The range of wind speeds in this simulation is reduced from the full range of wind speeds (0 to 25 m/s) and directions (0 to 360°) to only the prominent wind speeds and directions. In the case where wind conditions are not easily segmented into prominent regions using the wind speed and direction probability distributions (obtained from wind measurements), the full range of wind speed and directions should be used. Doing so provides wind speed at each turbine after which classification of turbines is performed by the SVC algorithm. Turbines that face high wind speed are placed in Cluster 1 while those that face low wind speeds (as they stay in wake in most wind conditions) are placed in the subsequent clusters. The number of clusters differs with incoming wind speed and direction. An example is shown in Table 6.1 for incoming wind speed of 10 m/s. Tables similar to this are formed for every incoming wind speed between 4 m/s and 15 m/s.

Using the tables for each wind speed, the frequency of each wind turbine in each cluster can be calculated. If a wind turbine exists more frequently in Cluster 1 it implies that it faces higher wind speed than others, whereas if a turbine frequently appears in Cluster 5 it faces reduced wind speed during the year. Frequency of turbines in each cluster is illustrated in Figure 6.1.

At different directions and wind speeds, turbines in a WF face different levels of wind. Figure 6.1 shows that it is difficult to choose Important wind turbines and Less Important wind turbines as the resulting frequencies are relatively close to one another. To simplify the analysis, Cluster 1 and 2 are merged together since wind speeds in both are relatively high. Similarly, Clusters 4 and 5 are also merged together. This leads to reduction in clusters...
from 5 to just 3 where cluster 3 with mediocre wind speed is ignored. The results of merging these clusters are shown in Figure 6.2 and Figure 6.3.

Table 6.1: Wind turbines arranged in clusters from high to low wind speeds at 10m/s (wind direction = 0 to 360°)

<table>
<thead>
<tr>
<th>Direction Range</th>
<th>Cluster 1 (highest wind speed)</th>
<th>Cluster 2</th>
<th>Cluster 3</th>
<th>Cluster 4</th>
<th>Cluster 5 (lowest wind speed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>100°-120°</td>
<td>1,2,3,4,5,6,7,8,9,10</td>
<td>15,16,17,18,19,20</td>
<td>22,23,24,25,26,27,29,30,31,32,33,34,36,37,38,39,40,41,43,44,45,46,47,48</td>
<td>none</td>
<td>none</td>
</tr>
<tr>
<td>120°-140°</td>
<td>1,2,3,4,5,6,7,14,12</td>
<td>8,9,10,11,12,13</td>
<td>15,16,17,18,19,20,27,34,41,48</td>
<td>none</td>
<td>none</td>
</tr>
<tr>
<td>140°-160°</td>
<td>1,2,3,4,5,6,7,14,21,22,23,24</td>
<td>13,20,27,34,41,48</td>
<td>8,9,10,11,12,19,26,33,40,47</td>
<td>none</td>
<td>none</td>
</tr>
<tr>
<td>160°-180°</td>
<td>7,14,21,28,35,42,49</td>
<td>6,13,20,27,34,41,48</td>
<td>1,2,3,4,5,12,19,26,33,40,47</td>
<td>11,18,25,32,39,46,8,9,10,15,16,17,22,23,24,25,26,27,28,30,31,32,33,34,35,36,37,38,43,44,45</td>
<td></td>
</tr>
<tr>
<td>280°-300°</td>
<td>1,8,15,22,29,36,37,39,40,41,42,43,44,45,46,47,48,49</td>
<td>30,31,32,33,34,35,36,37,38,39,40,41,42,43,44,45,46,47,48,49</td>
<td>2,3,4,5,6,7,9,10,11,12,13,14,16,17,18,19,20,21,23,24,25,26,27,28</td>
<td>none</td>
<td>none</td>
</tr>
<tr>
<td>300°-320°</td>
<td>1,8,15,22,29,36,43,44,45,46,47,48,49</td>
<td>37,38,39,40,41,42,43,44,45,46,47,48,49</td>
<td>2,9,16,23,30,31,32,33,34,35,36,37,38,39,40,41,42,43,44,45,46,47,48,49</td>
<td>3,4,5,6,7,10,11,12,13,14,17,18,19,20,21,24,25,26,27,28,29,30,31,32,33,34,35,36,37,38,43,44,45</td>
<td></td>
</tr>
<tr>
<td>320°-340°</td>
<td>1,8,15,22,29,36,43,44,45,46,47,48,49</td>
<td>2,9,16,23,30,37,40,41,42,43,44,45,46,47,48,49</td>
<td>3,10,17,24,31,38,39,40,41,42,43,44,45,46,47,48,49</td>
<td>4,5,6,7,11,12,13,14,18,19,20,21,25,26,27,28,30,31,32,33,34,35,36,37,38,43,44,45,56,7,12,13,14,19,20,22,26,27,28,33,34,35,40,41,42</td>
<td></td>
</tr>
<tr>
<td>340°-360°</td>
<td>1,8,15,22,29,36,43,44,45,46,47,48,49</td>
<td>2,9,16,23,30,37,44,45,46,47,48,49</td>
<td>3,10,17,24,31,38,40,41,42,43,44,45,46,47,48,49</td>
<td>4,11,18,25,32,39,5,6,7,12,13,14,19,20,21,26,27,28,33,34,35,40,41,42</td>
<td></td>
</tr>
</tbody>
</table>
To choose a few turbines in each of the two distinct merged clusters a threshold frequency of 70 is set for the high speed cluster (merged clusters 1
and 2), while for low speed clusters (clusters 4 and 5) this value is set to 17. This means turbines in Figure 6.2 with frequency above 70 are *Important* while turbines in Figure 6.3 with frequency above 17 are defined as *Less Important* wind turbines.

Figure 6.4: Wind farm layout showing important wind turbines in the red, less important wind turbines in blue and frequency of wind from various direction sectors in the background

It can be seen that wind turbines 1, 2, 8, 42, 48 and 49 receive higher wind speeds, whereas wind turbines 11, 18, 24, 25, 26, 32 and 39 are more likely to receive reduced wind speeds. From the layout of the WF in Figure 6.4 it is visible that, as expected, turbines receiving reduced wind speed more frequently are the ones deep inside the WF (highlighted in blue). Studies in literature [111, 213] report that the turbines in the middle of WF (under wake) will be under greater fatigue loads compared with wind turbines in the free-stream wind. It is assumed that turbines under fatigue loads will be under greater mechanical stress. Figure 6.4 shows that the turbines highlighted in red face higher wind speeds as they remain under free-stream wind most of the time. This is because wind is highly frequent from two directions at this site as visible from Figure 6.5. These turbines will hardly be under wake as direction of the wind is diagonal during most of the year. Wind turbines identified as *Important* and *Less important* in this case study are valid for this particular wind farm layout and for the site wind characteristic considered. The results will vary according to the geometry of the wind farm, wind turbine height and
distance and wind characteristic (wind speed and direction) at the site. Therefore, these factors should be considered for each study.

![Wind Rose Diagram](image)

Figure 6.5: Plot of a wind rose showing frequency of wind from each direction

### 6.4.1 Wind farm power production and energy yield analysis

The obtained results are subjected to further tests to assess the affect of shutting down wind turbines receiving high wind speeds and low wind speeds on WF power production. The same WF layout, shown in Figure 6.4, is used. The probability of power production is determined for three separate scenarios:

i) All wind turbines operating throughout the year (no unavailable wind turbine)

ii) Important wind turbines are unavailable (the rest are operating)

iii) Less important wind turbines are unavailable (the rest are operating)

If similar results are found for scenarios (ii) and (iii) this would imply that all turbines regardless of their position inside the WF and site condition produce the same amount of power and hence shutting down any turbine (irrespective of its location) has no impact on the energy yield.

In the previous section 6 important turbines and 7 less important turbines were identified. In order to perform a fair test, both scenarios (ii) and (iii) should have the same number of non-operational turbines. For this reason, the total number of non-operational less important turbines was modified from 7 to 6. This modification was performed by not shutting down wind turbine number 39.
It can be seen from Figure 6.6 when all turbines are in operation the rated power produced by the WF is 98 MW. In scenarios (ii) and (iii) (where 6 wind turbines were switched off) the rated power of the WF is reduced to 86 MW. Figure 6.6 also shows that when wind turbines 1, 2, 8, 42, 48 and 49 (important wind turbines) were switched off the probability to produce the same amount of power dropped more than when turbines 11, 18, 24, 25, 26 and 32 (less important wind turbines) were switched off. For example, the probability to produce 40 MW (as shown by orange line in Figure 6.6) when important wind turbines are off is 0.28 as compared to 0.31 when less important wind turbines are off. This proves that high and low wind speed receiving turbines have been correctly identified. Those facing higher wind speeds during the year contribute more towards power production from a WF and if they become unavailable loss of power production will be greater than compared to the loss due to unavailability of less important turbines.

### 6.4.2 Energy yield analysis

The effect of shutting down important and less important turbines on annual energy yield is also simulated. When all wind turbines are available (and in operation) the energy yield is calculated to be 288.95 GWh. When 6 turbines receiving reduced wind speed (Less Important WTs) are shut down the energy yield reduced to about 261.62 GWh while when 6 turbines facing high wind
speed (Important WTs) are switched off the energy output reduced to 250.18 GWh. In terms of capacity factor when Less Important WTs are shut down, the value decreased by 3.2% whereas when Important WTs were off it plummeted by 4.6%. This highlights the importance of keeping Important wind turbines available at all times. Table 6.2 shows that there is a difference of 11.44 GWh or about 4% between scenarios (ii) and (iii).

A reduction in energy yield can significantly affect the profits from a wind farm when the cumulative value is analysed over wind farm’s life time. Proper attention should be given to maintenance of critical wind turbines (in this case the Important wind turbines). These results highlight the importance of ascertaining the important turbines within a WF, especially when considering scheduling of preventive maintenance to ensure a greater availability and thus profits for the WF owner. The preventative maintenance of important wind turbines should be scheduled during less windy days so that a maximum energy output can be obtained.

<table>
<thead>
<tr>
<th>Scenarios</th>
<th>Energy yield (GWh)</th>
<th>Energy Yield Reduction</th>
<th>Capacity Factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>(i) All turbines ON</td>
<td>288.95</td>
<td>Reference</td>
<td>33.7%</td>
</tr>
<tr>
<td>(ii) Important turbines OFF</td>
<td>250.18</td>
<td>13.41%</td>
<td>29.1%</td>
</tr>
<tr>
<td>(iii) Less important turbines OFF</td>
<td>261.62</td>
<td>9.45%</td>
<td>30.5%</td>
</tr>
</tbody>
</table>

### 6.5 Summary

This chapter presented a probabilistic methodology to allow easy determination of turbines in a WF that face high free-stream winds (important wind turbines) as well as turbines that remain under wake most of the time (less important wind turbines). The method requires wind speed measurements from a single anemometer, and a wind farm layout. This data is then processed to determine probabilistic wind speed and direction entering the wind farm. Wind turbines with high and low incident wind speeds were identified using a combination of Support Vector Clustering, wake effect model and probabilistic analysis.

The results highlight how to identify productive turbines and those turbines under greatest mechanical stress in a WF comprising of 49 turbines. The results obtained are tested by shutting down an equal number of important and
less important turbines, then calculating the wind farm power output probability curve and performing energy yield analysis. It was found that shutting down important wind turbines lead to a greater loss in power and hence energy yield.

The proposed methodology is very flexible and can be used for a wind farm of any size and layout, installed at any location. It can be used with a wind farm having wind turbines of any height at any distance apart. The methodology can be used during pre-feasibility studies and on commissioned WFs. The method can be applied to a pre-feasibility study to test the shape and topology of the WF layout (wind farm layout optimisation) by ensuring the number of turbines receiving higher wind speeds is maximised. The method can also prove to be helpful during asset management of wind turbines. For instance, during normal operation and maintenance of a WF, the method can identify turbines facing higher wind speeds so that their maintenance can be prioritised to help reduce loss of profits.

Furthermore, the method can be useful during wind energy curtailments. It was discussed in Section 1.1 that in wind farms with stall control wind turbines the curtailment is performed by shutting down the turbines. The proposed method can also help identify wind turbines receiving reduced wind speeds and increased mechanical stresses. These wind turbines can be prioritised to be shut down when wind energy curtailments are required to prevent mechanical degradation of their components. Therefore, the method proposed can be useful for system operators as well as wind farm owners.
Chapter 7

Robust Design Methodology for Offshore Wind Farms

7.1 Introduction

In view of difficulty in gaining planning permission for onshore developments, in recent years attention has been given in particular to offshore wind farms. The world’s biggest offshore wind farm (Greater Gabbard) is currently under construction off the east coast of England, providing 500 MW of capacity and due for completion before the end of 2012 [216] and another bigger wind farm (London Array, Phase One, 630 MW) is planned for connection into the south east corner of England around the same time [30]. Recent reports published by the UK Carbon Trust [4] indicate that Britain could need at least 29 GW of offshore wind power to meet the EU’s renewable energy and low-carbon emission targets by 2020. Related reports published by BERR [217] and the Crown Estate [4] envisage that a number of large offshore wind farms will be built. The capacity of offshore wind farms in the future is expected to increase not only in the UK, but in many countries in Europe, as discussed in Chapter 1 and as shown in Figure 1.3. Apart from offshore wind farm capacity, the distance from shore is also expected to increase, with distances reaching up to 120 km away from the shore as seen in Figure 1.4.

As the capacity of a wind farm increases, the number of potential design options (i.e. choice of wind turbine capacity and quantity, type of transmission link with the shore, number of transmission cables, type of array configuration, choice of voltage levels and choice of substation equipment) also increases. This intensifies the complexity of the design task. In small capacity wind farms, many of the potential options are just not applicable, for instance, there is no
need for a substation or consideration of a high voltage DC (HVDC) option to link with the shore or very high voltage levels. Thus possible numbers of layouts in a small offshore wind farm are less as compared to a large offshore wind farm. In this chapter, design option for an offshore wind farm is also referred to as layout or electrical layout.

