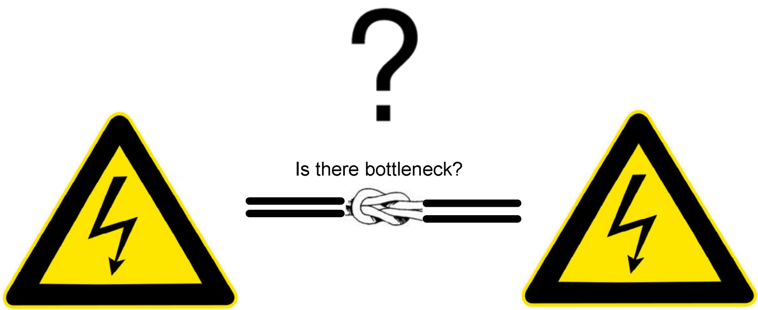
Master Thesis

New method for future transmission system bottleneck identification for interconnected power systems



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Technische Universiteit Delft

Master Thesis

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Preface

Modern society is critically dependent on the supply of electric power. Electricity provides us with innumerable possibilities to increase our welfare. However, the generation of electricity by burning fossil fuels is unsustainable and is co-responsible for a number of environmental problems, including global warming. New renewable energy sources, such as wind power provide an alternative for this, and are mostly built at remote locations. Extensive grid planning is needed to ensure that these new sources can be integrated into the grid. Planning and extension of electricity grids are mainly based on fast computer-based simulation tools that can provide useful information on the network parts which are more vulnerable to the anticipated changes in the energy production and market trends. This report is written for my master thesis. The task was to develop and present a robust method for future transmission system bottleneck identification for interconnected power systems. The principles of this new method are described in this thesis.

By good cooperation with the TU Delft, TenneT TSO and other parties the task has been successfully completed.

People who are interested why there is a need for this new method are referred to chapter 1, 2, 3 and 4.
People who are interested in the method and the results of the performed simulations are referred to chapter 5 and 6.

I would like to thank Dipl.eng.A.R.Ciupuliga, Dr.Eng.M.Gibescu , and Prof.ir.W.L.Kling for offering me the opportunity to perform my master's thesis at the power systems group. I want to thank my colleagues at TenneT TSO Ing.E.Pelgrum and Ir.P.G.H.Jacobs for their knowledge and interest on the project by providing me the necessary information for the project development. Furthermore I want to thank everybody for their pleasant daily/weekly supervision and immediate response to my questions providing practical ideas, advice on the structure of this thesis, useful suggestions, support, opinions and valuable remarks. I also want to thank the Central Western European Expert Group (CWE-EG) for providing the necessary data and offering me the opportunity to perform calculations on the CWE grid. Finally I want to thank all my friends, relatives, and colleagues who stood by me and helped me endure the toughest times during my thesis period.

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Abstract

An important task for transmission system operators is to assess and predict power flows for network planning and extensions, in order to detect bottleneck situations. This task is becoming more difficult and important due to the on-going liberalization process and the integration of renewable energy sources in the EU power systems, especially onshore and offshore wind power. These developments have increased the uncertainty of power flows, which are the result of levels and locations of generation and load in the network. Thus, multiple load flow simulations are needed in order to assess the worst loading levels of transmission system components, in particular lines and transformers. A new method is developed for future transmission system bottleneck identification for interconnected power systems. The developed method that is presented in this thesis offers the possibility to simulate many different combinations of load and generation and to assess the loadings of the transmission system components. A number of calculations/simulations were performed on the Limburg grid to illustrate the principles of this specific tool/method. A first step is set for identifying congestions in the Central Western European (CWE consists of The Netherlands, Belgium, France, Luxembourg and Germany) region, which is the concern of the CWE Regional Transmission Plan. This project has been done in close cooperation with Dutch TSO TenneT.

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1 Introduction

Electricity has played an important role in people's lives, since its discovery by providing them access to extremely valuable amount of services and goods. People use electricity on a large scale in their daily life in order to cover their basic needs as cooking, heating, lighting as other needs like transportation, telecommunication, education, entertainment and product manufacturing. Electricity consumption is strongly correlated with economic growth: economic growth allows further use of electric appliances which in turn increases electricity demand [3].

In the last century, the extensive use of power applications created the need for large scale generation of electricity from different sources and at different places and therefore the need for transportation and distribution of energy by means of complex grid structures. The liberalization process of the energy markets has motivated many people and companies to invest in the energy sector and to make profit from energy production and supply. The target of higher profit and lower cost for all parts can be easier achieved by energy transportation through different areas or countries. Thus, long transmission lines connect the different power systems and large amounts of energy flow through them, facilitating energy exchange and improving reliability of supply.

The transmission systems are planned by assessing and predicting the power flows in the system, in order to avoid bottleneck situations[1]. This task is becoming more difficult and important due to the on-going liberalization process and the integration of renewable energy sources in the European Union (EU) power systems, especially onshore and offshore wind power. These developments have increased the uncertainty of load flows, which are the result of levels and locations of generation and load in the network. Multiple load flow simulations are necessary for the capturing and analysis of all possible worst cases. The existing methods make use of a deterministic approach, where a power flow analysis is performed for a small number of predefined cases, which are expected to be the worst. In order to capture the increased uncertainties, new probabilistic methods need to be developed.

1.1 Objective of this thesis

The thesis objective is to develop and present a new robust method for future transmission system bottleneck identification for interconnected power systems. A number of calculations/simulations were performed on the Limburg grid to illustrate the principles of this specific tool/method. A first step is set for identifying congestions in the Central Western European (CWE consists of The Netherlands, Belgium, France, Luxembourg and Germany) region, which is the concern of the CWE Regional Transmission Plan. The simulations are based on scenarios, snapshots that are provided by the Regional Transmission Plan group (cooperation of the Central-West European TSOs). The reference time of the simulations will be the year 2018 and for this reason some assumptions have to be made before the simulation starts.

The main objective of the Regional Transmission Plan is to detect the bottlenecks on the extra high voltage electricity network of the region CWE. Bottleneck situations may lead

[1] A bottleneck situation occurs when the thermal limit of a line is exceeded and its consequence is at most times potential blackout of power systems.

to insecurity or even blackouts as transmission components are overloaded and taken out of service. Loads cannot be fed with the demanded power and thus such situations must be prevented because they endanger the security of supply.
In this thesis project the high and extra high voltage transmission grid of the CWE region were analyzed. The voltage levels that are taken into consideration are the 380 kV and 220 kV lines and some 150 kV and 110 kV lines.

1.2 Research method

The new method is needed due to a combination of the following factors: the continuing liberalization process in Western-Europe (increased inter-area power exchanges, market coupling), a number of projected investments by market parties in new generation capacity and the foreseen development of renewable energy sources (RES) as well as thermal energy in the CWE. All the above aspects increase the unpredictability of power flows in the system, which must be taken into account in the assessment of transmission capacities by the TSOs. The development of the new method tries to take advantage of the fact that computers nowadays can handle large amounts of data and have high processing power. Hence, simulating many load flows with different combinations in order to adequately estimate transmission system bottlenecks for the network is an achievable task.

The new method is the outcome of combining two simulation environments. The first program, called 'PowrSym3', decides the status (on or off) and output level of the generating units. The purpose of this program is to cover the load demand in the most efficient way from the units that are available at each moment. As in real power systems not all units are available at every moment in time due to various reasons, this had to be taken also into consideration. For simulating these uncertainties, the probabilistic Monte Carlo method is used within PowrSym3.The delineations and assumptions for the conventional units are very important for the outcome of this program and must be defined prior to the simulation application. PowrSym3 performs the unit commitment and economic dispatch for the thermal units for a total year divided in hourly (or 15-minutes time) intervals, following certain scenarios.

The second program, called PSS/e, calculates the power flows in the system for the different situations. The models that are used in this thesis for PSS/e are the Limburg and Central Western European transmission networks. Power flows at the steady state condition can be calculated accurately by this program. The research in this project is focused on the CWE transmission system for the 380 and 220, 150 and 110 kV voltage levels. For the Limburg system the focus is on the 150 kV lines in Limburg and the very near 380 kV grid. For the CWE region the output of PowrSym3 in each situation is imported to PSS/e with the help of an interface environment created in a Python programming language. The interface is responsible for correlating the units in the PowrSym3 model with the ones in the PSS/e model and thus provided with the respective data. Prior to running power flows simulations, the units in the PSS/e model have to be modified according to PowrSym3 modeled units. Some of the made assumptions are also programmed in the python interface.

From the base case where all considered lines are in operation, the n-1 contingency analysis is performed for all considered transmission lines. The number of different combinations of grid components is very high and therefore the n-2 analysis is not applied in this research. The principle of the application is exactly the same with the n-1 analysis. The PowrSym3 output is independent on the contingency analysis, because the generators outage cannot be seen from the power flow simulation program and in the power flow analysis no generators are taken out of service. Thus the contingency analysis is applied by running different combinations of in-service lines in PSS/e model with the same PowrSym3 output data.

The loading percentage for each line is obtained as an output of PSS/e. After exporting these results in Matlab for graphical representation, a bottleneck is defined for each case when the line loading percentage exceeds 100%; this fact is considered as congestion in the transmission grid.

1.3 Thesis overview

In chapter 2 some needed background knowledge to understand the subject more is described such as definition of an AC en DC power flow, contingency analyses, unit commitment and economic dispatch and more. The structure of the European interconnected electrical system is illustrated in chapter 3. More about the European market structure, transmission system as well about transmission planning in Europe is explained. Also a short description is given about the regional transmission plan CWE. Chapter 4 describes the power system operation of the CWE region such as the basics of power system operation as well as the load and generation of the CWE region. A description of the CWE transmission system is also illustrated in chapter 4. The development of the method is described in chapter 5 as well as the main programs (PowrSym3 and Pss/e) used. The made assumptions for making suitable load flows for the CWE region are also described in this chapter. The last paragraph of chapter 5 gives a brief description of Limburg grid on which also calculations/simulations are performed. The Results of Limburg grid and CWE snapshots calculations/simulations based on the presented method from chapter 5 are described in chapter 6. And the last chapter; chapter 7 illustrates the most important conclusions arising from this thesis project. Last but not least, some recommendations for further study are given.

2 Background knowledge

For a better understanding of this thesis, the most important used terms will be briefly explained in this chapter. In paragraph 2.1 the per-unit quantities are explained. Paragraph 2.2 gives the definition of an electrical bus is and reminds the existing types of busses. The AC en DC power flow, contingency analyses and unit commitment and economic dispatch are described respectively in paragraph 2.3, 2.4 and 2.5. Paragraph 2.6 explains what a Transmission System Operator is.

2.1 Per-unit quantities

Power transmission lines are needed in electrical networks for the distribution of energy. These power transmission lines operate at high voltage levels where kilovolt (kV) is the most convenient unit to express the voltage. This also applies for the transmitted power which is mostly expressed in kilowatts (kW) or megawatts (MW) for the active power, kilovolt amperes (kVA) and megavolt amperes (MVA) for the apparent power and reactive kilovolt amperes (kvAr) and reactive mega volt amperes (MvAr) for the reactive power. However, these quantities as well as amperes (current) and ohms (impedance) are often expressed as a percent or per-unit (p.u.) of a base or reference value specified for each case.

The per-unit value of any quantity is defined as the ratio of the quantity to its base expressed as a decimal. The ratio in percent is 100 times the value in per unit. Calculations of both the percent and per-unit methods are simplified and often more informative than the use of actual amperes, ohms and volts. Voltage, current, apparent power, and impedance are strongly related. The selection of the base values for any two of them determines the base values of the remaining two. For example if the base values of current and voltage are specified, the base impedance and the base apparent power can be determined. This can be done as shown in equations 2.1 and 2.2 [1].

$$I_{base} = \frac{S_{base}}{V_{base}} \tag{2.1}$$

$$R_{base} = \frac{V_{base}}{I_{base}} \tag{2.2}$$

The per-unit voltage can be calculated with formula 2.3.

$$V_{pu} = \frac{V_{actual}}{V_{base}} \tag{2.3}$$

The use of the per-unit system is applied in most load flow programs (also in PSS/e). It specifies the voltage amplitudes of the different busses of the system and for the definition of the machines, transformers and transmission lines impedances. When the per-unit system is applied the load flow algorithms become simplified and it is easier to perform load flows [1].

2.2 Electrical bus

A typical bus is a building block, where other power components are connected onto. Lines, loads, transformers or generators can be connected onto a bus and so a grid can be build.

Types of buses

Four potentially unknown quantities are associated with each bus i, namely the active power P_i, the reactive power Q_i, the voltage angle δ_i and the voltage magnitude V_i. During power flow calculations two out of the four quantities are specified and the remaining two are variable. The general practice in power flow studies is to identify three types of buses in the network. These are:

1. **Load buses**. These are the non-generator buses. A load bus is often called a P-Q bus because the scheduled values of the active and the reactive power are known. So in these buses the unknown quantities are in most cases the angle δ_i (angle difference with a reference bus assumed to have 0° angle) and the amplitude of the bus V_i.
2. **Voltage-controlled buses**. Any bus of the system at which the voltage magnitude is kept constant is voltage controlled. At each bus where a generator is connected to, the active power generation can be controlled by adjusting the prime mover, and the voltage magnitude can be controlled adjusting the generator excitation. Therefore at each generator bus the real power and the voltage magnitude may properly be specified. The generator reactive power required to support the scheduled voltage amplitude cannot be known in advance, and therefore the mismatch of reactive power Q is not defined. Also, at a generator bus the voltage angle δ_i is the unknown quantity to be determined. After this is solved the reactive power Q_i can be calculated. For obvious reasons a generator bus is usually set to be called a voltage controlled or P-V bus. Certain non-generator busses may have voltage control capability; such an example is a capacitor bank.
3. **Slack bus.** The slack bus is a bus that can provide or absorb the required amount of real or reactive power in order to cover any power mismatch in the rest of the buses. The voltage angle for the slack bus serves as reference for the angles of all other buses. The particular angle assigned to the slack bus is not important because of the voltage-angle differences determine the calculated values of real and reactive power flows between buses. So the usual practice is to set the voltage angle of the slack bus to zero. To the slack bus a generator is connected that can produce active and reactive power without limit and keeps the voltage amplitude of the slack bus at the defined value. In the present study, the slack bus is used to cover the power mismatch in the Central-Western Europe region.

2.3 AC and DC Power flow

Transmission lines are used in power systems for transporting the electric energy from the producing units to the consumers (loads). Therefore they connect the loads to the producers allowing power flows between the two. The importance of calculating the power flow in each line becomes obvious and power flow assessment can be done by a power flow study.

Power flow studies are of great importance in planning and designing the future expansion of power systems as well in determining the best operation of the existing systems. The principal information obtained from a power flow study is the magnitude and the phase angle of the voltage at each bus and the active and reactive power flowing in each line. However, more additional information of value is provided by the printout of the solution from the computer programs.

The power flow software used in the present study is called ‘PSS/e’. A power flow study for a system operating under actual or projected normal operating conditions is called a base case. The result from the base case constitutes a benchmark for comparison of changes in network flows and voltages under outage condition or contingency condition[2]. A typical power flow program is capable of handling systems of more than 2000 buses, 3000 lines and 500 transformers (PSS/e can handle much more).

Transmission lines are represented by their per-phase nominal π-equivalent circuits. For each line numerical values for the series impedance Z (resistance R and inductance X in p.u. values) and the total line charging admittance Y are necessary. The program can then determine all the elements of the bus admittance matrix. Other essential information includes transformer ratings and impedances, shunt capacitor and reactor ratings and transformer tap settings. In advance of each power flow study certain bus voltages and power injections must be given as known values, so data supplied to the computer must include the numerical values of the line and bus data and an indication whether a bus is the slack bus, a regulated bus where voltage magnitude is held constant by generation of reactive power Q, or a load bus with fixed P and Q. Limits of P and Q generation must be specified as well as the limits of line apparent power or line rating values [1],[2].

The power flow program PSS/e offers two choices for the iterative procedure of solution of power flow equations. The first is the Newton-Rapshon method and the second is the Gauss-Seidel method. The polar form of the power flow equations are shown in equations 2.4 and 2.5 [1].

$$P_i = \sum_{n-1}^{N} |Y_{in} V_i V_n| \cos(\theta_{in} + \delta_i - \delta_n) \tag{2.4}$$

$$Q_i = \sum_{n-1}^{N} |Y_{in} V_i V_n| \sin(\theta_{in} + \delta_i - \delta_n) \tag{2.5}$$

The polar form of the power flow equations provide calculated values for the net real power P_i and the reactive power Q_i entering the network at typical bus I, where V_i and V_n are the voltages in the I and the n bus and δ_i , δ_n are the angles of the same buses respectively. Y_{in} represents the elements of the bus admittance matrix Y_{bus} referring to buses i and n and θ_{in} is the angle defined by the resistance and the reactance values of the Y_{in} element.

Let P_{gi} denote the scheduled power being generated at bus I and P_{di} denote the scheduled power demand of the load at that bus. Then $P_{i,sch} = P_{gi} - P_{di}$ is the net scheduled power being injected into the network at bus i. Denoting the calculated value of P_i by $P_{i,\ calc}$ leads to the definition of mismatch ΔP_i as the scheduled value $P_{i,sch}$ minus the calculated value $P_{i,\ calc}$ as can be seen in equation 2.6 [1].

$$\Delta P_i = P_{i,sch} - P_{i,calc} \tag{2.6}$$

Likewise for the reactive power at bus i we have equation 2.7 [1].

(2.7)

[2] Definition of a contingency condition/analyses is explained in this chapter on page 10

$$\Delta Q_i = Q_{i,sch} - Q_{i,calc}$$

Mismatches occur in the course of solving a power flow problem when the calculated values of P_i and Q_i do not coincide with the scheduled values. If the calculated values match the scheduled values perfectly then the mismatches are zero at bus i. Each bus of the network has 2 such equations and the power flow problem is to solve the polar form equations for the unknown values of bus voltage (can be Q, V or δ) which cause the mismatches to be numerically satisfied, below a certain threshold at each bus.

The unscheduled bus-voltage magnitudes and angles in the input data of the power flow study are called state variables or dependent variables since their values, which describe the state of the system, depend on the quantities specified at all the buses. Hence, the power flow problem is to determine values for all state variables by solving an equal number of power flow equations based on the input data specifications. Once the state variables have been calculated, the complete state of the system is known and all other quantities which depend on the state variables can be determined. Quantities such as the real and reactive power of the slack bus, the reactive power of any voltage controlled bus and the power loss of the system are examples of dependent functions.

The functions P_i and Q_i of equations 2.4 and 2.5 are nonlinear functions of the state variables δ_i and V_i. Hence, power flow calculations usually employ iterative techniques such as the Gauss-Seidel and Newton-Raphson procedures. Each calculation of a new set of voltages is called iteration. The iterative process is repeated until the changes at each bus are less than a specified by the user minimum value.

The Newton-Raphson method solves the polar form of the power flow equations until the mismatches at all buses fall within specified tolerance. Taylor's series expansion for a function of two or more variables is the basis for the Newton-Raphson method of solving the power flow problem. The Gauss-Seidel method solves the power flow equations in rectangular (complex variable) coordinates until differences in bus voltages from one iteration step to another are sufficiently small. Both methods are based on bus admittance equations. The above mentioned methods perform AC power flows. An accurate solution of the power flows on an AC system is a non-linear problem. Consequently it requires an iterative approach and there is no guarantee of reaching a "convergent" solution.

The non-linear load flow equations (polar form) can be converted into linear load flow equations under additional assumptions. Performing a load flow with these linear load flow equations is called a DC load flow. DC load flow is a method to estimate power flows (active power) through lines on AC power systems. DC power flow analysis can be used where approximate solutions are acceptable, as in contingency studies. A DC load flow uses a simplified, linear form of modeling the AC system. Consequently its solution is non-iterative. It becomes a routine algebra problem, solving multiple equations with multiple variables. It is inherently less accurate than a "full" AC load flow solution, but it is useful where fast, dependable solutions are essential, and the approximation is acceptable. There is nothing "DC" about a DC load flow. In a DC load flow the model becomes a lossless network, all bus voltages are assumed to remain constant at nominal values of 1 per unit and it solves the angle to determine the active power. The power can be determined with equation 2.8 [2].

$$P_i = -\sum_{n=1, n \neq i}^{N} |Y_{in}||V_{nom}|^2 (\delta_n - \delta_i) \qquad (2.8)$$

Formula 2.8 is derived from formula 2.4 (non linear equation). This is possible when the following assumptions are valid:

- The line impedance of the transmission grid are mainly reactive, so $\theta_{in} = \pm \pi/2$
- The bus voltages are equal to their nominal values when the active power is calculated.
- The phase shift between the voltages of to each other connected busses is really small, so $\sin(\delta_i - \delta_n) \approx (\delta_i - \delta_n)$ and $\cos(\delta_i - \delta_n) \approx 1$

The voltage magnitudes of the buses affect primarily the reactive power flows in the lines (reactive flow calculations are ignored in DC load flows)

2.4 Contingency analyses

When a line is switched on or off in a system through the action of circuit breakers, line currents are redistributed throughout the network and bus voltages change. The new steady state bus voltages and line currents can be predicted by what is called the contingency analysis. Whenever a transmission line or transformer is removed from service an outage has occurred. Outages may be planned for purposes of scheduled maintenance or they may be forced by weather conditions, faults or other contingencies. A line or transformer is de-energized and isolated from the network by tripping the appropriate circuit breakers. The ensuing current and voltage transients in the network quickly die away and new steady-state operating conditions are established. It is important for both the network operator and the network planner to be able to evaluate how the line flows and bus voltages will be altered in the new steady state. Overloads due to excessive line currents must be avoided and voltages that are too high or too low are not acceptable because they render the system more vulnerable to follow-on (cascading) outages. The large numbers of possible outages are analyzed by means of a contingency analysis or contingency evaluation program. Great precision is required in contingency analysis since it is important knowing whether or not an insecure or vulnerable condition exists (including overloading magnitude) in the steady state following any of the outages. [1]

When only one system component, transformer or transmission line fails then this condition is called n-1 contingency analysis. A n-2 contingency condition is when two components are tripped simultaneously. It is possible to have more than two contingencies. It is then called n-# contingency condition where # is the number of the outaged components. Contingencies can also arise when a component outage has already occurred and a shift in generation is being considered to determine if a line overload caused by the outage can be relieved.

