Pentalateral Energy Forum
Support Group 2

Generation Adequacy Assessment

Description	Pentalateral generation adequacy probabilistic assessment	
Version	This version of the report is meant for distribution within PLEF SG2 only and not for publication beyond PLEF SG2.	
Date	05. March 2015	
Status	☐ Draft	☒ Final version

Disclaimer:

It must be noted that the conclusions in this report are inseparable to the hypotheses described and can only be read in this reference framework. The hypotheses were gathered by the TSOs according to their best knowledge at the moment of the data collection and validated by ministries and regulators. The TSOs emphasise that the TSOs involved in this study are not responsible in case the hypotheses taken in this report or the estimations based on these hypotheses are not realised in the future.

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1 Executive summary

The study mandated by the Pentalateral Forum to the TSOs has been fully and successfully completed. This study has been a significant step towards a harmonised regional adequacy assessment. It has been performed using a probabilistic and chronological approach with an hourly resolution for the year 2015/2016 and the year 2020/2021.

The results found in this study are consistent with those found in the corresponding national studies, i.e. potential adequacy problems are identified for France and Belgium in winter 2015/2016 due to the closure of many fossil fuel units which are not expected to be upgraded to meet the requirements of the Industrial Emission Directive by January 1st 2016 or due to mothballing of production units for economic reasons. The adequacy issues are expected to improve in 2020/2021 due to different measures taken by the affected countries, which have been in turn integrated into the study through the dataset. Risk exists in France for winter 2020/2021 but below the national criteria for security of supply. France and Belgium appear as the only countries which require further investigations through more advanced and specific modelling.

Moreover, the comparison of the results from interconnected and isolated cases reflect how regional exchanges are vital for security of supply. Yet, a comparison of the adequacy indicators at regional and national level reveals that most often Belgium and France would experience adequacy risk simultaneously. This result stresses the added value of studies at regional perimeter as already implemented by Elia and RTE for their own national studies.

The approach adopted in this study is a tremendous improvement in comparison to the existing deterministic approaches. Yet, with any simulations, various assumptions must be made for such studies. Some of the most basic and necessary assumptions include a simplified generation and grid representation (copperplate for each country except for Luxembourg), system marginal prices solely being marginal costs and perfect insight and forecasts in the Day-Ahead markets. Indeed, the methodology employed in this study is similar to the ones already implemented in Belgium and France, with both probabilistic modelling and regional perimeters, and to the target one for ENTSO-E as specified in their roadmap for improvement of adequacy assessment in the next few years.

One of the other main achievements of this study is the common regional dataset based on the same scenarios and assumptions collected and prepared by the PLEF TSOs. For example, it is the first time that a regional-wide temperature-sensitive load model and harmonised probabilistic hydrological data have been employed. In the process the TSOs exchanged their technical know-hows of their related systems and adequacy methodologies and strengthened their collaboration through the regional initiative. Meaningful sensitivity analyses have also been conducted to evaluate how different important factors can affect the adequacy assessment results. The extreme cold front in winter 2012 was an important sensitivity which demonstrates how cold weather regional wide can have severe impact on load and subsequently the ability of the region to match demand and supply. The sensitivity analyse with different combinations of reserves show how operational and strategic reserves can have an impact on affected countries. An extra analysis has been conducted for Belgium because two of the nuclear units have been taken offline unexpectedly during the course of the study.

The potential impact of demand side response (DSR) on adequacy is non-negligible and has been demonstrated in the sensitivity analyse in which the currently known DSR in France was included in the simulations. However, cross border exchange of DSR might not always have an impact on the neighbours in need, derived from a conclusion coming from the analysis on the usage of interconnection between France and Germany. The analysis shows that the interconnector would be already completely utilised in times France might have shortages, implying that any additional available capacity in Germany, e.g. in form of DSR, would not have an impact on the indicators for France.

2 Approach & Objective

Over the past decade, Transmission System Operators (TSOs) significantly improved their cooperation and coordination on security of supply. Within the framework of the Pentalateral Energy Forum1, TSOs cooperate on a regional basis with governments, regulatory authorities, market parties and power exchanges to improve electricity markets integration and security of supply. The added value of this regional perspective lies in its ability to move faster, to reach more specific recommendations and to act as a development centre for new ideas.

The Memorandum of Understanding of the Pentalateral Energy Forum (2007) laid the foundation for a first adequacy forecast for the whole region, by using a bottom-up approach compiling national scenarios. At their meeting on the 7th of June 2013, the Ministers of Energy of the Pentalateral Energy Forum acknowledged the initial steps on regional adequacy forecasting but also stressed the need to better take into account the current challenges from the energy transition, with changing generation patterns and market dynamics.

In the Political Declaration of the Pentalateral Energy Forum (2013), the Ministers therefore requested the Penta TSOs to deliver an enhanced pentalateral adequacy assessment. The analysis should be based on an advanced new common methodology, including a probabilistic modelling for all hours of the year and enabling a more consistent assessment of variable renewable energy generation, projected interconnector flows, demand side management and flexibility in the market.

This Pentalateral Adequacy Assessment offers an essential contribution to the development of a common approach to security of supply. It provides decision-makers with a more holistic assessment of potential capacity scarcities in the pentalateral region. And, more importantly, it illustrates the potential support each country can receive or give resulting from possible economic exchanges arising from the variety of generation mixes in the region.

In this study an advanced probabilistic adequacy assessment methodology for the PLEF region (AT, BE, CH, DE, FR, LU, NL) is applied for the first time. Such approach is different from the current methodology applied at the Pan-European level (ENTSO-E). The latter in comparison is a rather simplistic approach which is based on reserve margins assessment at only two specific time points in a year, while the PLEF approach provides results on an hourly basis for the whole year. This study can therefore serve as a pioneer of applying the advanced methodology for a wide scale perimeter (regional and pan-European).

The purpose of this report is to describe the methodology and disseminate the results of the adequacy assessment based on this advanced methodology to the Forum, while illustrating the benefits of a common regional PLEF assessment addressing the requirements of the region.

The layout of the report is given as follows: chapter 1 provides the executive summary of this report. While chapter 2 provides a short description of the approach and objective of the study, the detailed description of the methodology including the underlying assumptions of the data and parameters is provided in chapter 3. The description and explanation of the adequacy indicators is also given in this chapter. In chapter 4 the input data for the PLEF region and its countries are described. The results of the adequacy assessment for the different scenarios are reported and analysed in chapter 5. The conclusions of the whole study are given at the end of this this chapter. The lessons learnt in the whole process are summarised in chapter 6 while chapter 7 describes the possible next steps. In chapter 8, the Appendix, a description of the simulation tools employed in the study can be found. Glossary is given in chapter 9.

[1] The Pentalateral Energy Forum is the framework for regional cooperation in Central Western Europe towards improved electricity market integration and security of supply. It was created in 2005 by the Ministers of Energy of Benelux, France and Germany who aim to give political backing to a process of regional integration of electricity markets. In 2011, Austria joined the initiative and Switzerland became an observer.

3 Methodology

The methodology for this assessment will be characterised by the use of advanced tools. Two different tools will be used alongside each other. This will enable the analysis of lots of different extreme situations and adequacy problems will be looked at from different angles. Deterministic as well as probabilistic studies can be covered by the tools. This topic is described in section 3.1. Another improvement of the methodology lies in the collection of specific input data for this study. To perform an adequacy study it is important to cover all country specifics. For the PLEF region this means that temperature sensitivity to load and hydro modelling should be treated with care. Due to the increasing amount of intermittent energy sources, it is also very important to take this properly into account. All the input parameters will be elaborated upon in section 3.3.

In order to have a consistent data set, a common scenario is agreed upon. The scenario is based on and built upon the ENTSO-E scenario A, which is a rather conservative scenario. It is important to detect possible problems in the region in time, so that necessary actions can be taken. The focus of the study is on two time horizons: the winter of 2015 and 2020. The scenario settings will be described in section 3.2.

A probabilistic approach: future supply and demand levels are compared by simulating the operations of the European power system on an hourly basis over a full year. These simulations take into account the main contingencies susceptible of threatening security of supply, including outdoor temperatures (which result in load variations, principally due to the use of heating in winter), unscheduled outages of nuclear and fossil-fired generation units, amount of water resources, and wind and photovoltaic power production.

A set of time series, loads on the demand side and available capacity of units generating supply reflecting various possible outcomes are created for each of the phenomena considered. These series are then combined in sufficient number to give statistically representative results in shortages (risk of demand not being met due to a lack of generation) and annual energy balances (output of different units and exchanges with neighbouring systems).

Adequacy criteria are often defined on a national level. In this study adequacy indicators are additionally calculated on a regional level. These indicators will be described in section 3.6.

Although the proposed methodology has some significant improvements over the current ENTSO-E methodology, the methodology is still open to further improvements, for example flow based modelling or the extension of the climate database to cover more representative samples of the climatic variations. Some further improvements will be listed in the next steps. However, the envisaged work with improved parameters for the PLEF region will be very valuable as a test case for future use on an ENTSO-E scale. A summary of the methodology is shown in the following figure.

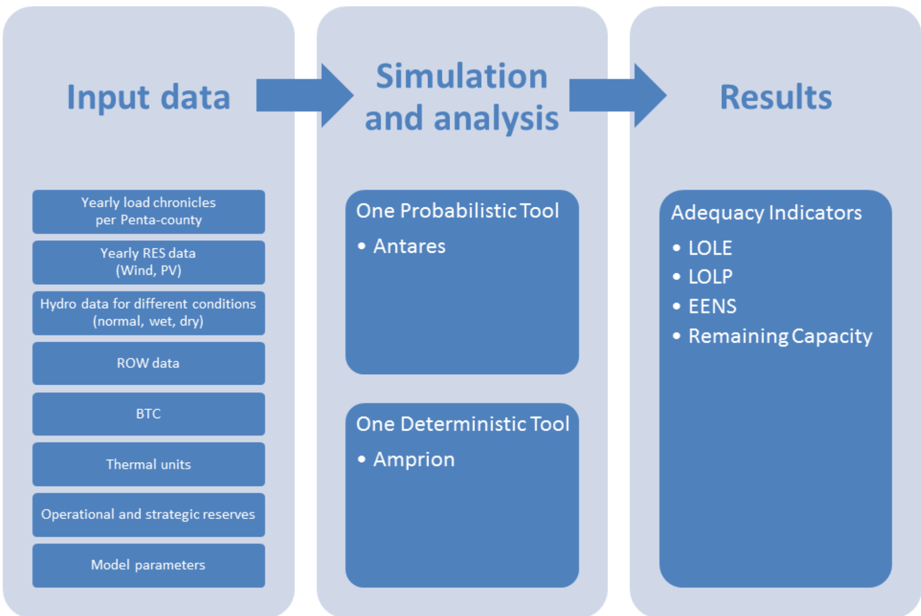


Figure 1 Methodology Summary

3.1 Advanced tools

In this section a general description on the tools employed for the PLEF adequacy analyses is given. This includes the main features one can expect from these tools. For the specific features which come with individual tools employed in the study please refer to the Appendix, where one could find more detailed description for Antares and the Amprion's inhouse tool.

In general the tools employed are built upon a market simulation engine. Such market simulation engine is not meant for modelling or simulating the behaviour of market players, e.g. gaming, explicit capacity withdrawal from markets, etc., but rather meant for simulating marginal costs (not prices) of the whole system and the different market nodes. Therefore the main assumption is that the markets function perfectly.

The tools calculate the marginal costs as part of the outcome of a system-wide costs minimization problem. Such mathematical problem, also known as "Optimal Unit Commitment and Economic Dispatch" is often formulated as a large-scale Mixed-Integer Linear-Programming (MILP) problem. In other words, the program attempts to find the least-cost solution in which no operational constraints (e.g. ramping, minimum up/down time, transfer capacity limits, etc.) are violated. In order to avoid infeasible solutions very often the constraints are modelled as "soft" constraints, which means that they could be violated, but at the expense of a high penalty, i.e. high costs. Most mathematical solvers nowadays are capable of solving large-scale LP problems with little computation time. However, with the presence of integer variables it is still common in commercial tools to solve the overall problem by applying a combination of heuristics and LP.

In the regional study for PLEF, the size of the problem, i.e. the number of variables and constraints could be huge, i.e. thousands of each of them. The size increases with the optimization time horizon and the resolution. For the PLEF study the horizon is a week and the resolution is hourly, i.e. given the constraints and boundary conditions the total system costs are minimized for each week on an hourly basis. The weekly optimization horizon means that the optimal values for each hour of the whole year are calculated, with the optimization problem broken up on a weekly basis, in order to reduce the computation time. A weekly optimization horizon is also a common practice for market simulations at many TSOs for network planning. The latter means that the results such as generation output of the thermal and hydro plants, marginal costs, etc. are given per hour. This setting of the parameters is also the common practice for the market simulations which are conducted for ENTSO-E TYNDP.

These tools also have the functionality to include the network constraints to a different degree. Nowadays the status quo approach pan-European or regional market studies is based on NTC/ATC-Market Coupling (NTC/ATC MC). This means that the network constraints between the market nodes are modelled as limits only on the commercial exchanges at the border. This approach is used in this study.

The EU target model is based on Flow-Based Market Coupling (FBMC). In this model the network constraints are modelled as real physical limits on selected "critical branches". Most TSO tools nowadays can do FBMC, even though they have not been thoroughly tested for large-scale applications. There are also tools which can model the physical network including all the technical constraints such as contingencies, thermal and voltage constraints, therefore supporting what is commonly known as OPF (Optimal Power Flow). Such feature is not yet common in Europe since there is no agreement or plans for a regional scale application of nodal pricing.