Designing an electrical network for a large offshore wind farm is a multi-dimensional problem where investment costs, reliability of the system and losses have to be balanced. In an offshore farm, achieving a certain level of redundancy is difficult as the cost of the project can rise significantly. Ideally an optimal layout should feature adequate level of reliability and be cost-effective, but as it will be seen in this chapter, a trade-off exists between these two factors.

Previous studies [24, 32, 73] have looked into ways of interconnecting turbines, choice of cables, possible connection options with the shore and so on. No methodology presented in open literature, however, looks at the wind farm design as a whole, i.e., from reliability, loss and cost perspectives. At present, prior to designing a wind farm, wind farm developers analyse a few electrical layouts based on the knowledge and experience they have gained from the previous projects. The capacity of the wind farms however will be much larger in the future in comparison to the past; hence a better approach is needed to identify cost-efficient electrical layouts for a large offshore wind farm.

This chapter provides a novel methodology that leads to the selection of an optimal electrical layout for a large offshore wind farm through cost-benefit analysis. A multi-level short-listing process is devised to narrow down the options. To start with, a list of all possible electrical layouts is created with different types and quantities of components. Through first level short-listing, a number of layouts are selected based on their technical feasibility and benefits. The investment cost of the remaining electrical layouts is evaluated using the cost models. At the second level of short-listing, the investment cost range set by the wind farm owner is considered, and therefore any layouts that fall beyond that range are discarded. The level of redundancy is then calculated in the layouts that remain to identify layouts with high and low reliability. At the third level of short-listing, layouts are selected based on the required redundancy criteria. The layouts selected are further tested for electrical and reliability based losses. Net Present Value (NPV) analysis is then carried out to
identify which layout performs better overall during the lifetime of the wind farm. The case study is performed on a 400 MW wind farm. The cases are developed and tested for losses in a commercially available power system software PSS®E.

At present, building a large electrical network (for an offshore wind farm) in commercial power system software takes a significant amount of time and effort because all the components have to be added manually. This means several nodes have to be added and named, voltage levels have to be defined, switchgear and cables have to be added, electrical data for transformers, cables, high voltage DC (HVDC) converters, wind turbine generators and onshore substation components have to be specified. It can be even more difficult when an offshore wind farm has more than one platform because then components for those platforms also have to be modelled. Performing load flow and reliability studies on such a large network manually can also be a very time consuming task.

To solve this problem a novel industrial-grade software tool has been developed as part of this research that can minimise the time and effort in building and testing such large networks. This chapter discusses the software tool that can be used for automated design and loss analysis of an offshore grid. The tool features a Graphical User Interface (GUI) through which parameters such as wind farm capacity, the distance between the turbines and the length of cables can be entered. Electrical parameters such as resistance, inductance and susceptance values for cables are loaded directly from component catalogues, available from manufacturers, to allow realistic estimation of electrical losses. The software allows a user to build and test a complete electrical grid for an offshore wind farm. A set of calculations including load flow, reactive power compensation, electrical and reliability based loss evaluations are automated. The costs of losses are determined based on the cost of energy entered. Since a large wind farm can have multiple platforms, the software also caters for this need and allows for creation of more than just a single platform. The platforms can be linked through cables by simply selecting the bus terminals and cable types in the GUI. The software features a save and read function through which entered parameters can be saved into an external file and later read back into the software tool. Using this feature, multiple electrical layouts can be rapidly generated without re-entering all the parameters into the GUI. The
software tool has been developed using Python programming language, QT, PyQt and PSS®E Application Programming Interface (APIs).

The software tool is a user-friendly application. It is useful for building and testing large offshore wind farm electrical networks in a short space of time with minimal effort. This chapter describes features of the software tool including inputs, outputs, structure and briefly the methodology behind the calculations.

### 7.2 Offshore wind farm network

Electrical layout of a large offshore wind farm is made up of a number of components as can be seen from Figure 7.1, this includes:

- a) Wind turbines
- b) Cables interconnecting the wind turbines
- c) Offshore substation carrying:
  - i) *Collector transformers* (2-winding or 3-winding) stepping up medium voltage (MV) to high voltage (HV).
  - ii) *Reactive power devices*.
  - iii) *Converters* for an HVDC link.
  - iv) *Converter transformers* (for a HVDC link) stepping up High Voltage (HV) to converter voltage i.e. Extra High Voltage (EHV).
  - v) *Switchgears*.
- d) Transmission link (HVAC or HVDC) to shore, see Figure 7.2.
7.2.1 Wind turbines

Today, wind turbines of various ratings are in use in offshore installations including 0.5 MW, 0.6 MW, 1.5 MW, 2.0 MW, 2.3 MW, 2.5 MW, 2.7 MW, 3.0 MW, 3.6 MW, 4.5 MW and 5.0 MW [12]. Depending on the project and investment budget, a wind farm owner can choose to deploy wind turbines of any capacity.

7.2.2 Wind turbine foundations

Holding vertically erected wind turbines in deep rough sea can be challenging. Therefore the type and complexity of wind turbine foundations varies according to the water depth of the sea as well as the hub height of a wind turbine. Various turbine foundations have been discussed in Section 1.2.2.2.

7.2.3 Wind turbine array

Normally, wind turbines are connected together in an array using 3-core cables. Voltage levels inside the array are typically established by the voltage at the secondary winding of the wind turbine transformer. Typically in European offshore wind farms a MV of 22 kV or 30-36 kV [12] is used, with 33 kV being a more common choice. Commonly employed array configurations i.e. radial, starburst, tree and radial with end loop, are discussed in Section 1.2.2.4.

7.2.4 Offshore substation transformers

An offshore platform may consist of 2- or 3-winding collector transformers to step up the MV to HV. The MVA rating of these transformers has to be decided from available products in the market. The voltage level at HV winding is typically between 130-160 kV and up to 220 kV [12], 245 kV and 275 kV are also used as observed from existing offshore wind farms. However, a step-up to
400 kV is also likely [218, 219]. The correct choice of rating and quantity is essential to have a cost-effective and reliable offshore network. For instance, installing two smaller units might be better in terms of reliability than having a single unit. On the other hand, two smaller capacity units might cost more than one large capacity unit. Therefore, various options should be tested.

Normally, collector transformers are sufficient if the transmission link to shore is established through HVAC cables, but if an HVDC link has to be setup then converter transformers are also needed. They convert HV (determined by the secondary winding of collector transformers) to EHV which is dependent on the converter voltage.

7.2.5 Switchgear

Switchgears are circuit breakers used to isolate and protect an electrical component; they also serve to clear a fault. Switchgears are used for connecting all components inside an offshore network. In case of cables, there is one circuit breaker at each end, while in the case of transformers, one circuit breaker at each winding is used. Gas Insulated Switchgear (GIS) is used in offshore platforms, whereas Air Insulated Switchgear (AIS) is used on onshore platforms. GIS is used in offshore platforms because it is resilient to an adverse climate and has a smaller footprint [29].

7.2.6 Transmission link to shore

A number of options can be considered when deciding on the type of transmission link to shore. The decision is influenced by the capacity of the wind farm as well as the distance to shore. A larger distance (several kilometres) means more reactive current generation due to line capacitance in an AC cable which can hinder the active current carrying capacity. At above 10 km (6 miles) some form of reactive power compensation is needed [19] but this adds towards the project costs. The size of a compensation device can be established by approximating the reactive power generation from cables. Reactive power generation of HVAC Cross Linked Poly Ethylene (XLPE) cables per km at various voltage levels can be estimated from Table 7.1. In Round 1 and 2 offshore wind farm projects in the UK (discussed in Chapter 1), connection with the shore is made mainly through submarine cables rather than overhead lines [20]. Therefore wherever links from offshore platform to
An HVAC link can be made using either 3-core or 3 single-core XLPE submarine cables. In comparison, the installation (cable lay and bury) cost of a 3-core cable is less than 3 single core cables. Another way to establish a connection with the shore is through an HVDC link but considering the cost of setup and converter losses, this option is only feasible for wind farms very far away. According to [32] for wind farms of up to 500 MW, 60 km away from the shore, a Voltage Source Converter High Voltage DC (VSC-HVDC) link is more expensive than an HVAC link (at 150 kV or 400 kV). If the distance to the shore equals to or exceeds 90 km then HVDC seems to be a cheaper option, even if the wind farm is only 100 MW. Hence both HVAC and HVDC link options should be considered during the electrical layout design of a large offshore wind farm as the choice will depend on the cost as well as the electrical losses.

### Table 7.1: Approximate reactive power generation by XLPE AC cables [29, 32]

<table>
<thead>
<tr>
<th>Voltage level</th>
<th>Reactive power generation with length</th>
</tr>
</thead>
<tbody>
<tr>
<td>33 kV</td>
<td>100 – 150 kVar/km</td>
</tr>
<tr>
<td>132 kV</td>
<td>1 – 1.16 MVar/km</td>
</tr>
<tr>
<td>245 kV</td>
<td>2.9 MVar/km</td>
</tr>
<tr>
<td>400 kV</td>
<td>6 – 8 MVar/km</td>
</tr>
</tbody>
</table>

#### 7.2.6.1 HVAC and HVDC link features

Characteristics of both an AC and a DC link are discussed below [19, 32, 220]:

**HVAC link**

- Submarine AC cables can generate a significant amount of reactive power at longer distances due to cable capacitance. Therefore a reactive power compensation is needed otherwise this can reduce the active power carrying capability of the cable.
- High capacitance of an AC cable may lead to resonance issues between the offshore and onshore grid which can distort the shape of the voltage profile.
- A fault in either the turbine array grid or in the main grid can propagate between each other since they are synchronously coupled.
- The link is cost effective unless distances (cable lengths) are very long.
**HVDC link**

- There is no capacitance issue, therefore no resonance between cables and other AC equipment. There is virtually no limit on the connection distance.
- There is no charging current for DC cables.
- Faults in the array grid do not propagate because the collection system and the main grid are not synchronously coupled.
- A DC link with VSC provides control over reactive power, therefore no extra reactive power compensation is needed.
- No contribution towards short-circuit current.

An AC link in comparison to a DC link is generally cheaper for shorter distances due to no extra costs of converters and converter transformers. But, if cables alone are considered then DC cables are less expensive than AC cables [220].

HVDC exists in two technologies:

1) Conventional thyristor based Line Commutated Converters (LCC).
2) Insulated Gate Bipolar Transistors (IGBT) based Voltage Sourced Converters (VSC). A typical VSC-HVDC system is shown in Figure 7.3.

**LCC**

Features of a conventional HVDC are briefly discussed below [19, 21]:

- A well established technology for land based transmission links.
- Suitable for very high capacity links at very long distances.
- Commutation voltage is needed for an offshore converter to work properly which is generally supplied by a synchronous compensator or a STATCOM.
- Deployment of filters and switchgear can take up an immense amount of space.
- Overall an LCC converter station takes about twice the area than that of a VSC converter station.

**VSC**

Characteristics of VSC-HVDC are briefly explored below [93, 221]:
- Self commutating (with high voltage and currents now possible with IGBTs) i.e. the current can be switched off hence no need for an active commutation voltage.
- Reactive power flow can be controlled at two terminals independent of each other.
- Overall size of VSC is smaller since harmonic distortion (at AC side voltage) is lower hence filters are not needed compared to LCC.
- VSC transmission losses are almost double that of LCC.

Figure 7.3: Typical VSC-HVDC system (adopted from [222])

For offshore wind farms, LCC is not well suited. Firstly, for commutation purposes it requires some source of AC current along with a reactive current source at the wind farm side and secondly, the size of conventional converters are quite large which adds towards structural costs of the platform [19]. It is also highly susceptible to AC network disturbances that can lead to a complete shut down of the HVDC system in worst case scenarios [32]. As an alternative, the VSC is a much better option both due to its ability to independently control active and reactive power exchange with the grid and its smaller installation size. For this reason, only the VSC is considered when HVDC links are discussed in this chapter.

Each of the two options can be connected either in a monopolar or bipolar configuration [223]. In case of a monopolar configuration, there is only one DC cable between the converters while the other end is connected to earth (ground), while in another configuration a monopolar connection can also be made with a return path as shown in Figure 7.4 (a) and Figure 7.4 (b) respectively. In a bipolar configuration, there are two DC cables between the two converters, both of them have opposite polarity to each other and are at a higher potential from the ground level. In cases when a single converter has a lower rated capacity than the wind farm, two or more monopolar connections
(Figure 7.4 (a)) can be made to form a bipolar configuration. A bi-polar configuration is illustrated in Figure 7.5.

In an HVDC link, converter transformers are usually connected with the rectifier and inverter at the offshore and onshore substations respectively. Their purpose is to step up the voltage level and link the AC network with the converter valves. For the sake of simplicity, in design options with HVDC, only a monopolar VSC link is used [76].

**Figure 7.4: Monopolar HVDC with (a) ground return (b) metallic return**

**Figure 7.5: Bipolar HVDC system**

### 7.3 Cost Models

Costs of wind farm components differ between manufacturers, therefore cost models [92, 224] are used to estimate the Capital Expenditure (CapEx) per layout.

#### 7.3.1 Wind turbines

The cost of wind turbines are generally inclusive of built-in wind turbine transformers but exclusive of the foundation, transport and installation costs, therefore these factors are considered separately. According to [224] the cost for turbines between capacity 0.5 MW and 2.5 MW (with a built-in transformer capable to step up generator voltage to 20, 30 or 50 kV) can be assumed to be a linear function of the power output. The cost of wind turbines within this capacity range can be evaluated from the following expression:

\[
Cost_{WT} = A_p + B_p P_{WT} \text{ (M€)}
\]  

(7.1)
where $P_{WT}$ is the rated power of a wind turbine, $A_p$ and $B_p$ are offset and slope constants with values -0.1848 and 1.0609 respectively.

In [225], the cost of wind turbines of capacity 2 MW to 5 MW is derived from data available from wind turbine manufacturers and is described by the following expression:

$$Cost_{WT} = 2.95 \times 10^3 \ln(P_{WT}) - 375.2 \text{ (k€)}$$ (7.2)

Transport and installation costs for all wind turbine units can be considered collectively, and although this depends on how far away they have to be transported, a general expression is assumed to include these costs [92]:

$$Cost_{WT-TI} = 1.1N_{WT}Cost_{WT}$$ (7.3)

where $N_{WT}$ is the number of wind turbines in the wind farm.