2.5 Unit Commitment (UC) and Economic Dispatch (ED)[3]

The unit commitment problem consists of the economical determination of a schedule for the generation units which will be used to cover the forecasted demand while respecting the operating constraints such as spinning reserve requirements, ramp rates, minimum up and

[3] The UC-ED is described in more detail in chapter 2.3.

down times of the conventional units, fuel and emission constraints over a short time horizon. In a non–deregulated market environment, the economic dispatch is solved together with the unit commitment and refers to how to distribute system load between the operating units for minimising the total operating costs. However in typical day-ahead markets, only bids for supply and demand price and quantities are submitted and the commitment decisions have to be made independently by each producer based on estimates of market prices and their share of the load [3].

The unit commitment and economic dispatch (UC-ED) is solved under a time horizon and considers a minimization cost path where all the constraints are re-evaluated. While the solution of the traditional power system unit commitment problem takes into account controllable sources such as conventional generation units, the transition to the future power systems is driven by two important factors:

1. The integration of renewable energy sources (RES)
2. The sustainable development
   This refers to efficient fuel utilization; decrease in emissions and in total fuel consumption.

In addition, the integration of wind power (wind power prediction) and liberalization of electricity markets bring more uncertainties in the UC-ED [3].

Simple UC-ED example

In this example [13] no constraints are taken into accounts. There are 3 units available with different specification as can be seen in table 2.1.

Table 2.1: Unit specification [13]

units	Max output (MW)	Min output (MW)	Input-output curve (MJ/h)
Coal-fired steam 1	600	150	$510+7.20P_1+0.00142P_1^2$
Oil fired steam 2	400	100	$310+7.85P_1+0.00194P_1^2$
Oil fired steam 3	200	50	$78+7.97P_1+0.00482P_1^2$

The fuel cost of each unit is also defined
Fuel cost unit 1 = 1.1 €/MJ
Fuel cost unit 2 = 1.0 €/MJ
Fuel cost unit 3 = 1.2 €/MJ

If we are to supply a load of 550 MW, what unit or combination of units should be used to supply this load most economically? To solve this problem, simply are the combinations of the three units are tried. Some combinations will be infeasible of the sum of all MW for the units committed is less than the load or if the sum of all MW for the units committed is greater than the load. In figure 2.1 the unit combinations and dispatch of the example can be seen.

Unit 1	Unit 2	Unit 3	Max Generation	Min Generation	P_1	P_2	P_3	F_1	F_2	F_3	Total Generation Cost $F_1 + F_2 + F_3$
Off	Off	Off	0	0				Infeasible			
Off	Off	On	200	50				Infeasible			
Off	On	Off	400	100				Infeasible			
Off	On	On	600	150	0	400	150	0	3760	1658	5418
On	Off	Off	600	150	550	0	0	5389	0	0	5389
On	Off	On	800	200	500	0	50	4911	0	586	5497
On	On	Off	1000	250	295	255	0	3030	2440	0	5471
On	On	On	1200	300	267	233	50	2787	2244	586	5617

Figure 2.1: Unit combination and dispatch for 550 MW load [13].

Where P_1, P_2, P_3 are the unit output and F_1, F_2, F_3 are the operation cost of the unit. The total operation cost is equal to the operation cost of each unit added up. From figure 2.1 it can be seen that the least expensive way to supply the generation is not with all the three units running, or even any combination involving three units. Rather the optimum commitment is to only run unit 1, the most economic unit by only running the most economic unit, the load can be supplied by that unit operating closer to its best efficiency. If another unit is committed, both unit 1 and the other unit will be loaded further from their best efficiency points such that the net cost is greater than unit 1 alone. The load varies during the day; this means that the number of committed units also can change depending on the size of the units. In figure 2.2 the unit commitment schedule is shown (dependent on the load variation, black line).

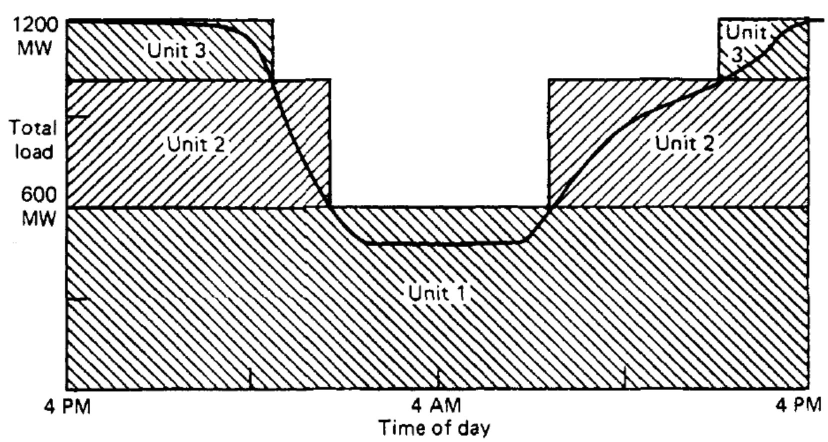


Figure 2.2: unit commitment schedule during the day [13].

From figure 2.2 it can be observed that if the load exceeds 600 MW, the load is bigger than the maximum output of unit 1, the second unit will be committed because that is then the most economical production combination. When the load becomes even higher the third unit is committed to cover the load [13].

Note that the UC-ED becomes more difficult when spinning reserve requirements, ramp rates, minimum up and down times of the conventional units, fuel and emission constraints are taken into account.

2.6 Transmission System Operator (TSO)

A Transmission System Operators (TSO) is responsible for the bulk transmission of electric power on the main high voltage electric networks. A TSO provide grid access to the electricity market players (i.e. generating companies, traders, suppliers, distributors and directly connected customers) according to non-discriminatory and transparent rules. In order to ensure the security of supply, the TSOs also guarantee the safe operation and maintenance of the system. In many countries, TSOs are in charge of the development of the grid infrastructure too. TSOs in the European Union internal electricity market are entities operating independently from the other electricity market players.

In Europe the European Network of Transmission System Operators for Electricity (ENTSO-E) is the collaboration of all EU TSOs. It addresses to technical and market issues in the whole region. The objectives of the ENTSO-E are to promote the reliable operation, optimal management and sound technical evolution of the European electricity transmission system in order to ensure security of supply and to meet the needs of the Internal Energy Market [5].

3 Structure of the European interconnected electrical system

In this chapter the structure of the European interconnected electrical system is described. Paragraph 3.1 focuses on the European market structure. The European transmission system is shortly described in paragraph 3.2. In paragraph 3.3 the transmission network planning in Europe is explained. Further the transmission planning process and the regional transmission plan CWE are described in respectively paragraph 3.4 and 3.5.

3.1 European market structure

Society and industry, in Europe and elsewhere, are increasingly dependent on the availability of electrical energy and therefore on the reliable operation of the electricity systems. Due to security of energy supply, energy market restructuring and environmental pressures in Europe, the electric generation and transmission system are experiencing trends which may significantly impact on their design and operation. In Europe, as well in other continents/countries, electricity industry is in the midst of a transition from a structure dominated by vertically integrated utilities to one dominated by competitive markets. One of the consequences of the electricity market liberalization has been called the so-called 'unbundling' (separation) of former vertically integrated, monopolist utilities.

This ownership unbundling has concerned particularly the separation of generation from transmission. This entails that the returns on transmission investments are regulated, today, entirely at country level, while the profitability of generation investments, on the other hand, is determined largely by interactions in the frame works of competitive markets. This liberalization process has led that market parties have become free to make arrangements for trading electrical energy between countries/areas, consumers and businesses have been able to choose where they purchase their energy. Inter-area power exchanges in electricity markets have significantly increased and further growth can be foreseen. Also, the penetration of Renewable Energy Sources (RES) connected to the European grids has been impressive in recent years; this is particularly the case for onshore wind power plant. Further grid connection of large scale onshore and offshore wind power plants is expected, in order to meet Europe's environmental and energy targets for 2020 and beyond. Over the last ten years, the changes affecting the European system have led to: regularly occurring and quick shifts of power flows, increased interconnection of large synchronous areas (such as the Scandinavian and the continental ones) and an increasing number of Direct Current interconnections and phase-shifting transformers installed.

The current electricity transmission system in Europe does not generally seem adequate to reliable cope with large-scale penetration of such variable power plants (like wind). Flexible, coordinated and adequate transmission networks are needed for the integration of RES. Renewable energy is generally connected to network infrastructure as any form of production. In particular, large-size wind farms are very dependent on adequate transmission capacity, as they are often situated further away from consumption centers.
Thus adequate development of network infrastructures is a precondition for the development and effective integration of renewable electricity [4].

3.2 European transmission system

The pan-European transmission system consists of seven major supranational power systems:

1. **UCTE**[4] (Union for the Co-ordination of transmission of electricity) is the interconnected transmission system of continental Europe. The UCTE region can be divided in 5 smaller regions:
    1. CWE => Central-Western Europe
    2. SWE => South-Western Europe
    3. CSE => Central-Southern Europe
    4. CEE => Central-Eastern Europe
    5. SEE => South-Eastern Europe
2. **NORDEL** includes the transmission system of the Nordic countries (part of Denmark, Finland, Iceland, Norway and Sweden), which are interconnected except for Iceland.
3. **BALTSO** consists of power systems of Estonia, Latvia and Lithuania, synchronously interconnected with the Russian IPS/UPS systems and since 2006 asynchronously interconnected (via HVDC) with the Finish power system.
4. **ATSOI** cover the transmission system of the Republic of Ireland and Northern Ireland, which are now operated by the Irish TSO EirGRID.
5. **UKTSOA** consists of the power transmission system of England, Wales and Scotland (Great Britain) and is now operated by the British TSO NGC.
6. **IPS/UPS** consists of the Independent Power Systems of several Asian countries and the Unified Power System of Russia (IPS/UPS countries are: Belarus, Ukraine, Moldavia, Russia, Georgia, Azerbaijan, Kazakhstan, Uzbekistan, Kirgizia, Tajikistan and Mongolia).
7. **TEIAS** is the Turkish TSO operating the transmission system in Turkey.

The above motioned power systems are shown in figure 3.1 where the UCTE region divided in the 5 sub regions.

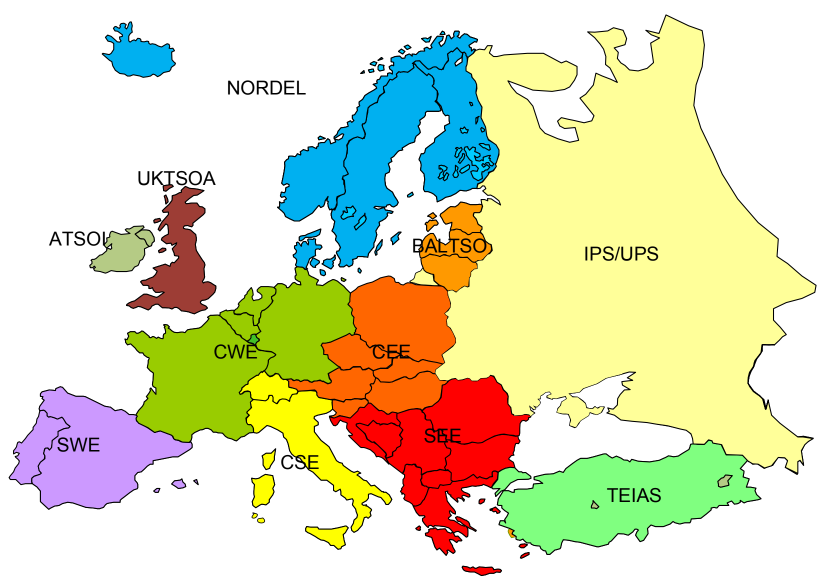


Figure 3.1: Synchronous systems in Europe [14].

[4] The Albanian system is actually interconnected to the bordering UCTE transmission systems, but the Albanian TSO is still in the process of joining the UCTE organization.

Most of the above mentioned seven major networks are weakly interconnected through HVDC links, Except for BALTSO, which is synchronously and strongly interconnected with the IPS/UPS system. The UCTE system is synchronously connected with the Maghreb countries in North Africa (via Morocco) and with Western Ukraine [4].

In figure 3.2 a geographical overview is shown with some key figures on the different synchronous systems in Europe.

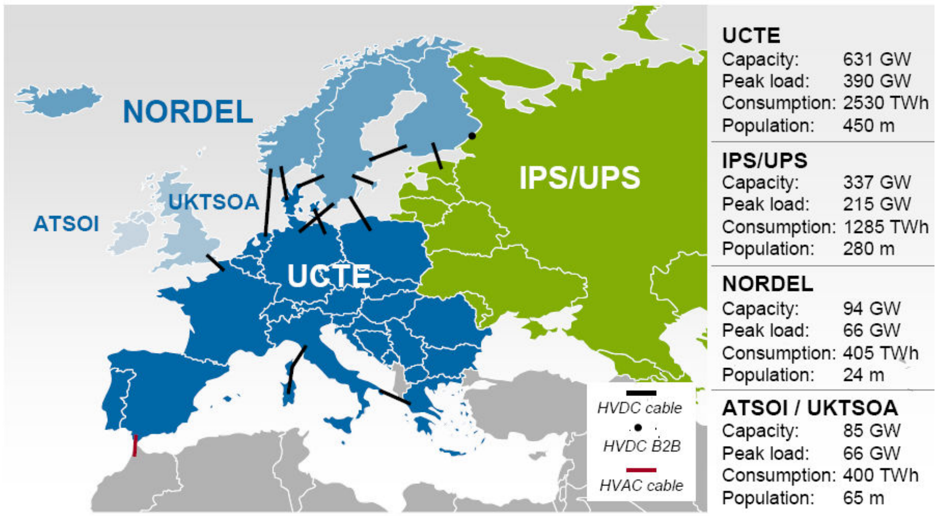


Figure 3.2: Synchronous systems in Europe with HVDC links [4].

3.3 Transmission network planning in Europe

The transmission network planning is a very complex process. The trends and challenges experienced by the electric generation and transmission systems in Europe, as mentioned before[5], make it harder for transmission planners to carry out their tasks nowadays. In the past, before the electricity market liberalization, in a centrally managed power system, the system operator generally controlled the generating units, the transmission and distribution networks and the demand. The goal of the planners was then to expand the transmission network in such a manner that both generation and transmission costs were minimized subject to meeting static and dynamic technical constraints to ensure a secure and economically efficient operation. Today, in a competitive European system, the TSO, in charge of only transmission after the utilities' unbundling, plans the expansion of its network minimising transmission cost (investment and operation) and pursuing social welfare, while meeting static and dynamic technical constraints to ensure a secure and economically efficient operation. Resolving then the trade-off between minimum transmission investment costs versus maximum social welfare is a further complicated task [4].

Moreover, the network planning and development process currently face specific issues: due to environmental constraints, the time required to get the authorizations to build new transmission assets is generally much longer than the time needed to build new power plants; the TSOs must take timely actions in an environment characterized by increasing uncertainties, mostly related to market decisions and growing variable RES deployment. In addition, as generation is affected by major changes resulting not only from the development of RES but also from the renewal and/or phasing-out of thermal power plants,

[5] See first part of paragraph 1.2 European market structure on page 7.

in most EU countries generation tends to exert the greater influence in terms of new requirements placed on the transmission system. In this context, with decisions being out of TSOs' control (e.g. energy policy objectives at European and national level, strategies adopted by the generating companies, etc.), proper assumptions must be made on the evolution of different parameters, such as consumption, generation and also market mechanisms [4].

The UCTE recalls that the TSOs aim at three main objectives when planning the development of the transmission grid [6]:

1. Security of supply (maximize).
2. Market, integrating the market in order to allow an efficient use of the generation and by this way minimizes total costs.
3. Integrating renewable energy sources.

In a liberalised, but optimised interconnected electricity system the transmission grid should from the pure technical (and not political) point of view preferably be used for [7]:

- Interconnection of power plants with a geographical context like mines for lignite power plants, mountains for run of river, storage or pump storage power plants and flat land or open sea for wind turbines with centres of demand;
- Interconnection of electricity systems to share generation capacity as spinning reserve, as secondary reserve or for emergency reasons;
- Interconnection of electricity systems with different load patterns or stochastic generation to reduce needs in flexibility of dispatchable generation.

3.4 Transmission planning process

The main objective of transmission planning is to ensure, with respect to mid and long term horizon, the development of adequate transmission system which, ensures safe system operation, provides a high level of security of supply, contributes to a sustainable development, facilitates grid access to all markets participants and contributes to an internal market integration and harmonization. Issues like in future expected system congestions, contingencies of grid elements leading to cascading outages or transmission instability that can result in blackouts or voltage collapse are indentified in planning and mitigation measures are initiated. This enables the development of an adequate, reliable and stable transmission system that can fulfill the current and future transmission need [7].

The objectives of the planning process should be met under the economical and social conditions that can reasonably be foreseen given the applicable planning horizon.
Transmission network planners have four basic tasks that can be summarized as follow [4]:

1. To forecast the load flows on the power grid (based on scenarios).
   Market simulations and load flow calculations are needed to forecast the flows in the grid.
2. To check whether or not the acceptable limits (constraints) might be exceeded (in standard conditions as well as in the case of loss of system components, contingencies); checking for congestions/bottlenecks.
3. To devise a set of possible strategies/solutions to overcome the criticalities
4. To select the one(s) having the best cost benefit performance.

The transmission system planning process consists of a complex optimization between various aspects.

As investments need years to be commissioned, the transmission network planners must decide as earlier as possible what the most adequate solutions are. In the case of 400kV reinforcements, one generally considers 5 to 10 years to be commissioned. Therefore in order to fulfill their tasks, the TSOs rely on scenarios of forecasted consumption, generation development, and power exchanges evolution. For each scenario, they have to take into account the stochastic aspects of the phenomena: load varies on the basis of human activity and weather conditions; generating units may produce or not, depending also upon external factors such as wind or hydro conditions and forced outages; the scenarios should reflect the asset and bidding strategies of the generation companies and other market players; cross-border exchanges may largely vary also depending on the behavior of the different market players (Scenarios based on information given by the market, on information provided by the authorities and on their long experience as TSOs).
Nevertheless it should be emphasized that the exercise of detecting bottlenecks on HV networks is complex since future congestions must be identified. The identified future congestions are naturally very sensitive to the long term market hypotheses contrary to the current congestions [4].

At the present time, each TSO is using its methodology to create forecasted market scenarios to identify future constraints. This is called national transmission network planning; each TSO does the planning for his own area/country. In bilateral studies, TSOs are sharing information in order to build common scenarios. For example information about existing and future consumption, generation equipments and assets. This cooperation between TSOs leads to transmission network planning on a regional level from an European perspective also called regional transmission planning. National plans should be considered as a best estimate of what is needed from a national perspective: investment projects are based on national scenarios. While a regional plan is based on more global regional scenarios that can differ slightly or seriously from the national scenarios, bringing a regional perspective. It is clear that a larger regional scope for market simulations will, a priori, lead to other conclusions and constraints than just a national scope focusing on the development of the internal grid. Therefore, the development of the grid should be seen as a bidirectional "cascade", i.e. top-down as regional needs have an impact in each country and bottom-up as national needs can also have an impact on the region. This sort of cascade guarantees in the end the consistency between the different development plans, being regional and national.

The difference between the national transmission planning approach and the regional transmission planning approach resides in the data used to model the market and the grid. Usually, each TSO uses a simplified model of its neighbouring countries in such a way that its own market and grid are correctly represented as well as the impacts of the neighbouring markets and grids. This is the case for national transmission planning but for regional transmission planning the cooperating TSOs work together to form a detailed market- and grid model. The TSOs are creating a common database of the existing and future consumption/generation equipments. The part on generation must be especially detailed in order to be able to simulate realistic market behaviours. Grid simulations must also be achieved by the TSOs at a regional level. A common detailed database is made in order to share in an efficient way data and information on the existing and future assets of each TSO. Up to now, the TSOs were using UCTE reference cases in order to model the grid and generation and load of neighbouring TSOs. Those models are well designed for short term planning studies. For long term studies, they are usually sufficient to realise internal studies. However for bilateral/multilateral studies those models are too simplified [7].