Most of the market simulation tools can be used for adequacy analysis purposes. For probabilistic modelling Monte-Carlo simulation is required. This involves a large number of simulations with random draws (combinations) on the stochastic variables (e.g. climate data, load, hydrological conditions, forced outages etc.) in order to work out a probability distribution curve of the required outputs (e.g. ENS, LOLE). To facilitate this, the tools would have features which enable easy handling of these additional inputs and outputs, e.g. multiple time series of load, solar, wind etc. and the corresponding outputs, in a probability distribution curve, etc. In order to reduce the time required for this big number of simulations, some tools also have a "quick-run" feature which reduces convergence time significantly for each run through the simplification of the optimization problem (e.g. removing integer variables, i.e. the on/off decisions, the ramping constraints, etc.).

It is important to mention that the use of multiple tools with the same dataset as inputs, though more time-consuming, improves the quality of the results since debugging of the inputs and models as well as the benchmarking of the results can be facilitated.

3.1.1 Use of multiple models and outputs comparison

For this study two different models (Antares and the Amprion's inhouse tool) were used in parallel. The aim of the use of different models and the comparison of the model outputs is to create consolidated, representative and reliable results. The process is shown in Figure 2. The comparison of the results was done for a "reference year" (2015-2016, weather data 2007-2008, normal hydro conditions) and it was done in four steps:

- Preparation of aggregated output data of the models
- Visualization of the output data in form of comparison charts
- Discussions and analyses within the PLEF TSO group
- Specification of actions regarding model or data improvement

The comparison was done three times during the whole course of the project.

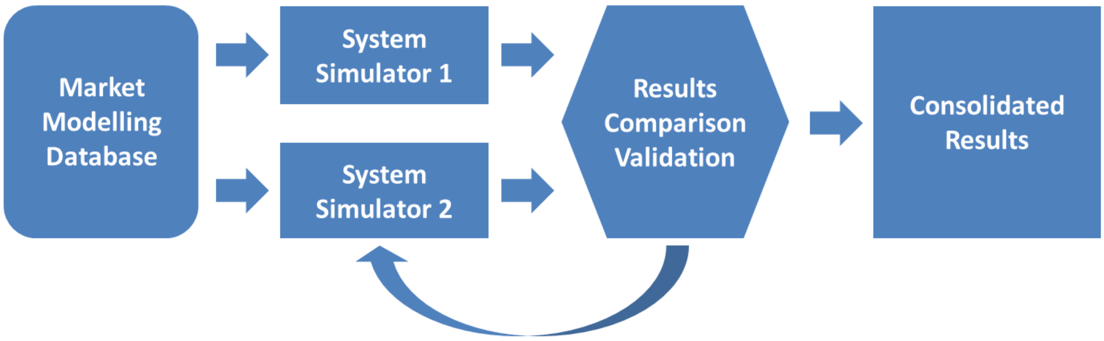


Figure 2 Use of Multiple Models

Although the use of multiple models and the output comparison is a lengthy and time consuming procedure, some major advantages are connected to it e.g.:

- **Input data quality:** Owing to the fact that multiple models are used the input data are checked multiple times independently. This way, errors in the input data will be detected more likely and can be corrected. See also feedback loop no. 3 in Figure 3. This leads to a consistent set of input data and at the same time input data of high quality.

- **Synchronization of input data:** Some of the input data are also part of the aggregated output data of the models (e.g. PV feed-in, load per country). This way possible input data differences (between the different models) can be detected and corrected. The synchronization of the input data is the basis for the comparison of the actual results and also helps to gain a common understanding of the input data. See also feedback loop no. 2 in Figure 3.

- **Comparison of results:** The identification of differences in the results of the models, enables a discussion about e.g. how the models work and how the modelling (e.g. of hydro power plants, biofuel units) is done. Furthermore it also enables a discussion about the influence of model parameters that are not part of the aggregated output data (e.g. fuel and CO_2 prices). This leads to an adaptation of the modelling (see feedback loop no. 1 in Figure 3) and subsequently to a better understanding of the influence some of the parameters (e.g. outages) have on the system.

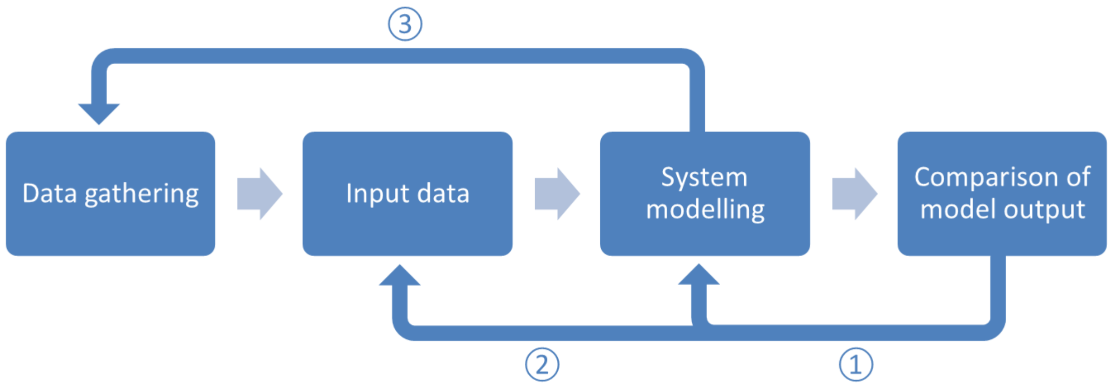


Figure 3 Feedback-loops related to the Use of Multiple Models

If the described process with its feedback-loops is followed thoroughly a better understanding of the results and also higher quality results can be obtained. In our case the results of the models converged although some differences remained. Overall it was possible to increase the confidence in the results.

3.1.2 Assumptions for basic parameters

In this section the assumptions for some of the generic parameters applicable to all tools are briefly described. The technical details for each of the tools might differ and are described in the user manuals.

Hydro modelling, weekly profiles

Since the optimization horizon in the simulations is on a weekly basis, the information regarding reservoir inflow, river flow as well as reservoir level is predefined and given as inputs which are treated as constraints in the optimization. In the PLEF simulations the tools are fed with weekly or monthly profiles to define the boundary conditions for the optimization.

Modelling a hydro production system, especially one including storage and pump storage power plants is challenging due to its complexity and the presence of many stochastic variables, e.g. cascades of reservoir basins and unclearly defined marginal costs. Therefore some simplifications have to be made. As the optimization horizon of the simulations is on a weekly basis, the weekly starting and ending levels of the reservoir of annual storages are treated as constraints in the optimization. These weekly values are either found from interpolation, e.g. for reservoir level, or from equally dividing the monthly values, e.g. for flow quantity. The marginal costs for hydro production are by default zero. This means that hydro units will be committed before thermal units. But within the week the simulation tries to reach a minimum system cost using all dispatchable units such as pump storages, storages and thermal units. In this way hydro dispatch is dependent on market price signals in the whole week, i.e. opportunistic costs. For reservoir power plants min/max of pumping and turbining capacities are additional optimization constraints. Natural reservoir inflow per week is also predefined and given in different profiles (time series) according to different hydrological years (wet, normal, dry). For run-of-river the amount of energy which has to be produced within the week is predefined.

Therefore, in the PLEF simulations the tools some of the important parameters on a hydro system are based on historical hydrological values. It should be noted that the weekly reservoir levels and constraints can in theory be optimized and calculated for each scenario with the aid of a long-term optimization tool. This step has not been performed for the PLEF studies.

Outages & maintenance draws

Every thermal unit is given a rate of unavailability that is based on the type and fuel of the unit. Those values are the reference values used in ENTSO-E studies and come from historically observed forced unavailability of units. The simulation tool will choose which unit will be unavailable based on these rates. Every draw of outages will be different but the average over a period of time is the same. This method allows the simulation of different combinations of outages and extreme events.

Interconnector availability

The maximum commercial transfer capacity between different countries is defined by the value of the NTC. In the annual PLEF simulations two NTC values are used: one for winter and one for summer. In practice however the NTC values given to the market changes every hour because of different factors such as outages, maintenance as well as temperature affecting the thermal transfer capacity of the transmission lines. The winter and summer values used for the simulations represent the average of the hourly fluctuating values.

3.2 Scenario settings

Corner stones of the generation adequacy assessment

In order to give a clear picture of the expectations on this adequacy study it should be stated that this study will model the power system using predefined situations described in scenarios. Also the commissioning and decommissioning of generation capacities are given exogenously with the scenario definition. The adequacy assessment study will model how this given production will meet the forecasted demand but should not lead to statements on whether or not the market works properly or investments will be made in the near future. This stems especially from the fact that a central optimized dispatch is simulated – not a bottom up market – and the available generation capacity is given exogenously. Targeted market modelling exercises are more suitable to derive information such as optimal installed capacity of generation facilities.

PLEF time horizons

The following years have been identified to give a complete overview of the adequacy situation in the short-term and mid-term time horizon in the countries of the Pentalateral Energy Forum (what is referred to as "PLEF" in the report).

- 01.10.2015 – 30.09.2016 – short-term analysis
- 01.10.2020 – 30.09.2021 - mid-term analysis

Scenario for short-term analysis: PLEF Scenario 2015

For the short-term adequacy assessment (10/2015 – 09/2016;) the scenario "PLEF Scenario 2015" has been defined mostly based on the conservative ENTSO--E Scenario A given in the Scenario Outlook & Adequacy Forecast 2013-2030 (SO&AF). The PLEF scenario 2015 uses generation capacities which are available by 1st of October of 2015.

The PLEF scenario (or conservative scenario) is a bottom up scenario taking into account only confirmed additional investments in generation to maintain the current level of supply. Only the commissioning of new power plants which are considered as confirmed according to the information available to the TSOs are taken into account. The same approach is taken for the decommissioning of existing power plants. Corrections with respect to closure and temporary shutdown of generation assets will be taken into account if possible.

Contrary to the ENTSO-E Scenario A in the PLEF scenario renewable generation is taken into account on the basis of the "best estimation" of the TSOs as in the most cases the commissioning of renewables are not confirmed in an early stage.

Also Load forecasts are the best national estimates available to the TSOs under normal climatic conditions. A more detailed description on load modelling is given in section 3.1.1.

For the short-term scenario Fuel and CO2 prices are based on the "Current Policies Scenario" used in the IEA report World Energy Outlook 2013. More description is given in section 3.3.5.

Scenario for mid-term analysis: PLEF Scenario 2020

For the mid-term adequacy assessment (10/2020 – 09/2021) the scenario "PLEF Scenario 2020" has been defined. This scenario is based on the same approach as the "PLEF Scenario 2015".

Harmonization of data for scenarios

In order to improve the quality of the assessment, all scenarios make use of:

- a common approach of RES (solar and wind) availability based on historical climate data,
- correlated and synchronized hydro data for specific hydrological conditions ("normal", "dry" and "wet" years) for Switzerland, Austria and France and Germany,
- temperature sensitivity of load with a common approach by using time series of temperature from the ENTSO-E climate database (correlated to the solar and wind time series)

3.3 Data definition

In addition to an improved methodology, TSOs will also use improved data. Correlated weather data on the one hand, allowing the production of time series of wind and solar generation, and improved hydro data on the other hand, making it possible to show important correlations with climatic conditions. The temperature sensitivity is one of the big drivers for this study. More details are described in the following sub-sections.

3.3.1 Load

Load is a very important input parameter in a generation adequacy assessment. A lot of effort is put in calculating correlated input data between the different countries.

As a starting point the TSOs delivered a normalized load profile (no temperature sensitivity) for the coming years according to their best estimate of growth rate using the calendar of the year 2007.

As a second step the sensitivity to temperature is added to the load profiles according to common and correlated data, since weather conditions can significantly affect electricity demand in some countries of the PLEF region. A widespread use of electric heating is the primary factor explaining the surge in demand observed during cold spells in winter and leads to high demand fluctuations from one year to the next.

A "temperature-sensitivity-model" was developed and implemented to address this issue. It offers two features:
1. Define the current winter temperature sensitivity for each country
2. Define load time series for each country based on temperature data and the defined temperature sensitivity

The model determines the current thermo-sensitivity based on historical demand data and corresponding temperature data from the Pan-European Climate Database (PECD). The model is structured around three complementary concepts: gradient, threshold temperature and smoothed outdoor temperature during the winter months (see also Figure 4):
- **Gradient (MW/°C**) represents the increase in power demand corresponding to a given drop in temperature
- **Threshold temperature** corresponds to the temperature below which demand becomes sensitive to weather condition
- **Smoothing of outdoor temperatures** takes into account various phenomena, such as thermal inertia of buildings, human factors and the influence of cloudiness

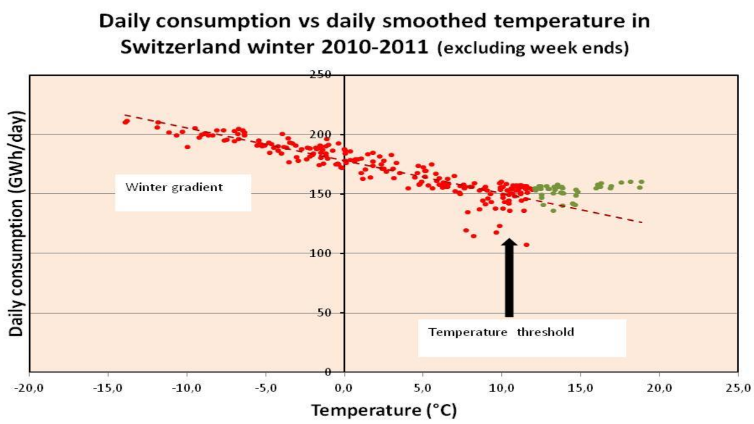


Figure 4 An Example of Winter Gradient for Switzerland

All the countries whose sensitivity to temperature is significant used the proposed model to define the winter gradient.