### 7.3.1.1 Foundations

Wind turbine foundations used for offshore installations are generally very expensive. The turbine foundations have to be transported from the manufacturing facility to the sea and then installed for each turbine. Therefore manufacturing, transport and installation costs should be calculated for each turbine foundation. Offshore wind turbines are generally installed in water depths of 2 to 30 meters. If foundation costs for onshore wind turbines and offshore wind turbines are compared it will be seen that there is almost a five fold difference. Normally, foundations for onshore turbines cost between 40 and 50 €/kW, but for offshore turbine foundations this value is around 250 to 300 €/kW in a water depth of 8 meters. The cost for offshore wind turbine foundations increases by 2% per meter for a sea depth greater than 8 meters. A general cost model is proposed in [17] that can be used to obtain approximate offshore wind turbine foundation costs. The influence of the turbine dimension is considered through a Load Factor (LF):

$$LF = h\left(\frac{D}{2}\right)^2$$ (7.4)

where $h$ is the turbine hub height in meters, $D$ is the turbine rotor diameter in meters. The foundation cost can then be calculated by the following expression [92]:

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\[ \text{Cost}_f = 320 P_{WT} \left( 1 + 0.02(S_d - 8) \right) \left( 1 + 0.8 \times 10^{-6} (LF - 10^5) \right) \text{(k€/turbine)} \] (7.5)

The transport and installation cost for the foundation units is estimated to be [92]:

\[ \text{Cost}_{F-TI} = 1.5 N_{WT} \text{Cost}_f \] (7.6)

where \( S_d \) is the sea depth in meters.

### 7.3.2 Submarine cables

The costs of submarine cables are dependent on a number of factors including voltage level, conductor size and the length. Furthermore, the cable has to be shipped on a vessel and laid 2 meters deep under the sea bed to prevent damage from sea currents and ship’s anchors. Therefore transport and installation (lay and bury) costs should also be added to the overall cable costs.

The cost model given in [224] is applied to calculate manufacturing costs of all AC cables (wind turbine array cables and cables from offshore platform to the shore) in the wind farm. This cost model is expressed below:

\[ \text{Cost}_{AC\_CABLE} = A_1 + A_2 \exp \left( \frac{A_3 S_n}{10^6} \right) \text{(k€/km)} \] (7.7)

\[ S_n = \sqrt{3} V_r I_r \text{ (VA)} \] (7.8)

where \( S_n \) is the rated power of the cable (VA), \( V_r \) is the rated voltage of the cable (V), \( I_r \) is the rated current of the cable (A), where \( A_1, A_2 \) and \( A_3 \) are cost coefficients.

The model allows calculation of cable costs at various voltage levels specified in Table 7.2.

<table>
<thead>
<tr>
<th>Voltage level (kV)</th>
<th>( A_1 ) (k€/km)</th>
<th>( A_2 ) (k€/km)</th>
<th>( A_3 )</th>
</tr>
</thead>
<tbody>
<tr>
<td>22</td>
<td>36.2076</td>
<td>73.8078</td>
<td>6.15</td>
</tr>
<tr>
<td>33</td>
<td>52.0326</td>
<td>75.4536</td>
<td>4.1</td>
</tr>
<tr>
<td>45</td>
<td>65.3256</td>
<td>77.4792</td>
<td>3</td>
</tr>
<tr>
<td>66</td>
<td>87.1008</td>
<td>79.125</td>
<td>2.05</td>
</tr>
<tr>
<td>132</td>
<td>249.5286</td>
<td>26.4594</td>
<td>1.66</td>
</tr>
<tr>
<td>220</td>
<td>402.7146</td>
<td>13.926</td>
<td>1.16</td>
</tr>
</tbody>
</table>
Figure 7.6 shows the relationship between the voltage level, rated capacity of the cable and the cost. The figure has been plotted using cable current, voltage and cross-sectional area given in [150] and using equations (7.7) and (7.8) to calculate the cost.

Since cost coefficients $A_1$, $A_2$ and $A_3$ for 275 kV were not available in [224], the cost of 275 kV cable is assumed to be the same as the cost of 220 kV cable. The transport cost of the cable is estimated to be 52 k€/km as in [92, 225], while the installation cost (lay and bury) is estimated to be 286 k€/km, therefore the total transport and installation cost ($Cost_{AC,T&I}$) is 338 k€/km. Overall costs for manufacturing, transport and installation is evaluated through the following expression:

$$Cost_{AC,CABLE,TOTAL} = Cost_{AC,CABLE} + Cost_{AC,T&I} \text{(k€/km)}$$

(7.9)

### 7.3.3 Offshore platform

The cost of offshore platforms given here is for empty platforms i.e. this cost does not include the cost of electrical equipment installed on them. According to [8], the average cost of a self-installing HVAC platform in a sea water depth of 20 to 30 meters is €40 million (£34.75 million). On the other hand, average cost of a self installing HVDC platform in a sea water depth of 30 to 50 meters is €74.75 million (£65 million).
An AC platform is used for an HVAC link, while a DC platform is used for an HVDC link. An HVAC offshore platform consists of collector transformers, MV & HV switchgears and reactive power compensation. A DC platform consists of collector transformers, converter transformers, converters and MV, HV and EHV switchgears. The cost of equipment installed on the platforms is calculated separately using the cost models given in the sections below.

7.3.4 VSC converters

The cost of a VSC converter is estimated to be €166.75/kW (£145/kW) from data available in [8].

7.3.5 HVDC cables

A cost model for DC cables is developed using cable data given in [226] and cable cost data given in [8] for two voltage levels (150 kV and 320 kV). These two voltage levels are assumed because a VSC converter in [226] operates at these voltages. Two types of DC cables, Extruded subsea and Mass Impregnated Insulated are commonly used in an offshore environment. The cost model is developed for Extruded subsea cable using average material and installation costs.

150 kV:

\[
Cost_{DC\_CABLE\_150kV} = 0.1486CSA + 736 (\text{€/m})
\]  

(7.10)

320 kV:

\[
Cost_{DC\_CABLE\_320kV} = 0.1017CSA + 869.71 (\text{€/m})
\]  

(7.11)

where CSA is the cable cross-sectional area in mm².

The number of DC cables that connect an offshore platform with the shore is dependent on the number of VSC converters. Since monopole configuration is used, each converter has one cable attached to it. The model provides costs for a single DC cable buried under the sea bed in a single trench.

7.3.6 Offshore and onshore compensation device

Components inside an electrical system for an offshore wind farm can generate or consume reactive power. For instance, wind turbine array AC
cables and HVAC cables linking the offshore platform to shore generate reactive power while collector transformers consume reactive power.

Offshore and onshore reactive power compensation devices are required to maintain voltage levels at buses inside a wind farm and, if required, to provide reactive power support to the grid. Table 7.3 provides the cost of a compensation device installed offshore and onshore [217]. An estimate size of a reactive power device can be established using Table 7.1 if the number of HVAC cables and their lengths are known. This device is placed at the onshore substation. All modern wind turbines feature power factor controls therefore it is assumed that any reactive power generated in the wind turbine array cables will be absorbed by the wind turbines through a power factor adjustment.

Table 7.3: Cost of offshore and onshore reactive power compensation

<table>
<thead>
<tr>
<th></th>
<th>Offshore</th>
<th>Onshore</th>
</tr>
</thead>
<tbody>
<tr>
<td>€/kVAR</td>
<td>28.75</td>
<td>17.25</td>
</tr>
</tbody>
</table>

### 7.3.7 Transformers

Collector transformers that step up MV to HV have either 2- or 3-windings. Based on Danish projects, a 32/150 kV transformer with a rated capacity of 180 MW can cost around €8 million, including foundation and installation costs [17]. However, the cost model proposed in [224] is used to estimate the cost of collector transformers. The cost in this model is dependent on the rated capacity of a transformer. It estimates the cost of one transformer unit with a capacity of between 6.3 MVA and 150 MVA with an MV level between 11 kV and 77 kV and an HV level between 47 kV and 140 kV using the following expression:

\[
Cost_{TRANS} = T_1 + T_2 P^{x}_{TRANS} \text{ (k€)}
\]

where \( T_1 \) is -153.05 (offset constant), \( T_2 \) is 131.1 (slope constant), \( g \) is 0.4473 and \( P^{x}_{TRANS} \) is the rated power of the transformer in MVA. It should be noted that this model will not work for transformers smaller than 6.3 MVA or greater than 150 MVA.

When size of the transformer is greater than 150 MVA, the model proposed in [227] can be used which is applicable for transformer rated powers between 40 MVA and 800 MVA.
where \( T_2 \) is 42.688 and \( g \) is 0.7513. The costs for both 2-winding and 3-winding transformers are assumed to be the same, as separate cost models for the two transformer configurations were not available. The cost of a converter transformer is also computed using the cost models given in (7.12) and (7.13).

### 7.3.8 Switchgear

All components at the offshore substation are connected using circuit breakers. The 2-winding collector transformers are connected with the MV bus through an MV switchgear and with the HV bus through an HV switchgear. The 3-winding collector transformers are connected with two MV buses using two MV switchgears and with one HV bus through one HV switchgear. The cost of an MV switchgear is calculated using [224]:

\[
Cost_{SG,MV} = S_1 + S_2 V_{RATED} \text{ (k€)}
\]  

(7.14)

where \( V_{RATED} \) is the nominal voltage in kV, \( S_1 \) and \( S_2 \) are offset and slope constants with values 40.543 and 0.76 respectively.

The quantity of MV switchgear varies according to the type of transformer considered. For instance, 3-winding collector transformers require twice as many MV circuit breakers as 2-winding transformers, but the quantity of HV switchgear is the same in both transformer configurations.

High-voltage switchgear is available in two categories i.e. AIS and GIS. GIS is commonly employed in offshore substations, whereas AIS are used in onshore substations. In this study only GIS switchgears are considered and their cost is tabulated [92] in Table 7.4:

<table>
<thead>
<tr>
<th>Voltage level (kV)</th>
<th>Single busbar GIS (Million €)</th>
</tr>
</thead>
<tbody>
<tr>
<td>132</td>
<td>0.92</td>
</tr>
<tr>
<td>150</td>
<td>0.965</td>
</tr>
<tr>
<td>275</td>
<td>1.25</td>
</tr>
<tr>
<td>320</td>
<td>1.39</td>
</tr>
<tr>
<td>400</td>
<td>1.58</td>
</tr>
</tbody>
</table>

At voltage levels where the cost data was unavailable, linear interpolation was used for the estimation.
7.4 Robust Offshore Wind Farm Electrical Layout

There are several components to choose from when creating an offshore electrical layout. These components are:

- Capacity of the wind turbines
- Type of array configuration
- Array voltage level
- Type of collector transformers (2-winding or 3-winding)
- Quantity and capacity of the collector transformers (with and without a redundant transformer)
- Type of transmission link to shore
- Transmission voltage level
- If an HVAC link is used, then the number of cables from platform to the shore (with and without a redundant cable) and the size of reactive power compensation
- If an HVDC link is used, then the capacity and voltage level of the converters and capacity of converter transformers.

Each of these components has further options, represented by a variable $N$, a combination of which leads to several possible electrical layouts. For instance, starting with the wind turbines; say there are two wind turbine capacities available to choose from e.g. a 2 MW or a 3 MW machine; to connect the turbines in an array configuration, a radial, starburst, tree or radial with end loop might be used. Therefore, either 2 MW or 3 MW turbines can be used in either of four array configurations. In this example, only 2 possible wind turbine capacities and 4 possible array configurations were discussed and this lead to 8 possible combinations. Similarly, when all components are considered collectively, where each component has its own options, this leads to several combinations and thus several possible electrical layouts. In order to narrow down the choice of layouts a novel methodology is proposed as shown in the flow chart in Figure 7.7.
7.4.1 Possible Design Options

To quantify the total number of electrical layouts, the following expression can be used:

\[ N_{\text{Tot},1} = (N_{\text{WT,\text{cap}}}.N_{\text{arr}}.N_{\text{arr,\text{Vol}}}.N_{\text{coll,\text{trans,\text{win}}}}.N_{\text{coll,\text{trans,\text{cap}}}}.N_{\text{transm,\text{Vol}}}) + N_{\text{coll,\text{trans,\text{red}}}} \]  \hspace{1cm} (7.15)

If an HVAC link is used between the offshore platform and shore:

\[ N_{\text{Tot,\text{HVAC}}} = N_{\text{Tot,1}}.N_{\text{transm,\text{cab,\text{quant}}}} \] \hspace{1cm} (7.16)

If HVDC link between the offshore platform and shore:

\[ N_{\text{Tot,\text{HVDC}}} = N_{\text{Tot,1}}.N_{\text{conv,\text{tr,\text{vol}}}}.N_{\text{conv,\text{tr,\text{cap}}}}.N_{\text{conv,\text{cap}}} \] \hspace{1cm} (7.17)

Total number of electrical combinations is found by the following expression:

\[ N_{\text{Tot}} = N_{\text{Tot,\text{HVAC}}} + N_{\text{Tot,\text{HVDC}}} \] \hspace{1cm} (7.18)

where \( N_{\text{WT,\text{cap}}} \) is the number of wind turbine capacities considered, \( N_{\text{arr}} \) is the number of different types of array configurations considered, \( N_{\text{arr,\text{Vol}}} \) is the number of different MV levels considered, \( N_{\text{coll,\text{trans,\text{win}}}} \) is the number of different types of collector transformer windings considered, \( N_{\text{coll,\text{trans,\text{cap}}}} \) is the number of
different collector transformer capacities considered, $N_{\text{trans}_V}$ is the number of different HV levels considered at collector transformer secondary windings, $N_{\text{coll}_\text{trans}_\text{red}}$ is the number of extra options considered having redundant collector transformers, $N_{\text{Tot}_\text{HVAC}}$ is the total number of electrical layouts when an HVAC link is used to connect the offshore platform with the shore, $N_{\text{Tot}_1}$ is the total number of combinations if the electrical layout from the wind turbines to the collector transformer is considered, $N_{\text{trans}_\text{cab}_\text{quant}}$ is the number of different quantities of HVAC cables considered, $N_{\text{Tot}_\text{HVDC}}$ is the total number of electrical layouts with an HVDC link from platform to shore, $N_{\text{conv}_\text{tr}_\text{vol}}$ is the number of different EHV voltage levels considered at the converter transformer secondary windings, $N_{\text{conv}_\text{tr}_\text{cap}}$ is the number of different capacities of converter transformers considered, $N_{\text{conv}_\text{cap}}$ is the number of different VSC converter capacities considered and $N_{\text{Tot}}$ is the total number of electrical layouts when both HVAC link and HVDC link options are considered.