3.5 Regional transmission plan CWE

In December 2007 the transmission system operators (TSOs) of the Central Western European region (CWE) have introduced the first regional transmission plan (RTP)[6]. In order to fulfill the European and national targets regarding the climate protection, substantial incentives were given by national governments to increase the installed renewable energy sources (RES) in electricity grids. Considering the ongoing RES and especially massive wind power development in parts of several control areas of the CWE region and also the starting activities in further parts of Europe, one has to emphasize the possible risks linked to uncoordinated measures (due to local/regional lack of adequate demand -and thus an excess of production). The wind energy has to be transmitted by a limited number of transmission lines over longer distances, creating huge flows in a grid that up to now is not dimensioned for this purpose.

Besides the large-scale RES integration, the implementation of the Integrated Electricity Market (IEM) also includes open grid access and open trading that especially increases cross-border exchanges.

In collaboration with the Regional Adequacy Forecast Expert Group (EG RAF) of the Regional Forum CWE an approach for common grid calculation based on the market simulations performed in this parallel group has been proposed in this plan. At the time being the CWE TSOs established a common grid model sufficiently detailed to simulate the impact on the grid of the evolution of the generation mix in each country and of the subsequent exchanges. Based on suitable results of regional market simulations, the future bottlenecks of the CWE grid will be analysed in a transparent way [7].

The CWE Region consists of 5 countries:

1. Netherlands
2. Germany
3. Belgium
4. France
5. Luxembourg

The main objective of the Regional Transmission Plan is to detect the bottlenecks on the extra high voltage electricity network of the region CWE. These bottlenecks will depend on different factors. Amongst them, one can retain [7]:

1. The evolution of the demand
2. The evolution on the production mix (power plants type and location)
3. The European and nationals politics

[6] According to the commitment stated in Annex 2, Section 32 of the Memorandum of Understanding (MoU).

4 Power system operations Central Western Europe

For a better understanding of this thesis, the power system operations of the CWE is discussed in this chapter. The basics of system power operation in the CWE region are discussed in paragraph 4.1. Paragraph 4.2 discusses the load and generation of the CWE region.

4.1 Basics of power system operation

In this paragraph the main steps in power system operation in CWE are described. Also the impact of intermittent energy generation on power system operation will be considered.

4.1.1 Generation control

Almost all generating companies have tie-line interconnections to neighboring utilities. Tie lines allow sharing of generation resources in emergencies and under normal operation conditions. For purposes of control the entire interconnected system is subdivided into *control areas* which usually conform to the boundaries of one or more TSOs. In figure 4.1 different control areas that are connected by tie-lines are shown.

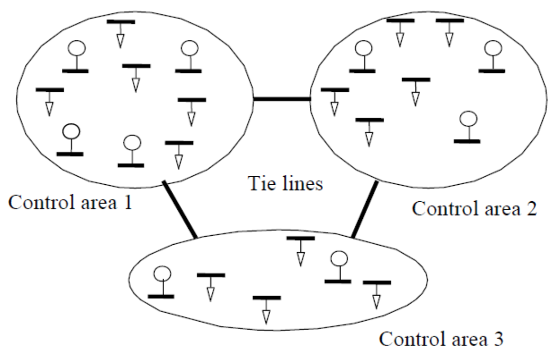


Figure 4.1: Connected control areas [9].

The net interchange of power over the tie lines of an area is the algebraic difference between area generation and area load (plus losses). A schedule is prearranged with neighbouring areas for such tie-line flows, and as long as an area maintains the interchange power on schedule, it is evidently fulfilling its primary responsibility to absorb its own load changes. But since each area shares in the benefits of interconnected operation, it is expected also to share in the responsibility to maintain system frequency [1].

Frequency changes occur because system load varies randomly throughout the day so that an exact forecast of real power demand cannot be assured. The imbalance between real power generation and load demand (plus losses) throughout the daily load cycle causes kinetic energy of rotation to be added or taken from the on-line generating units, and frequency throughout the interconnected system varies as a result. Each control area has a central facility called the energy control center, which monitors the system frequency and the actual power flows on its tie-lines to the neighbouring areas. The deviation between desired and actual system frequency is then combined with the deviation from the net scheduled interchange to form a composite measure called the *area control error* (ACE). To remove area control error, the energy control center sends commands signals to the generating units at the power plants within its area to control the generator outputs so as to restore the net interchange power to scheduled values and to assist in restoring the system to its desired value. A negative ACE means that the area is not generating enough power to send the desired amount out of the area. The ACE can be calculated with equation 4.1 [1].

$$ACE=(P_a-P_s)-10B_f(f_a-f_s) \tag{4.1}$$

Where:
P_a = the actual net interchange
P_s = the scheduled net interchange
f_a = the actual frequency
f_s = the scheduled frequency
B_f = the frequency bias setting

Not only the ACE is important but also the station control error (SCE); is the amount of actual generation of all the area plants minus the desired generation. This SCE is negative when desired operation is greater than existing operation. The key to whole the control operation is the comparison of the ACE and the SCE. Their difference is an error signal.
The monitoring, telemetering, processing and control functions are coordinated within the individual area by the computer based *automatic generation control* (AGC) system at the energy control center
The automatic generation control consists of three different controllers [9]:

1. Primary active control
   - Maintaining the power balance.
2. Secondary active control
   - Cause the area to absorb its own load.
   - Provide prearranged net interchange with neighbors.
   - Allow the area to do its share to maintain the desired system frequency.
     The area control error is continuously recorded within the control center to show how well the individual area is accomplishing the above mentioned tasks.
3. Tertiary active control
   - Ensure the economic dispatch output of each area plant.

For these controls to work some generating reserves have to available (spinning reserves, primary reserves, secondary reserves, tertiary reserves). These reserves[7] are needed when for example at a certain moment more power is demanded.

4.1.2 State estimation

Interconnected power systems have become more complex and the task of securely operating the system has become more difficult. To help avoid major system failures and regional power blackouts, electric utilities have installed more extensive supervisory control and data acquisition (SCADA) throughout the network to support computer-based systems at the energy control centers. The data bank created is intended for a number of application

[7] Reserve: the generation capability that is in place to ensure that electricity supply is matched to demand over the time scales from seconds to hours, that is, to provide the system balancing function.

programs, some to ensure economic system operation and others to assess how secure the system would be if equipment failures and transmission line outages were to occur [1].

Before any security assessment can be made or control actions taken, a reliable estimate of the existing state of the system must be determined. For this purpose the number of physical measurements cannot be restricted to only those quantities required to support conventional power flow calculations. The inputs to the conventional power flow program are confined to the P, Q injections at load buses and P, V values at voltage controlled buses and the other values are free to choose for the power flow program. Real time differences in one or more of the input quantities can cause the power flow results to become useless. In practice, other conveniently measured quantities such as P, Q line flows are available, but they cannot be used in conventional power flow calculations. These limitations can be removed by state estimation. The state of the ac power system is expressed by the voltage magnitudes and phase angles at the buses. Although relative phase angles of bus voltages cannot be measured, they can be calculated using real time data acquired from the system. These data are processed by the state estimator, a computer program which calculates voltage magnitudes and relative phase angles of the system buses [1].

4.1.3 Voltage quality

Voltage stability is another major issue for the power systems. Especially the present power system has set very strong restrictions at the size and duration of voltage fluctuations because some loads and especially electronic apparatus are very sensitive to the voltage changes. The voltage should maintain an acceptable value; a too low voltage will drive the system towards thermal overloading and voltage collapse; a too high voltage leads to damage or destruction of electrical equipment. It is important that the demand and supply for reactive power is equal, because the reactive power balance determines the voltage profile (voltage at each node in the system). The demand for reactive power is determined by the work factor ($\cos\varphi$) of the connected loads and the amount of reactive power that is generated or absorbed by the electrical system. Loads are in general reactive, so they absorb reactive power. Coils and transformers absorb reactive power, capacitors and cables generate in general reactive power. Voltage stability is mainly maintained by the voltage control of the generators and with the use of large capacitors banks or coils that are connected to the grid in predefined times or when a voltage problem occurs. Except from the banks and coils, power electronic devices that can control the voltage level at certain points of the grid are used. In some cases synchronous machines that produce or absorb reactive power in order to control the voltage are used, these machines are called synchronous compensators [1].

There are also 3 controllers that control the reactive power throughout the system [2]:

1. Primary reactive control
    - The primary reactive control controls the voltage of the producing unit
      The voltage at each bus will differ, so this controller will only have a local effect
2. Secondary reactive control
    - The secondary control wants the voltage profile to recover, this is not required. Required is that the voltage profile is acceptable (within the defined limits).

3. Tertiary control
   - The tertiary reactive control influences the production as result from optimizing the reactive power balance.

The quality of the voltage depends on [2]:
1. The voltage level
2. Frequency
3. Waveform
4. Symmetry of the three-phase system

4.1.4 Impact of intermittent energy generation on power system operation
Renewable energy resources for electric power generation are gaining momentum to substitute for less environmentally-friendly electrical energy sources. Many countries have targets and aspirations for growth in renewable energy.
A substantial fraction of renewable energy generation will compromise intermittent[8] generation, particularly wind power, which is less controllable than conventional fossil-fired plants. This trend places new challenges to the electric system operator in assuring both angle and voltage stability of the system (due to a not constant output of RES). This need becomes more significant with the increase in penetration levels of renewable generation sources [10].

Electricity systems are run with installed generation greater than the peak demand (available reserves, system margin) so that the peak demand can be met even when a plant is unavailable. Measures such as loss of load probability (LOLP) are used to define system reliability. Loss-of-load probability is the probability that a load will be forced to disconnect from the system because insufficient generation is present, this is expressed as a percentage. With intermittent generation making up a part of the capacity, the system margin needs to be larger to maintain the same probability of meeting the peak demand.
This is due to the fact that the electrical output of intermittent sources fluctuates in time and is difficult to predict [10].

A good example is wind power. Wind power may affect the use of primary and secondary reserves during the operational time. Wind power development will have little to no influence on the amount of primary reserve needed, as concluded by several studies. On second/minute time scales fast variations in total wind power capacity output occur randomly, like the already occurring load variations. The amount of primary reserve allocated in the power systems is dominated by outages of large thermal generation plant, hence more than large enough to cope with these very fast variations. To assess the impact of wind power on the secondary/tertiary reserves, the variability of large scale wind power at the hour during which the system operator assumes control is relevant. Even in extreme cases, the output of distributed wind power plants does not change more than $\pm$10% of installed capacity in one hour in larger areas (value noticed by Nordel the system operator of the Nordic countries) [11]. For the use of reserves, all variations that have not been predicted will affect the net system imbalance. Part of the wind power production will remain unpredicted. The predictability of wind power depends on the time horizon it is

[8] Terminology differs between authors, and many analysts advocate, the use of ‘variable’ in preference to ‘intermittent’, noting that all power sources are interruptible; hence intermittent. However, the term intermittent is in widespread use and is used here.

realized. The closer the time horizon the more accurate are the results, so in the absence of a perfect forecast, the unit commitment decision has some uncertainty. The result is that sometimes a unit might be committed when it is not needed, and sometimes a unit might not be committed when it is needed or is more economical. Aggregating wind power imbalances together with all other deviations from schedules (especially load forecast errors) will determine the total net imbalance and the reserves needed for the power system. In principle the power producers can try to correct their production levels to the scheduled levels up until the operating hour by trade or re-scheduling their own conventional capacity. If this was done, then only the in-hour variability of wind power would affect the secondary reserves. The largest impact of wind power will be on how conventional units are scheduled to follow load (hour to day time scales). The more flexible power units there are, the later the unit commitment decisions need to be done [11].

It is also important to note that any new generation technology (applies for RES) will lead to a change in the total cost of operating the system. The main factors affecting the costs are [10]:

- The nature of the environmental resource on which the generation depends.
- The installed capacity of intermittent sources and their geographical dispersion.
- The physical nature of the electricity transmission and distribution infrastructure.
- Operating and regulatory practices associated with the system.

So the integration of intermittent energy generation will have impact on, the available reserves, the UC-ED and the operating costs of the system.

4.2 Load and generation

In this part the load and generation of the Central Western European region are analyzed. Also the generation-demand balance will be discussed.

4.2.1 Load

Demand for electric energy grows and has a variable nature. The growing population in combination with the continuously increasing number of electric power uses and applications has created a large interest for electric energy. Demand of electric energy is called load. Load on a global level is thus continuously changing. In the power system terminology load is every consumer that is connected to the electricity grid and absorbs energy to cover his needs. The load continuously changes during the day (load curve). This is because each consumer of electric power absorbs the energy he needs within a certain time frame. In figure 4.2 the estimated load curve/pattern for the first week of 2018 is shown for the CWE countries.

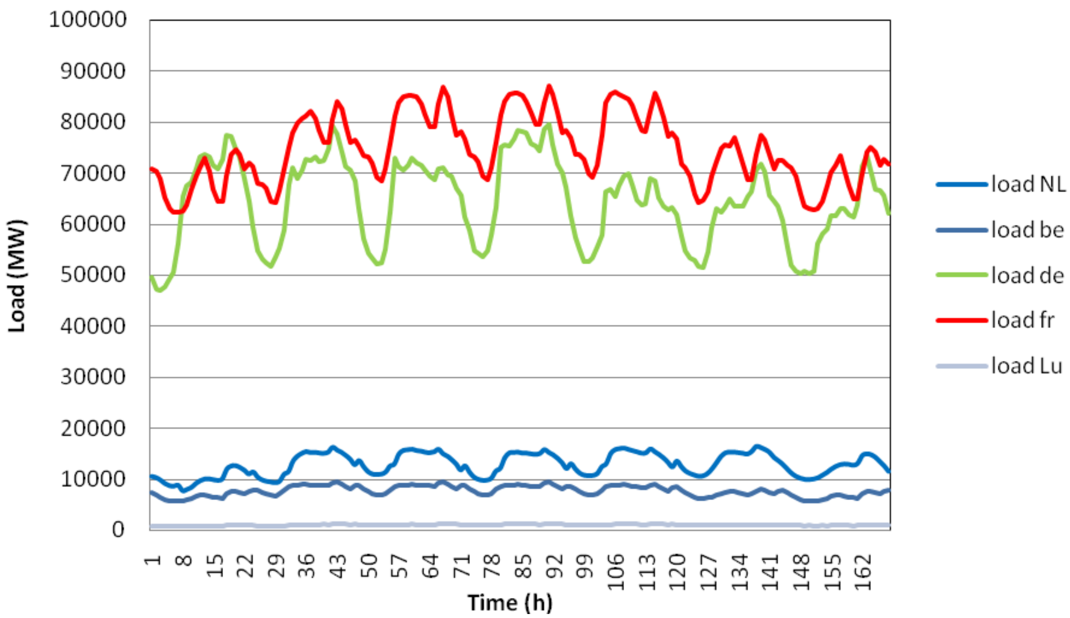


Figure 4.2: Estimated load pattern of the CWE countries for the first week of 2018.

The x-axis of figure 4.2 is the number of hours (7 times 24=168 hours total so 168 samples) and the y-axis represents the magnitude of the load in MW. From figure 4.2 we see that the load pattern is different for all the countries in the CWE region. The load of France (red) is much bigger compared to the Dutch load, Belgium load and the load of Luxembourg. We also see that there is a difference between the load during the day and during the night. During the day the load is at its maximum and during the night at its minimum. The load estimation is done by the TSOs. The load estimation is done by monitoring the demand of energy during a couple of years. With this monitored data a percentage for the growth of the load per year per country can be derived called average annual load growth.

The estimated average annual load growth (GWh) for the CWE region is presented in table 4.1 (valid for 2018).

Table 4.1: Estimated average annual load growth for the CWE region

	BE	DE	FR	NL	LU	CWE
Average annual growth (GWh)	0.9 %	0.1 %	0.8 %	1.6 %	2.9 %	0.7 %

The estimated load for 2018 for the CWE region is presented in figure 4.3.

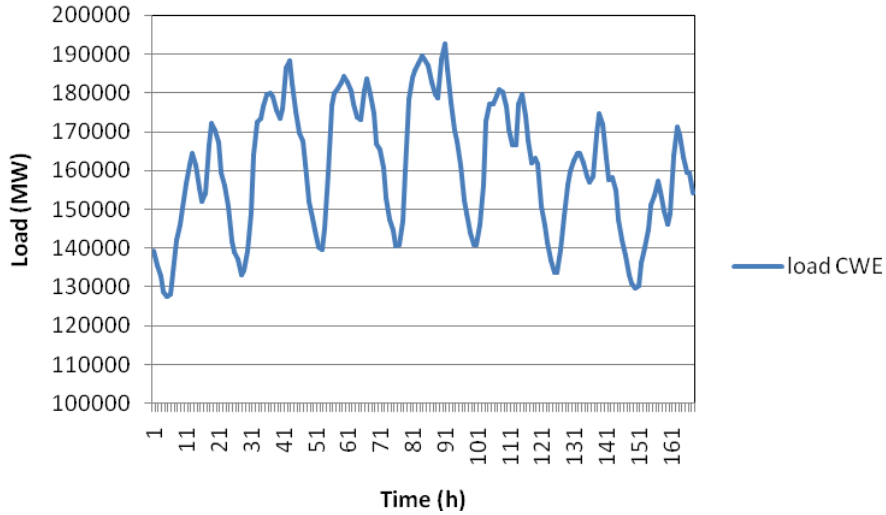


Figure 4.3: Estimated load for 2018 for the CWE region.

From figure 4.3 we see that the CWE load has an average value of 162 GW and the maximum peak load is around 192 GW (year 2018).

4.2.2 Generation

If generation of electricity would always cover regional demand no interconnected transmission grid would be needed from a pure technical point view. Nowadays transmission grids between electricity markets are additionally necessary to allow installation of huge amounts of decentralised non dispatchable generation units like wind farms or solar generation.

Electric energy is nowadays generated through conventional and partly sustainable resources. Conventional generation basically is thermal plants. The plants operated by power utility systems are normally at locations selected as a result of factors considered to be desirable by the utility. Conventional generation consists of fossil fuels (coal-fired, oil), natural gas-fired plants and combined heat and power plants (CHP units). Nuclear generation is a non-renewable energy form and is regarded as thermal generation. All these sources cover today more than 90% of total power production in a global level and depend on the availability of fuel supply. Steam turbines can be built to very large sizes (up to over 1000 MW) and have relatively high efficiencies. Power plants (except nuclear plants) offer the advantage of controlling their output with high accuracy but they are not free pollutant sources as they emit gases such CO_2 and NO_x.

The most important sustainable energy sources are wind power, hydro power, solar power and biomass. They offer the advantage that they are clean resources and that there is not the fear of the resource depletion. It is believed that most of these sources will play a more important role in the fulfillment of our energy needs in the future due to a combination of factors as the expected depletion of fossil resources, the greenhouse effect and the liberalization of the energy market that gives space to more sustainable applications. On the other hand these resources vary their output according to the environmental conditions like wind speed, solar radiation and thus their output are partly predictable and dependent on environmental characteristics.

The current trend is to install more small scale production facilities close to the consumption centers. These units are mainly gas-fired whose capacity level varies from kilowatts up to some tens of megawatts. These units are called distributed generators (DGs) and are connected directly to the medium voltage or the distribution grid (MV-LV networks). Onshore wind units can be considered a form of DG as it can be installed at any size and connected even at low or medium voltage levels. A small portion of the total installed capacity of the CWE region consists of distributed generators that are not all included in the system operator's supervisory system. The DGs are locally dispatched or not dispatched at all. The generation connected at the distribution level that is generally not controlled, contributes to the high minimum generation together with the many CHP units

A group of the generation units located in the CWE region are combined heat and power plants also called CHP units. Because these units are heat demand driven, power comes as a by-product of the production of heat or steam. The operational flexibility is therefore constrained to the power levels associated with specific demands for heat or steam for the area served. CHP units often have a must-run status, defined from the operational area limits as seen in figure 4.4. This must-run status of the CHP units influences the UC-ED because the CHP units must be committed.

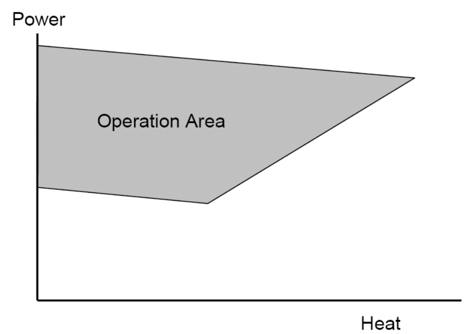


Figure 4.4: Example of an operation area of a CHP-unit [8].

In figure 4.5 an estimation of the growth of different generation types that are installed in the CWE region are shown ranging from year 2008 till 2015.