Based on the demand time series under normal conditions, temperature data from the PECD (Pan European Climate Database) and estimated winter gradient, load time series under several climatic conditions are built for several years. As a first approximation we consider that our climate data base covers a representative sample of the climatic variations. As a consequence normal temperature corresponds to the average temperature of the PECD. As an example the graph below shows the demand sensitivity to several weather conditions for France.

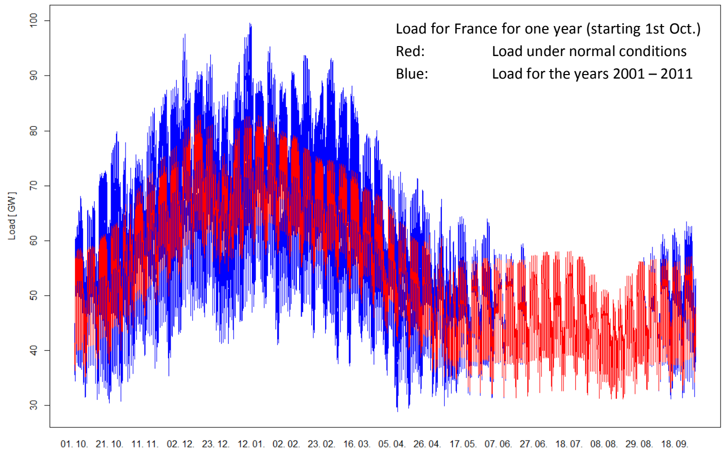


Figure 5: An Example of Demand Sensitivity to Several Weather Conditions in France

A topic closely related to demand data is interruptible demand capacity or demand response (DSR). TSOs confirm that this issue is very relevant for generation adequacy assessment, but also a very difficult one because of the different contracts that are behind this capacity for different countries. Therefore, simplified modelling of DSR is taken into account as an extra sensitivity (see chapter 5.2.5)

3.3.2 Wind, Solar, Other-RES, Other Non-RES

The modelling of wind, solar and other renewable capacity and energy in-feed in the adequacy assessment is challenging mainly due to two reasons: availability of these energy sources in case of scarcity and the uncertainty of new installed capacity in operation according to the national remuneration policies in place or changing in the coming years. The RES installed capacity is based on TSO best estimates. Improvements regarding the availability of these RES units have been used.

<u>Wind/solar</u>

Historical load data coupled with the usage of the PECD (Pan European Climate Database) containing 12 years of hourly correlated wind, solar and temperature data, enables the correlation of demand, wind and solar in-feed. Together with TSOs best estimates on the increase of wind and solar capacities in the coming years the hourly availability or these renewable units can be forecasted assuming that these units will be used in a similar way as in the past. During this study the available PECD data were updated with weather data of the year 2012. The beginning of 2012 was distinguished by a cold spell. To improve the results of this assessment the extended PECD data (wind, solar and temperature) were used for sensitivity calculations.

<u>Other RES / Other non-RES</u>

Other RES (other renewables)

For each market node and scenario the total installed capacities (GW) and hourly time series (MW) of non-despatchable generation out of all renewables which have not been depicted elsewhere are provided. This category is simulated as an inflexible source and is not price-driven. Below a non-exhaustive list of Other RES generation:

- Tidal generation
- Wave generation
- Geothermal generation
- Biomass
- Waste (renewable)

Other non-RES (other non-renewables)

For each market node and scenario the total installed capacities (GW) and hourly time series (MW) of non-despatchable generation out of all non-renewables which have not been depicted elsewhere are provided. This category is simulated as an inflexible source and is not price-driven. Below examples of Other non-RES generation:

- Combined Heat and Power (CHP)
- Waste (non-renewable)

3.3.3 Hydro data

A good probabilistic representation of the hydro generation system is required for the PLEF region because there is significant amount of hydro installed capacity in three (Austria, France and Switzerland) of the countries in the region. In the whole region hydro also has a significant role since the total installed hydro capacity amounts to 16% in 2015 (14% in 2020) of the total installed capacity, which ranks the second highest, directly after gas, which amounts to 21% in 2015 (20% in 2020, followed by 17% of onshore wind). Historical data has shown that the total annual hydro production can vary up to more than 20% between a dry and a wet year. In particular, in the Alpine region where seasonal pump-storages are dominant, the hydro electricity production in winter could significantly reduce in a dry year. This could therefore result in a critical condition when the winter also happens to be cold.

The goal of this exercise is therefore to define suitable hydro profiles which can be used as a common approach for all PLEF countries taking into account the availability of data. Because of the geographical proximity of these three countries, it is expected that their hydrological conditions should be closely correlated, i.e. when there is a dry year in Switzerland, it should also be dry in Austria and France, and vice versa. By applying statistical analyses three distinctive hydro profiles are derived: “dry”, “wet” and “normal”. To facilitate the probabilistic methodology, each of these profiles has to be associated to its corresponding probability, which represents the likelihood/frequency of its occurrence. Each of these profiles contains the weekly values for RoR (Run-of-River), reservoir production (storage, pumped storage, and swell power plants) and natural inflow for reservoir.
The definition of the different hydrological years is as follows:

Type of hydrological year	Definition
Dry	Relatively small amount of aggregated electricity production from all the run-of-river and reservoir plants
Wet	Relatively big amount of aggregated electricity production from all the run-of-river and reservoir plants, without flooding being caused
Normal	Expected amount of aggregated electricity production from all the run-of-river and reservoir plants

Table 1 Definition of the different hydrological years

To derive these three special hydrological conditions, monthly historical data of the past 14 years (1999-2012) for the Swiss hydro electricity production from reservoirs, RoR, reservoir levels and pumped consumption were analysed.

In order to eliminate the influence of the different installed capacities in different years, water quantity, instead of production, was used (e.g. if installed capacity is increased over time and we would not be able to distinguish if an increase in production came from the additional installed capacity or from a “wet” year). In order to validate if this approach – using water quantity instead of electrical production to define the hydrological years - is applicable, the correlation between electricity production and water quantity for RoR and also reservoir power plants was evaluated. A strong correlation can be found (as shown in the next two diagrams) which leads to the assumption that this approach is feasible.

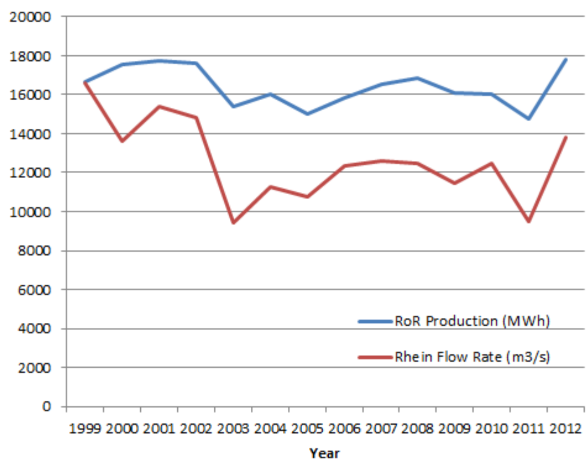


Figure 6 Correlation between RoR production and Rhein flow

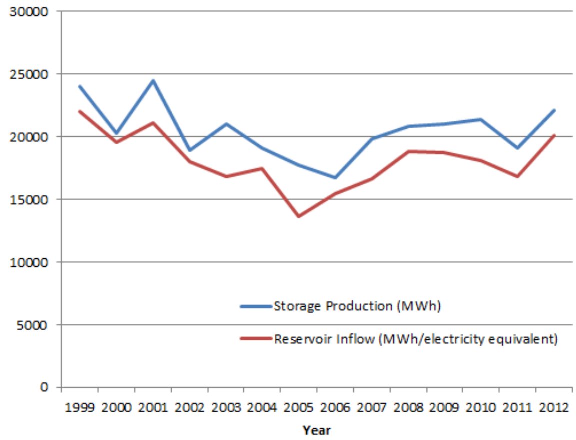


Figure 7 Correlation between Storage Production and Reservoir Inflow

In order to use the combined information of river flow rate together with reservoir natural inflow for the determination of the relevant hydrological years, the weighted average of river flow (Rhein) and reservoir inflow was calculated and the resulting outcome is shown in the next diagram.

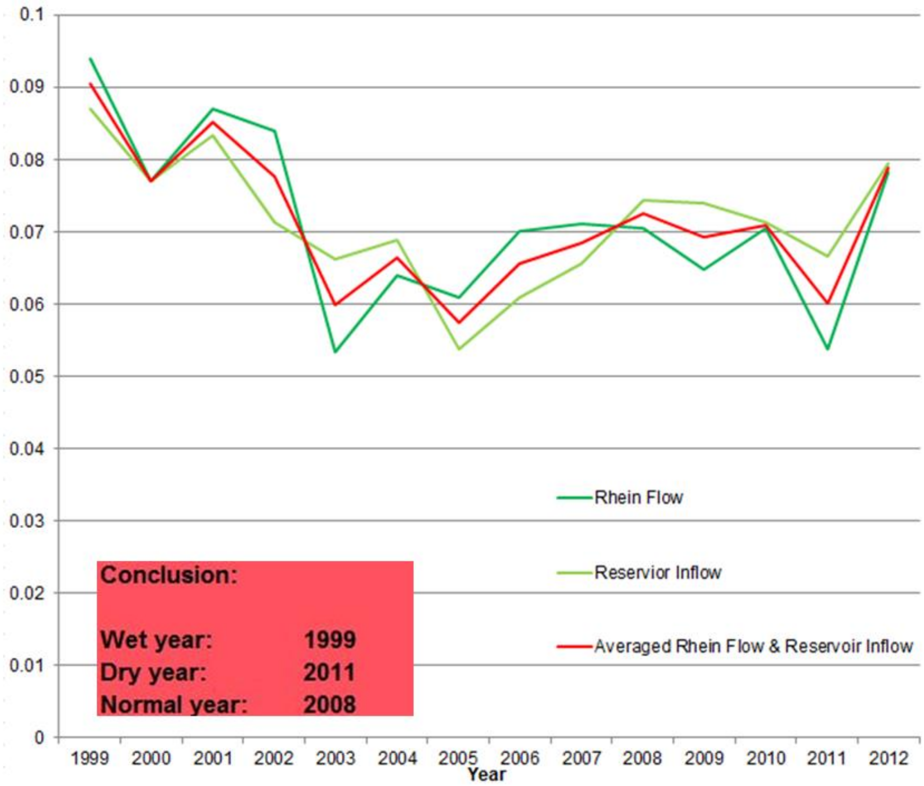


Figure 8 Aggregated Weighted Average of Water Quantity and the Different Hydrological Years

Based on this 1999 was chosen for the wet year, 2011 for the dry year and 2008 for the normal year.
In order to derive a more statistically sound set of probabilities which corresponds to the derived hydrological years, more historical years needed to be analysed. For this purpose 81 years of RoR river flow was employed. At the time of the study it was not possible to acquire the same data for water inflow, but instead the RoR data were representative enough because of the high correlation between the two, as indicated previously. The distribution of the RoR data is plotted in the following diagram.

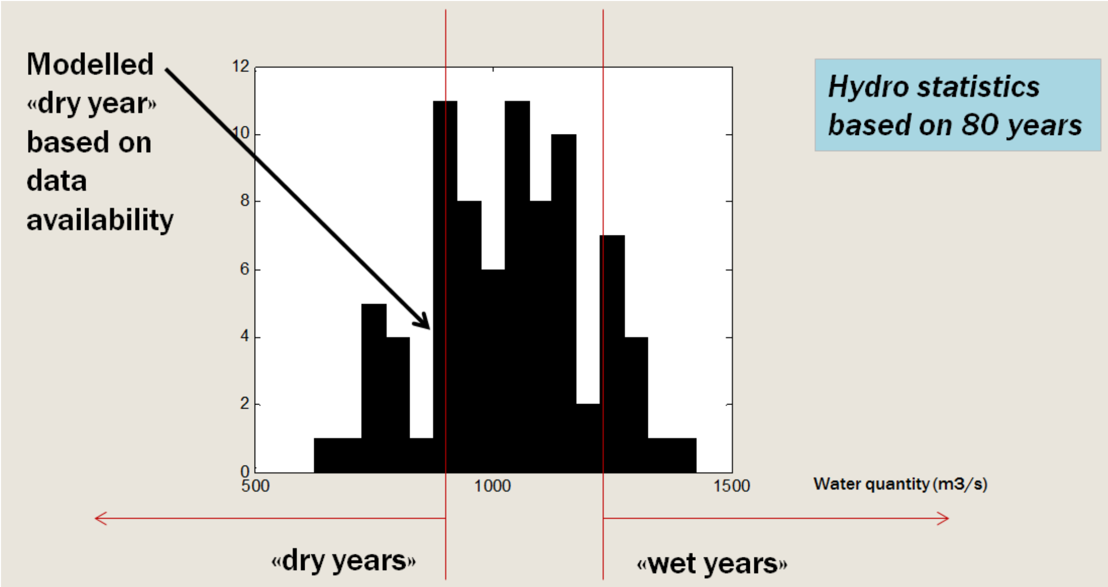


Figure 9 Distribution of Likelihood of Occurrence of the Different Hydrological Years

With this information the likelihood of occurrence of the derived hydrological years was extracted, by comparing and ranking the amount of hydro quantity of these years among those from the dataset. The representative dry and wet years were selected based on the probability of about 10% at both sides of the spectrum. The resulting probabilities are listed in the following table.