As a case study, a 400 MW wind farm is used that is 50 km away from the shore. This capacity and distance from the shore was selected by analysing present and future installations of offshore wind farms in Europe. The analysis is presented in Chapter 1. It can be seen from Figure 1.3 and Figure 1.4 that 11 offshore wind farms with an exact capacity of 400 MW are proposed, implying they are either under construction, submitted or approved. Although it is difficult to build a consensus on the distance to shore, as seen from Figure 1.4 wind farms will on average be 50 km away from shore. The wind turbines inside the wind farm are assumed to be 400 m apart. Nevertheless, the method proposed can be applied to a wind farm of any capacity at any distance from the shore.

### 7.4.2 Quantity and rating of components

The methodology is demonstrated by applying it to a 400 MW wind farm. Therefore, all possible combinations for an electrical layout for this wind farm are created.

First of all, wind turbine capacities that are most popular are determined. This is done by analysing data from 120 offshore wind farms in Europe including those existing, under construction, submitted and approved offshore wind farms. From this analysis it was determined that 2 MW, 2.3 MW, 3.6 MW and 5 MW capacity wind turbines are very popular. (All wind turbines are
assumed to have power factor varying capability, such that they can vary their power factor between 0.95 leading and 0.95 lagging).

In order to connect these wind turbines together, four popular array configurations are investigated i.e. radial, starburst, tree and radial with end loop, as they are the typical array configurations within existing wind farms or are most commonly discussed in the literature. Details on these array configurations can be found in Section 1.2.2.4. The voltage level inside the array is assumed to be 33 kV, because this is a very commonly used voltage level inside offshore wind farms. All turbines have a built-in 0.69/33 kV transformer. Power generated by these wind turbines is collected at an offshore substation from where its voltage level is stepped up to HV level and then this power is transmitted to the shore.

Next, the voltage level for transmission has to be selected. The MV level can be stepped up from 33 kV to 132 kV, 275 kV or 400 kV. Each voltage level has its own characteristics which affects both the cost of the components as well as the electrical losses. Therefore, all three HV level options will be considered.

To scale up the voltage level from MV to HV, collector transformers are needed. These transformers can have either 2- or 3-winding. Both 2-winding and 3-winding transformers will have a certain MVA rating. Three different MVA ratings of 100 MVA, 120 MVA and 240 MVA [8, 228] are tested for 2-winding and 3-winding transformers in the case study. The quantity of the collector transformers is dependent on the capacity of the wind farm.

Next, power transmission options from the offshore platform to the shore are analysed. Both HVAC and VSC-HVDC link (monopolar) options are considered. In the case of an HVAC link, the power from the collector transformers is delivered to the shore through HVAC cables. Based on the collector transformer voltage level, an HVAC link can be established using 132 kV, 275 kV or 400 kV cables. The quantity of the cables depends on the current carrying capacity of a cable and the voltage level used. For example, a 132 kV cable can carry a maximum of 188 MVA, hence three of these will be employed to carry 400 MW to the shore but if 275 kV is considered, then one 392 MVA cable will be sufficient. Cable data from [150] is used.

In the case of an HVDC link, the VSC converter voltage levels can be 150 kV or 320 kV, according to ABB's Light technology [226]. In order to step up the voltage level from HV (132 kV, 275 kV or 400 kV) to EHV (150 kV or 320 kV),
converter transformers are used. Only 2-winding converter transformers are considered and these converter transformers can be available in different MVA ratings. In this case study, two different capacity converter transformers are used i.e. 200 MVA and 400 MVA. The quantity of converter transformers depends on the capacity of the wind farm.

The capacity of the VSC converters varies with the voltage rating of the converters. At 150 kV, the VSC converters can send rated powers of 190 MW, 373 MW and 570 MW, while at 320 kV the converters can send powers of 408 MW, 802 MW and 1224 MW [226]. Therefore, converters with all voltage levels and capacities are considered in the analysis. The quantity of converters depends on the capacity of the wind farm. DC cables with enough capacity to carry the power to the shore are chosen from [226].

An estimated size of the reactive power compensation device is established where the link to the shore is made through HVAC. The ability of wind turbines to consume or produce reactive power is exploited to maintain unity power factor at the primary side of collector transformers (MV bus). For an HVAC link, a reactive compensation device is installed onshore. For an HVAC link, the size of reactive compensation depends on the voltage, length and quantity of cables installed and is approximated through values given in Table 7.1. In the case of a VSC-HVDC link, having a reactive power compensation device is not mandatory, as converters have the ability to regulate reactive power.

All the above mentioned components and their options lead to several electrical layout combinations. Further, additional layouts are also produced with a certain level of redundancy to test the impact on the investment cost and reliability of the offshore electrical network. In this case study additional electrical networks with redundant collector transformers and redundant HVAC cables were created. The process of combination development can be visualised from Figure 7.8.

An $N_{Tot} \times N_{comp}$ matrix stores all electrical layout combinations in $N_{Tot}$ rows, whereas $N_{comp}$ defines the number of columns of this matrix and each column stores the type, capacity and quantity of each component.

Using the approach illustrated in this example, possible electrical layouts for an offshore wind farm of any capacity can be created. However, only those
components available from the manufacturers should be considered to keep the
analysis realistic.

It was noticed that for a 400 MW offshore wind farm, the combinations and
options analysed above lead to $N_{Tot} = 4,320$ electrical layouts (inclusive of
additional layouts with redundancy). Choosing the most feasible layout from
these 4,320 layouts is not straight forward. The method developed to short-list
this many layouts is explained in the section below.

![Figure 7.8: Combination of components and options for an offshore wind farm electrical layout](image)

### 7.4.3 Level of redundancy

If an electrical network consists of components that prevent interruption of
power delivery to the shore, in the case of a fault, then that network is
considered to have some level of redundancy. There are three types of
redundancies considered here:

1) An extra HVAC line that can carry power in case one goes out.
2) Collector transformers of additional capacity that can be used if one is
   non-operational.
3) Use of *radial with end loop* so that if one string is out of order, the other
   string can carry its power.

The more types of redundancy a network possesses, the higher its
*Redundancy Level*. For instance, if a network has only one extra HVAC cable
its redundancy level is 1, but if the same network also uses a *radial with end
loop* configuration then its redundancy level is 2 and so on. In layouts with no
redundancy the redundancy level is 0.
7.5 Short-Listing Layouts based on Investment Cost and Redundancy Level

The total number of possible electrical layouts for any large WF is enormous. Analysing so many electrical layouts for electrical losses, reliability based losses and investment costs is not practical. Therefore, short listing is performed to eliminate economically unfeasible options.

The first level of short-listing is performed to rule out layouts with components that are least likely as either they are too expensive or they would not add significant benefit. The following criteria can be used as a general rule for any WF:

1) The use of three VSC-HVDC links with capacity 190 MW each will lead to a total of 570 MW, out of which 170 MW will not be used, therefore two links with a maximum capacity of 380 MW can be used instead. This will save the investment cost of converters and cables. The probability of WF operation at full power is low therefore this is a fair assumption.

2) Any VSC-HVDC links (to shore) made with a converter capacity larger than 405 MW can be ignored. VSC-HVDC links up to 1224 MW were considered during the combination development.

3) A radial array configuration is normally built with an end-loop, therefore a simple radial array configuration can be removed from consideration. A tree configuration is more commonly used in existing wind farms than a starburst, hence a starburst can also be taken out of consideration.

4) Having a redundant collector transformer is too expensive so any extra capacity in transformers can be used to provide redundancy. For instance, if four 120 MW transformers are used and if one goes out, about 360 MW can still be transferred. This option is cheaper than having a fifth (redundant) transformer of 120 MW which may rarely be used.

Layouts with components mentioned in the four points above will be removed from consideration. Although these suggestions are to reduce the number of total layouts so that they can be easily analysed, if any of these suggestions are not relevant for a particular wind farm design they can be ignored. After first-level of short listing, 4320 options (electrical layouts) were
reduced to just 672 layouts, but this is still a large number, therefore further reduction is necessary.

In the next step, the investment cost is evaluated for each of the remaining layouts. The investment cost of each layout is calculated using the cost models given in Section 7.3. The cheapest and the most expensive of the 672 electrical layouts are determined, by sorting the list (containing investment cost of each layout) in ascending order. The cheapest layout was found to be €805.57 million while the most expensive layout was found to be €991.97 million.

To perform second level of short-listing, a criterion for investment cost is established to select only those layouts that fall into that range. This is to limit the layouts to a fixed budget range given by the wind farm owner. In the case studied, the wind farm owner is assumed to have a limited budget of up to €860 million. Therefore, electrical layouts that cost between €805.57 million and €860 million are short listed; this is also illustrated in Figure 7.9. After this short-listing level, the number of electrical layouts is reduced from 672 to about 189. These 189 layouts are the cheapest electrical layouts.

In the third level of short-listing, the previously selected 189 layouts are further reduced, based on their redundancy level. As established earlier, the redundancy level has a range between 0 and 3, where 0 indicates that a layout has no redundancy, whereas 3 indicates that a layout has the highest level of redundancy. This short-listing level allows only reliable electrical layouts to be filtered through. In the case studied, the redundancy level of 189 layouts is
calculated using the method described in Section 7.4.3. Layouts with redundancy level of 2 or above are selected while the rest are ignored. This level of short-listing reduces 189 layouts to just 33. These 33 short-listed layouts are the cheapest, yet they feature a certain level of redundancy. The investment cost and the level of redundancy for each of these 33 layouts can be seen in Figure 7.10.

![Figure 7.10: Investment cost and redundancy level of layouts after third level short-listing](image)

In the fourth (final) level of short-listing, these 33 layouts can be further reduced, depending on the wind farm design requirements which can be project specific. In this case study, three layouts are picked out mostly from the remaining 33 layouts, to further test them for energy losses and cost-benefit analysis. The three short-listed layouts are given below:

Case 1: The cheapest layout (selected from 672 layouts)
Case 2: The most reliable layout (redundancy level 3) yet cheapest in its category
Case 3: A medium level of reliability (redundancy level 2) yet the cheapest in its category
Case 4: (Optional)

Case 1 can be the cheapest of all the layouts; from the results obtained, the cheapest electrical layout has an investment cost of €805.57 million but it has no redundancy. This layout is found from the list generated after second level short-listing i.e. from 189 layouts in this scenario. This case is given
consideration to determine whether a cheap layout will have any efficiency advantage over other layouts.

Case 2 can be the most reliable layout (with the highest level of redundancy) and yet the cheapest in its category. For instance, out of 33 short-listed layouts, two layouts have a redundancy level of 3 (the highest level) while both of these layouts have different investment costs, the cheapest of the two layouts is selected. From the results obtained after short-listing, the layout that matches this criterion has an investment cost of €844.74 million and a redundancy level of 3. It can be seen from case 2 that when the redundancy level increases, the investment cost also increases.

Case 3 can be a reliable yet cheap option. As is observable from Figure 7.10, several short listed layouts have a redundancy level of 2, while the cheapest one out of these has a cost of €819.14 million. This layout has a mediocre level redundancy (redundancy level is 2), yet it is the cheapest in its category.

Apart from these three layouts, consideration of further cases is optional. The three layouts obtained have an HVAC link with the shore, therefore a fourth case is tested with an HVDC link. This layout is chosen so that an adequate energy loss comparison can be performed between layouts with different transmission options. This layout is chosen from the 33 short listed cases, it has a mediocre level redundancy (redundancy level is 2) and is the cheapest of the layouts with an HVDC link. The cost of this layout is €849.08 million.

Figure 7.11: Electrical layouts of four short listed cases
It might be against expectation that an electrical layout with an HVDC link was not amongst the first three cases. The reasons being high investment cost to establish the link and lack of a redundant export cable. Due to these two factors an electrical layout with a HVDC link is not shortlisted in the first three cases. Typically, a HVDC based design option becomes feasible when distances are large, therefore if for the same capacity wind farm a larger distance from the shore was considered, the results might be different.

The outcome of the short listing will vary according to the range of investment budget set by the wind farm owner, assumptions and criteria used and redundancy level required for the project.

The electrical layouts for four cases selected can be seen in Figure 7.11 while their equipment ratings are given in Table 7.5.

<table>
<thead>
<tr>
<th>Case</th>
<th>Wind turbine</th>
<th>Array</th>
<th>Collector Transformer</th>
<th>Converter Transformer</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2 MW</td>
<td>Tree 33/132</td>
<td>V (kV) 240 MVA 2</td>
<td>V (kV) MVA Quantity</td>
</tr>
<tr>
<td>2</td>
<td>2 MW</td>
<td>Radial +End 33/132</td>
<td>120 MVA 4</td>
<td>- - - -</td>
</tr>
<tr>
<td>3</td>
<td>2 MW</td>
<td>Radial +End 33/132</td>
<td>120 MVA 4</td>
<td>- - - -</td>
</tr>
<tr>
<td>4</td>
<td>2 MW</td>
<td>Radial +End 33/132</td>
<td>120 MVA 4</td>
<td>132/320 400 MVA 1</td>
</tr>
</tbody>
</table>

HVAC cables linking the platform to the shore in cases 1, 2 and 3 can carry a maximum of 134 MW each. In case 1 and 3, three HVAC export cables carry power from offshore platform to the shore, whereas in case 2 there are four HVAC export cables. The fourth export cable in case 2 is a redundant cable. Each collector transformer in case 1 has a capacity of 240 MVA, while in cases 2, 3, and 4 the capacity is 120 MVA each. The converter transformers in case 4 have a capacity of 400 MVA. The VSC converter has a rated capacity of 405 MW, therefore only one is needed for this wind farm. The MV, HV and EHV voltage levels, the capacity of wind turbines, the type of array configurations and the quantity and capacity of the components used in these four cases are listed in Table 7.5.