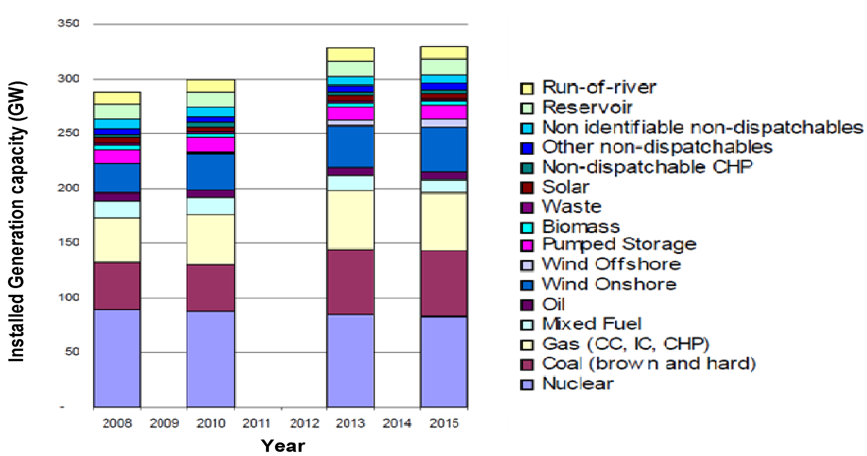


Figure 4.5: Estimated growth of available installed units of the CWE region [7].

There are a lot of different generation categories/types as shown in the above figure. The total installed generation is around 290 GW for 2008 and around 330 GW for the year 2015. More than 50 % of the installed generating units are the conventional thermal plants (gas, coal, oil, nuclear). There is also a relative large growth of wind offshore power and other sustainable energy sources. The installed capacity is always bigger than the load because not all the units are committed (installed capacity > running capacity) [7].

4.2.3 Generation-Demand balance

The load characteristic varies with time as a result of different factors. Every load can be modeled as a normal distribution around a mean value. This means that there is a high correlation between different loads over the whole day. The load and generation are never perfectly predictable. Thus, it is impossible to perfectly balance the load and generation to each other in advance. The load changes in time and also the generation fluctuates due to variable wind power, alternative energy sources, equipment outages etcetera. This difference between load and generation creates an energy mismatch[9]. The system manager (TSO) is responsible that this mismatch disappears.

Energy that is consumed in the load centers has to be provided by generator units. The power balance in the system is in equilibrium when at each moment the power produced equals the load. This is the prerequisite in order to keep the frequency of the system at the nominal level. The nominal frequency at the European power system is 50 Hz. If load is higher than generation the frequency decreases and this can cause problems in the equipment connected to the system. On the other hand if load is less than generation then the frequency in the system rises with also negative consequences. Keeping the frequency in a specific range is thus of primary importance and for this reason power plants are generally equipped with devices that control with high accuracy their output power.

4.3 Transmission system description

In this paragraph a short description is given about the electrical transmission system in the CWE region.

4.3.1 Role of the transmission system

Loads demand energy that is most of the time produced at locations not close by. Sometimes the location of power plants (example: offshore wind park) is very remote from the largest consumption centers such as cities or industrial areas. So it is necessary to transmit energy from the generation points to the locations where the loads are. For transmitting the electrical energy, a transmission system is needed. A transmission system consists of high voltage transmission lines (sometimes also extra HV, not in CWE) and distribution networks. The transmission lines transport energy between areas and the distribution networks distribute the electrical energy over the local loads. The high voltage lines in the CWE region are operated at AC voltage with magnitudes of 380 kV, 220 kV, 150 kV and 110 kV. The high voltage lines are usually operated by the local TSO and they take care of the transmission services.

[9] The market party that is responsible for creating this mismatch has to pay for the costs required to disappear the mismatch.

In a distribution network are the voltage levels usually lower than 60 kV and can reach at the lowest value 400 V phase to phase (230 single phase) where the households are connected. So the distribution of power is provided at medium and low level voltage.

There is a separation between generation services and transmission services (TSO). This separation makes the task of transmission planning even more difficult (TSO have no power at making decisions at the generation side).

Transmission systems of different countries are connected to each other by so called cross border interconnections. The capacity of these interconnections depends on various factors. The cross border connections make it possible for countries/areas to import or export energy from each other. In figure 4.6 the border exchanges are shown between the CWE countries ranging from year 2004 to 2007.

Exchanges per border [TWh]	2004	2005	2006	2007	Average 2004-2006	Average 2004-2007	differences averages
	TWh	TWh	TWh	TWh	TWh	TWh	TWh
Belgium ⇒ The Netherlands	4.05	4.43	5.02	5.09	4.50	4.65	0.15
The Netherlands ⇒ Belgium	4.63	5.08	5.60	5.27	5.10	5.14	0.04
Belgium ⇒ Luxembourg	1.57	1.37	1.70	1.63	1.55	1.57	0.02
Luxembourg ⇒ Belgium	2.38	2.37	2.48	2.08	2.41	2.33	-0.08
Germany ⇒ The Netherlands	17.36	19.26	22.34	18.06	19.65	19.25	-0.40
The Netherlands ⇒ Germany	0.56	0.33	0.28	0.30	0.39	0.37	-0.02
Germany ⇒ Luxembourg	4.93	5.03	5.13	5.22	5.03	5.08	0.05
Luxembourg ⇒ Germany	0.751	0.79	0.80	0.80	0.78	0.79	0.01
France ⇒ Belgium	7.60	6.76	10.64	8.35	8.33	8.34	0.00
Belgium ⇒ France	1.18	2.22	1.98	2.32	1.79	1.93	0.13
France ⇒ Germany	15.48	16.23	16.17	16.43	15.96	16.08	0.12
Germany ⇒ France	0.40	0.49	0.84	0.73	0.58	0.61	0.04

Figure 4.6: Border exchanges between CWE countries from 2004 till 2007 [7].

4.3.2 Parameters of transmission lines

In this subparagraph the important parameters that influence the functioning of power lines (transmission lines) are briefly explained.

An electric transmission line has in total four parameters which affect its ability to fulfill its function as part of a power system: resistance, inductance, capacitance and the conductance These parameters are strongly dependent on how the transmission line is constructed and operated [1].

Resistance

The resistance of transmission-line conductors is the most important cause of power loss in a transmission line. Reducing the current in a line reduces the power losses due to the resistance of the line, which vary by the square of the current. As the voltage of the line is increased the current required for a given amount of active power is reduced. The resistance among other factors depends on the atmospheric temperature, the conductor material, length and cross section area (effective resistance). The power loss in a conductor due to the resistance can be calculated using equation 4.2 [1].

$$\text{Power loss in conductor} = R \times |I|^2 \qquad (4.2)$$

A higher voltage leads to lower losses for the same transfer of energy. For these and other reasons transmission lines are normally operated at higher voltage levels than those of lines used for local distribution of power [1].

Inductance

The variation of the current in the conductors causes a change in the magnetic flux linking of the circuit. Any change in the flux linking of a circuit induces a voltage in the circuit which is proportional to the rate of change of flux. The inductance of the circuit relates the voltage induced by changing flux to the rate of change of current [1]. The inductance is mainly responsible for the power distribution over a transmission line. Two parallel lines, where line 1 has a two times higher inductance than line 2, draws half the current of line 2.

Capacitance

Capacitance of a transmission line is the result of the potential difference between conductors. The capacitance between conductors is the charge per unit of potential difference. Capacitance between parallel conductors is a constant depending on the size and spacing of the conductors. For transmission lines less than about 80 km long, the effect of capacitance can be slight and is often neglected. For longer lines of higher voltage capacitance becomes increasingly important [1]. For cables this is in important parameter even at short distances.

Shunt conductance

The conductance exists between conductors or between conductors and the ground. Conductance accounts for the leakage current at the insulators of overhead lines and through the insulation of cables. Since leakage at insulators of overhead lines is negligible, the conductance between conductors of an overhead line is usually neglected. Another reason for neglecting it is that since it is quite variable (due to dirt, atmospheric conditions), there is no good way of taking it into account. Corona, which results in leakage between lines, is also quite variable with atmospheric conditions [1].

Material of conductors

In the early days of the transmission of electric power conductors were usually copper, but aluminum conductors have completely replaced copper for overhead lines. That is because for the same resistance the aluminum conductor has lower weight and cost from a copper conductor. Furthermore, the use of aluminum offers an extra advantage of less corona losses because the aluminum conductors have larger diameter than the respective copper conductors and thus smaller voltage gradient across the surface and less tendency to ionize the air around the conductor. Ionization produces the undesirable effect called corona [1].

Thermal limits of conductors

Overhead transmission lines reach their thermal limit if the electric current heats the conductor material to a temperature above which this material will start to soften. The maximum permissible continuous conductor temperature varies between 50^0C and 100^0C, depending on the material, its age, the geometry, the height of the towers etcetera. The thermal limit or current-carrying capacity of the conductors depends on the ambient temperature, the wind velocity, solar radiation, the surface conditions of the conductor and the altitude above sea level. The loading on short transmission lines (less than 100 km long) is usually restricted by the heating of the conductors rather than by stability considerations. The current carrying capacity at higher wind speeds is higher than at lower wind speeds. In places, where wind speeds are higher in the winter, the low temperatures also contribute to an increase in the current-carrying capacity. Other network elements such as breakers, voltage and current transformers and power transformers could further restrict the transmission capacity of some network branches. The thermal limit of the transmission line is then set by the lowest rating of the associated equipment [12].

The thermal limit of a transmission line or transformer is the restricting factor that is studied in the present project. A bottleneck occurs if the loading of a line exceeds the capacity of the line defined by the current that can flow through it without causing any damage to the structure. The current (power) that flows through the lines is found with the load flow calculations.

Voltage standardization of lines

There is certain standardization in the selection of voltages so that only a few standard voltage levels are normally used. Transmission voltage levels are usually considered to be 60 kV and above. In the CWE transmission system the standardized levels of 110 kV, 220 kV and 380 kV are used. Lines that operate with voltages above 300 kV are called extra high voltage lines (EHV) and they extend up to 1000 kV. The cost and physical problems with insulation systems have limited such lines to this range. The transmission system of the CWE region doesn't consist of EHV transmission lines.

Another distinction in the transmission lines is between the overhead lines and cables. Cables are preferred in the urban areas or at voltage levels that do not exceed 150 kV, especially if their installation in the ground does not create many difficulties. On the other hand overhead lines are preferred when power is transferred for longer distances. The CWE transmission system consists of both types. At the 380, 220 and partly 150 kV and 110 kV levels the overhead lines dominate. At lower voltage transmission and distribution levels cables are dominant, especially in rural areas.

Representation of transmission lines

Distinction of the transmission lines can be made according to their length. Short are the lines with length no longer than 80 km. Medium length are the lines with length roughly between 80 and 240 km and long are the lines with length longer than 240 km. According to their length, the appropriate equivalent circuit for the line representation is used [1].

The general equations relating voltage and current on a transmission line recognize the fact that all four of the parameters of a transmission line are uniformly distributed along the line. Using lumped parameters gives a good accuracy for short and medium length lines. If an overhead line is classified as short, the shunt capacitance is small and it can be omitted entirely with little loss of accuracy, so we need to consider the series resistance R and the series inductance L for the total length of the line [1].

A medium length line can be sufficiently represented by R and L as lumped parameters, with half the capacitance to neutral of the line lumped at each end of the equivalent circuit, as shown in figure 4.7 [1].

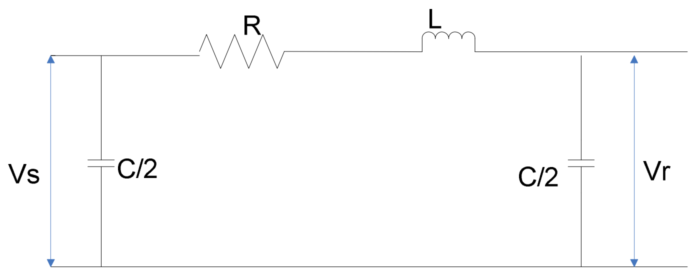


Figure 4.7: Single phase equivalent of a medium length line with lumped parameters.

V_S and V_R are the sending and receiving voltage respectively. The same circuit can represent the short line if capacitors are omitted. Long lines require calculations in terms of distributed constants if a high degree of accuracy is required, although for some purposes a lumped parameter representation can be used for lines up to 320 km long [1].

The equivalent circuit of figure 4.7 is used for every line representation in the power flow program (PSS/e), independent of the line length.

Compensation of transmission lines

The performance of transmission lines, especially those of medium length and longer can be improved by reactive compensation of a series or parallel type. Series compensation consists of a capacitor bank placed in series with each phase conductor of the line. Shunt compensation refers to the placement of inductors from each line to neutral to reduce partially or completely the shunt susceptance of a high voltage line, which is particularly important at light loads when the voltage at the receiving end may otherwise become too high [1].

Series compensation reduces the series impedance of the line, which is the principal cause of voltage drop and an important factor in determining the maximum power that the line can transmit for stability reasons. The desired reactance of the capacitor bank can be determined by compensating for a specific amount of the total inductive reactance of the line. This leads to the term "*compensation factor*", which is defined by X_C/X_L, where X_C is the capacitive reactance of the series capacitor bank per phase and X_L is the total inductive reactance of the line per phase.

A proper compensation reduces the reactive current that flows through the transmission lines [1].

4.3.3 HVDC Transmission

Another option of transferring electrical energy is with dc voltage. Transmission systems are normally operating with ac voltage and current so the use of dc requires the presence of converters at both ends of the lines that convert the ac voltage to dc (rectifiers) and the dc voltage to ac (inverters). The transmission of energy by direct current becomes economical when compared to ac transmission when the extra cost of the terminal equipment (converters, inverters etc.) required for dc lines is offset by the lower cost of building the lines. Direct-current lines usually have one conductor which is at a positive potential with respect to ground and a second conductor operating at an equal negative potential. Such a line is said to be bipolar. The line could be operated with one energized conductor with the return path through the earth, which has a much lower resistance to direct current than to alternating current. In this case, or with a grounded return conductor, the line is said to be monopolar. DC transmission lines may operate at 500 kV dc or more (positive or negative) and the voltage between conductors may be over 1000 kV. HVDC is used in many cases especially at the interconnection of power systems between countries/regions. It is preferred because it offers greater flexibility and control of the power flows with the semi conducting devices of the converters in both sides of the dc cable. As the cost of conversion equipment decreases with respect to the cost of line construction, the economical minimum length of dc lines also decreases [1].

In general it is more economical to build an AC-connection when this is technical possible. This is not the case when [2]:

- Connecting asynchronous networks
- Long cable connections
- A weak connection between large systems
- Large transports are needed over very long distances

Advantages of HVDC transmission compared to HVAC transmission are [2]:

1. Higher transport capacity
2. Lower losses
3. Ease of power flow control
4. No short circuit current
5. No reactive behaviour

Disadvantages of HVDC transmission are [2]:

1. High cost of power electronics (inverters, rectifiers etc.)
2. Introduction of harmonics in the ac currents

Two recent examples of HVDC interconnections are the connections between the Netherlands- Norway and the Netherlands-United Kingdom. The connection between Netherlands and Norway has a capacity of 700 MW, length of 580 km and an operating voltage of ± 450 kV. The construction of the direct current cable link to Great Britain has started and it is planned to be taken into operation before 2014. Such connections are in line with the European's Union policy of interconnecting markets and increasing liquidity in the market. HVDC transmission technology may also be used for the connection of the offshore wind farms to the mainland transmission grid. A number of studies has been done, the pros and cons of HVDC technology compared to transmission with high voltage AC technology have. For deciding the best alternative the total cost each technology offers, the losses, the necessary maintenance, the expected lifetime and other factors are taken into consideration in this type of analysis.

4.3.4 Phase shifting transformer

When there are two or more parallel paths for power to flow between power systems or within a network, the load will divide inversely proportional to the path impedances. In some cases a transmission line with greater power handling capability may be longer and has higher impedance than a short line with low load capacity. If such lines are operated in parallel, the line with low load capability may overload before the capacity of the larger line is reached. Power flows on a line with impedance X are proportional to the angular displacement δ between the sending and receiving ends of the line with voltages V_S and V_R respectively, according to the equation 4.3 [15].

$$P=\frac{|V_s|\times|V_r|}{X}\sin\delta \tag{4.3}$$

Equation 4.3 gives an idea on how power division between parallel lines may be controlled. By the application of proper control devices such as a phase shifting transformer installation, the power flow on a line operated in parallel with other lines can be controlled as desired. The idea behind this operation is that the phase shifting transformer enforces the phase angle δ by adding or subtracting a line voltage being perpendicular to one of the phase voltages of the main transformer. Thus the magnitude of the voltage changes but more importantly a phase shifting angle (named α in many references) is added to this bus voltage. Therefore the active power that flows in the line increases or decreases respectively. Because the network is consisted of many buses and lines the final angle between the same two buses is not the sum of the initial angle with the phase shifting angle (δ+α) but different because the rest network reacts to this change as a feedback. However the real power flow transmitted between these two buses is affected.

The advantage of introducing phase shifting transformers in a grid is that the line loading of the connected lines can be influenced. This makes it possible to use parallel lines efficiently.

5 Method development

In this chapter the development of the method/tool is described. While paragraph 5.1 focuses on the methodology itself, paragraph 5.2 offers a brief introduction with the two main programs PowrSym3 and PSS/e used in the method/tool.

5.1 Methodology

Power flows in the system depend on the load and generation locations. The uncertainty of power flows in the system lies mainly in the volatile infeed of RES, the uncertainty of both power imports and the commitment and dispatch of conventional generators, which in turn are dependent on system load, generation levels and renewable energy source levels/location (namely wind power). Taking the latter as fixed, conventional generation and power imports can be determined and the load flow can be calculated. Because of the many different combinations of load and generation, a large number of load flows should be used to capture the so-called worst cases, which are used for transmission system capacity bottleneck identification. All the load flow results for each line results in line loading curves, as can be seen in figure 5.1.

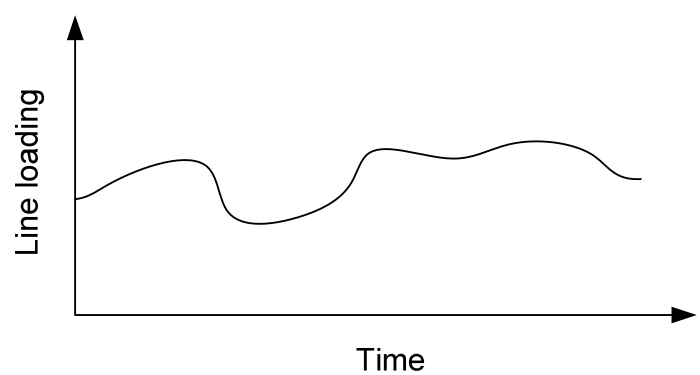


Figure 5.1: loading curve.

The method allows a better approximation/estimation of all possible loadings for each transmission line, including the real worst case, compared to a probable worst-case selection on beforehand.

The method that will be followed in order to identify congestions in the Central-West Europe transmission system involves the cooperation of two main programs. The year under examination can be divided into 15-minutes or hourly intervals. Consequently, the total number of time intervals during a year is either 24x365 = 8760 samples for hourly intervals or 4x24x365 = 35040 samples for 15 minutes intervals. It means that each computational step of the Unit Commitment, Economic Dispatch and load flow would represent a 15 minutes or one hour situation. Inside this time interval it is assumed that each generator (including wind power), load and interconnection power exchange will have a fixed value. Within this method the dynamic behaviour of the system is omitted.

The advantage of this method is that by running totally 8760 load flows a good approximation is taken of all possible combinations between load and generation throughout a year, so in fact this tool permits to identify any reasonable bottleneck in the transmission system with higher accuracy compared to the conventional method (worst cases), without making assumption for the combination of load and generation levels that drive to the worst case for the loading of lines on beforehand. It is also possible to perform sensitivity analysis, to see how the system behaves under different system conditions. In figure 5.2 the building blocks of the tool/method are shown.

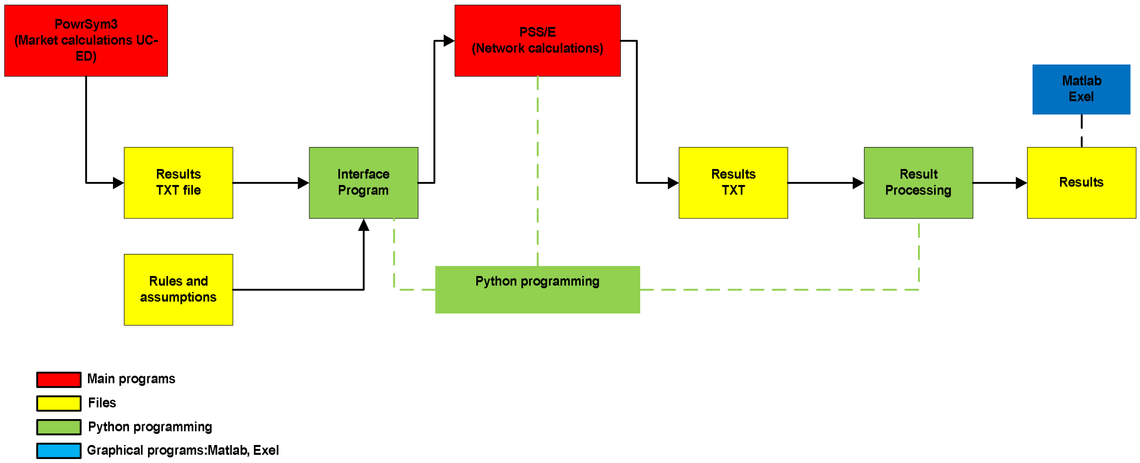


Figure 5.2: building blocks of the bottleneck identification method/tool.