	Determined Year	Probability of occurrence
"Dry" year	2011	10%
"Wet" year	1999	10%
"Normal" Year	2008	80%

Table 2 Probability of the Different Hydrological Years

These values and the hydro data profiles for the different Swiss hydrological years were used in order to derive the corresponding required input data for the PLEF countries (especially for Austria and France). The probability of occurrence helped to ensure that the event of having a certain set of conditions (e.g. a dry year) will happen simultaneously for all the PLEF countries during the Monte-Carlo simulations.

3.3.4 Thermal units

Thermal generation categories and main characteristics

In order to ensure coherency of the market behaviour of thermal units in Europe, and to avoid deviations in the simulation runs carried out in this study, 22 different categories for thermal power plants were used. These categories – defined in the guidelines for the Pan European Market Modelling Data Base (PEMMDB) – use standard values for the main technical and economic characteristics. These thermal categories are dependent on:

- fuel (e.g. gas, hard coal, lignite…)
- type (e.g. OCGT, CCGT…)
- and age (e.g. old 1, old 2, new…), which corresponds to a certain range of efficiency of the power plant.

The despatchable CHPs were assigned to the common used fuel, bearing in mind the consequence on the merit-order. The fully non-despatchable CHP units were included in the category 'Other RES' (if renewable) or 'Other non RES' (if not-renewable) data set.[2]

[2] The CHP operation is an optimisation on its own and it would be difficult to include it in our simulations. Therefore it is modelled with hourly profiles ("Other RES" or "Other non RES") whenever possible.

Considerations

This generation adequacy assessment is carried out on a conservative basis and only takes into account certain shutdowns or certain commissioning of thermal generation units. With respect to mothballing units:

- mothballed units will not be considered available to the system[3] and;
- only official data will be taken into account .

3.3.5 Prices: fuel and CO2

Fuel and emission prices form part of the basic input dataset required for market simulations. The SO&AF Scenario A dataset defines the installed generation capacity, but unlike the ENTSO-E 2030 visions, it does not include or give indication on fuel and emission prices. It is therefore necessary to use another known reliable source. For this the IEA WEO (World Energy Outlook) 2013 edition was chosen, which is also a typical choice for ENTSO-E TYNDP scenarios.

In the IEA WEO there have been so far seven basic scenarios (with *Current Policies*, *New Policies* and *450 ppm* being the most frequently quoted ones). For the PLEF studies the Current Policies Scenario was chosen, which is defined as follows:

"Current Policies Scenario: A scenario in the World Energy Outlook 2010 (but still being referred to and updated in later editions) that assumes no changes in policies from the mid-point of the year of publication (previously called the Reference Scenario)"

The scenarios define the political and economic settings which result in a specific set of fuel as well as emission prices. In the 2013 edition, however, no data were published for year 2015/2016. Because of that, the values given in WEO for 2012 and for 2020 were used to interpolate the values for year 2015. The results are shown in the following table:

Source IEA WEO 2013 ($ 2012)			2015 linear interpolation			2020		
		2012	NP	CP	450	NP	CP	450
IEA crude oil import	barrel	109	110.5	113.1	109.4	113.0	120.0	110.0
Natural gas Europe import	Mbtu	11.7	11.8	12.0	11.6	11.9	12.4	11.5
OECD steam coal import	Tonne	99	101.6	103.9	99.8	106.0	112.0	101.0
CO2	Tonne	10	11.9	13.8	19.4	15.0	20.0	35.0

Table 3 Raw Input Data for Fuel and CO2 Emission Prices

The values for our simulations are highlighted in red and it is observed that the fuel prices do not vary significantly between the scenarios, except for CO2 prices. The reason for the high value in the *450 ppm Scenario* is because of the limitation on the concentration of greenhouse gases in the atmosphere to about 450 parts per million of CO2, so that global increase of temperature would be limited to 2 degree Celsius. With the recent development of CO2 prices this would be an extreme case and therefore is not applicable for the PLEF studies.

When converted to marginal costs, this set of values would result in a typical merit-order (without start-up costs) which we observe nowadays, i.e. starting from the technology with the lowest cost:

Nuclear < Lignite < Hard coal < Gas < Oil

This is only an indicative merit-order curve, as in the simulation tools the economic dispatch is also determined by other parameters such as start-up costs, ramping constraints, etc.

3.3.6 Perimeter

The perimeter of the study is not limited to the PLEF region. The so called "ROW" (Rest Of the World) refers to the countries which are not in the PLEF region, but are required in the model in order to have a good representation of the interconnected system between the PLEF countries and the neighbours. Given that data collection is a very lengthy process and because of our limitation in available resources, we have adopted a pragmatic approach for the ROW modelling which is described in this section.

All of our first neighbours (i.e. those with a direct electrical connection with the PLEF countries) are modelled, but in a different degree of detail. For the smaller or less influential countries (see Figure 11: Small 1st neighbours) we took the ENTSO-E SO&AF (Scenario Outlook and Adequacy Forecast) data and approach. In the SO&AF ap-

[3] The TSO do not necessary have information about how long it takes for a mothballed power plant to get back online again. As the re-activation time might be different for each of the mothballed units TSOs decided to consider these units in the following way: If a mothballed unit is contracted by a TSO (and can therefore be activated in due time) it is taken into account, if a mothballed unit is not contracted by a TSO it will be taken out of the dataset.

proach a surplus or deficit margin is defined by the term “RC-ARM”, as shown in the public SO&AF report. “RC” means Remaining Capacity while “ARM” refers to Adequacy Reference Margin. This margin is derived for two particular points in time in the year, namely one in winter and one in summer. Using this information an extra node (so called “simple x-node”) representing a certain neighbouring country with either a fixed hourly consumption (deficit) or generation (surplus) profile for winter and summer is added to the simulation model.

For the bigger and more influential countries with a higher “RC-ARM” value (Spain, Italy and Great Britain) a more detailed approach in the modelling was adopted. The approach is still based on the current set of SO&AF data, but instead of taking the “RC-ARM” values the SO&AF dataset (i.e. installed capacities of different types of generation and load) was mapped into the PEMMDB format which was used to model the PLEF countries. The mapping is done by combining data sources (SO&AF and PEMMDB) for different years available at ENTSO-E level. This means that, as the complete database in the format of PEMMDB does not exist for these countries for year 2015/2016, the numerical difference of the values (e.g. installed capacity, demand, etc.) between years 2015 and 2020 from the SO&AF dataset is used in order to estimate the missing values for year 2015/2016, by means of a simple ratio retaining relationship. The derived values will be presented together with the values for the PLEF region in section 4.2.8. For year 2020 these countries are modelled based on the PEMMDB database (Scenario EU2020), which provides most of the necessary data required for modelling.

To ensure that no important exchanges or flows of these bigger and more influential countries are missed, their first neighbours (GR, PT, IE and NI), i.e. PLEF region second neighbours, are included and modelled using the aforementioned simplified “RC-ARM-approach”. The “RC-ARM” values derived are listed in Table 4. The extent of the detail applied to each region within the model is demonstrated in Figure 11.

First Neighbours	Remaining Capacity (GW) - 2015 winter	Adequacy Reference Margin (GW) - 2015 winter	RC-ARM (GW) - 2015 winter	Remaining Capacity (GW) - 2016 summer	Adequacy Reference Margin (GW) - 2016 summer	RC-ARM (GW) - 2016 summer
ES	*16.3*	*7.35*	*8.95*	*21*	*8.89*	*12.11*
GB	*8.11*	*0*	*8.11*	*14.39*	*0*	*14.39*
IT	*27.69*	*12.25*	*15.44*	*34.51*	*12.17*	*22.34*
PT	3.87	2.28	**1.59**	4.38	1.84	**2.54**
NI	0.34	0.28	**0.06**	0.36	0.37	**-0.01**
IE	2.16	0.75	**1.41**	2.53	0.67	**1.86**
GR	3.66	1.84	**1.82**	3.8	1.94	**1.86**
ME	0.31	0.1	**0.21**	0.4	0.15	**0.25**
DK	-1.32	0.3	**-1.62**	-0.95	1.09	**-2.04**
SE	4.88	4	**0.88**	10.4	4.6	**5.8**
CZ	4.02	2.12	**1.9**	5.6	1.44	**4.16**
PL	3.34	3.11	**0.23**	1.15	2.5	**-1.35**
SI	0.2	0.23	**-0.03**	0.52	0.31	**0.21**
HU	0.55	0.67	**-0.12**	-0.32	0.71	**-1.03**
NO	5.6	2.6	**3**	17.2	1.2	**16**

First Neighbours	Remaining Capacity (GW) - 2020 winter	Adequacy Reference Margin (GW) - 2020 winter	RC-ARM (GW) - 2020 winter	Remaining Capacity (GW) - 2020 summer	Adequacy Reference Margin (GW) - 2020 summer	RC-ARM (GW) - 2020 summer
PT	4.18	2.44	**1.74**	3.95	1.76	**2.19**
NI	-0.02	0.26	**-0.28**	0.53	0.39	**0.14**
IE	1.38	0.77	**0.61**	1.83	0.68	**1.15**
GR	4.2	2.06	**2.14**	4.62	2.12	**2.5**
ME	0.16	0.23	**-0.07**	0.36	0.2	**0.16**
DK	-2.35	0.47	**-2.82**	-1.68	1.17	**-2.85**
SE	4.9	4.1	**0.8**	10.6	4.6	**6**
CZ	2.31	2.19	**0.12**	4.42	1.44	**2.98**
PL	0.79	3.11	**-2.32**	-0.72	2.54	**-3.26**
SI	-0.25	0.21	**-0.46**	0.23	0.31	**-0.08**
HU	-1.27	0.68	**-1.95**	-1.77	0.73	**-2.5**
NO	6.1	2	**4.1**	17.1	1	**16.1**

Table 4 Derived “RC-ARM” Values for PLEF First and Second Neighbours (2015/16 and 2020)

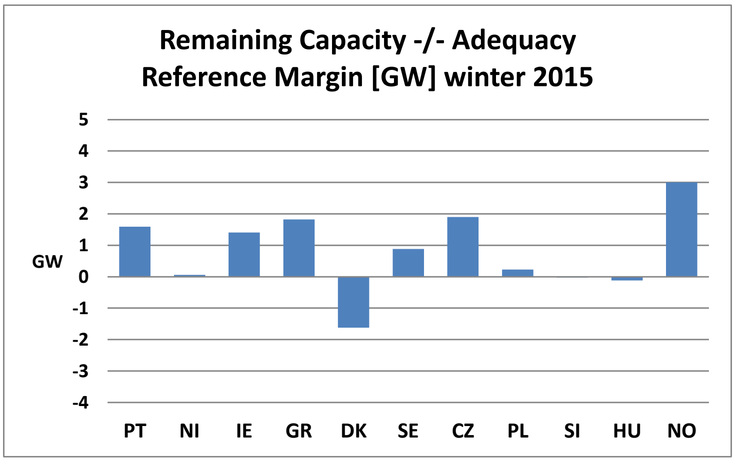


Figure 10a Remaining Capacity minus Adequacy Reference Margin 2015 in GW

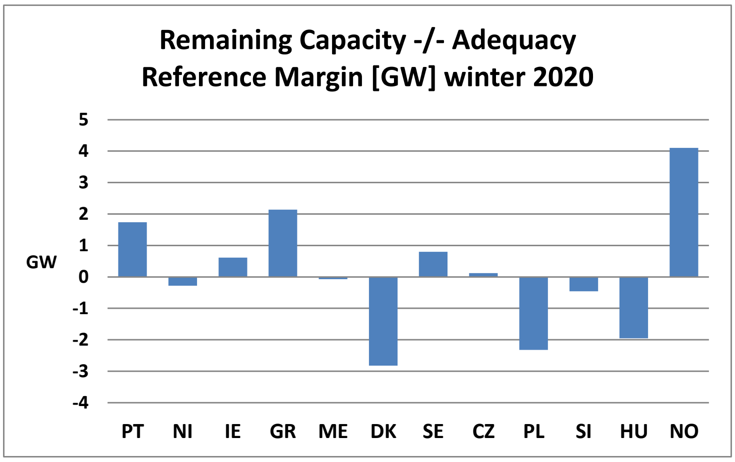


Figure 10b Remaining Capacity minus Adequacy Reference Margin 2020 in GW

It should be noted that, however, due to the lack of detailed load data, there is no thermo sensitivity modelling of the countries outside the PLEF region. Furthermore IE + NI and DKe + DKw were combined into two x-nodes respectively.

In order to model the possible exchanges between the PLEF countries and the first and second neighbours, BTC values are needed. The BTC values used are the best estimates for the year 2015 provided by these TSOs during the TYNDP 2014 internal processes. These exchanges will be described in more detail in the next section.

For the reporting of the results (see section 5), only the countries of the PLEF region and the PLEF region as a whole will be considered, not the ROW countries.