The following sections describe the way electrical losses and reliability based losses are computed for the four selected cases (layouts).
7.6 Electrical Loss and Reliability Calculations

This section focuses on the methodology behind the following tasks:

- Calculation of electrical losses
- Voltage/reactive power compliance and coordination
- Reliability assessment

The final outcome of all calculations is the cost of:

- Annual energy lost due to electrical losses.
- Annual energy loss due to reliability based losses

To calculate the energy losses, a wind power frequency curve is used to estimate wind speed and power production from the wind turbines.

7.6.1 Wind power frequency curve

The use of chronological wind speed measurements would take a substantial amount of time to perform load flow and to calculate electrical losses, therefore the power bin frequency method is applied. A generic wind power frequency curve is developed using the Weibull distribution and wind turbine power curves. The Weibull function given in (7.19) is used to estimate the wind speeds and their probability at a site during the year. The probabilities are converted into frequencies (in hours) by multiplying them with the total number of hours in a year (8760). Turbine power curves are used to convert wind speed into power output; this yields a wind power frequency curve as shown in Figure 7.12. Using this curve, the frequency of each power bin can be obtained. Shape and scale parameters $k_s = 1.8$ and $s_c = 11.2$ were used. These parameters were derived from wind speed data available at a site in the east coast of the UK. (Similar parameters have been reported in [229] for the North Sea).

$$f(v) = \frac{k_s}{s_c} \left(\frac{v}{s_c}\right)^{k_s - 1} \exp\left(-\frac{v}{s_c}\right)^k$$  \hspace{0.5cm} (7.19)
7.6.2 Voltage/reactive power compliance and coordination

With respect to the voltage compliance, the following requirements are fulfilled in terms of reactive power exchange between:

- The shore substation and the grid
- The arrays and the offshore platforms

as recommended in the Grid-Code [230]. According to these recommendations, a wind farm at the point of interface with the grid should be able to provide full voltage control over a reactive range. Also, a wind farm should be able to vary its reactive power at the grid interface from power factor 0.95 lead to 0.95 lag whilst operating at rated MW capacity. The minimum requirement at the MV bus is unity power factor although an offshore generator can provide a wider reactive range if agreed with the Offshore Transmission Owner (OFTO) [231].

To comply with these requirements, an automated voltage coordination algorithm is developed. The algorithm is an iterative procedure that adjusts the reactive power outputs/voltage set points of the turbines, HVDC and compensation devices to achieve the requirements stated above. For example, when calculating electrical losses, the voltage coordination is carried out for each power bin (in the power frequency curve) independently to ensure voltage compliance can be met for a number of different wind conditions.

7.6.3 Electrical loss methodology

Once a wind farm is voltage compliant, electrical losses can be calculated. Voltage magnitudes and angles are obtained for each node in the network after load flow analysis. Once voltages are known, current and $I^2R$ losses are calculated for every branch.
In general, losses inside transformers and VSC-HVDC are divided into two types, namely, load losses and no-load losses. No-load losses occur inside VSC converter stations due to transformers (iron losses) and phase reactors (dielectric losses). Load losses occur during power transmission and they increase with the loading of the DC transmission lines and converters. These losses occur due to ohmic conduction losses (in DC lines and converter stations) and switching losses (in converter stations). In PSS®E [76], the converter losses are evaluated as:

\[\text{Converter Losses} = L_{\text{NO-LOAD}} + L_{\text{LOAD}} I \text{ (kW)}\]  \hspace{1cm} (7.20)

where \(L_{\text{NO-LOAD}}\) represents no-load converter losses (kW) and \(L_{\text{LOAD}}\) represents load losses (kW/A) that increase with the amount of current. Transformer losses are calculated as in [76].

Cables with copper conductors are used, although aluminium conductor cables can also be used. Continuous current rating and technical data such as resistance, inductance and capacitance is obtained from [150, 206]. Electrical parameters for DC cables are obtained from [226]. The cable’s sizing is optimally chosen from the manufacturer’s catalogue, such that it carries the desired amount of power and is neither under nor over rated.

Electrical parameters for wind turbine 0.69/33kV transformers and converters were not available, therefore typical values are assumed. The wind turbine transformers are assumed to have a resistance of 0.8% and a reactance of 12% on a 100 MVA base, while no-load and load converter losses are assumed to be 500 kW (~0.1% of the rated HVDC transmission capacity) and 7.32 kW/A (~1.2% of the rated HVDC transmission capacity) per converter respectively. The converter loss ratios used here are very similar to that of HVDC Light technology in [232]. Collector transformer and converter transformers parameters are obtained from [228].

### 7.6.4 Reliability assessment methodology

Reliability assessment is based on a frequency and duration method [233], where only credible outages are considered. For the sake of simplicity, only single failures are considered as credible. For each failure/fault a \textit{fault clearance area} is identified, which is illustrated by an example in the Figure 7.13. In this figure, a fault on a radial string between ‘Bus 1’ and ‘Bus 2’ (Figure
7.13 (a)) will trigger the opening of the nearest circuit breakers and isolate part of the string with turbines ‘WT2’ and ‘WT3’, as shown in Figure 7.13 (b). This isolation of part of the string causes a Power Interruption (PI) of 7.2 MW, assuming that wind turbines were operating at the rated power of 3.6 MW each.

Similarly, Annual Energy Interruption (AEI) caused due to this fault is calculated using the wind power frequency curve, failure rate and repair times of components and (7.21). Each component in the electrical system is connected through circuit breakers. The same method is applied for all components in the network to determine reliability based energy curtailments (AEI).

\[
AEI(MWh \text{ year}) = \sum_{i=1}^{n} PI.P_i.H_i \cdot \lambda \cdot r
\]

where \( P_b \) is the power in a bin given in per units (p.u.) with respect to the installed capacity, \( H_b \) is the ratio of hours in that bin to the total number of hours (8760), \( \lambda \) is the failure rate (frequency of fault occurrence per year – occ/year), \( r \) is repair time in hours, \( n \) is the number of bins. Failure rates and repair times for offshore components are not easily available since offshore installations are fairly recent. Data available in [23, 217, 234, 235] are used instead. The values are listed in Table D.1 Normal situation in Appendix D. Average values between the best and the worst situations identified in Table D.1 were assumed for components for which the data was not available.

Figure 7.13: (a) Fault on line between Bus 1 and 2 under normal operation (b) Fault cleared by opening nearest circuit breakers
7.7 Results of the Analysis

The electrical and reliability based energy losses (MWh) are computed for four cases using the procedure and the parameters described in the previous section. Both types of losses are calculated assuming that the wind farm connected to the grid operates at unity power factor. The energy losses in MWh are then converted into €, using the cost of offshore energy, to estimate the cost of losses in each case. Finally, Net Present Value (NPV) analysis is performed to decide the economic feasibility of the four cases. The cost of offshore wind energy is estimated to be 6 €cent/kWh [3, 236] in all calculations.

7.7.1 Electrical losses

Electrical losses for all four short listed layouts are evaluated using the methodology described in the previous section. It can be seen from Table 7.6 that the lowest losses occur in case 2, while the highest losses occur in case 4.

Losses in case 2 should be the same as case 3 as same components are used in both, however in case 2 the redundant HVAC cable is also brought into use under normal operation which allows power flow through four cables instead of three. This allowed distribution of power equally among four cables and thus reduction in overall transmission losses.

Overall, case 2 leads to the lowest amount of electrical losses, whereas case 4 leads to the highest electrical losses. A greater portion of electrical losses in case 4 occurs inside the VSC converter stations, which amounts to about 3.11%, whereas losses inside the DC cables are just 0.26%. In cases 1, 2 and 3 the HVAC cables are the leading source of electrical losses compared to electrical losses in other components. By comparing losses inside wind turbine arrays, it was found that the tree configuration leads to higher electrical losses than the radial with end loop configuration.

7.7.2 Reliability based losses

Reliability based losses for all four cases (short-listed layouts) are given in Table 7.6. It can be seen from Figure 7.11 that both cases 1 and 3 have three HVAC cables carrying power to the shore. Tripping of a single HVAC cable in both cases will lead to a power interruption of 134 MW. Case 1, however has higher reliability based losses than case 3 because the tree array configuration
does not provide any redundancy, whereas the *radial with end loop* configuration can handle a single cable outage by connecting the redundant link between the two strings in case of an inter-turbine cable outage. Therefore, the *radial with end loop* configuration prevents power loss from several turbines in a string, whereas in a tree configuration, a single fault in the cable linking the last wind turbine to the MV bus can cause a major power interruption. Another difference between case 1 and case 3 is that case 1 has two 240 MVA collector transformers, whereas case 3 has four 120 MVA collector transformers. Hence outage of one collector transformer in case 1 leads to a power interruption of 160 MVA, whereas in case 3 the power interruption will be of just 40 MVA (when wind farm is operating at its rated capacity).

Case 2 has a redundant HVAC cable therefore outage of a single cable will not cause any power interruption because if power delivery from one cable is stopped, the redundant line will be brought into operation and it will carry that power. In case 2, power interruption due to loss of a single HVAC cable is zero. Furthermore, case 2 has four 120 MVA collector transformers implying that loss of one collector transformer will only reduce power by 40 MVA. The wind turbines are connected in a *radial with end loop* configuration, hence the loss of one cable will not lead to loss of power from all turbines in a string. For these reasons, case 2 leads to the lowest reliability based losses compared to the other layouts.

In case 4 the reliability based losses are 6.67%, although this layout has *radial with end loop* configuration (to connect wind turbines) and four 120 MVA collector transformers, but only one DC cable carrying 400 MW to the shore. Therefore, a fault in either converter transformer, VSC converter station or the DC line will lead to a complete power interruption.

Overall, case 1 leads to the highest amount of reliability based losses (as it has no level of redundancy) in comparison to the other three cases, but it is the cheapest option in terms of investment cost. Case 2 on the other hand has the highest level of redundancy and thus leads to lowest reliability based losses. However, case 2 is significantly more expensive. Cases 3 and 4 have significantly high total energy losses than case 2, but they are lower than that of case 1.
7.7.3 Total energy losses and investment cost

Total energy losses are computed as the sum of electrical and reliability based losses. The cost of losses is computed by multiplying the MWh energy losses with the cost of energy in €/MWh. It can be seen from Table 7.6 that case 1 leads to the highest overall energy losses. But on the other hand, it is the cheapest layout in terms of investment cost. Case 2 leads to the lowest energy losses but it is €39.17 million more expensive than case 1. Case 3 is a trade-off between reliability and investment cost; it has a mediocre level of redundancy and leads to 11.51% energy losses per annum. The investment cost of case 3 is also not significantly higher than case 1. Case 4 has lower energy losses than case 3 but has a higher investment cost.

An electrical layout can be chosen from these four short-listed cases depending on whether the requirement is to spend less (case 1), have a more reliable layout (case 2) or to have a reliable yet cheap layout (case 3). But when the rate of investment return and operation and maintenance costs over the lifetime of the wind farm also has to be considered, a Net Present Value (NPV) analysis should be performed.

7.7.4 Net present value analysis

The four cases are further tested using an NPV analysis to investigate their profitability. NPV is a technique used to analyse the profitability of an investment. A positive value indicates the project will be profitable, while a negative and null value indicates non-profitability and breaking even respectively [90]. The following expression can be used for NPV formulation:

\[
NPV(i,t) = \frac{N_1}{1+i} + \cdots + \frac{N_t}{(1+i)^t} - IC
\]

where \(N_k\) is the net cash flow at \(k\)th year representing income produced by selling wind power to the grid (after all losses), \(i\) is the discount rate, \(t\) is the number of years spanned by the investment, \(IC\) is the investment (capital) cost.

The lifetime of the wind farm is typically 20 years [237]. The operation and maintenance cost (O&M) is related to sea water depth and the distance from the shore for offshore projects. According to [238], O&M will increase linearly per annum, this cost is assumed to be €60,000/MW/annum. This amounts to about €24million/annum for a 400 MW wind farm. A linear increase in O&M
cost is assumed over the lifetime of a wind farm based on a 4% interest and discount rate.

Table 7.6: Losses as % of annual energy production, incurring cost of losses, investment cost and NPV per case

<table>
<thead>
<tr>
<th>Case</th>
<th>Electrical Losses (%)</th>
<th>Reliability based Losses (%)</th>
<th>Total Energy Losses (%)</th>
<th>Cost of Energy Losses (M€)</th>
<th>Investment Cost (M€)</th>
<th>NPV (M€)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2.91</td>
<td>12.10</td>
<td>15.01</td>
<td>16.26</td>
<td>805.57</td>
<td>500.11</td>
</tr>
<tr>
<td>2</td>
<td>1.81</td>
<td>1.25</td>
<td>3.06</td>
<td>3.31</td>
<td>844.74</td>
<td>687.27</td>
</tr>
<tr>
<td>3</td>
<td>2.12</td>
<td>9.39</td>
<td>11.51</td>
<td>12.46</td>
<td>819.14</td>
<td>551.61</td>
</tr>
<tr>
<td>4</td>
<td>4.00</td>
<td>6.67</td>
<td>10.68</td>
<td>11.56</td>
<td>849.08</td>
<td>521.91</td>
</tr>
</tbody>
</table>

Results from NPV analysis are provided in Table 7.6. It can be seen from this table that all four cases have a positive NPV, implying that all cases are implementable and will lead to profits over the lifetime of the wind farm. However, case 2 has the highest, while case 1 has the lowest NPV. The selection of the suitable design option from these four layouts depends on the requirements of the wind farm designer. A discussion to summarise various aspects of layouts is presented below.

### 7.8 Discussion

During the initial analysis it was found that there are 4,320 layouts possible for a 400 MW offshore wind farm. Minimum and maximum costs of layouts were €805.57 million and €991.96 million respectively. This comes to about €2 – 2.5 million/MW. Similar cost figures have been used in other studies such as [236], therefore the cost calculated through the cost models is justified.