The first main program is a unit commitment and economic dispatch program called PowrSym3. PowrSym3 is the program that makes the Unit Commitment and Economic Dispatch (UC-ED) schedule and gives at its output the loading of each generation unit as well as the inter-area[10] programmed power flows. The output of PowrSym3 includes the actual production level for all units for each 15-minute or 60-minute period of one year. In this output planned maintenance and forced outages periods of (Central-West European) conventional units are integrated in order to obtain more different unit commitment combinations. The outage periods are defined through a Monte Carlo stochastic method, where factors like the age and type of generators are taken into consideration.

The PowrSym3 output is fed through a data interface programmed in Python into the second main program, a load flow program, called PSS/e which contains a model for the (Central-West European) investigated transmission network[11]. The data interface is programmed in such a way that the results from PSS/e can be easily traced back from the output of PowrSym3 in order to allow an assessment of specific cases. The data interface is also used to implement some rules and made assumptions (yellow block in figure 5.2) and also to process the output data from PSS/e. In PSS/e, data for each generator and load are assigned to a bus in the transmission system model. For each 60 minute (or 15 minute) period, the power flows in the system are then calculated using an AC or DC-load flow simulation (the tool can perform both AC and DC load flows). Transmission system capacity bottlenecks are identified by investigating the loadings of lines in each load flow calculation (base case). Furthermore, a contingency analysis (n-1) can be carried out.

[10] Flow between defined areas (for the CWE study is the inter area flow the flow between countries). These areas can be both countries and regions.

[11] The network model(s) for this thesis project are obtained from the Dutch Transmission System Operator Tennet (TSO).

The 8760 situations (one year) can then be used as input for the contingency analysis, by putting out of service a grid element such as a transmission line or transformer. The loading levels of all considered lines throughout a year for each contingency scenario of a line's outage can be represented with the form of histograms or box plots (plots are made with Matlab).

The strong advantages of the presented method are:

1. Hourly, weekly or yearly simulations can be performed in order to discover the worst case scenarios.
2. Results of different market simulations can be compared to each other.
3. The two main programs are commercial products and can be purchased by everyone.
4. The flexibility of the two main programs allows the user to perform an important number of calculations.
5. Process automation is easy.

5.2 Main programs: PowrSym3 and PSS/e

5.2.1 PowrSym3

PowrSym3 is a multi-area, multi-fuel, production-costing model in which system operation is simulated to minimize total system cost over weekly time horizons in sequential time steps of one hour (or shorter time period). It has the accuracy and level of detail necessary for short term operational studies as well as long term planning studies. In addition to simulating production cost, PowrSym3 will schedule unit maintenance and calculate system reliability statistics. Hydro operation is simulated with a load leveling routine. The operation of pumped storage units is simulated by trading high cost peak generation against low cost off-peak pumping energy to the point of no additional savings observing reservoir constraints in the process. There are both commit and dispatch types to order the non-economic operation of generating units as needed. PowrSym3 is a very robust model with much flexibility [16].

PowrSym3 takes into account the planned maintenance and the forced outage of the generators. During its planned maintenance, a generator is not considered in the unit commitment schedule. The programmed maintenance for the combined heat and power units (CHPs) is for the summer periods when these units are out of operation, as their operation would be inefficient due to the unnecessary heat production. For the rest of the units a maintenance work is programmed to be done during the periods when their loading will be the lowest. In general this period doesn't exceed 30 days throughout a year, but it always depends on the type, size, age and expected lifetime of the unit and it is made once per year [16].

The forced outage of generators is applied to PowrSym3 program through Monte Carlo stochastic method. This is a probabilistic method that introduces randomly the outages of generators in the PowrSym3 model. For the conventional units the outage duration equals the minimum down time of the respective unit according to PowrSym3 specifications. Then PowrSym3 re-dispatches the generation among the rest operating units [16].

PowrSym3 uses nodes and links with fixed transfer capacities (can be changed) for modelling different areas and calculates the international exchange levels depending on the prices in neighbouring areas and on the interconnection capacity levels (national transport capacities). It is important to see that these international exchanges are determined by the market conditions and are not the real flows of power. This is because the market simulations are independent of a under laying grid. Real physical flows between countries are calculated by performing a load flow [16].

PowerSym3 needs input data in order to solve the unit commitment and economic dispatch problem. In this thesis the input data consists of:

1. Load files:
   The estimated load for 2018 for every hour is given for all the CWE countries as an input. The UC-ED is done to cover the load for every hour for all the countries.
2. Database with the generating units:
   In this database all the generating units for each country are described. The units are described by defining what generation technology (thermal, wind, hydro etc) is used, the 'must run' status, fuel consumptions, emission restrictions, run costs start time, ramp up and ramp down rates, minimal down time, outages, spinning and operating reserves (constraints, unit variables) etc. It is difficult to know all these variables for future scenarios. The accuracy of the described units is important; the output will be more different if the units are extensively defined.

This database used for this thesis is provided by the Dutch TSO TenneT in cooperation with the CWE TSOs in order to validate the method.

With the above mentioned input data a generation schedule can be made. In table 5.3 an example of such a generation schedule determined by PowrSym3 is shown. The generation schedule of table 5.1 is only for two units and two hours.

Table 5.1: Example of a generation schedule from PowrSym3

Year	Week	Hour	Unit identifier in database	Unit name	Output (MW)
2018	1	1	107	Unit 1	0.00
2018	1	1	108	Unit 2	370.64

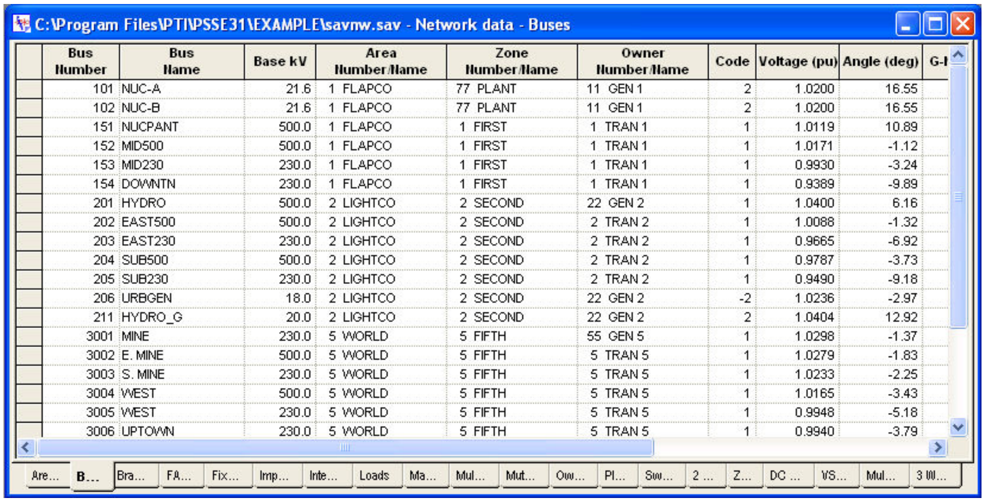
The great number of variables and flexibility allow us to perform sensitivity analysis. A sensitivity analysis is, for example, to see how the gas price increase influences the generation schedule, leading to different power flows. PowrSym3 can also provide other useful data such as operating data, cost data, emission data etc. but in this thesis only the generation schedule determined by PowrSym3 is of only interest.

5.2.2 PSS/e program

PSS/e can perform a number of different calculations such as load flow, fault analysis, switching studies etc, but for the purpose of this study only load flow (contingency included) calculations are performed. Before a load flow can be performed first a description of the transmission network (model) on which the load flow is performed is needed. The model is build up with buses, branches, generators, loads, transformers etc. These components can be created or adjusted using the options and build in functions of PSS/e. A great advantage of PSS/e is that the build in functions are compatible with Python. This means that PSS/e can be controlled with Python by using the commands in the library psspy. For example, if a AC contingency analysis needs to be performed the automated function accc can be called, the syntax is psspy.accc(variables). This can be done for all the options and functions in PSS/e [17].

Buses in PSS/e

The high voltage transmission model of the CWE region consists of a large number (hundreds) of buses. In figure 5.3 a user interface is shown for the buses in PSS/e; the bus data can be seen and changed in this interface.



Bus Number	Bus Name	Base kV	Area Number/Name	Zone Number/Name	Owner Number/Name	Code	Voltage (pu)	Angle (deg)	G-I
101	NUC-A	21.6	1 FLAPCO	77 PLANT	11 GEN 1	2	1.0200	16.55	
102	NUC-B	21.6	1 FLAPCO	77 PLANT	11 GEN 1	2	1.0200	16.55	
151	NUCPANT	500.0	1 FLAPCO	1 FIRST	1 TRAN 1	1	1.0119	10.89	
152	MID500	500.0	1 FLAPCO	1 FIRST	1 TRAN 1	1	1.0171	-1.12	
153	MID230	230.0	1 FLAPCO	1 FIRST	1 TRAN 1	1	0.9930	-3.24	
154	DOWNTN	230.0	1 FLAPCO	1 FIRST	1 TRAN 1	1	0.9389	-9.89	
201	HYDRO	500.0	2 LIGHTCO	2 SECOND	22 GEN 2	1	1.0400	6.16	
202	EAST500	500.0	2 LIGHTCO	2 SECOND	2 TRAN 2	1	1.0088	-1.32	
203	EAST230	230.0	2 LIGHTCO	2 SECOND	2 TRAN 2	1	0.9665	-6.92	
204	SUB500	500.0	2 LIGHTCO	2 SECOND	2 TRAN 2	1	0.9787	-3.73	
205	SUB230	230.0	2 LIGHTCO	2 SECOND	2 TRAN 2	1	0.9490	-9.18	
206	URBGEN	18.0	2 LIGHTCO	2 SECOND	22 GEN 2	-2	1.0236	-2.97	
211	HYDRO_G	20.0	2 LIGHTCO	2 SECOND	22 GEN 2	2	1.0404	12.92	
3001	MINE	230.0	5 WORLD	5 FIFTH	55 GEN 5	1	1.0298	-1.37	
3002	E. MINE	500.0	5 WORLD	5 FIFTH	5 TRAN 5	1	1.0279	-1.83	
3003	S. MINE	230.0	5 WORLD	5 FIFTH	5 TRAN 5	1	1.0233	-2.25	
3004	WEST	500.0	5 WORLD	5 FIFTH	5 TRAN 5	1	1.0165	-3.43	
3005	WEST	230.0	5 WORLD	5 FIFTH	5 TRAN 5	1	0.9948	-5.18	
3006	UPTOWN	230.0	5 WORLD	5 FIFTH	5 TRAN 5	1	0.9940	-3.79	

Figure 5.3: PSS/e interface with a list of buses [17].

Each network bus to be represented in PSS/e is introduced through a bus data record. Each bus data record includes not only data for the basic bus properties but also includes information on an optionally connected shunt admittance to ground. That admittance can represent a shunt capacitor or a shunt reactor (both with or without a real component) or a shunt resistor. It *must not* represent line connected admittance, loads, line charging or transformer magnetizing impedance, all of which are entered in other data categories [17].

The bus data records are [17]:

Bus number: Each bus has a unique bus number ranging from 1 to 999997.

Bus name: The name may be up to twelve characters

Base kV: It indicates the base voltage level of the bus in kilovolts.

IDE Bus type code (CODE):

1. Load bus or other bus without any generator boundary condition
2. Generator or plant bus either regulating voltage or with fixed reactive power (Mvar). A generator that reaches its reactive power limit will no longer control voltage but rather hold reactive power at its limit.
3. Swing bus or slack bus. It has no power or reactive limits and regulates voltage at a fixed reference angle.
4. Disconnected or isolated bus.

IDE = 1 by default.

GL: Active component of shunt admittance to ground; entered in MW at one per unit voltage. GL should not include any resistive admittance load, which is entered as part of load data. GL = 0.0 by default.

BL: Reactive component of shunt admittance to ground; entered in Mvar at one per unit voltage. BL should not include any reactive impedance load, which is entered as part of load data; line charging and line connected shunts, which are entered as part of non-transformer branch data; or transformer magnetizing admittance, which is entered as part of

transformer data. BL is positive for a capacitor, and negative for a reactor or an inductive load. BL = 0.0 by default.
Area: Area number, it specifies in which area the bus is located. An area is mostly a country or big region.
Zone: Zone number, it specifies in which zone the bus is located. A zone is mostly a part of a area.
VM: Bus voltage magnitude, entered in per-unit.
VA: Bus voltage phase angle, entered in degrees.
OWNER: Owner number, it specifies who the owner of the bus is.

It has to be noted that not all this variables have to be filled in when creating a bus, some variables are then set to default values.

Loads in PSS/e
Each network bus at which a load is to be represented must be specified in at least one load data record. If multiple loads are to be represented at a bus, they must be individually identified in a load data record for the bus with a different load identifier. Each load at a bus can be a mixture of loads with different characteristics. The most important characteristics are [17]:
I: Bus number, or extended bus name enclosed in single quotes
ID: One- or two-character uppercase non blank alphanumeric load identifier used to distinguish among multiple loads at bus "I". It is recommended that, at buses for which a single load is present, the load be designated as having the load identifier ’1’. ID = ’1’ by default.
STATUS: Initial load status of one for in-service and zero for out-of-service. STATUS = 1 by default.
AREA: Area to which the load is assigned .By default, AREA is the area to which bus "I" is assigned.
ZONE: Zone to which the load is assigned. By default, ZONE is the zone to which bus "I" is assigned.
PL: Active power component of constant MVA load; entered in MW. PL = 0.0 by default.
QL: Reactive power component of constant MVA load; entered in Mvar. QL = 0.0 by default.

Other components (machines, transformers, capacitor banks etc.) are created in the same way but are specified by different variables.

Transmission lines or Branches in PSS/e
The transmission lines or branches are represented in PSS/e as in the following figure. When a new line has to be imported then the “from bus number “and the “to bus number” have to be completed by the user. The program automatically puts the default values for the rest of the line characteristics. The most important characteristics are [17]:
From Bus Number-To Bus Number: Denotes the starting and the end bus of a line.
From Bus Name-To Bus Name: The program automatically completes the names of the buses as they are in the bus list.
Id: It’s a one or two characters non blank alphanumeric branch circuit identifier that is used to make the distinction between parallel lines. The program completes by default the number ‘1’, if it’s not completed by the user. The from bus number, to bus number and the

id are the three necessary data for Python program in order to read the loadings or power flows for each line and write them to the output file.
Line R: It's the branch resistance entered in pu. A value of R must be entered for each branch.
Line X: It's the branch reactance entered in pu. A nonzero value of X must be entered for each branch.
Charging: Is the total branch charging susceptance entered in pu. It's 0 by default.
In service: It denotes if the branch is in operation or not.
Rate A: First loading rating entered in MVA. If it is set to 0.0, the default value, this branch will not be included in any examination of circuit loading. There is also a second and a third rating but they are not used in the present thesis project.

Power flow in PSS/e
After all the components (loads, generators, buses etc.) of the transmission grid are defined in PSS/e, a power flow can be performed.

DC load flow
One very widely used approximation is the linearized or DC power flow, which converts the nonlinear AC problem into a simple, linear circuit analysis problem. The advantage of this approach is that efficient, non iterative numerical techniques can be used to compute an approximate power flow solution. Many alternatives or contingencies can be investigated with the same computer effort that would be expended to calculate one AC power flow solution. The DC power flow model is useful for rapid calculation of real power flow. It ignores reactive power flow and changes in voltage magnitudes, and assumes that, for most circuits, $X_{ij} >> r_{ij}$ (reactance > > resistance) and the angle between two buses is small. These assumptions result in the power flow from bus i to bus j simplifying to equation 5.1 [17].

$$P_{ij} = \frac{\delta_i - \delta_j}{X_{ij}} \tag{5.1}$$

Where:
δ_i = angle at bus i
δ_j = angle at bus j
X_{ij} = reactance between buses i and j

The DC load flow is launched using the DC network solution and report function.
AC load flow
It is possible to perform AC load flows in PSS/e. One problem when performing an AC load flow is that it does not always converge, it depends on the data.

Before starting running the load flows the user has to define a number of options in the PSS/e power flow program. Most options can be defined through the python interface file. The most important of them for the accuracy of the power flows are [17]:

Solution method:

- **Newton-Raphson** iterative method: The Newton-Raphson methods are generally tolerant of power system situations in which there are difficulties in transferring real power, but are prone to failure if there are difficulties in the allocation of generator reactive power output or if the solution has a particularly bad voltage magnitude profile. There are 3 methods available:

1. Fixed slope decoupled Newton-Raphson
2. Full Newton-Raphson
3. Decoupled Newton-Raphson

- **Gauss-Seidel** iterative method: The Gauss-Seidel methods are generally tolerant of power system operating conditions involving poor voltage distributions and difficulties with generator reactive power allocation, but do not converge well in situations where real power transfers are close to the limits of the system. There are 2 methods available:
    1. Gauss-Seidel
    2. Modified Gauss-Siedel

Transformer tap adjustment:
It sets the mode of tap adjustment in the solution process to be either off, step or direct.
The off mode suppresses transformer adjustments during the power flow solution.
In the step mode of tap adjustment each transformer is checked independently, outside of the main power flow iteration. If the controlled voltage is outside of its specified band the tap ratio is moved at least one user-specified step. The user has defined how much percent the voltage changes per tap change.
The direct mode is a Newton-based method of tap adjustment. If any tap ratios need to be adjusted, a simultaneous adjustment is made of all voltage controlling transformers as well as of all bus voltage magnitudes. Upon convergence of the main power flow iteration, tap ratios of controlling transformers are moved to their nearest step and the solution refined with tap ratios locked at those positions.

Area interchange control:
It sets the mode for the area interchange control. There are 3 options:
a) Disabled: Indicates to disable area interchange control. That option is chosen through python interface for this project.
b) If tie lines only are selected, an area's net interchange is defined as the sum of the flows on all of its tie lines. Tie flows are calculated at the metered end as power flowing out of the area.
c) If tie lines and loads are selected, a load whose area assignment differs from that of the bus to which it is connected is considered a tie branch for net interchange calculation purposes; that is, an area's net interchange includes tie line flows as well as contributions from loads connected to area buses that are assigned to areas other than the bus' area, and from loads assigned to the area which are connected to buses assigned to other areas.

Solution options:
1) *Phase shift adjustment*: It turns phase shift adjustment ON or OFF during the solution process.
2) *DC tap adjustment*: Locks or unlocks dc transformer taps during the solution process.
3) *Switched shunt adjustment*: Allows or suppresses the adjustment of switched shunts during the solution process.

4) *Non-divergent Newton solution*: It allows the power flow solution to be terminated prior to blowing up when performing the fixed slope decoupled Newton-Raphson solution, fully coupled Newton-Raphson solution or AC contingency analysis.
5) *Flat start*: The user has the option to start the power flow from a flat-start point. This option sets the phase angles of all buses, including the swing bus to zero degrees and the bus voltage magnitudes to the pre-defined values. Especially if the solution has diverged (blown up) the flat start control option should be used to establish a feasible starting point for the next solution. In this study each power flow solution starts with a flat start-method; this option is given in the definition of parameters for the AC load flow function inside the python-written code interface program.

Var limits: The user has control over the number of iterations during which generator reactive power limits will first be applied. In the present study this option is set to "ignore" that means the reactive power limits are to be ignored at all type '2' buses. There are also another three options:
"Apply automatically": Reactive power limits are to be ignored until the largest reactive power mismatch has been reduced to a preset multiple of the convergence tolerance.
"Apply immediately": Reactive power limits are to be recognised on the first mismatch calculation, preceding the first iteration.
"Apply at": Reactive power limits are to be applied either on iteration number "n" or when the largest reactive power mismatch is within a preset multiple of the tolerance, which ever occur first.

After the solved load flow base case is available an AC or DC contingency analysis can be performed. After the power flow is performed a graphical view of the flow through the branches can be seen. In figure 5.4 a graphical example of a power flow performed on a transmission grid in PSS/e is shown.

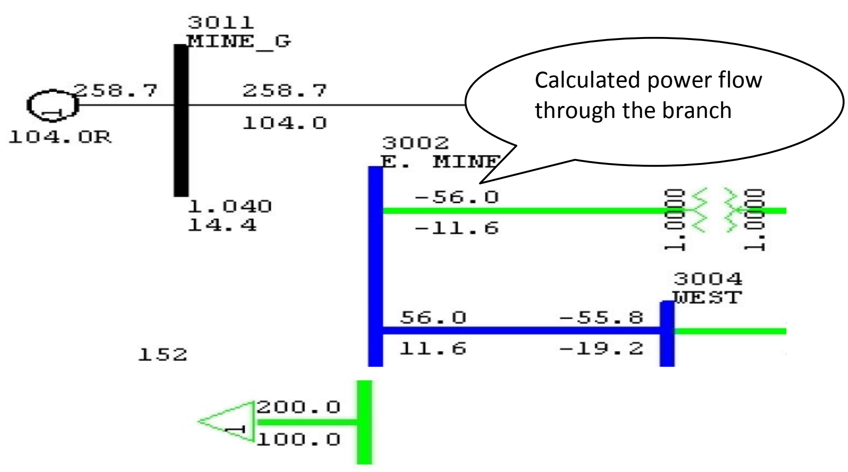


Figure 5.4: Graphical example of a transmission grid in PSS/e [17].