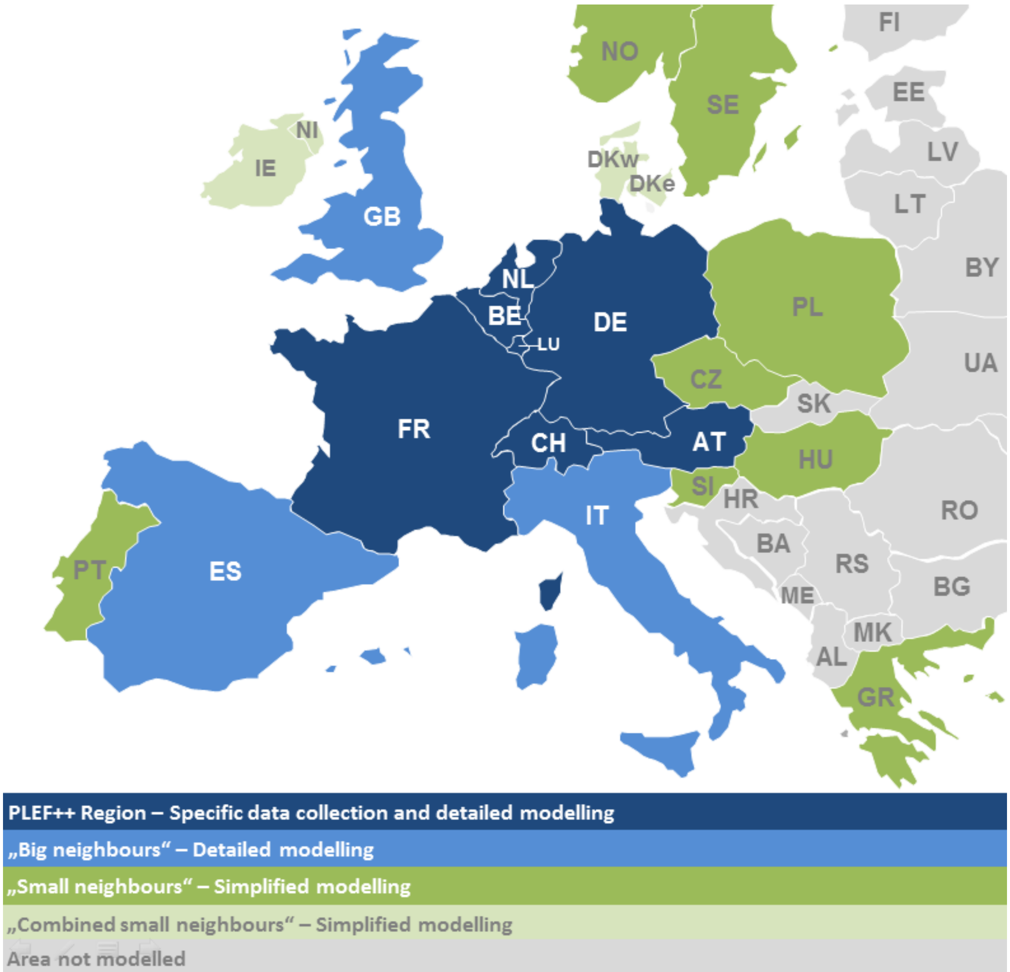


Figure 11 Overview of the Modelling Detail of the PLEF and its Surroundings

3.3.7 Import/Export capacity

The PLEF countries and their neighbouring countries are interconnected and modelled via market nodes. The bilaterally agreed transfer capabilities between market nodes (BTC) should specify the expected capacity available for the market on an interconnection between two areas. BTC values have been determined for all countries involved. The BTC values from the PLEF countries are a result of agreements between TSOs on prudent exchange capacities and mainly derived from available data of previous studies for ENTSO-E.

As France is a big country in the region, in order to ensure good results, it is vital to model their neighbouring non PLEF countries as well, this study will therefore be carried out including detailed data of Great Britain, Spain and Italy as mentioned in the previous section. Consequently interconnection data of their first neighbours (Ireland, Portugal, Greece) will also be taken into account. It was also decided for this adequacy study to use the mutual BTC values of neighbouring countries.

BTC-values are collected for winter and summer periods and in case of a bilateral difference the lowest value counts. Every country involved in this study has the option to define sum constraints on simultaneous import and export capacity, with the aim not to overestimate the possible level of import and export.

3.3.8 Reserves

Compared to the ENTSO-E data an extra data collection is performed for reserves. Two types of reserve data are collected:

- Operational reserves: total of primary, secondary and tertiary reserves contracted to balance the electricity system
- Strategic reserves: reserves contracted for adequacy purposes. Up to now strategic reserves are foreseen in Belgium and Germany:

- Belgium: due to the start of the nuclear phase out and the large amount of mothballed gas units, the TSO of Belgium contracts strategic reserves which can be activated only in case of adequacy problems in Belgium. The need for and the volume of the strategic reserves is determined each year by the Minister.
- Germany: due to the energy transition and limited transport capacity between the northern and southern part of Germany, the TSO of Germany will contract strategic reserves till the end of 2017. These "Strategic reserves" can be activated by the TSO in case of critical grid and adequacy situations in Germany

3.4 Analyses conducted

In this section the analyses conducted are summarized, their results will be presented in chapter 5. The following table depicts the summary:

2015-2016

Climate Years 2001-2011				
LOLE (h)				
OP res	WITH	WITH	NO	NO
Strat res	WITH	WITH	WITH	NO
	isolated	interc.	interc.	interc.

Climate Year 2012				
LOLE (h)				
OP res	WITH	WITH	NO	NO
Strat res	WITH	WITH	WITH	NO
	isolated	interc.	interc.	interc.

2020-2021

Climate Years 2001-2011				
LOLE (h)				
OP res	WITH	WITH	NO	NO
Strat res	WITH	WITH	WITH	NO
	isolated	interc.	interc.	interc.

Climate Year 2012				
LOLE (h)				
OP res	WITH	WITH	NO	NO
Strat res	WITH	WITH	WITH	NO
	isolated	interc.	interc.	interc.

Table 5 Summary of the Analyses Conducted

<u>The modelling of reserves</u>

Two sets of simulations are performed:

- All reserves included: operational reserves and strategic reserves are not corrected for in the supply side (meaning that they are NOT reduced from the total installed capacity). The simulation gives the most optimistic view since all reserves (also the operational reserves) will be used for adequacy purposes.
- Reserves partly or fully withdrawn: operational reserves and strategic reserves will be taken away from the supply side. The simulation without operational reserves and with strategic reserves gives a more pessimistic view, but is important in order to detect on time possible adequacy problems[4] (since operational reserves are no longer used to only balance the electric system). This is referred to as "Base Case" in this study. The simulation without operational and without strategic reserves gives an even more pessimistic view and shows the need for strategic reserves in Belgium.

<u>Extreme climate conditions</u>

The year 2012 is regarded as a rare climatic year in which a cold spell last for persisted period in deep winter. Because of this the PLEF study, through the extension of the ENTSO-E Pan-European Climate Database (PECD), is extended by means of an extra set of simulations. The extension includes hourly temperature (indirectly changing load for countries which have temperature-sensitive load), wind and solar data for all countries in Europe. Because of the fact that the climate conditions so depicted are rare (probability < 10%) these data are not combined in the other more "normal" years, i.e. 2001-2011, in order that the statistics do not become distorted.

Indeed, February 2012 was an exceptional climate event since it's the third most severe cold spell, in terms of intensity and length, observed in France since 1987 and the fifth over the past 70 years.

[4] These simulations are also used in the national studies from Belgium and France.

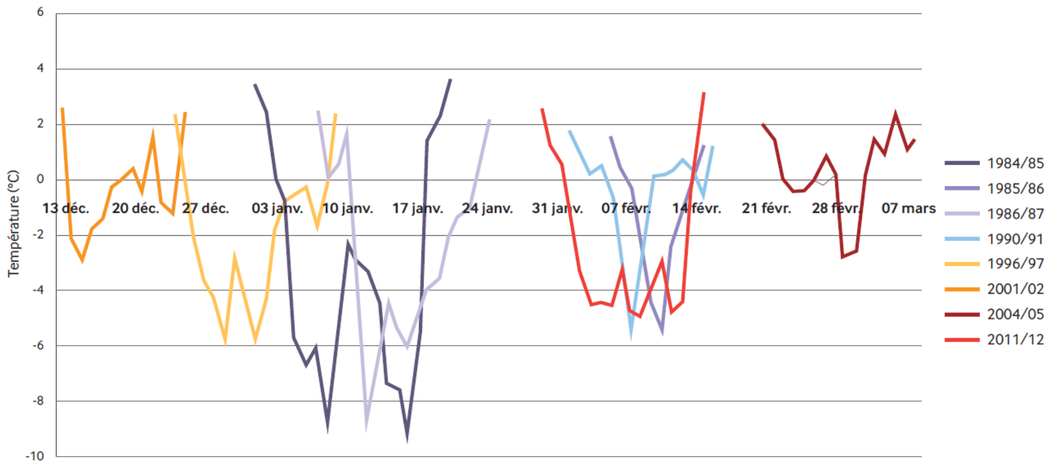


Figure 12 Average Daily Temperature in France

<u>Isolated cases</u>

In order to investigate the importance of interconnection a set of hypothetical simulations are set up in which all the PLEF countries were to be electrically isolated. The way it is done is by reducing the NTC values to zero at all the borders. Alternatively speaking, these analyses would show how the different countries are dependent on import in order to maintain adequacy.

<u>Demand response</u>

Because information on market penetration of demand response is only available to restricted countries it is not possible to have a systematic analysis in which demand response is modelled in the whole PLEF region. However, for France this information is available (3GW) and modelled using a simplified model as an extra sensitivity study. There will also be attempt to model demand response in another big country like Germany in the PLEF region but as reported and explained in chapter 5.2.5 it would not affect the results.

3.5 Convergence of the probabilistic assessment

In order to reach a representative average value, all in all 220 Monte-Carlo years were employed. The reason why 220 years were required is given in the following graphical illustration, which shows that based on the probability of the 3 different hydrological years (0.1, 0.1 and 0.8), combined with the 11 climate years, each having equal probability, a sum of 220 can be deducted (11x2+11x2+11x16=220). Each of these 220 years is then given random outages and maintenance schedules based on the specified technical parameters of the types of plants.

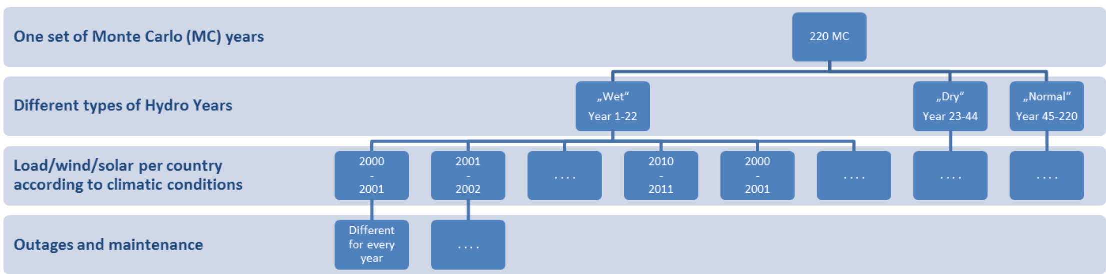


Figure 13 Graphical Illustration of the Amount of Monte-Carlo Years Required for Convergence

3.6 Adequacy indicators

A generation adequacy analysis attempts to identify and to assess the level of risk faced by the power system during critical periods. These critical periods can be a cause of several individual or combined reasons: strong weather conditions, lack of renewable generation, forced or planned outages of thermal units, etc.

There are two main methodologies to calculate the reliability indicators: one based on a probabilistic assessment of generation adequacy or the other one a quantitative approach based on a capacity margin. In this study the focus is on the first methodology.

In case of a probabilistic assessment, typically three different criteria are calculated. These are often defined on an annual scale and can be measured both at national and regional level**:**

- **Loss of Load Expectation (LOLE)**, expressed in hours per year, is defined as the expected number of hours per year for which the available generating capacity is insufficient to cover the demand. LOLE is a statistical measure of the likelihood of failure and does not quantify the extent to which supply fails to meet demand. To calculate the LOLE for a year, a computer program evaluates the LOLE at every hour throughout the year; The LOLE of the year is then the sum of all these hourly contributions.
- **Expected Energy not Served (EENS)**, expressed in GWh per year, is the magnitude of load that has been lost when demand exceeds the available generation. In order to facilitate the comparison of values of EENS between different countries, it is possible to calculate a dimensionless indicator by dividing EENS by the (average) annual consumption of a specific country:

  Relative EENS per country = EENS / (average annual consumption per country)
- **Loss of Load Probability (LOLP)**, expressed in percentage, is defined as the probability that the load will exceed the available generation. It defines the likelihood of encountering loss of load but not the severity.

In addition to the three basic annual indicators already mentioned, a fourth important feature of the system behaviour could be assessed: the probability density function of the duration of the shortage expected when adverse operation conditions are met. However, owing to time constraints, this will not be included or analysed in this report. This option could always be further investigated in future studies.

The adequacy criteria that have to be met are normally defined by each country, for example LOLE of 3 h/year for Belgium[5] (Belgian law 'Elektriciteitswet' of April 1999) and France (French law February and August 2004) and 4h/year for the Netherlands (Dutch adequacy criteria in paragraph 4.2 of report Monitoring Security of Supply (in Dutch 'Rapport Monitoring Leveringszekerheid 2013-2029', www.tennet.eu) of Dutch TSO TenneT). For the moment there is no such definition for the region.