Comparing four layouts, case 2 leads to the lowest total losses and apart from this it has a high NPV value, but also a high investment cost. On the other hand, case 1 leads to the highest overall losses and a low NPV, but it is the cheapest option. Case 3 might be a feasible option because neither the total losses nor the investment cost is too high, yet the NPV is also not the lowest. Case 4 is the most expensive option, mostly due to the cost of components to establish an HVDC link and the energy losses are also high therefore this case might not be very suitable.
The decision about the final layout for implementation has to be made by the wind farm developer or the wind farm owner. Features, losses, reliability and costs of each layout are different; some offer a higher level of redundancy, some have lower losses while some have a lower investment cost. Given these four cases, case 3 is a good trade-off between redundancy and investment cost, therefore, it can be declared as a robust offshore wind farm design option. This layout features a certain level of redundancy and the losses and the investment cost are not the highest among the four cases.

The methodology proposed allows selection of three robust layouts out of the possible 4,320. Short listing is dependent on the criteria imposed by the wind farm designer, with the procedure being sensitive to the components being considered, the budget and the level of reliability required.

The methodology presented is scalable according to the wind farm capacity. However, for very large wind farms (> 1GW) the number of electrical layouts will increase tremendously since multiple platforms will have to be considered. In that scenario, more assumptions and criteria will have to be introduced in the first level of short-listing to limit the electrical layouts, however the second and third levels of short-listing will still be applicable.

The case study performed in this chapter on a 400 MW considered real components available from manufacturer’s catalogues (e.g. AC cable ratings, capacity of VSC converters, voltage levels, capacity of wind turbines) during the electrical layout combination testing. However, when using the proposed methodology for a real wind farm design, the data about existing components available in the market should be collected and used. Although cost models have been used in this case study, if the cost of real components is available then they should be used instead.

### 7.9 Software Tool for Automated Design and Loss Analysis of an Offshore Grid

A novel software tool has been developed in this thesis that allows rapid creation and testing of large offshore wind farm electrical layouts. The software tool which has been developed is novel because currently no existing commercial power system software offers the facility to build and test electrical networks for an offshore wind farm with such minimal effort. Existing commercial software packages allow the user to create an electrical network by
selecting components and then manually building up the network. To evaluate electrical losses in existing software packages, parameters have to be continuously adjusted manually. For example, power generation of wind turbines have to be continually adjusted for each bin of wind power frequency curve. Furthermore, voltage levels should be made Grid Code compliant and for this, the power factor of wind turbines and HVDC converter settings may also need adjusting for each power bin. Often, existing software features either automated load flow or automated electrical loss studies or automated reliability studies. It is difficult to find a commercial software that can do all of these studies with minimal user input.

The main features of the software tool developed are described as follows:

- The software utilises a GUI that can be used to drive the design of an offshore wind farm with or without platform interconnections.
- It creates a steady-state network model for an offshore wind farm that can be used as a starting point for load flow and short-circuit calculation studies.
- It carries out automated calculations for: load flow, size of reactive power compensation required, calculation of electrical losses and assessment of annual reliability based energy losses.
- It uses manufacturer’s data from the catalogues of components (where available) for calculation of losses.

7.9.1 Implementation of the software tool

The tool has been developed using Python programming language, QT, PyQT library (for the development of the user interface) and PSS®E (a power system analysis software) [76] API.

7.9.2 Input parameters

The structure of the software tool and the input parameter options are designed to build an offshore wind farm electrical layout, therefore it is essential that a user has knowledge of typical offshore wind farm components. For instance, the user should know that a large offshore wind farm normally consists of wind turbine arrays (MV cables, turbines and turbine transformers), an offshore collecting point (platform/s carrying two or three winding MV/HV collector transformers, MV/HV switchgear, HVDC converter stations) and
transmission circuits (to link offshore platform/s with an onshore substation), as illustrated in Figure 7.1. There can also be a number of offshore platforms interconnected via high voltage AC (HVAC) cables for the same offshore wind farm.

Electrical parameters of components such as resistance, inductance and susceptance of AC cables available from manufacturer component catalogues are stored in a common database as illustrated in the flow chart in Figure 7.16. Depending on the component category, relevant electrical parameters are loaded into the GUI dropdown menu from the database as shown in Figure 7.15. For instance, if a user wants to select a 33 kV array cable, the following cables appear in the drop-down menu: 70 mm², 95 mm², 120 mm², 150 mm², 185 mm², 240 mm², 300 mm², 400 mm², 500 mm² and 630 mm². By selecting any of these cables the electrical parameters are automatically adjusted in the electrical network.

The following points describe the complete set of information that should be entered through the GUI of this tool:

1. The choice of nominal voltages for turbines, MV and HV (see Figure 7.14).
2. The size of the wind farm and size of each wind turbine (see Figure 7.15).
3. The selection of the transmission system to be used (AC or DC).
4. The number and type (AC or DC) of collector platforms, the number and arrangements of MV and HV busbars and the number and type (2-winding or 3-winding) of collector transformers.
5. The layout of the arrays (for example, radial turbine strings, radial turbine strings with end loops, array tree configuration or starburst configuration), a screenshot is shown in Figure 7.15.
6. If DC transmission is selected then the number of HVDC converters per platform, and the voltage and rating of these converters need to be provided. The number and rating of converter transformers and the number of cables connecting each converter to the shore are required.
7. The type of HVDC link (e.g. monopolar, bipolar-metallic return, bipolar-ground return) also needs to be selected.
8. If HVAC transmission is selected, then the number of AC cables connecting the platform(s) with the shore needs to be provided.
9. For each AC or DC cable, the length has to be specified and the cable type can be chosen from the catalogue of components displayed as a drop down menu as shown in Figure 7.15.

10. If there is more than one platform or there are tie-lines to other offshore wind farm platforms, then the cables linking the platforms need to be selected as discussed in point 9.

To perform reliability studies, parameters such as failure rate (occurrences per year) and duration of failures (in hours) of components should also be entered as input parameters. Furthermore, the wind power frequency curve (to represent wind power output of the wind farm throughout a year) is also needed in order to calculate the energy losses.
7.9.3 Creation of an electrical network

There are two options in terms of entering data:

1. A new design can be created entirely driven by the user interface (following all ten steps mentioned in Section 7.9.2).
2. Modification of an existing design where the previously created offshore design is loaded into the user interface and then modified.

For new designs, the user enters data into the forms that can be used for instant creation of the network, otherwise it can be saved in a configuration file. When modifying existing designs, any previously saved configuration files can be loaded into the software that populates data back into the forms. Using this save and read functionality, a set of sub-options or scenarios can be created quickly with minimal effort. More screenshots of the software tool can be seen in Appendix E.

The information from the configuration files and the manufacturer catalogues are then fed into PSS®E through the Python API (Application Programming Interface), where the creation of the actual network model takes place. In the network model formed, all components are connected with busbars.
through circuit breakers that allow fault isolation during reliability studies. At the completion of the network model, a load flow test is run to ensure solvability of the model. The complete design and calculation process from entering data until energy loss evaluation is explained by a flowchart shown in Figure 7.16.

Reactive power compensation is an essential part of the design and calculation process as shown in Figure 7.16. It ensures a good voltage profile for the offshore wind farm by managing reactive power production from medium voltage (MV) array cables and HVAC cables and reactive power consumption in collector transformers. An acceptable voltage profile is an essential pre-requisite for realistic estimation of electrical losses which is the next step in the process, shown in Figure 7.16. For AC links to shore, onshore reactive power compensation is automatically added, whilst for DC links no compensation device is needed since Voltage Source Converters (VSC) can regulate the reactive power flow.

Figure 7.16: Design and calculation process
7.9.4 Load flow and loss evaluation studies

The software tool makes the electrical network Grid Code compliant to perform load flow and loss evaluation studies. Both electrical and reliability based losses can be calculated through an automated procedure.

The calculation of electrical losses is based on a number of different loading conditions where each is created using a wind power frequency curve (as shown in Figure 7.12). A voltage coordination and reactive power compensation strategy is developed (described in Section 7.6) to ensure Grid Code requirements are followed. This check is performed for all loading conditions prior to electrical loss evaluation. The final outcome of this calculation is the annual MWh estimation of electrical losses that is converted into cost (€) using a €/MWh cost value.

The reliability based loss evaluation is based on a state enumeration technique which is a frequency and duration method [233]. The state enumeration technique processes only the credible failures and, based on their frequency of failure and duration, calculates the wind energy that will be not delivered per year. For each failure, a fault clearance area is located (as shown in Figure 7.13) and possibilities in terms of network reconfiguration are considered. If there are no possibilities in terms of reconfiguration, or they are limited, the wind power cut takes place and the energy not delivered is calculated using the wind power frequency curves. The main output of the reliability evaluation is an estimated MWh energy loss that can be converted into costs (€) similar to the conversion discussed above for electrical losses. The procedure for reliability based loss calculation is described in Section 7.6.4.

The software tool can be further improved by integration of cost models described in Section 7.3. This will allow the user to evaluate the investment cost for each electrical layout which can lead to a more complete cost-benefit analysis.

7.10 Case Study

As a test study, a sample network of a 400 MW wind farm is created using the software tool in PSS®E. The inputs to the software tool’s GUI are the parameters for the wind farm electrical layout. The input parameters that can be entered are discussed in Section 7.9.2 and illustrated through Figure 7.14
and Figure 7.15. The outcome of the calculation and developed software is the electrical network built into PSS®E as shown in Figure 8.4.

In the network created in this case study the wind turbines are connected in a radial configuration at MV level of 33 kV. Four 2-winding collector transformers scale up the voltage from 33 kV to 275 kV and from this point the power is transmitted to shore by a VSC HVDC link in a monopole configuration.

7.10.1 Parameters and loss studies

Failure rate and repair times are collected from various sources (as mentioned in Section 7.6.4 and these are given in Appendix D.

7.10.2 Network development time

This software significantly reduces the time required for creation of a large network. In this example of a 400 MW wind farm, the offshore network has 1,042 buses, 843 circuit breakers, 211 branches, 202 machines, 206 transformers (wind turbine, collector and converter), 2 VSC converters (rectifier/inverter) and 1 HVDC line. Setting up all these components in PSS®E one-by-one manually (with names) will take a long time (perhaps a day or longer). However, by using this software tool, it only takes couple of minutes to fill-in the GUI and seconds for the network creation in PSS®E. The naming of the components is also done automatically so that the user can identify each component in the network. Automation of the design and calculation process illustrated in Figure 7.16 saves a considerable amount of time.
Figure 7.17: Diagram of network created in PSS®E by the software tool
7.11 Summary

This chapter presented a novel methodology for selection of a robust design option (electrical layout) for an offshore wind farm through cost-benefit analysis. A case study has shown that a large capacity wind farm can have several possible electrical layouts from which a wind farm designer has to choose the most feasible layout. At present, no methodology allows such comprehensive and detailed investigation and short-listing of electrical layouts for an offshore wind farm.

At first, a comprehensive list of possible layouts is generated, considering components that are available and that can be used for the electrical layout design. Technically possible combinations of various components and their options such as capacity of wind turbines, MV/HV/EHV levels, types of array configurations, capacity of collector transformers, types of transmission links etc. lead to several electrical layouts. Then, through a process of multi-level short-listing these electrical layouts are filtered down. The investment cost of the layouts is calculated using the cost models.

Multi-level short listing is then performed to narrow down the selection. In the first level, technically non-feasible options are eliminated. In the second level, layouts are filtered according to the investment budget available. In the third level, layouts with a higher redundancy level are selected from previously shortlisted layouts. In the final level, the three cheapest yet most reliable options are picked out and considered for further analysis. More than three options can be considered but this is optional.

Further tests on the three selected layouts are performed to calculate annual electrical and reliability based losses. The NPV is analysed to determine the most and the least profitable layouts for a 20 year lifetime of the wind farm.

Since each layout has a different capital cost, redundancy level, losses and NPV the final choice depends on the criteria or preferences set by the wind farm designer. Choice of an electrical layout after analysing several possible configurations can lead to a justifiable solution. The methodology can be used by wind farm designers or wind farm owners in general. This technique is applicable to an offshore wind farm of any size and layout and at any distance from the shore.
Furthermore, this chapter also presented a novel software tool which has been created for the automated design and loss analysis of an offshore wind farm. The software tool developed has a user-friendly interface and it allows a quick creation of an offshore wind farm electrical network. It also features an automated electrical and reliability loss evaluation procedure that enables fast analysis of energy losses and requires minimal effort. Using this software, several offshore wind farm electrical layouts can be tested. The layouts may differ in array configurations, medium or high voltage levels, type of transmission link to the shore, type and quantity of collector transformers, number of platforms and electrical parameters. The chapter also describes the design and calculation process of the software, the input parameters required and the parameter save and read functionality. The software tool significantly reduces both the time and effort required to build and test a large offshore wind farm electrical system in a commercial power system software PSS®E.
Chapter 8

Conclusions and Future Work

This thesis proposed improvements to offline and online modelling techniques for offshore wind farms. The potential areas of improvement were identified through a comprehensive literature review. The thesis also presents an overview of the present and future offshore wind farm installations in the UK and the rest of Europe. It was observed that in future the presence of wind power in the network will increase mainly through offshore wind farms. These offshore projects will have very large capacities and will be further away from the shore.

Two types of modelling are considered in this analysis i.e. offline studies and online studies. In normal practice, offline studies are performed during the design phase of a wind farm and when a pre-feasibility study has to be performed. Generally, offline modelling is performed prior to integration of a wind farm into the network. But due to the growing presence of high capacity wind farms in the network, online modelling is gaining popularity amongst transmission and distribution utilities. Online analysis will allow system operators to carry out transient stability simulations using data collected in real-time from network components. The earlier chapters of this thesis presented models for online studies and this is followed by models for offline use in the later chapters.