This graphical representation is suitable for small transmission grids. However, for a large transmission system the one in the CWE study, it is better to write the results of the power flow to a text file.

5.3 Assumptions made for making suitable load flows for the CWE region[12]

5.3.1 Market simulations

Node modelling

The countries in the CWE region (Belgium, France, Germany, Luxembourg and the Netherlands) are modeled into nodes whereas the rest of the interconnected electric system is represented less detailed as a simplified outer ring.

Details of the national electrical systems are not of any interest. All interconnection lines between two national systems can be modeled as one single aggregated connection between two nodes. The related transmission capacities are specified in NTC values.

Generation

The generation units located in the CWE region are categorized in the market simulations in the following main generation technologies, also known as the generation mix:

- Nuclear
- Lignite
- Coal (Existing and new)
- Combined cycle gas turbine (Existing and new)
- Combined heat production (must run)
- Fuel-oil
- Reservoir
- Run of river
- Wind
- Other non-dispatchables

The units are specified by defining their location (country), fuel consumption, costs, maintenance schedule, status etc.

The merit order of all the CWE units in this study is the following:

1. Renewables and other non-dispatchable units or must run status
2. Lignite and nuclear units
3. New coal power plants
4. New combined cycle gas turbines
5. Existing coal power plants
6. Existing combined cycle gas turbines
7. Oil-fired power plants

The merit order between gas and coal depends on the CO_2 price assumption. With the same fuel costs but with a much higher price for CO_2 most CCGTs would be less expensive than hard coal units. The heat benefits of CHP units (including some CCGT units) were included in the simulations through the introduction of must run units

[12] Due to confidentiality issues, not all the details on the made assumptions, grid model etcetera will be described in this thesis. The reader can always address himself to the official publications of each TSO on their proper websites.

Load

The load for 2018 is estimated by at the average annual load growth. The estimated annual load growth can be seen in table 4.1.

The Expert Group System Adequacy Forecast (SAF-EG, responsible for the market simulations) has delivered three snapshots[13] on which the Regional Transmission Plan Expert Group (RTP-EG) should base the common calculations. The snapshots are seen as the worst case scenarios for 2018. The snapshots are:

1. Low wind in GB or High load GB and High Wind DE or Low load DE
2. Low Wind DE or High Load DE and High Wind GB or Low load GB
3. High wind situation in the CWE region

5.3.2 Load Flow

Load flow case

The UCTE reference cases are exchanged for planning purposes. Cases for typical summer and winter situations that contain various incoherences as described in the report from the UCTE secretary are available. The most current exchange models at the time of writing are the summer and winter case of 2013 and 2018. The transmission network model that has been used for this analysis is a part of the UCTE winter 2013 case. The reasons for this choice are:

1. The RAF group did market simulations for 2018. This is based on the expected cross border capacities between the countries. When the 2018 network model is used, limited amount of overloadings are expected and the added value of network extensions cannot be brought to the surface. In the 2013 case a number of network extensions have been expected to be commissioned. In the winter case the winter capacity of each line is indicated, which in some situations is higher than the summer rating.
2. The Rest of the World has been removed from this winter case, since there is no information on the market behaviour of that part of the UCTE grid. On the borders of the CWE with the rest of the world, a network reduction has been applied in such a way that the flow to the rest of the world can be modelled, but the influence of the adjacent grid is omitted.

Rest of the world

Germany and France have interconnections to countries that are not part of the CWE region. All members, except Luxemburg have DC connections to asynchronously coupled areas. Germany and France also have AC connections to the other countries. In the market simulation some assumptions have been made, for the flow to the Rest of the World (RoW). However, the flow to the rest of the world should be included the model somehow.
The following assumptions are made:

[13] Each snapshot is a hourly interval in which the generation mix and load are estimated by market simulations within the CWE region. The snapshot information is put into a grid model on which the calculations/ simulations are based.

1. German members have indicated the borders to the rest of the world (including DC connections). The flow to the rest of the world is spread regarding to the given information on all the borders as can be seen in table 5.2.

Table 5.2: German information on border connections

Connection	Snapshot 1 (MW)	Snapshot 2 (MW)	Snapshot 3 (MW)
1 DE-DK	19.8	-136.5	-84.1
2 DE-DK	19.8	-136.5	-84.1
3 DE-DK	19.8	-136.5	-84.1
4 DE-DK	19.8	-136.5	-84.1
5 DE-SE	19.8	-136.5	-84.1
6 DE-PL	19.8	-136.5	-84.1
7 DE-CZ	19.8	-136.5	-84.1
8 DE-CZ	19.8	-136.5	-84.1
9 DE-AT	19.8	-136.5	-84.1
10 DE-AT	19.8	-136.5	-84.1
11 DE-AT	19.8	-136.5	-84.1
12 DE-CH	19.8	-136.5	-84.1
Total flow	238	-1638	-1010

For making a better and easier automatic implementation, all German interconnectors have been categorised by border (country-country). It has been counted how often the borders are mentioned in the table above. This has been put in the table 5.3. Now for each border the relative amount of the flow to the row has to be distributed.

Table 5.3: German border multiplier

Border	Multiplier
DE-DK	4
DE-SE	1
DE-PL	1
DE-CZ	2
DE-AT	3
DE-CH	1
Total	12

From table 5.3 the following can be said: 4/12 of the total flow to RoW is going through the DE-DK connection. The same is done for the other connections. In the network model the physical number of borders has been identified. The amount of power flow to Row that should be put over the border is spread homogeneously over all the physical borders.

2. For France estimated flow to RoW for the three snapshots can be seen in table 5.4.

Table 5.4: French flow to RoW

	Italy	Spain	Swiss	Row
Snapshot 1	2280	1258	2367	5905

Snapshot 2	2210	303	2238	4751
Snapshot 3	2257	1256	2737	6251

The borders to the rest of the world have been identified. Also the number of interconnections is determined and the flow from France to these countries is spread homogeneously over the borders.

3. Great Britain is electrically connected to the CWE region. This means that there is a flow of power from and to the CWE region from Great Britain. The connections between GB and CWE is such that of the overall exchanged power between GB and CWE:
    - 3/5 of the total exchanged power is going through the France – Great Britain connection.
    - 1/5 of the total exchanged power is going through the Belgium – Great Britain connection.
    - 1/5 of the total exchanged power is going through the Netherlands – Great Britain connection.
4. The connection between the Netherlands and Norway has been modelled explicitly in the market simulations

The Region model approach or Germany

The detailed information for Germany on the location of generation is unavailable and therefore another approach has been chosen for this country. According to the German Regionen model [7] Germany can be divided into 18 regions where the transmission grid behaves like a copperplate. For each region the amount of installed capacity of a specific type of generation unit is known. Adding them up, also the total installed capacity of that type of generation unit in Germany is known. So every region gets a share of the total generation of every type of generation unit. When adding the total output of every type of generation for one region the total generation in a region is known. The total generation is then scaled homogeneously over the existing generators in that region. In figure 5.5 the division of Germany in these regions is shown. Also the distribution for the generation technology per region is illustrated.

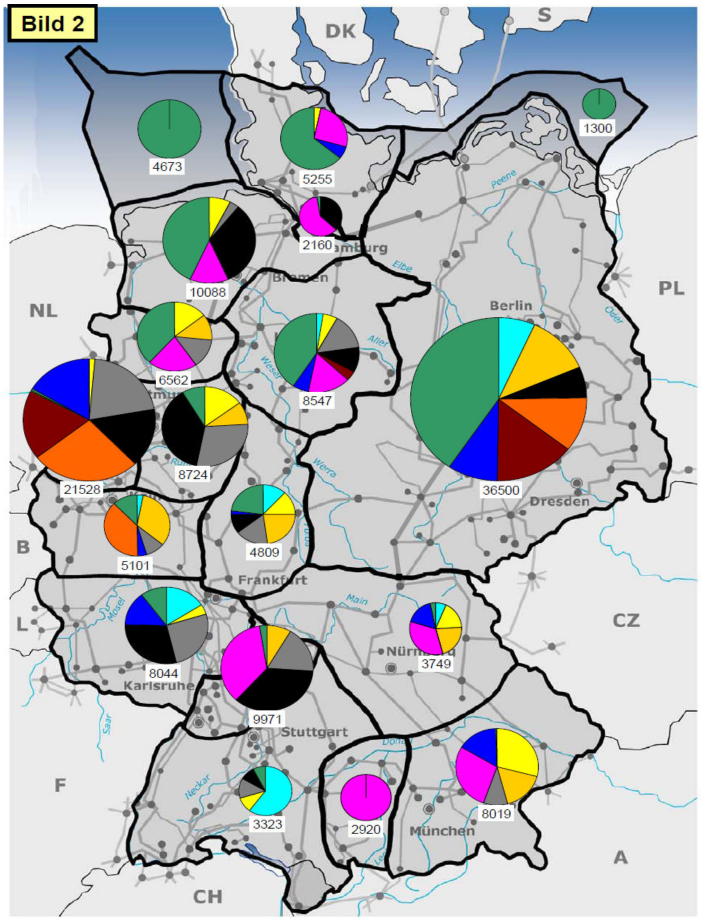


Figure 5.5a: Region model Germany [7].

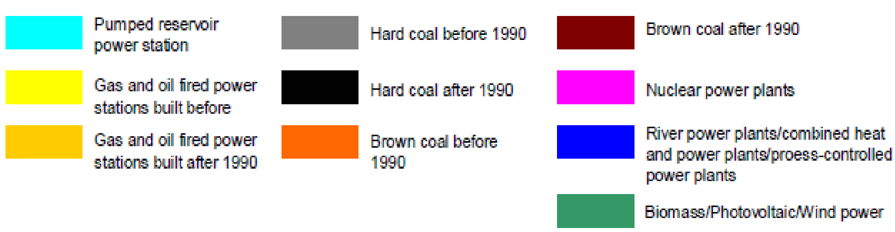


Figure 5.5b: Production types in the region model [7].

For the load a similar approach is followed. The load of the whole country is spread over the regions according to the relative amount of load in the region based on the information from the region model. Then the resulting load of every region is scaled over the existing loads in the UCTE summer case 2013 in that region.

Centralised generation

The generation schedule is obtained from the market simulations for every category of centralised generation. The generation is not given per producing unit but per generating category[14] (grouping). So for example: All the coal units in the Netherlands are represented

[14] The categories are shown on page 44 generation.

by the category NLcoal. This means that it is not possible to say that one coal unit in the Netherlands produces more than the other coal unit. This is solved by dividing the total category output equally over all the coal units in the Netherlands. This is done for every category in the SAF database.

The Expert Group RTP has given (one or more depending on the number of units) UCTE nodes where the generators of that category are located. The total output of every category is set equally to each generating unit in that country. If for example a category has an output of 1200 MW and there are 4 machines of that category in that country, the active power output of each machine is 300 MW. This is the theoretic approach for every country except for Germany.

Load

In the market simulations the load of every country is given (estimated values). For every country there is only one load curve. In principle, the spread of the load over the UCTE nodes in the model is done via homogeneous scaling according to the load of the UCTE summer case 2013. This has been chosen because of the assumption that the load in the UCTE summer case 2013 is not that much 'contaminated' with dispersed generation. Per country there are some categories of generation however that have to be compensated with the load. This is the type of dispersed generation like wind, run of river and other non-dispatchables. Per country it is listed here below:

1. Germany, from the total load of Germany the following category of decentralised generation is subtracted:
   - Other non-dispatchables
2. Netherlands, from the total load of The Netherlands, the following categories of decentralised generation are subtracted:
   - Installed onshore wind capacity, being the total wind minus 250 MW
   - Run of river
   - Other non-dispatchables
3. Belgium, the load in Belgium in the summer case 2013 has some compensation for generation of the reduced (underlying) network. This means that some loads in the UCTE summer case were increased before scaling. The types of dispersed generation from the market simulation that has been subtracted from the total load is:
   - Wind onshore
   - Run of river
   - Other non-dispatchables

   Pump storage hast been added to the load.
4. France, from the total load of France, the following categories of decentralised generation are subtracted:
   - Wind onshore
   - Run of river
   - Resorvoir
   - Other non-dispatchables
5. Luxembourg, from the total load of Luxembourg, the following categories of decentralised generation are subtracted:
   - Other non-dispatchables

5.4 Limburg grid simulations

The made assumptions from paragraph 5.3 are made on base of the supplied data by the expert groups (TSO's). More research by the expert groups about these assumptions and thus the delivered snapshots is necessary to explain the consequences of these assumptions on the calculations/simulations. The assumptions may be too raw for representing a realistic model. Before this research is done, there is no added value in performing numerous calculations/simulations on the CWE grid.

To prove the principles of the developed method simulations/calculations were performed on another grid, the Dutch Limburg area. This area is part of the Dutch 380 kV grid and the whole 150 kV Limburg grid (89 lines in total). Simulations have been performed for only one week. It has no added value to perform simulations on this grid for a whole year (52 times a week), the only difference is that the whole year has more data output. The Limburg grid is chosen for the simulations because the grid can easily be seen as an islanded grid (stand alone). The reason for this is that the Limburg grid is connected to the rest of the electrical power system by few interconnections, and most of these interconnections are open (regulated by switches). The flows of power over the other interconnections[15] and the measurement data on the generators and 150/10kV transformers are available for every hour so that the power balance of the Limburg region is maintained. The Limburg grid is located in the southern part of the Netherlands and forms a small portion of the total Dutch grid. The simulations on the Limburg grid are not part of a study[16] but are to prove that the presented method/tool described in paragraph 5.1 is capable of performing a lot of reliable simulations/calculations.

Some modifications have been made in the Limburg model. One of the modifications is that a phase shifter is introduced in the grid. The reason for this is that there are many phase shifters in service in the CWE grid. In this way the consequences of a phase shifter in a grid are investigated under both an AC and a DC load flow. PSS/e has a bus-branch model. This means that the actual circuit breakers are not modelled. For most lines this is correct but specific for T junctions an error is made. In a T-Junction with no circuit breaker a real outage will result in tripping the whole line and also the T connected branch. In the current study, the T junctions are modelled as three individual lines that results in three different outages when performing a contingency analysis. This can result in overloadings that cannot occur in reality. For this proof of principle this is no big issue. In reality this would be dealt with in building the contingency cases. The simulated model cannot be compared to the real Limburg model due to the modifications. A layout of the 150 kV and 380 kV transmission lines in the Limburg grid is shown in figure 5.6. The 150 kV lines are coloured blue and the 380 kV are red.

[15] Can be seen as import or export of power from other regions.
[16] No conclusions will be drawn from the simulation results.

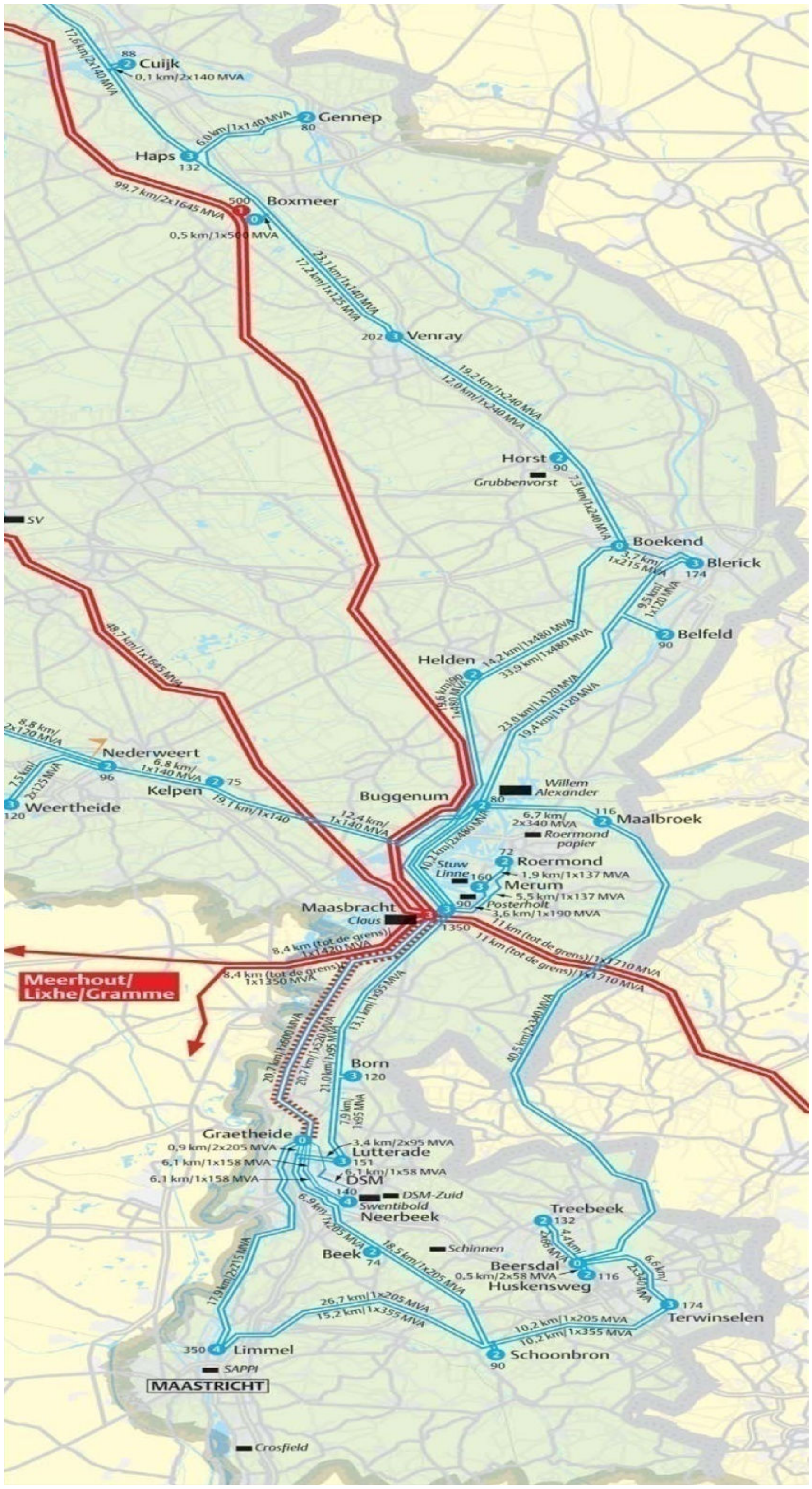


Figure 5.6: 150 kV and 380 kV Limburg grid model [14].

6 Simulation results

In this chapter the simulation results of the Limburg grid and the CWE study are expressed. This is respectively done in paragraph 6.1 and 6.2.

6.1 Limburg grid results

The Limburg results illustrate the principles of the newly developed method. The simulations/calculations are performed on 86 lines. Both AC and DC calculations/simulations were performed on the Limburg grid. The AC load flow took ± 3 min to perform and the DC load flow ± 1min. The AC and DC load flow outputs were converted into useful figures that provide a good overview of the line loading situation. This output conversion is done by means of some useful functions. In figure 6.1 an AC plot is shown generated by the function *"counter"*.

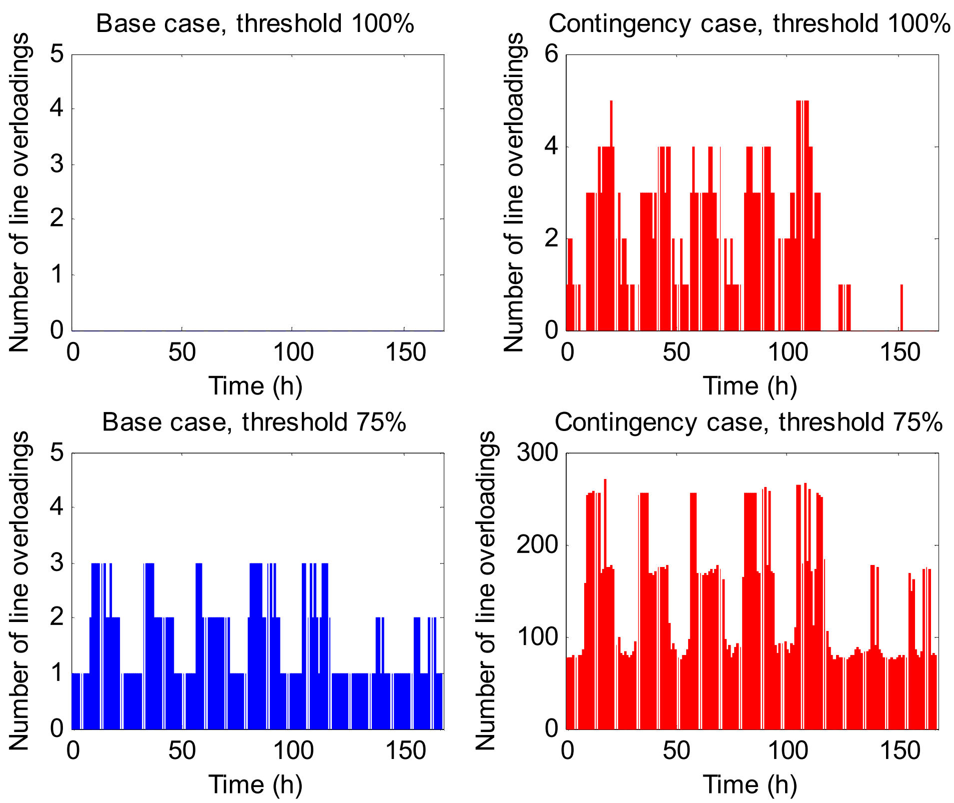


Figure 6.1: AC counter plot.