All of the above indicators can reflect the degree and amount of deficit for every PLEF country or even for the PLEF region in case there are adequacy problems. However, for the countries which show "zero" everywhere with these indicators, it would be interesting to have an indicator which can show the amount of surplus or how far one is to the border of being inadequate. In order to show this, an indicator will also be applied, named "Remaining Capacity". For the PLEF region, the "Remaining Capacity" would be equivalent to the remaining thermal capacity, which is defined as the capacity remaining in each country after all generation units are committed and despatched optimally by the simulation tool. It is because the marginal costs for wind, solar and hydro are zero they will be dispatched completely because the thermal plants are committed. Special attention should be paid to the interpretation of this indicator for hydro countries like Switzerland and Austria. For example, if Switzerland has a wet year or has a typical surplus in summer, the remaining capacity for Switzerland itself would not be changed, but rather an increase of the remaining capacity in the neighbouring countries through export might be observed.

[5] Belgium has a double criteria defined in the law, namely LOLE of 3h/year for normal conditions and LOLE of 20h/year for exceptional conditions (P95).

4 Input data

The data collection procedure is required according to the methodology chosen. For this assessment an extra challenge lies in the fact that not only do TSOs have to cooperate on agreeing and aligning the model methodology and data gathering and analysing process, but they also have to meet individual expectations from market parties, regulatory bodies as well as governmental bodies regarding this generation adequacy assessment.

The time line of the whole process is very tight and validation of the procedure itself and its data is required. TSOs are dedicated to get a common understanding of an improved method, reliable data and coherent assumptions.

4.1 PLEF region

For this generation adequacy assessment detailed input data from the PLEF countries have been collected. As mentioned before it is very important to model some of the neighbouring countries in more detail due to their influence on the region. Therefore this generation adequacy assessment study will be carried out using also the detailed data (besides thermo sensitivity modelling of load) of Great Britain, Spain and Italy. Consequently interconnection data and a surplus or deficit of their first neighbours will also be taken into account. Data from the neighbouring countries were derived from the SO&AF data (System Outlook & Adequacy Forecast) and the ENTSO-E's Pan European Market Modelling Database, as described in 3.3.6.

In this section the shown figures represent the installed capacity per fuel for the PLEF countries and the PLEF region including the big first neighbours (according to Figure 11) as well as the total demand per country 2015/2016 and 2020/2021. The corresponding numbers can be found at the end of this chapter.

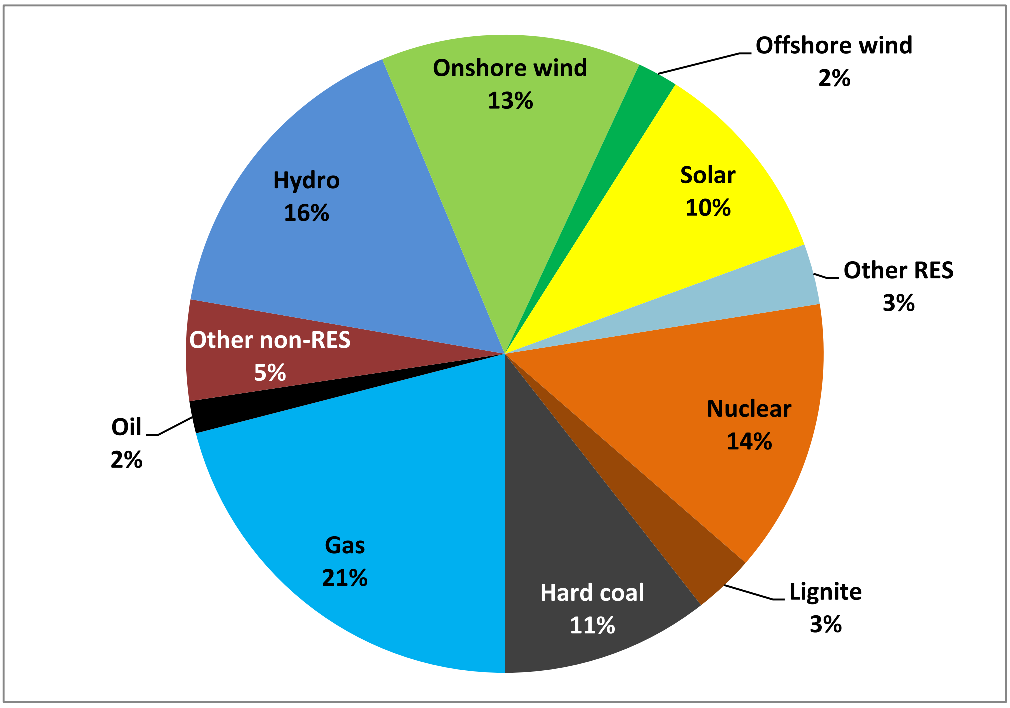


Figure 14a Generation mix (installed capacities) of PLEF modelled countries [%] 2015-2016

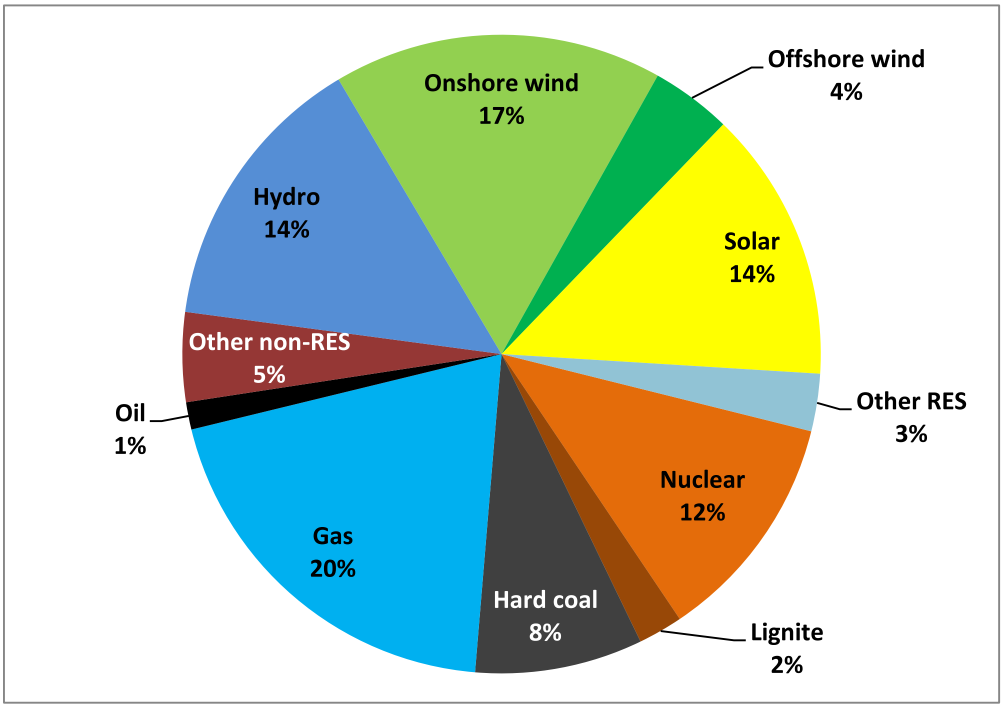


Figure 14b Generation mix (installed capacities) of PLEF modelled countries [%] 2020-2021

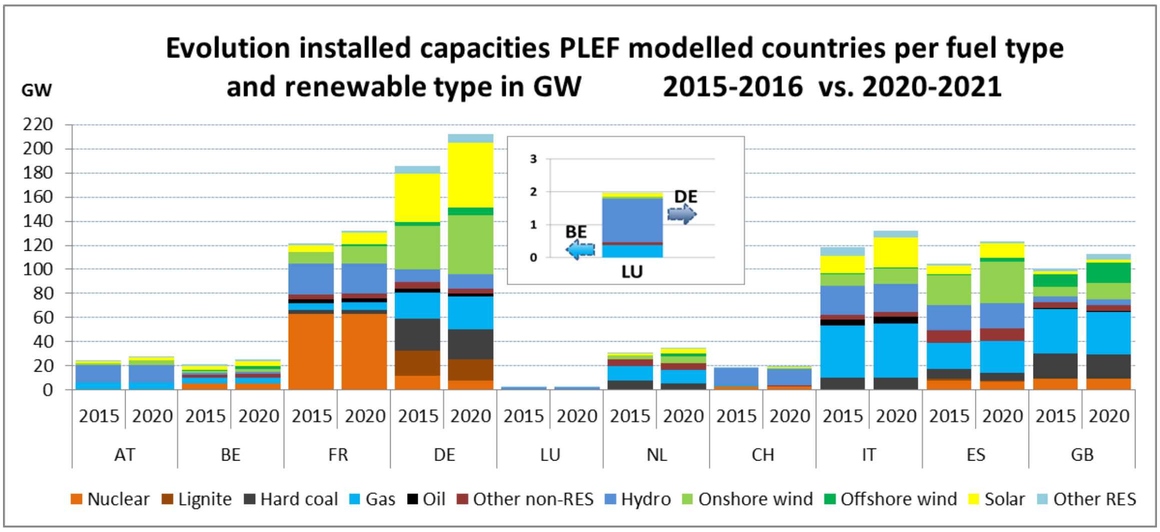


Figure 15a Installed capacity PLEF countries per fuel type and renewable type [GW] 2020-2021

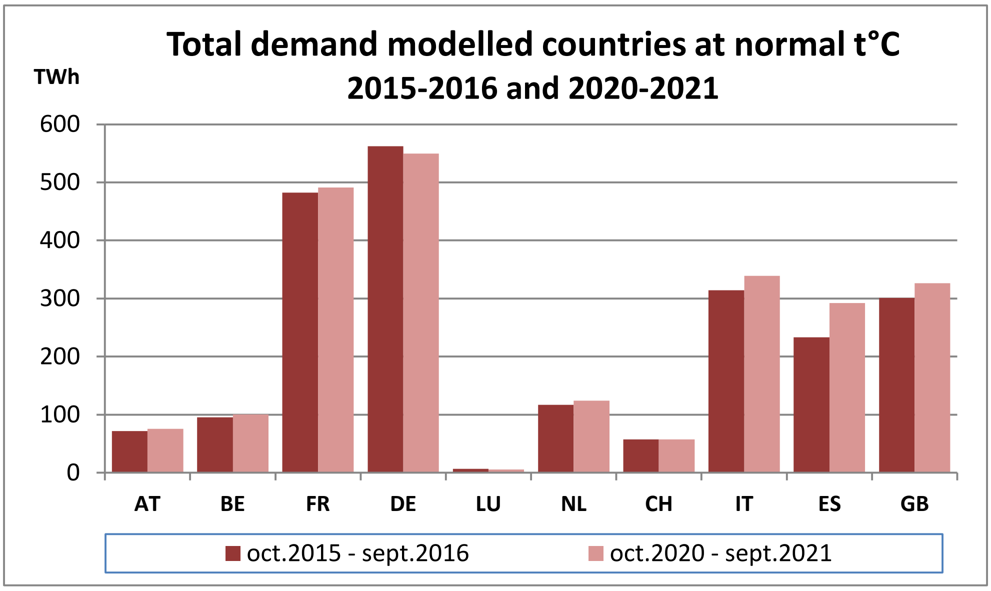


Figure 15b Total demand: modelled countries at normal temperature [TWh/year] 2015-2016 and 2020-2021

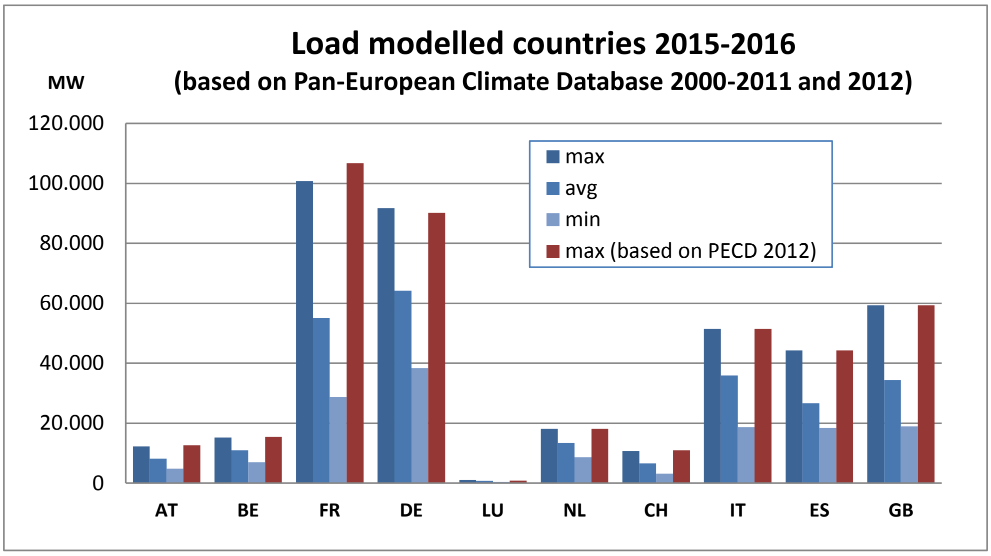


Figure 15c Load: modelled countries, maximum, average, minimum [MW] 2015-2016

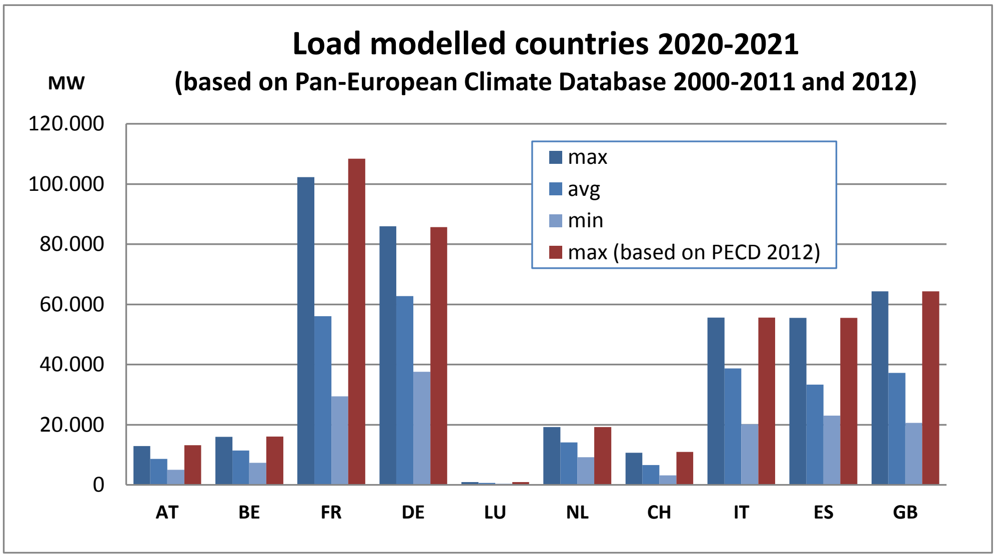


Figure 15d Load: modelled countries, maximum, average, minimum [MW] 2020-2021

4.2 Country specifics

4.2.1 Austria

Installed power plant capacities published by E-Control were used for this study. This includes also the capacities of Vorarlberger Illwerke AG which are connected to German TSO Transnet BW. Also power plants whose energy is transferred to German TSOs by a virtual tie-line are counted 100% for Austria. Virtual tie-lines are used to consider generators physically located in another control area in real time without schedule. (see Continental Europe Operation Handbook, P2 Scheduling and Accounting, C-D4.2.)