The presence of several rapidly varying power producing units (wind farms) in the system requires fast modelling tools for steady-state as well as dynamic analysis. A new aggregation model has been developed in this thesis that allows a large wind farm to be represented by few wind turbines determined by probabilistic analysis. The developed methodology takes into account layout of the wind farm (position of wind turbines), wake effects, array collector system and site’s wind characteristics. The methodology works by first calculating the wind speed at each turbine for every wind measurement. This calculation is performed through VebWake, a software program developed (in this thesis) to
calculate wind speed at each turbine in a wind farm. Then, clustering wind turbines receiving similar wind speeds using the Support Vector Clustering technique and then arranging these clusters further into groups. The most probable group is chosen (through probabilistic analysis) as the best representation of the wind farm for the entire year. As a case study, an aggregate model of a large wind farm consisting of Doubly Fed Induction Generators (DFIG) is established. Results from probabilistic aggregation model showed that a 49 turbine wind farm can be modelled with just 3 equivalent wind turbines for the whole year. The dynamic response from the aggregate model is compared (at two wind conditions) against the detailed wind farm response as well as against two existing aggregation models. A simulation time reduction of up to 96% was achieved in the case studied. The model is intended to be used by utilities and wind farm operators during real-time, online, simulation studies which are gaining popularity among transmission system operators. The proposed probabilistic aggregation model is compared against existing aggregate models to test simulation time reduction, accuracy of dynamic response, ease of setup and use. It was found that the developed probabilistic aggregate model is practical, accurate and easy to use for online analysis. The development of the VebWake software program and development of a new probabilistic aggregation technique are the first and second original contributions of this thesis.

To facilitate the increasing need for accurate yet fast simulation models, a new method to probabilistically estimate the power production from a wind farm is developed. This method is useful during real-time online studies. The methodology evaluates the fluctuation in wind speed at a turbine under wake in a wind farm. This fluctuation occurs due to turbulence added by the wake of the turbines. Due to this fluctuation, at a given incoming wind speed and direction, a wind turbine under wake can produce different amounts of power. Therefore, a probabilistic power output is more likely than a deterministic power output. To simulate this fluctuation inside a wind farm, Frandsen’s turbulence model is combined with Jensen’s wake model. The model is useful to obtain probabilistic power outputs from wind farms for a forecasted wind condition. The wind power output obtained from this method can allow system operators to decide on the unit commitment and spinning reserve allocation. Due to a lower computation burden and reduced simulation time, the model is
useful for online studies (instantaneous power estimation). The probabilistic wake effect model was applied to calculate power output (in real time) and energy yield from a wind farm. In the case studied (98 MW wind farm) it was found that deviations in power output for a given wind scenario reached as large as 7 MW whereas on average this difference was about 2 MW. When used for energy yield calculation the results did not show a significant difference than with a deterministic wake model. Therefore probabilistic wake model should be used for real time power output estimation from a wind farm whereas deterministic wake model should be used for energy yield estimation. The development of probabilistic wake model is the third original contribution of the thesis.

Realistic estimation of energy yield can only be obtained once all factors that influence the outcome have been taken into account. Several factors can affect the overall energy yield from a wind farm. These factors include wake effect, electrical losses, reliability based losses and wind resource variation. Profit from a wind farm depends on the energy sold to the grid, therefore it is also important to have a good estimate of potential energy curtailments if a wind farm is being built in an area with a transmission bottleneck. A new analytical method is proposed to evaluate the reliability based losses and energy losses due to curtailments. The reliability method takes into account both single and all multi-component failures for four array collector systems. A brief investigation involving three wind farms in a hilly area revealed that there is no correlation between wind speed and turbine availability. This might not be the case for other wind farms located on plains and offshore, therefore all possible correlations were investigated in conjunction with transmission line loading. Through correlation coefficient analysis, it was found that maximum curtailment losses occurred when wind speed was high, turbines were available and the transmission line was occupied. Pre-feasibility studies often under estimate the loss due to wake effects and it was shown through a sensitivity analysis that wake losses can be high. From case study it was found that energy yield was reduced due to: wake losses by 2% to 7%, electrical losses by 2.16% to 2.84%, wind farm component unavailability by 0% to 13.05% and energy curtailment by 0% and 14.04%. A 10% variation (increase) in wind resource increased the energy yield by 13.05% but energy curtailments also rose up by 6.46%. The impact of energy losses due to various factors on capacity
factor of a wind farm was also analysed. It was found that when all losses are included, the capacity factor decreased from 39.8% (without any losses) to 26.9% (in worst case with all losses). The methods proposed are useful for offline pre-feasibility studies regularly carried out prior to wind farm installation. These methods can enable a wind farm owner to reach a more informed decision about feasibility of the project and whether curtailments are a better option than transmission line reinforcement. The reliability based loss evaluation method and the wind energy curtailment loss evaluation method are the fourth and the fifth original contribution of the thesis.

Curtailment of wind energy is commonly carried out by shutting down a few wind turbines inside the wind farm. A new methodology is presented in this thesis that allows wind farm operators to identify turbines in an existing wind farm that receive higher and lower wind speeds. Turbines that stay under single or multiple wakes can more often accumulate fatigue loading, therefore it is suggested that these turbines should be given priority during the curtailment shut down procedure. The results obtained are also useful to schedule preventive maintenance. Wind turbines facing high wind speed (free-stream wind) during the year produce the most amount of power. Therefore they should be scheduled for preventive maintenance on less windy days so that they are operational most time during the year and produce power when wind is high. As a case study, high and low wind speed receiving turbines were identified in a 49 turbine wind farm. From the geometry of the wind farm and site wind conditions studied, it was found that turbines deeper inside face lower wind speeds and are more prone to fatigue damage as compared to those outside. This method is the sixth original contribution of the thesis.

With an increase in offshore wind farm capacity, the design complexity has also increased. Due to the millions of € of investment cost involved in these large-scale wind farm projects, careful consideration is needed for their design. A new methodology is developed that investigates various possible electrical layouts for cost-benefit analysis and filters out the few best layouts based on the criteria used. At first, a list of possible electrical layouts is generated using available components from the manufacturers. Then, through a multi-level short listing process, the total number of layouts is reduced to just a few. These short-listed layouts are further tested for electrical and reliability based losses. The electrical parameters are collected from the manufacturer’s catalogues
(where possible), whereas failure rates and repair times are gathered from various studies. An NPV analysis on the short-listed layouts further helps in deciding which layout is economically more feasible. The case study showed that for a 400 MW wind farm there were more than 4300 possible layouts, based on the components considered. Through the short-listing procedure, the total number of layouts was reduced to just three. From these layouts, only one was chosen as it was a good trade off between redundancy and investment cost. This layout had electrical losses of about 2.12%, reliability based losses of 9.39% and an investment cost of €819.14M. The outcome of the method depends on the criteria imposed and the assumptions made during the short-listing process. This method is the seventh original contribution of the thesis.

A bigger capacity of wind farms implies use of more equipment involving large sets of buses and cables. Developing a network model for a large wind farm with all buses, cables and switchgears etc. in a commercially available power system can be a tedious and time consuming task. It was noticed that a network for a wind farm of 400 MW can easily exceed more than 1000 buses, 200 cables and transformers. Moreover, entering electrical parameters for each component can take the user even longer. A novel industrial-grade software has been developed using Python, QT and Python QT programming languages. The software tool allows the user to enter wind farm data by a Graphical User Interface (GUI). The user can select electrical parameters for components from manufacturer’s catalogues that are stored in the software database. Once all the data has been entered, the software tool automatically creates the electrical layout for an offshore wind farm in PSS®E. The tool also enables a user to quickly evaluate the electrical and reliability based losses of the electrical layout developed. The design and calculation process, along with screenshots of the software tool developed are presented in this thesis. Overall, the tool allows fast development of an electrical layout with minimal effort. Using this software tool, several electrical layouts can be tested easily in a very short space of time. The developed software is the eighth original contribution of the thesis.

8.1 Future Work

Although various areas for improvement were identified in the first chapter and summarised in the form of problem statements but some of these areas
could not be addressed due to limitation of time. The following section provides areas identified but not addressed as well as potential further improvements of the methodologies developed in this thesis. A general overview of the possible challenges that the wind industry may face in the near future is also discussed in this section.

8.1.1 Future work on modelling

This section describes possible advancements that can be made to the work presented in this thesis.

The cost-benefit methodology developed in Chapter 7 is very new and it analyses all components for an offshore wind farm design collectively. Variation in wind speed inside the wind farm due to wakes was ignored during the cost-benefit analysis. This is because the aim was to test and obtain the best offshore wind farm design with complete set of electrical components that should be used. In the design phase however, consideration of wake effects is essential when deciding on the placement of the wind turbines. To advance the methodology developed further, the physical layout of the wind turbines can be considered in conjunction with the electrical system of the wind turbine array because both of these factors are linked. If wind turbines are placed too close to each other, it increases the wake losses, if they are quite far apart, however, it increases the distance and hence the costs of the array cables. In terms of wind turbine array cabling configurations, only radial, starburst, tree and radial with end loop configurations were considered in that chapter. An optimisation algorithm can be developed in the future to optimise both the placement of wind turbines as well as the array cabling route. This will allow analysing the problem holistically, i.e., placing wind turbines in such a way to reduce wake losses yet optimising the electrical cable costs. Furthermore, different medium voltage levels can also be considered as part of overall optimisation. This way an optimal wind turbine array electrical system can be obtained, that is cost-effective yet leads to lower losses. The optimised array system can be studied in conjunction with the methodology developed in Chapter 7 to obtain a more cost-efficient overall wind farm design. The need for such holistic optimisation approach was also identified in problem statement 2 mentioned in Section 1.4.2 but could not be completed due to limitation of time.
The cost-benefit methodology proposed for wind farm electrical layout design (in Chapter 7) can be advanced to incorporate very large offshore wind farms that are bigger than 1 GW. More criteria and assumptions will have to be introduced for the optimal design of such large wind farms because multiple platforms will become a possibility. In that case, the methodology should be able to provide for an optimal choice of components at each platform. Overall, it should lead to a cost-effective and reliable electrical layout for a wind farm with multiple platforms. To reduce the explosion of possible design options in a multiple platform wind farm a true optimisation algorithm can be developed for multi-objective optimisation. The objective function should be to maximise the reliability of design while minimising the capital costs.

The probabilistic aggregate model developed in Chapter 4 has been tested on wind turbines with Doubly Fed Induction Generators (DFIGs). It will be interesting to analyse how the model performs on a Full Scale Converter Rating wind turbines. The probabilistic aggregate model can be further validated by testing and comparing the transient stability plots with detailed wind farm model under all wind conditions i.e. for all wind speeds (within turbine operating range) and wind directions (0° to 360°). Furthermore, an aggregate model for a radial array configuration has been proposed in that chapter, because this configuration is very commonly used in wind farms. An aggregate model for other array connection layouts such as starburst and tree layout can also be developed. Apart from this, probabilistic wake effect model developed in this thesis can be used instead of Jensen’s wake model.

The correlation between wind speed and wind turbine availability in Chapter 5 could only be tested for three existing wind farms. More wind farms should be analysed to see if there is any correlation between the wind speed and the wind turbine availability. The curtailment method presented in Chapter 5 allows determination of energy that will be curtailed in a year. A study can be performed in which energy from a wind farm installed in an area with a transmission bottleneck can be stored in the storage device instead of spilling the energy through curtailments. A cost-benefit analysis can determine the advantage of either curtailments or installing a storage device as compared to building a new transmission line. Different types of storage devices can also be explored and their investment costs compared. Additionally, the model proposed in that chapter assumes that the transmission line has a fixed
transfer capacity, instead, seasonal line ratings or dynamic line ratings could be introduced. The method could be tested with a more complex power network rather than with a single line connected wind farm.

The probabilistic wake model proposed in Chapter 3 should be validated against wind speed measurements obtained at wind turbines in several wind farms. Measured wind speed data at the wind turbines was not available. This is the first time such a model has been devised, therefore there is certainly a room for further testing and improvement.

### 8.1.2 Challenges to overcome for Round 3 offshore wind farms

This section provides an overview of technical challenges that the wind farm industry is likely to face within the next 7 or 8 years. Round 3 in the UK was announced in January 2010, however installations of the wind farms may only begin to take place around 2017 as so far, only zones have been identified. This round includes wind farms with a big capacity and distances which are very far away from the shore as compared to both Round 1 and 2 wind farms. Offshore wind farms may be built as far as 300 km away from shore [239]. Such extensive distances bring new challenges, including greater sea depths. It is forecasted that offshore wind turbines may have to be installed in sea depths of 60 m which is much deeper than the current depths of 20 m. For this purpose, better foundations are needed for offshore turbines and offshore platforms since capacity and thus weight of turbines will increase. Commuting is another issue, as vessels currently used for turbine and substation installation have to turn back to shore if the sea is predicted to get rough. Newer vessels will be needed that can withstand such weather conditions and can stay at the site for days. According to an estimate, an investment of €2.25 billion (£2 billion) might be needed just for one installation vessel. Platforms will have to include medical facilities in case the crew gets injured so they can be treated offshore, as travelling time by air (helicopter) to get to shore may take around 3 hours. Self installing platforms should be built that can sail and install themselves which can save extra installation costs.

Installation of cables to connect wind farms this far away also presents another major issue. A single long cable is a preferred option, rather than adding joints which makes the offshore network more prone to faults. Making a cable joint in a submarine cable takes around a week and is extremely
expensive. On the other hand, longer cables have a greater mass, and generally the weight of a cable is 90 kg/m therefore a 100 km cable weighs around 9000 tonnes. Transportation of such heavy cables from the manufacturing plant to the shore and then their transfer onto the vessel will pose additional challenges. The development of such long cables is another issue as the manufacturers may face an excessive demand which can add delay in supplying them. The chances of these transmission cables under the sea getting dragged by shipping anchors will increase as their length and quantity increases. Therefore, a Global Positioning System (GPS) mapping of cable routes may be needed to avoid such damage.

Much higher DC voltage cables will have to be tested to reduce load losses during transmission. At present, all turbine arrays use AC cables but DC voltage should also be considered as an option to connect array turbines and this might even lead to elimination of converters from the turbines. Furthermore, keeping in mind the aforementioned issues, the cost of the overall project has to be minimised. Connections between wind farms is a possibility which can be looked into further as this will not only reduce the offshore cabling cost but also add a certain level of reliability in security of supply. On land, the equipment and land leasing cost (for an onshore substation) will also be reduced. However coordination between the wind farm manufacturers will be needed to enable wind farm interconnection. A set of rules for this coordination might have to be established that must be followed by all parties involved. This is to have complete awareness of expectations and so nothing is left out.
References

References


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A. S.-Dobakhshari and M. F.-Firuzabad, "Integration of large-scale wind farm projects including system reliability analysis," *IET Renewable Power Generation*, vol. 5, no. 1, pp. 89-98, 2011.