The function counter counts the number of line loadings above (overloading) a defined threshold per hour. The threshold can be set to any value. The left upper subplot of figure 6.1 illustrate that there were no line loadings above 100% (threshold is 100) for the base case. The right upper plot illustrates that there are many line loadings above 100%. For example, in the first hour there are two line loadings above 100% for the contingency case[17]. It can be that the same line is responsible for both line overloadings. The same was done for a threshold set to 75% as can be seen in the lower part of figure 6.1. There are some line

[17] There are in total 86 lines in the grid model. This means that for one hour 86 load flows were performed.

loadings above the threshold for both the base case (max 3 per hour) and the contingency case (max 280 per hour). The function counter also provides a list containing the lines with line loadings above the threshold per time period (derived from figure 6.1). From this list a useful table can be made as can be seen in table 6.1.

Table 6.1: Number of 100% AC overloadings in week1.

Transmission connection	Overloadings
Line 3	26
Line 2	67
Line 5	199
Line 6	4

Table 6.1 illustrates that, for example, line 5 has in week1 199 times a line loading above the threshold. The counter function can be seen as a selection tool where the "critical lines" are filtered. The "critical lines" for the AC load flow are shown in table 6.1.

The same was done for the DC load flow, this can be seen in figure 6.2 and table 6.2.

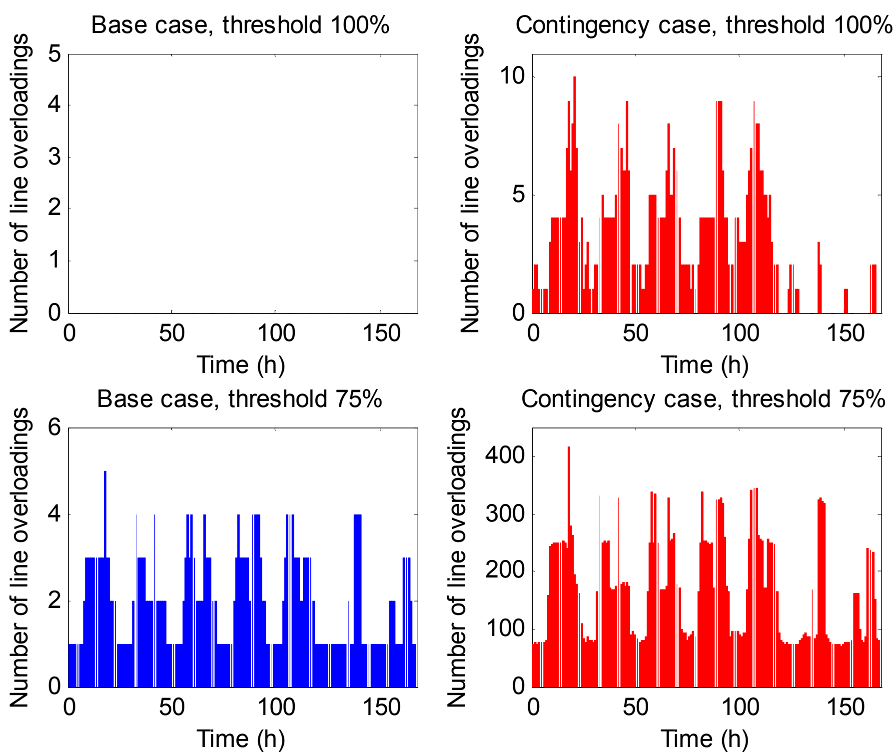


Figure 6.2: DC counter plot.

Table 6.2: Number of 100% DC overloadings in week1.

Transmission connection	Number of overloadings
Line 3	36
Line 2	82
Line 5	303
Line 6	15
Line 4	4

Line 7	32
Line 8	19

Figure 6.2 and table 6.2 illustrate that there in the DC load flow there are more overloadings and "critical lines" compared to the AC load flow. The reason for this becomes clear if a closer look is taken at loading curve per line per week.

With the second function, called *"loading curve"*, the loading curves for each line per time period can be made. In figure 6.3 the loading curves for both the AC and DC are shown for line 1 for 1 week.

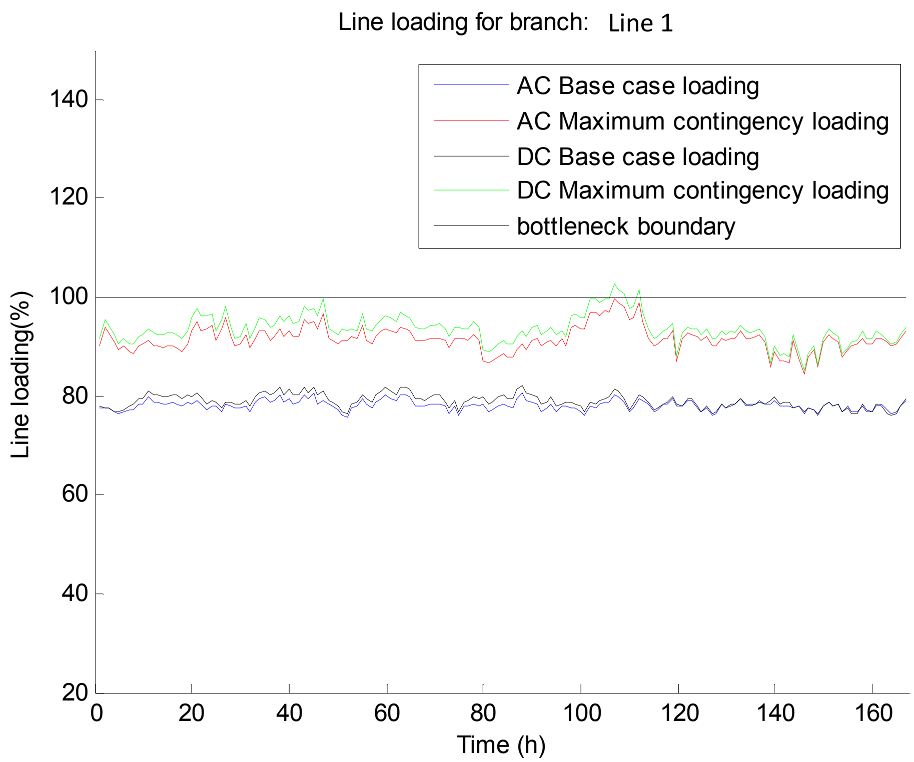


Figure 6.3: AC and DC loading curves line 1 for one week.

From figure 6.3 it can be seen that the line loading for both the AC base case and the DC base case is below the 100% threshold for the whole week. The AC contingency maximum loading for line 1 is also below the 100% threshold, but for the DC contingency maximum loading there are two overloadings at different two hours. The DC Loading in figure 6.3 is ± (3-5)% higher than the AC loading. This is due to the fact that the reactive power is ignored and the voltage levels are kept at a constant value (1 per-unit) when a DC load flow is performed. With an AC load flow the reactive power is not ignored and the voltages are not kept at a constant value (voltage is being regulated). This means that the voltage can be set to a higher value, for instance 1.05 per-unit. Electrical power is the voltage times the current, so a lower current is needed for the AC load flow (higher voltage) compared to the DC load flow to transport the same amount of power. This means that the transmission lines are loaded at a lower percentage for the AC load flow compared to the DC load flow[18]. The

[18] This statement is only true when the transported reactive power is low. The reactive power transport is low in the Limburg grid simulations.

higher DC line loading is also accountable for the higher number of overloadings and "critical lines" as concluded from figure 6.2 and table 6.2.

The function loading curve can be helpful to zoom in on a "critical transmission line". In figure 6.4 the loading curve is shown of the "critical line" line 5.

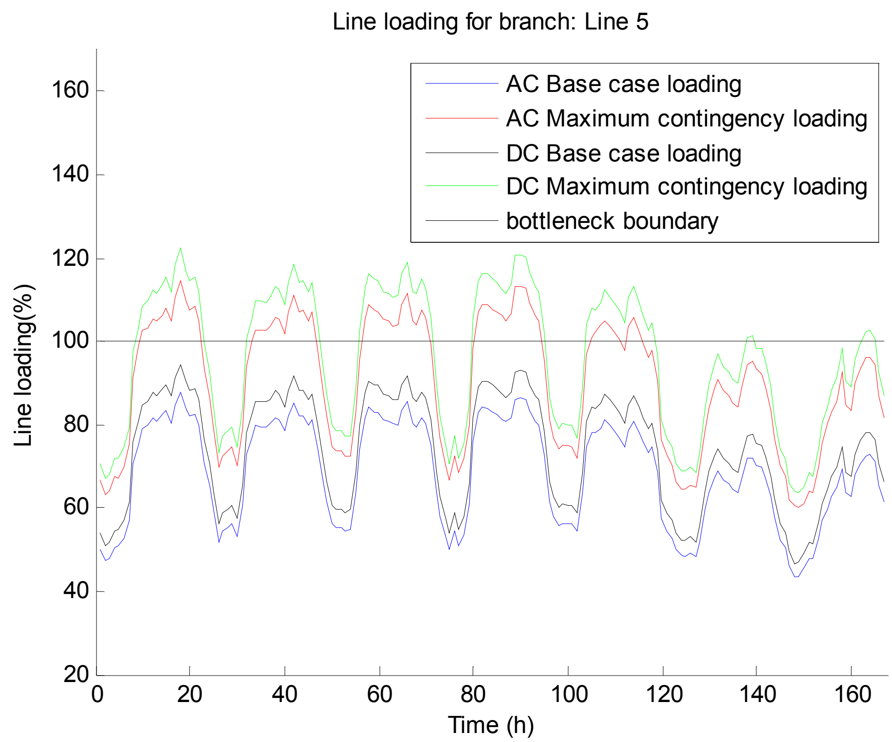


Figure 6.4: AC and DC loading curves line 5 for one week.

The AC and DC base case loadings are below the 100 % boundary as can be seen in figure 6.4. This is not the case for the AC and DC contingency cases. There are many hours where line 5 is overloaded. The high line loading variation (pattern) is caused by the day and night power demand.

With a third function, called *"maximum line loadings"*, the maximum line loadings for the AC and DC cases are shown for all the lines for a certain time period. The maximum line loadings are illustrated for the AC and DC cases in figure 6.5.

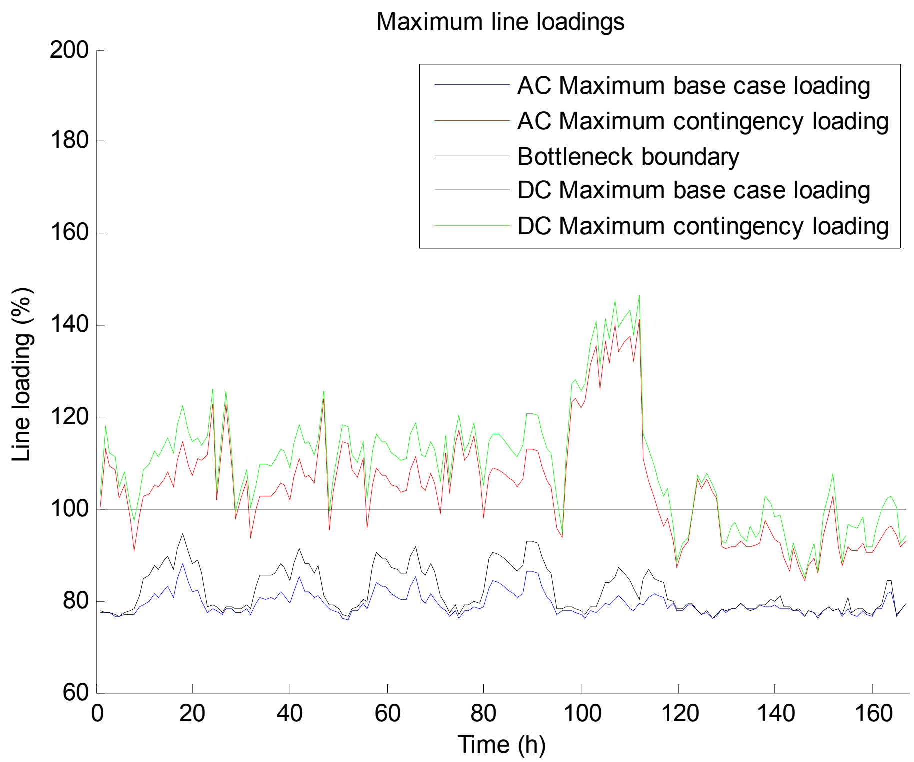


Figure 6.5: AC and DC maximum loading curves for one week.

The maximum AC and DC base case loadings are always below the 100% boundary as can be seen in figure 6.5. This means that all the lines are not loaded above 100% for all the AC and DC base cases in this week, no overloadings in the base cases. But looking at the AC and DC contingency cases there are many overloadings. At hour 110 the overloading has a magnitude of ± 140%.However, figure 6.5 only provides the maximum line loading per hour (worst case per hour). It is possible that there are more overloadings at a certain hour. The difference between the loading curve (figure 6.3 and 6.4) and the maximum loading curve is that the maximum loading curve does not zoom in on a line but considers the maximum loading of all the transmission lines.

Another helpful function is the fourth function, called *"boxplots"*, which constructs box plots for a number of selected lines[19]. The box plots of the selected lines can be represented in one figure as shown in figure 6.6 for the AC load flow.

[19] It is also possible to make box plots for all the lines in a grid, but for really large grids (CWE) it is better to make a selection.

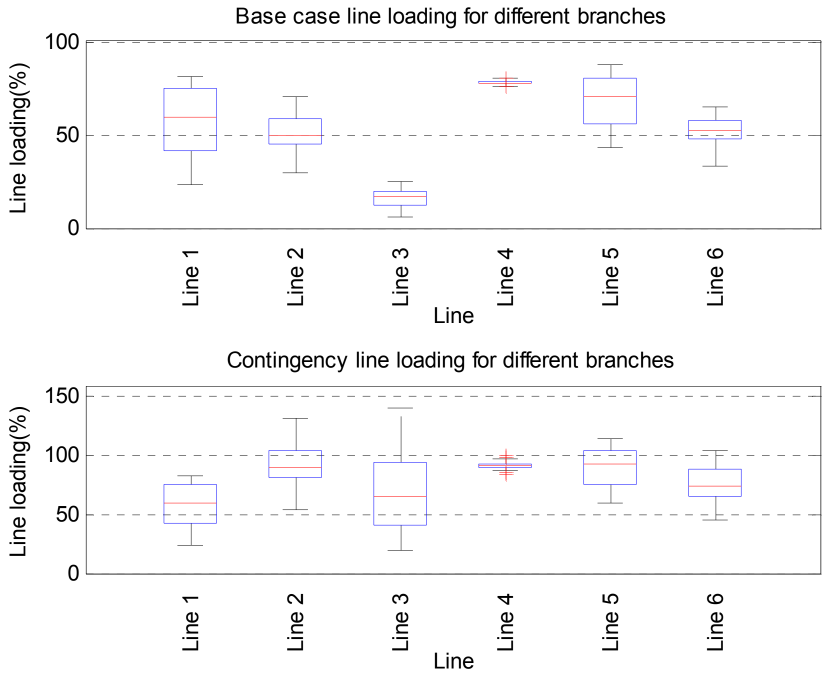


Figure 6.6: AC box plots of 6 selected transmission lines.

The blue boxes from figure 6.6 represent the loading interval between 25 and 75% of all samples being put in an increasing order. The red line in the middle of the box plot shows the median. Median is the value of the middle sample if all samples are put in an increasing order. The tail (whiskers) shows the samples that are out of this interval.

In figure 6.6 there are two subplots shown, one for the base case and one for the contingency case. Six lines are in total investigated and the results are represented by box plots, where lines 2, 3, 4, 5 and 6 are labeled as “critical lines”. Line 4 is transmission line that is connected to the phase shifter transformer. The angle is being controlled by the phase shifter for the base case only (not for contingency cases) which means that the power flowing through this line is kept at a constant value. This is the reason why all the data points have almost the same magnitude in the base cases. For the contingency cases the phase shifter is kept at the same angle as in the base case (fixed angle). This means that there is some spread in data points. The box plots are very useful because in this way the spread of the loadings for the selected lines can be seen, a comparison of the results for different cases (snapshots/scenarios) and their evaluation can be done easier.

The box plots give overview of the line loading spread, but an image plot provides an overview of the magnitude of the line loadings and the duration of the overloading. In figure 6.7 and 6.8 the AC image plots are shown (the Y-axis represents the line) of respectively the base cases and the contingency cases for the same selected lines as in figure 6.6. The line loading of each line is not represented by a value but by a color. The translation between the line loading and the color can be seen in the color bar. From figure 6.8 it can directly be observed that some lines are overloaded (red colored) for ±(3-8) hour’s continuously (see line 2, 3 and 5).

The same is done for the DC load flows. In figure 6.9 the DC box plots are illustrated. Figure 6.10 and 6.11 show the image plots for respectively the base cases and the contingency cases.

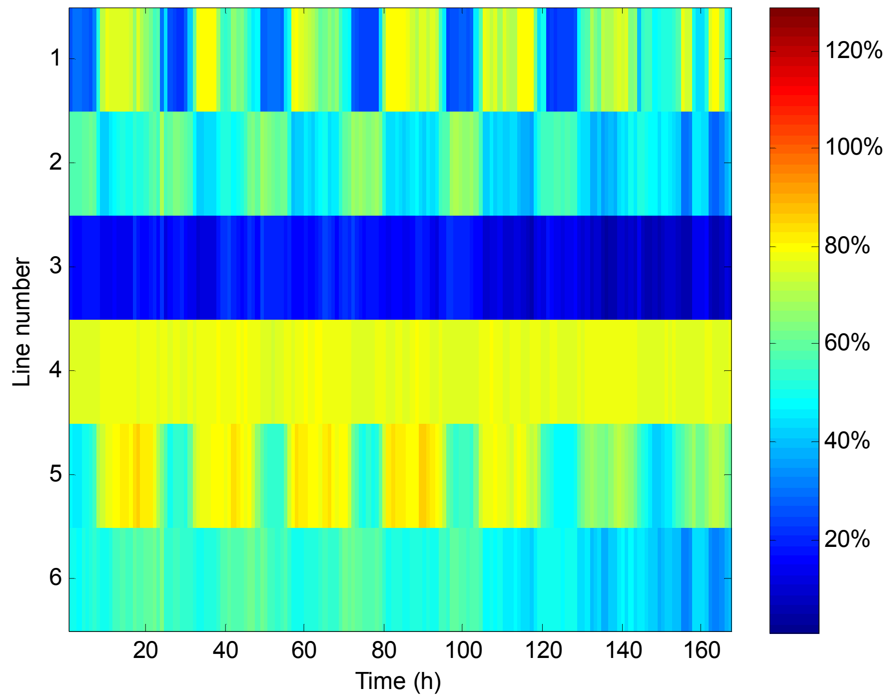


Figure 6.7: AC image plot for the base cases of 6 selected transmission lines.

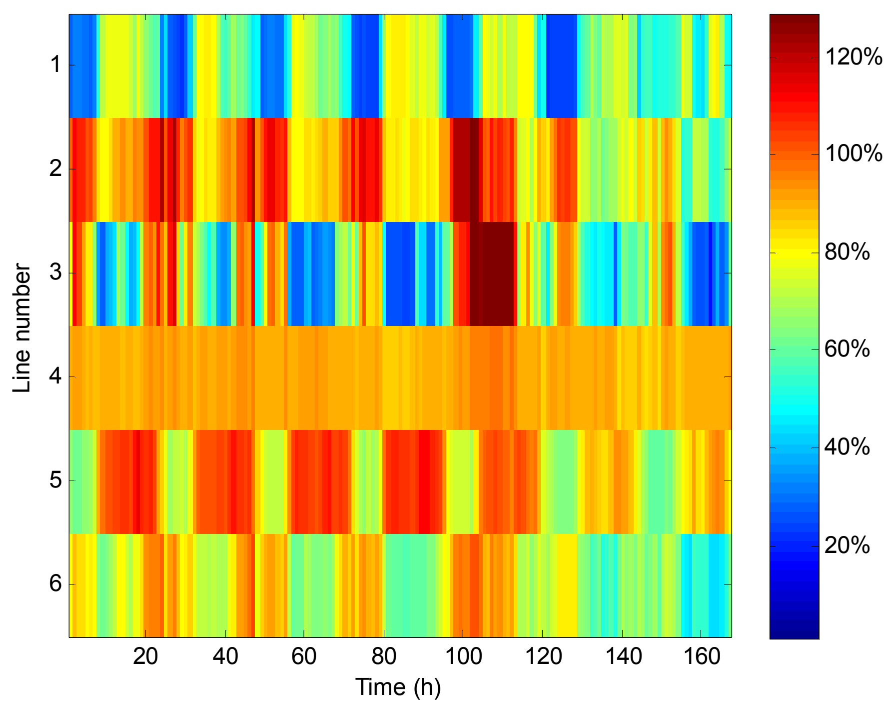


Figure 6.8: AC image plot for the contingency cases of 6 selected transmission lines.