The pumped storage power plant Reisseck II which will be put into operation 2015 was considered as new hydro power plant for the scenarios.

For the thermal capacities no further commissioning of power plants is foreseen in Austria in years up to 2020/2021. Planned shut-down units like Riedersbach (2016: 168 MW), Neudorf-Werndorf 2 FHKW (2015: 164 MW) and Dürnrohr Verbund (2015: 405 MW) but also the mothballed units of the new CCGT power plant of Verbund in Mellach (2015: 832 MW) were taken as not available.

The increase of wind and solar power capacities were calculated based on assumptions used for the green Scenario of Masterplan 2014 of APG.

An annual increase of load for the coming years of 1.1% was taken into account (Basis: E-Control: MONITORING REPORT Versorgungssicherheit Strom Oktober 2013). In order to calculate temperature sensitivity the years 2003 to 2010 of load data (Assumptions were made to get “Gesamte Last” as hourly time series) were used to estimate gradient values and temperature threshold. The values estimated for this study are in line with those calculated by a study published by E-Control 2005 (Title: “Temperaturabhängigkeit des Strom- und Gasverbrauchs”). No growth rate of electric space heating is expected in the coming years for Austria.

BTC values have been agreed upon with neighbouring TSOs. As there is a common market between Austria and Germany a very high BTC value was given for this border to consider the thermal possibilities of the interconnection lines.

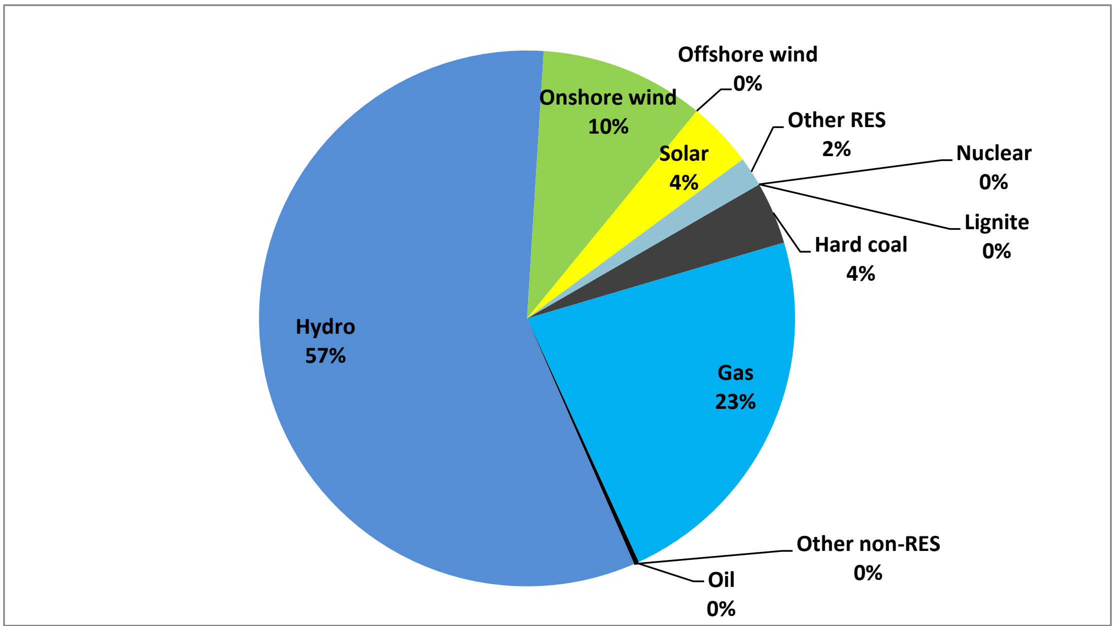


Figure 16a Generation mix (installed capacities) of Austria, 2015-2016

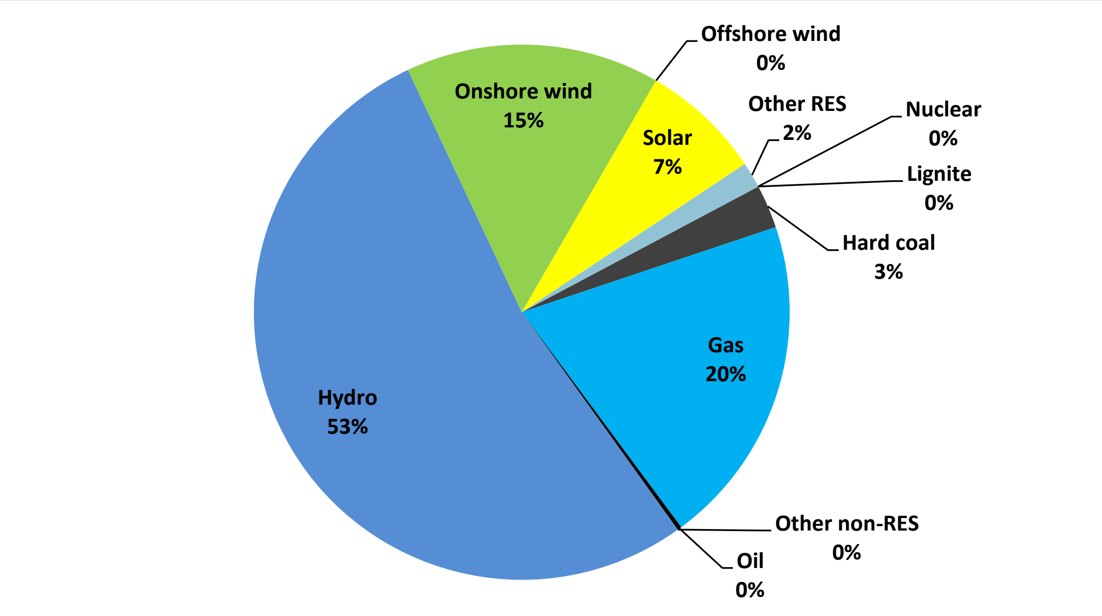


Figure 16b Generation mix (installed capacities) of Austria, 2020-2021

4.2.2 Belgium

The generation mix in Belgium is largely characterized by 3 components:

- Nuclear: due to the start of the nuclear phase-out according to the Belgian law the first nuclear power plant (Doel 1 and 2)[6] is out of service for the simulation 2015/2016 and 2020/2021. The nuclear units Doel 3 and Tihange 2 are shut down for issues in the reactor pressure vessels. The restart of those 2 reactors (total of 2 GW) is not confirmed yet. A sensitivity analysis is included to shows the impact if those 2 units will not come back before the winter 2015-2016.

- Renewables: an increase of the installed capacity of RES is taken into account according to national and regional perspectives.

- Gas: for the coming years a significant number of gas units has announced to go into mothballing and no new gas projects are confirmed to be build.

To guarantee security of supply in this context for the coming years the following initiatives are defined in Belgium:

- Strategic reserves[7]: generation units that are not available for the market and can only be activated in case of adequacy problems in Belgium (current definition). The strategic reserves are included in the generation mix, but require some specific modelling for Belgium. For the 2015/2016 and 2020/2021 simulations an estimation for the volume of strategic reserves is used based on national adequacy calculations performed in March 2014. The volume for 2015/2016 and 2020/2021 is not yet confirmed by the Minister.

- Tender of 800MW for new generation units included in the simulations for 2020/2021.

For the Belgian load a growth rate of 1% is taken into account for the normalized temperature, coherent with previous national adequacy studies. The temperature sensitivity is modelled and is estimated at 110MW/°C.

NTC values have been agreed upon with neighbouring TSOs. For 2015/2016 Belgium is only interconnected with the Netherlands and France. New interconnection projects with Germany, Great-Britain and Luxembourg are

[6] According to the law Doel 1 will be decommissioned 12/02/2015 and Doel 2 01/12/2015. For simplicity in the simulations, both units are completely taken out for the 2015/2016 simulations. This approach is conservative to be in line with the scenario definition. Discussions are ongoing to prolong the decommissioning of Doel 1 and Doel 2. This is not taken into consideration in this study.

[7] Strategic reserves are covered by generation as well as demand (strategic generation reserves and strategic demand reserves). For this study the strategic reserves are modelled as strategic generation reserve.

foreseen for the 2020/2021 simulations. On top of the NTC values a simultaneous import/export capacity of 3500MW[8] is foreseen.

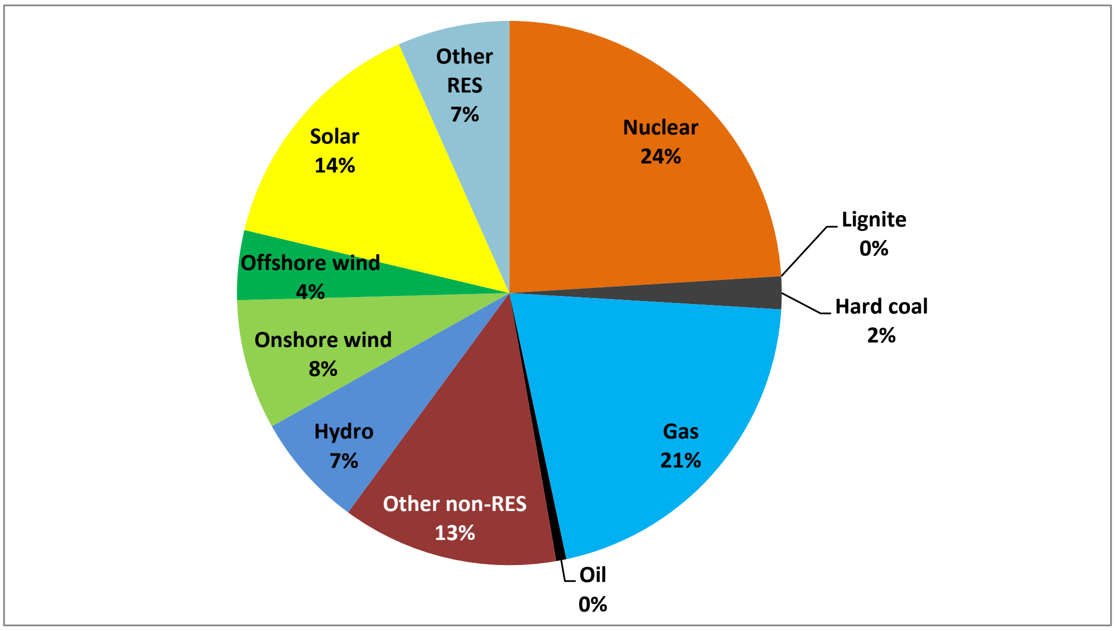


Figure 17a Generation mix (installed capacities) of Belgium, 2015-2016

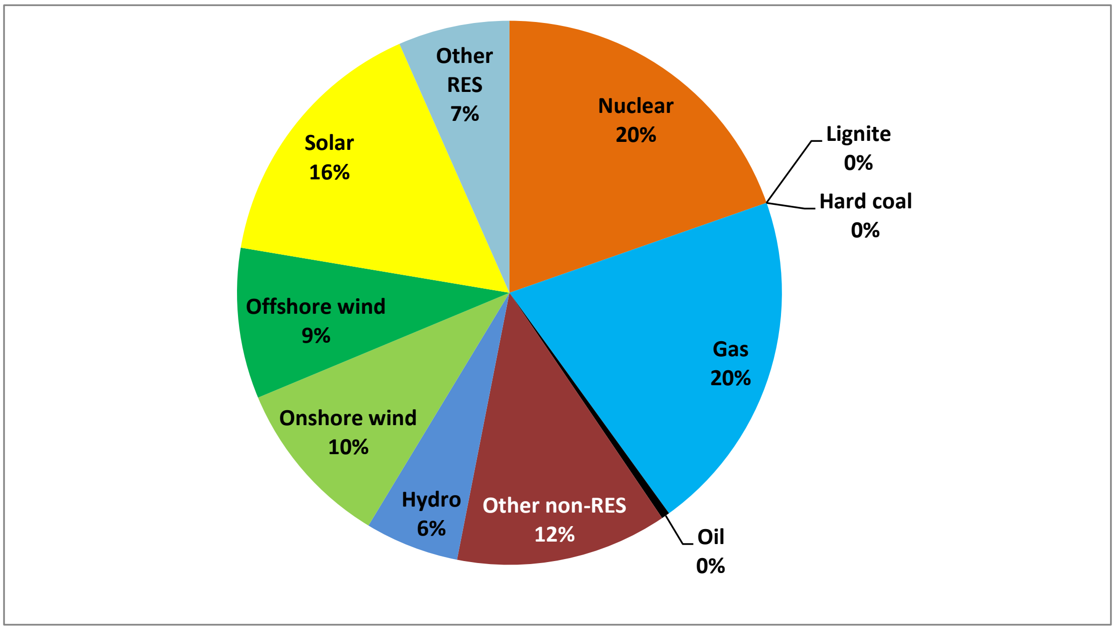


Figure 17b Generation mix (installed capacities) of Belgium, 2020-2021

4.2.3 France

For both 2015/2016 and 2020/2021 adequacy assessment, French hypothesis are established in the framework of the 2014 edition of the French generation adequacy forecast (http://www.rte-france.com/sites/default/files/-bilan_complet_2014.pdf).