References


References


References


REFERENCES

References


References


References


Appendix A

Parameters of Wind Turbine

Table A.1: Parameters of the wind turbine

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type</td>
<td>Pitch regulated, Yaw controlled</td>
</tr>
<tr>
<td>Rotor diameter (m)</td>
<td>80</td>
</tr>
<tr>
<td>Area swept by the rotor (m²)</td>
<td>5,027</td>
</tr>
<tr>
<td>Number of blades</td>
<td>3</td>
</tr>
<tr>
<td>Height (m)</td>
<td>60 – 67 – 80</td>
</tr>
<tr>
<td>Cut-in wind speed (m/s)</td>
<td>4</td>
</tr>
<tr>
<td>Nominal wind speed (m/s)</td>
<td>15</td>
</tr>
<tr>
<td>Cut-out wind speed (m/s)</td>
<td>25</td>
</tr>
</tbody>
</table>

Table A.2: Wind turbine generator parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency (Hz)</td>
<td>50</td>
</tr>
<tr>
<td>Maximum power (kW)</td>
<td>2000</td>
</tr>
<tr>
<td>Generator end voltage (kV)</td>
<td>0.69</td>
</tr>
<tr>
<td>Transformer secondary end voltage (kV)</td>
<td>33</td>
</tr>
</tbody>
</table>

Table A.3: Wind turbine parameters of DFIG machine

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator type</td>
<td>DFIG</td>
</tr>
<tr>
<td>Rated mechanical power (MW)</td>
<td>2</td>
</tr>
<tr>
<td>Nominal Frequency (Hz)</td>
<td>50</td>
</tr>
<tr>
<td>Shaft Stiffness (Nm/rad)</td>
<td>33,200,000</td>
</tr>
<tr>
<td>Torsional Damping (Nms/rad)</td>
<td>560,000</td>
</tr>
<tr>
<td>RPM Nominal turbine speed (rpm)</td>
<td>18</td>
</tr>
<tr>
<td>DC-Link Capacitance (uF)</td>
<td>1925</td>
</tr>
<tr>
<td>Rated DC Voltage (kV)</td>
<td>1.15</td>
</tr>
<tr>
<td>Rated AC Voltage (kV)</td>
<td>0.69</td>
</tr>
<tr>
<td>Single cage rotor</td>
<td>Yes</td>
</tr>
<tr>
<td>Stator resistance (p.u)</td>
<td>0.002989</td>
</tr>
<tr>
<td>Stator reactance (p.u)</td>
<td>0.125</td>
</tr>
<tr>
<td>Magnetising reactance (p.u)</td>
<td>2.5</td>
</tr>
<tr>
<td>Rotor resistance (p.u)</td>
<td>0.004</td>
</tr>
<tr>
<td>Rotor reactance (p.u)</td>
<td>0.05</td>
</tr>
<tr>
<td>Rotor Inertia (kg m²)</td>
<td>40.68</td>
</tr>
<tr>
<td>Transformer type</td>
<td>3-winding</td>
</tr>
<tr>
<td>Slip (%)</td>
<td>8</td>
</tr>
<tr>
<td>Zero-sequence resistance (p.u)</td>
<td>0.01</td>
</tr>
<tr>
<td>Zero-sequence reactance (p.u)</td>
<td>0.1</td>
</tr>
<tr>
<td>Number of pole pairs</td>
<td>2</td>
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</tbody>
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Table A.4: $C_p$, $C_t$ and power values of the wind turbine at different wind speeds

<table>
<thead>
<tr>
<th>Wind speed (m/s)</th>
<th>Power (MW)</th>
<th>$C_p$</th>
<th>$C_t$</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>0.0663</td>
<td>0.228</td>
<td>0.818</td>
</tr>
<tr>
<td>5</td>
<td>0.152</td>
<td>0.358</td>
<td>0.806</td>
</tr>
<tr>
<td>6</td>
<td>0.28</td>
<td>0.401</td>
<td>0.804</td>
</tr>
<tr>
<td>7</td>
<td>0.457</td>
<td>0.422</td>
<td>0.805</td>
</tr>
<tr>
<td>8</td>
<td>0.69</td>
<td>0.433</td>
<td>0.806</td>
</tr>
<tr>
<td>9</td>
<td>0.978</td>
<td>0.435</td>
<td>0.807</td>
</tr>
<tr>
<td>10</td>
<td>1.296</td>
<td>0.424</td>
<td>0.793</td>
</tr>
<tr>
<td>11</td>
<td>1.598</td>
<td>0.396</td>
<td>0.739</td>
</tr>
<tr>
<td>12</td>
<td>1.818</td>
<td>0.350</td>
<td>0.709</td>
</tr>
<tr>
<td>13</td>
<td>1.935</td>
<td>0.294</td>
<td>0.409</td>
</tr>
<tr>
<td>14</td>
<td>1.98</td>
<td>0.240</td>
<td>0.314</td>
</tr>
<tr>
<td>15</td>
<td>1.995</td>
<td>0.196</td>
<td>0.249</td>
</tr>
<tr>
<td>16</td>
<td>1.999</td>
<td>0.162</td>
<td>0.202</td>
</tr>
<tr>
<td>17</td>
<td>2</td>
<td>0.135</td>
<td>0.167</td>
</tr>
<tr>
<td>18</td>
<td>2</td>
<td>Not known</td>
<td>0.14</td>
</tr>
<tr>
<td>19</td>
<td>2</td>
<td>Not known</td>
<td>0.119</td>
</tr>
<tr>
<td>20</td>
<td>2</td>
<td>Not known</td>
<td>0.102</td>
</tr>
<tr>
<td>21</td>
<td>2</td>
<td>Not known</td>
<td>0.088</td>
</tr>
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<td>22</td>
<td>2</td>
<td>Not known</td>
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<td>23</td>
<td>2</td>
<td>Not known</td>
<td>0.067</td>
</tr>
<tr>
<td>24</td>
<td>2</td>
<td>Not known</td>
<td>0.06</td>
</tr>
<tr>
<td>25</td>
<td>2</td>
<td>Not known</td>
<td>0.053</td>
</tr>
</tbody>
</table>
Appendix B

Results of Aggregation using a Small Wind Farm

Table B.1: Wind turbines arranged in clusters, clusters arranged into groups

<table>
<thead>
<tr>
<th>Group</th>
<th>Clusters</th>
<th>Wind turbines</th>
<th>Equivalent wind turbine (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>G1</td>
<td>c1</td>
<td>1,2,3,4,5,6,7,8,9</td>
<td>18</td>
</tr>
<tr>
<td>G2</td>
<td>c1</td>
<td>1,2,4,5</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>c2</td>
<td>3,6,7,8,9</td>
<td>10</td>
</tr>
<tr>
<td>G3</td>
<td>c1</td>
<td>1,2,3,4,7</td>
<td>10</td>
</tr>
<tr>
<td></td>
<td>c2</td>
<td>5,6,8,9</td>
<td>8</td>
</tr>
<tr>
<td>G4</td>
<td>c1</td>
<td>1,4,</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>c2</td>
<td>2,3,5,6,7,8,9</td>
<td>14</td>
</tr>
<tr>
<td>G5</td>
<td>c1</td>
<td>1,4,</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>c2</td>
<td>2,5</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>c3</td>
<td>3,6,7,8,9</td>
<td>10</td>
</tr>
<tr>
<td>G6</td>
<td>c1</td>
<td>1,2,</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>c2</td>
<td>3,4,5,6,7,8,9</td>
<td>14</td>
</tr>
<tr>
<td>G7</td>
<td>c1</td>
<td>6,9</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>c2</td>
<td>1,2,3,4,5,7,8</td>
<td>14</td>
</tr>
<tr>
<td>G8</td>
<td>c1</td>
<td>6,9</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>c2</td>
<td>5,8</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>c3</td>
<td>1,2,3,4,7</td>
<td>10</td>
</tr>
<tr>
<td>G9</td>
<td>c1</td>
<td>8,9</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>c2</td>
<td>1,2,3,4,5,6,7</td>
<td>14</td>
</tr>
<tr>
<td>G10</td>
<td>c1</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td></td>
<td>c2</td>
<td>2,4,5</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>c3</td>
<td>3,6,7,8,9</td>
<td>10</td>
</tr>
<tr>
<td>G11</td>
<td>c1</td>
<td>1,2,3,4,7</td>
<td>10</td>
</tr>
<tr>
<td></td>
<td>c2</td>
<td>5,6,8</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>c3</td>
<td>9</td>
<td>2</td>
</tr>
<tr>
<td>G12</td>
<td>c1</td>
<td>1,2,3</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>c2</td>
<td>4,5,6</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>c3</td>
<td>7,8,9</td>
<td>6</td>
</tr>
</tbody>
</table>
A total of 14 groups are identified, they are not unique groups. It is seen that Groups 6, 9 and 11 have a higher probability to be used. Probability of each group is calculated and plotted as shown in the figure below:

Figure B.1: Groups arranged in descending order based on probability of usage during the year

Figure B.2: Groups for wind directions between 100° - 180° inside the wind turbine operating range
Figure B.3: Groups for wind directions between 280°-360° inside the wind turbine operating range

Table B.2: Identification of unique groups is carried out as shown in the table below

<table>
<thead>
<tr>
<th>Unique Groups</th>
<th>Similar Groups</th>
</tr>
</thead>
<tbody>
<tr>
<td>Group A</td>
<td>G1</td>
</tr>
<tr>
<td>Group B</td>
<td>G2, G3</td>
</tr>
<tr>
<td>Group C</td>
<td>G4, G6, G7, G9</td>
</tr>
<tr>
<td>Group D</td>
<td>G10, G11</td>
</tr>
<tr>
<td>Group E</td>
<td>G5, G8</td>
</tr>
<tr>
<td>Group F</td>
<td>G12</td>
</tr>
<tr>
<td>Group G</td>
<td>G13, G14</td>
</tr>
</tbody>
</table>

Figure B.4: Unique groups are identified and arranged in descending order according to their probability of usage
Group C has the highest probability therefore this will be used for the wind farm representation during the year. Its components can be seen from the tables above. A 9 turbine wind farm can be represented by just 2 equivalent turbines with the rated powers of 4 MW and 14 MW.

Figure B.5: Circuit diagrams for (a) detailed nine WIND TURBINE model and (b) aggregated two turbine equivalent model
## Appendix C

### Cost of Transmission Lines

Table C.1: Types of transmission lines and their costs for different voltage levels

<table>
<thead>
<tr>
<th>New Transmission Line</th>
<th>Unit</th>
<th>60/70kV</th>
<th>115kV</th>
<th>230kV</th>
</tr>
</thead>
<tbody>
<tr>
<td>Double Circuit, Strung on both sides, Lattice Tower</td>
<td>per mile</td>
<td>£874,800</td>
<td>£874,800</td>
<td>£1,036,800</td>
</tr>
<tr>
<td>Double Circuit, Strung on one side, sides, Lattice Tower</td>
<td>per mile</td>
<td>£680,400</td>
<td>£680,400</td>
<td>£810,000</td>
</tr>
<tr>
<td>Double Circuit, Strung on both sides, Tubular Steel Pole</td>
<td>per mile</td>
<td>£946,080</td>
<td>£946,080</td>
<td>£1,166,400</td>
</tr>
<tr>
<td>Double Circuit, Strung on one side, sides, Tubular Steel Pole</td>
<td>per mile</td>
<td>£810,000</td>
<td>£810,000</td>
<td>£939,600</td>
</tr>
<tr>
<td>Single Circuit, Tubular Steel Pole</td>
<td>per mile</td>
<td>£609,120</td>
<td>£609,120</td>
<td>£712,800</td>
</tr>
</tbody>
</table>
Appendix D

Failure Rates and Repair Times for Components

Table D.1: Failure rates and repair times for offshore wind farm components

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Worst Situation</th>
<th>Normal Situation</th>
<th>Best Situation</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Failure rate (1/year)</td>
<td>MTTR</td>
<td>Failure rate (1/year)</td>
</tr>
<tr>
<td>Turbine Transformer</td>
<td>0.0131</td>
<td>30 days</td>
<td>0.0131</td>
</tr>
<tr>
<td>Collector Transformer</td>
<td>0.03</td>
<td>6 months</td>
<td>0.03</td>
</tr>
<tr>
<td>Converter Transformer</td>
<td>0.02</td>
<td>5 months</td>
<td>0.02</td>
</tr>
<tr>
<td>Array Cable (1/km)</td>
<td>0.001</td>
<td>3 months</td>
<td>0.0094</td>
</tr>
<tr>
<td>Export Cable (1/km)</td>
<td>0.001</td>
<td>3 months</td>
<td>0.0094</td>
</tr>
<tr>
<td>Converter</td>
<td>0.12</td>
<td>4 weeks</td>
<td>0.12</td>
</tr>
<tr>
<td>DC Cable</td>
<td>0.00148</td>
<td>3 months</td>
<td>0.00094</td>
</tr>
</tbody>
</table>
Appendix E

Screenshots of the Developed Software Tool

Figure E.1: GUI Form (Main window – Enter basic information)
Figure E.2: GUI Form (Transmission to shore through HVAC/HVDC)

Figure E.3: GUI Form (Bus, Transformer and Tie-Line data)
Figure E.4: GUI Form (Save data in a file)

Figure E.5: GUI Form (Read data from a file)
Figure E.6: GUI Form (Create network)

Figure E.7: Network created in PSS®E by the software tool
Appendix F

Author’s Thesis Based Publications

International Journal Papers


International Conference Papers


Appendix F


**Industrial Software**

F.10 Software tool for cost-benefit analysis of offshore wind farm electrical system, version 1.0, updated 16/06/2011.
Appendix G

VeBWake Software CD

The CD is attached to the back cover of this thesis.