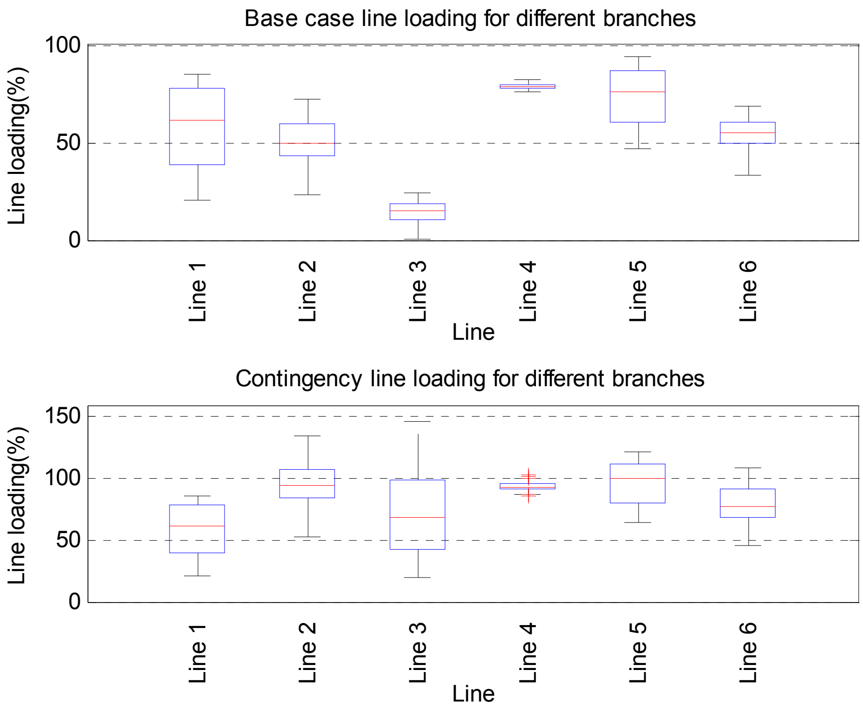


Figure 6.9: DC box plots of 6 selected transmission lines.

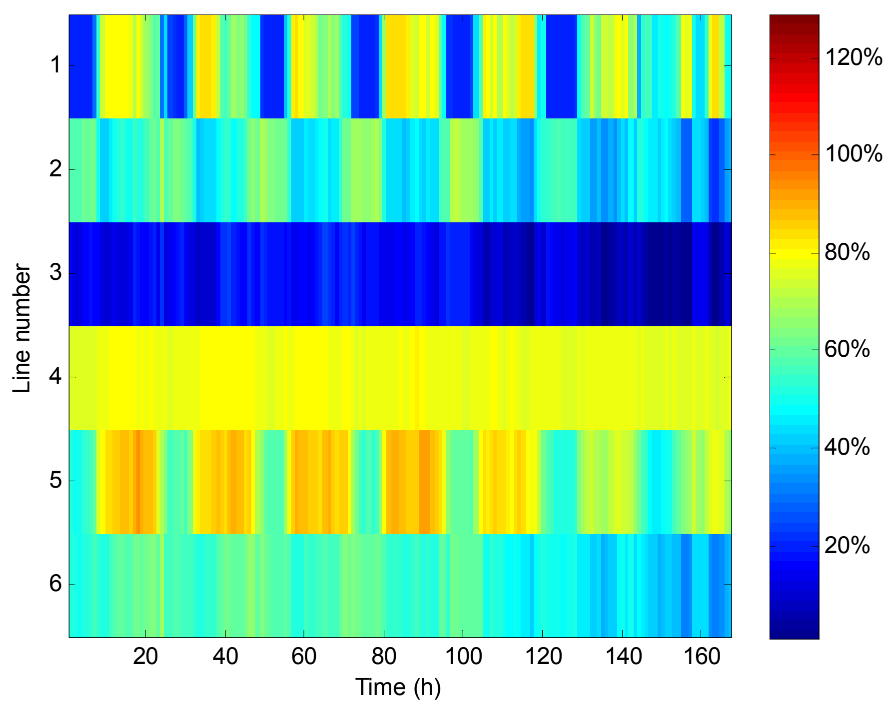


Figure 6.10: DC image plot for the base cases of 6 selected transmission lines.

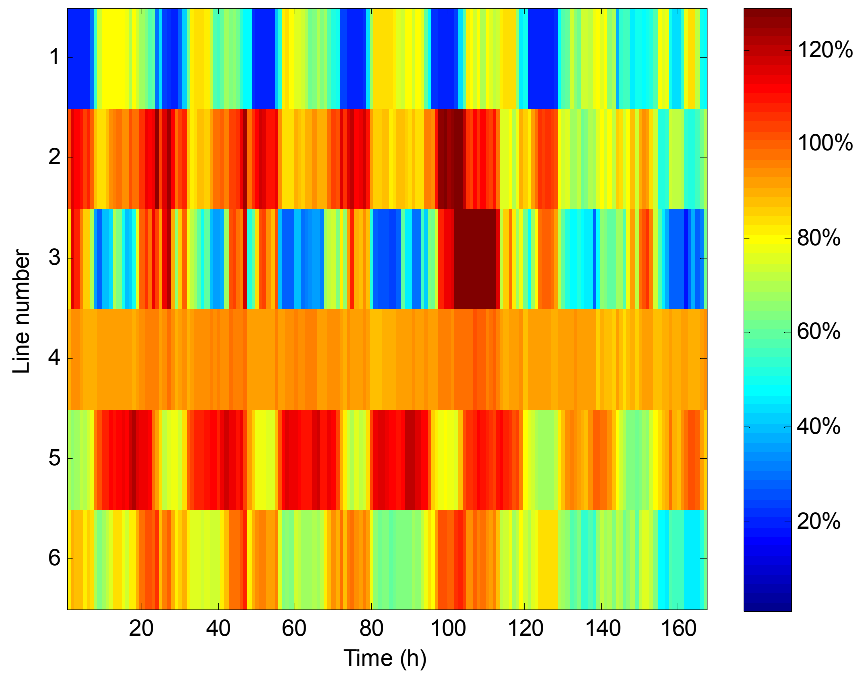


Figure 6.11: DC image plot for the contingency cases of 6 selected transmission lines.

The last used function, called “sort”, sorts the magnitudes of the AC and DC load flows in descending order. With this function a load duration curve (in Dutch “belasting duur kromme”) can be made as is illustrated in figure 6.12. The same data is used as in figure 6.5 (maximum values).

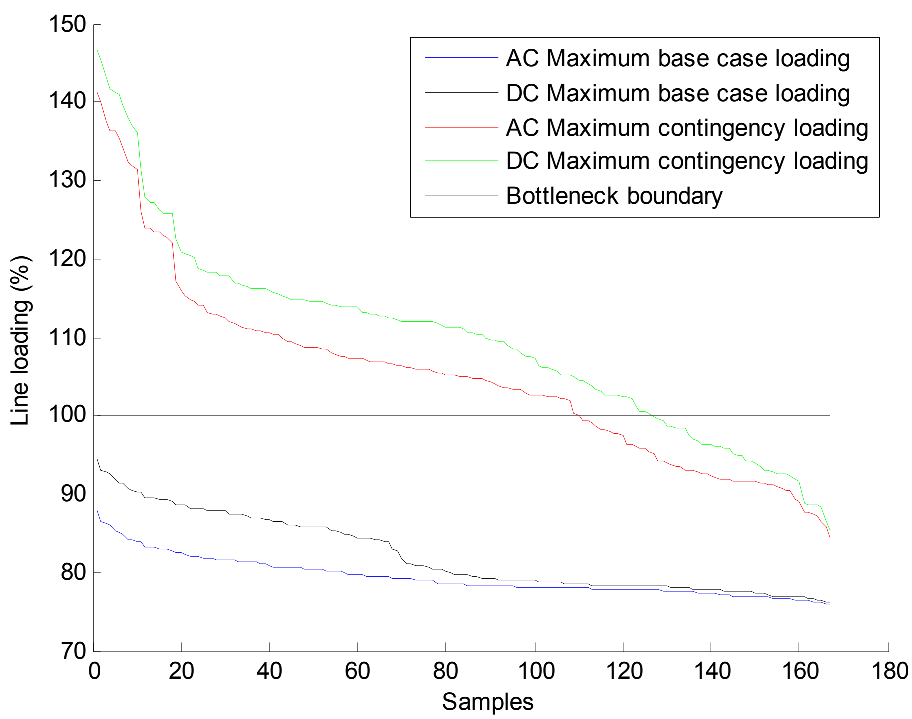


Figure 6.12: Maximum AC and DC load duration curve.

Figure 6.12 illustrates that for the AC load flow for ± 110 samples (hours) minimal one line is overloaded. For the DC load flow for ± 125 samples minimal one line is overloaded.

If the DC and AC load flow results are compared then it can be concluded that *the DC load flow is a good approximation for the AC load flow when the reactive power transport through the grid is low*.

6.2 CWE study results

At this moment RTP-EG is using 3 snapshots of possible situations in the grid to assess the possibilities for common grid calculations on a larger, regional, scale. Seen the limited number of snapshots, no conclusions can be drawn from these calculations since further investigations of the grid behaviour on the underlying assumptions has to be performed.

In this section an example of a DC analysis of the full CWE region is shown, focusing on the 132 interconnections (including the RoW interconnections). It is chosen to perform DC calculations to avoid particularities linked to the voltage plan in the studied case. This assumption can be made because it is known that the different TSO will undertake in real time the necessary actions to secure the voltage plan. Another advantage of using DC approach is of course the gain in calculation time.

In figure 6.13 an overview is given of the number of DC overloadings for snapshot 2. This figure is similar to figure 6.1 but for one hour. The number of overloadings is given per case (base case, contingency 1 till contingency 132) for one hour.

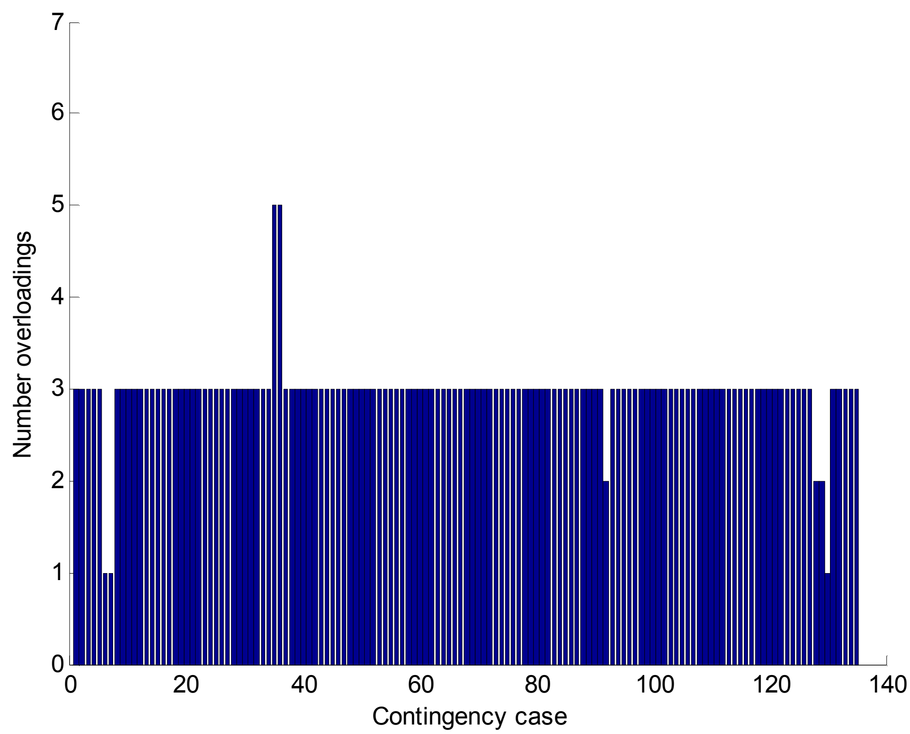


Figure 6.13: Number DC overloadings per studied contingency for snapshot 2.

From figure 6.13 it can be seen that there are 3 lines (2 % of the border interconnections) overloaded in the base case but in some contingency cases there are fewer overloadings compared to the base case. This can occur when the overloaded line (base case) is taken out of service (contingency case). The power of the line is then distributed over other connections which can be lower than 100% for the contingency case. The new loading of the interconnections can be lower than 100% which means that there is one overloading less than the base case. There are some contingency cases where only one line overloaded. This can be due the fact that the line loading in the base case is just above the 100% limit but in the contingency case just below this limit. This means that the power distribution over the line is different. From figure 6.13 nothing can be said over the magnitudes of the overloaded interconnections. In figure 6.14 the line overloadings are categorized by magnitude for the base case and each contingency case.

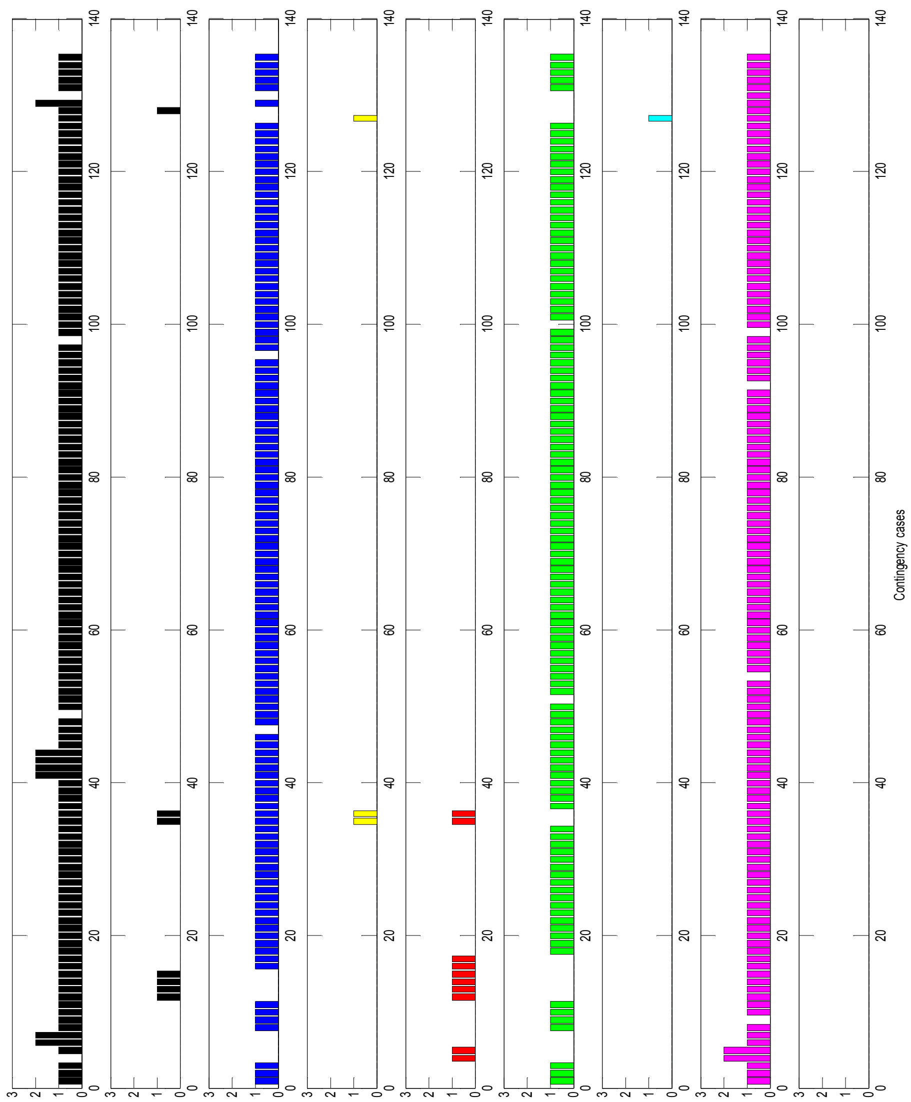


Figure 6.14: DC categorized magnitudes of overloaded interconnections for snapshot 2.

Figure 6.14 illustrates the distribution of the magnitudes of the overloaded interconnections. In almost each contingency there is one overloaded interconnections with magnitude between 130-135% (purple color).

Form the defined categories the average severity for the overloadings for each case can be calculated. The average severity is calculated using equation 6.1.

$$\text{Average severity} = \frac{n_1*100\%+n_2*105\%+n_3*110\%.........}{n_1+n_2+n_3..........} \tag{6.1}$$

Where n_1 = the number of overloadings in the 100 – 105% category.

The average severity of all the contingency cases (base case included) for snapshot is illustrated in figure 6.15.

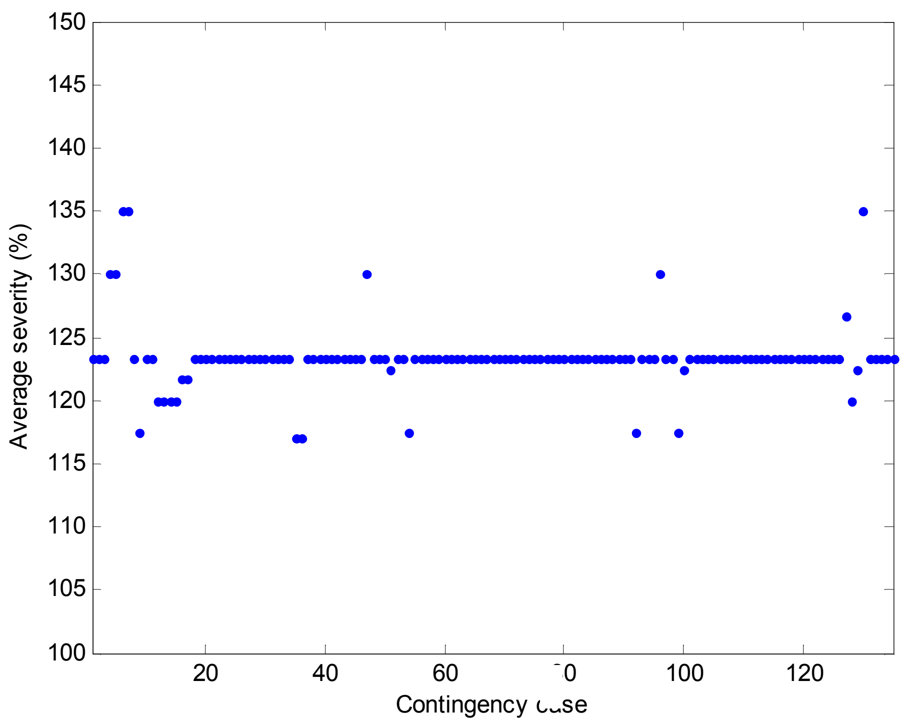


Figure 6.15: Average severity of all cases for snapshot 2.

From figure 6.15 it can be seen that the average severity for the base case is ± 123%. There are some cases where the average severity is lower compared to the base case. This is caused by some contingency cases where the number of overloadings is less compared the base case. The overloading magnitude is also lower in some of these contingency cases which causes a lower average severity.

7 Conclusion

The objective this thesis was to develop and present a robust method/tool for future transmission system bottleneck identification for interconnected power systems. This objective has successfully been completed.

The unit commitment and economic dispatch (UC-ED) optimization tool PowrSym3 has been coupled to the load flow program PSS/e through a Python interface. The strong advantages of the presented method are:

1. Hourly, weekly or yearly simulations can be performed in order to discover the worst case scenarios.
2. Results of different market simulations can be compared to each other.
3. The two main programs are commercial products and can be purchased by everyone.
4. The flexibility of the two main programs allows the user to perform an important number of calculations.
5. Process automation is easy.

The developed method that is presented in this thesis offers the possibility to simulate many different combinations of load and generation and to assess the loadings of the transmission system components. A number of calculations/simulations were performed on the Limburg grid to illustrate the principles of this specific tool/method. The load flow results were converted into useful figures which make the task of identifying bottlenecks easier. A first step is set for identifying congestions in the Central Western European (CWE consists of The Netherlands, Belgium, France, Luxembourg and Germany) region, which is the concern of the CWE Regional Transmission Plan. 3 snapshots were delivered on which calculations were performed. Seen the limited number of snapshots, no conclusions can be drawn from these calculations since further investigations of the grid behaviour on the underlying assumptions has to be performed.

Recommendations for future work

Some functions of the developed tool are still controlled by hand, like the figures made from the load flow results. These actions can be automated, this means that the tool can be developed further.

The consequences of the assumptions made for the CWE snapshots must be investigated before any conclusion can be drawn. If the consequences of the made assumptions are known or more detailed information is provided, then weekly or yearly simulations can be performed in order to discover the worst case scenarios. Thus, both AC and DC load flows can be performed focusing on all or some selected lines (not only border connections) to identify congestions.

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