Load is consistent with the Reference scenario which assumes central assumptions for each driver of demand.

[8] In the latest national adequacy study performed by Elia (November 2014), the simultaneous import capacity is reduced to 2700MW due to the observation of structural changes in the energy fluxes in the CWE network during winter peak moments.

The French power system is very sensitive to temperature swings and an extreme climate event could create a shortfall situation in France. It was therefore decided to implement, as a first step, a simplified modelling of the temperature sensitivity of load for this study.

The hypotheses for generation are the up-to-date park forecasts as of May 16th, 2014, in line with the information disclosed on May 13th at the CURTE, RTE's consultation body.

For 2015-2016, the scenario takes into account: two operative nuclear units at Fessenheim, whose decommissioning is officially foreseen at the end of 2016 and two late CCGTs mothballs notified by Poweo/Verbund.
For 2020-2021, the scenario takes into account the commissioning of a new nuclear plant in Flamanville and the commissioning of 2 CGT units at the planning stage.

NTC values have been agreed between TSOs.

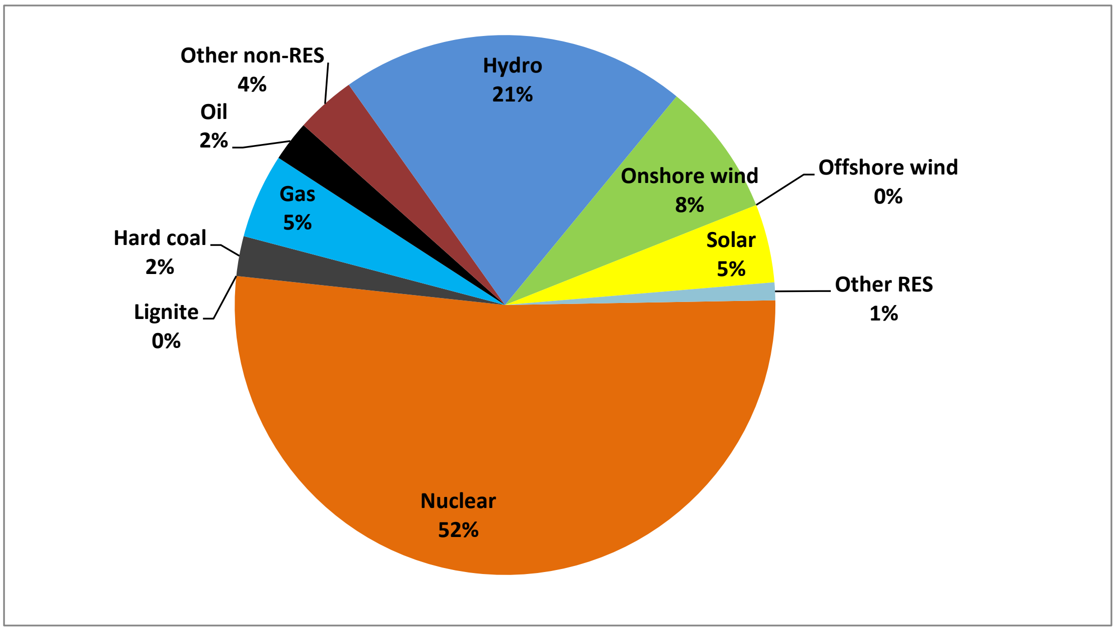


Figure 18a Generation mix (installed capacities) of France, 2015-2016

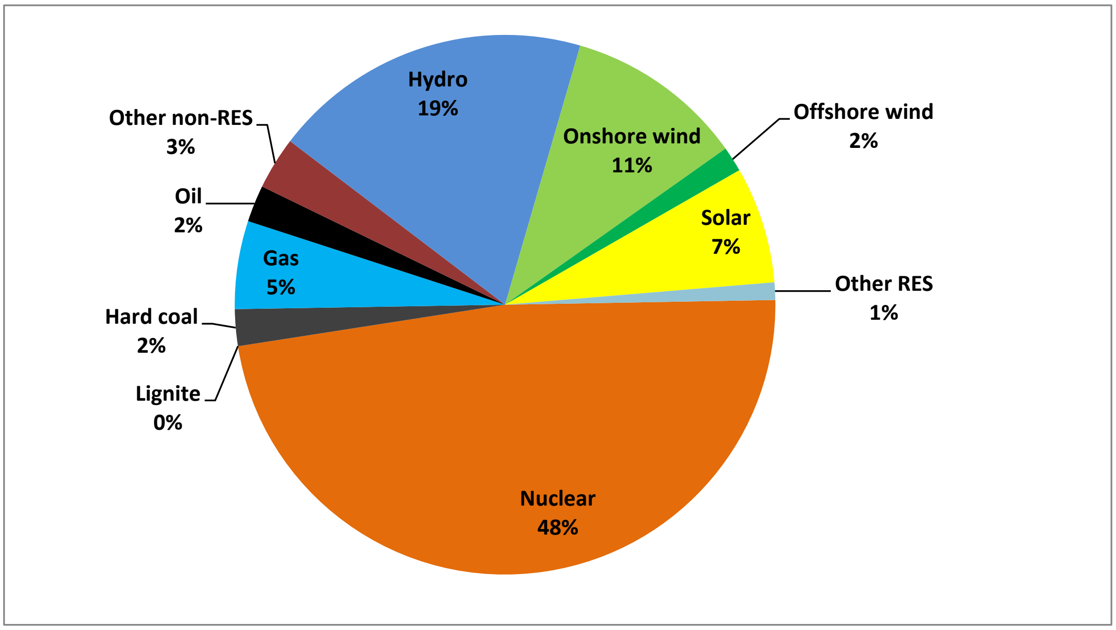


Figure 18b Generation mix (installed capacities) of France, 2020-2021

4.2.4 Germany

For the 2015/2016 adequacy assessment, the data for Germany correspond with other relevant studies and analysis both on a European and domestic level.

In order to prevent critical gird situations German TSOs contract dedicated power plants. The volume of these plants currently amounts to 2,6 GW (Winter 2013) and is expected to increase to 7 GW until 2017/beginning of 2018. These power plants do not operate in the market and may exclusively be activated by the TSO. So far activations have only taken place in very rare instances in winter 2011/2012. In 2013 only one activation has taken place. The trigger for activations may be critical grid situations and imbalance problems.

In Germany the closure of power plants has to be announced by power plant owner to the respective TSO and the NRA. In case a power plant is of relevance for the security of the system the TSO may disapprove the power plant closure.

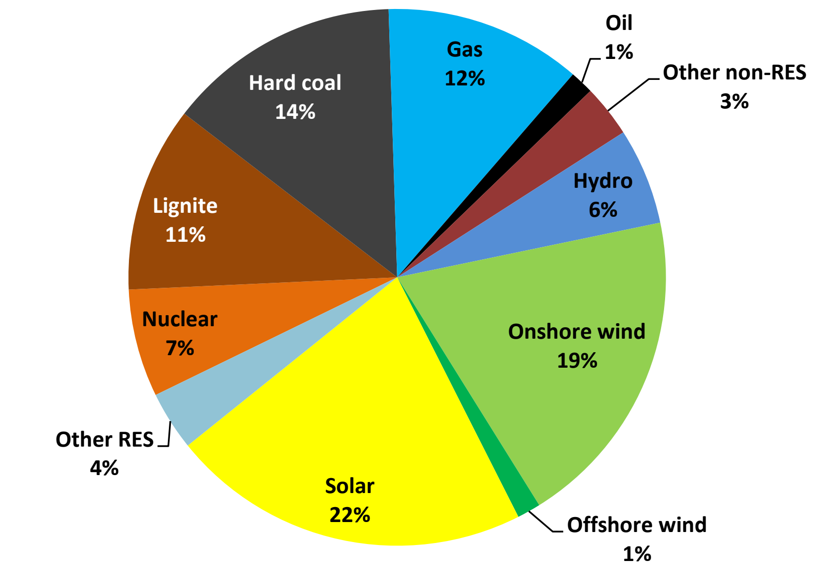


Figure 19a Generation mix (installed capacities) of Germany, 2015-2016

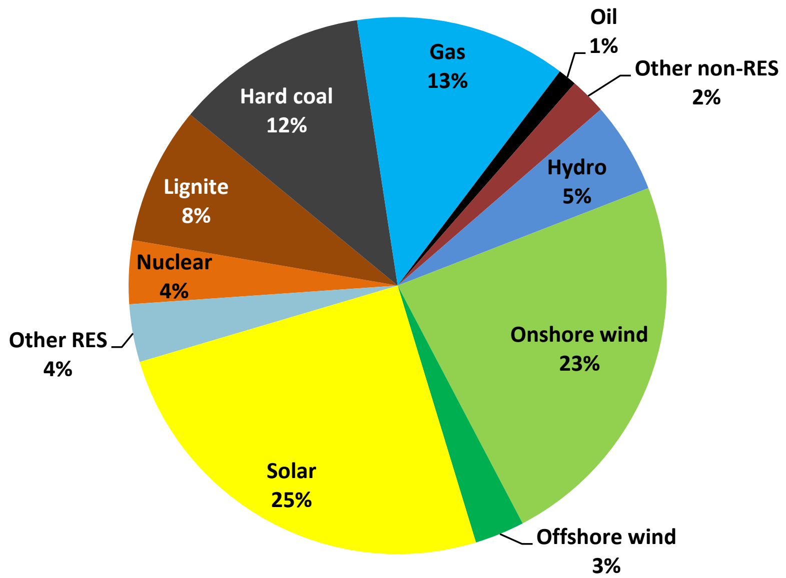


Figure 19b Generation mix (installed capacities) of Germany, 2020-2021

4.2.5 Luxembourg

The load increase is based on an annual growth of 1.1% according to a GDP scenario STATEC called "base scenario". The Luxembourgian generation capacity is specific due to the fact that the main production units located in Luxembourg are injecting in the grid of the neighbouring countries Germany and Belgium and thus make an important contribution to the security of supply in the region.

The pump-storage with a total capacity of 1300 MW located in Vianden is directly linked to the German Grid operated by the German TSO Amprion. The CCGT power plant located in Esch-sur-Alzette called Twinerg with an installed capacity of 375 MW is integrated into the control area of the Belgian TSO Elia. The data of both power units are included in the dataset of Germany respectively Belgium.

Although the net generating capacity installed on the Luxembourgish territory exceeds the load expectation, the capacity of the two major power plants Vianden and Twinerg do not directly contribute to the adequacy of Luxembourg but of the whole region.

A new interconnection between Belgium and Luxembourg will be in operation in 2016. NTC and thus the BTC values have been determined in cooperation with the neighbouring TSOs.

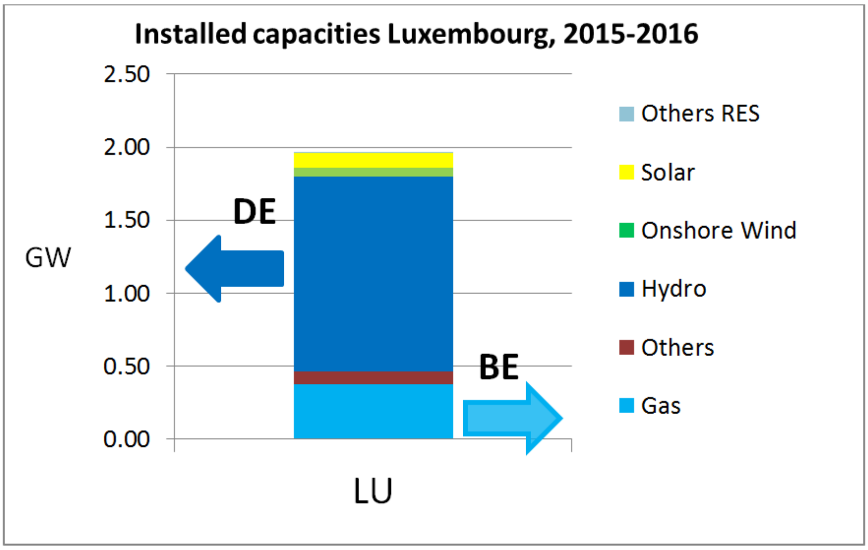


Figure 20a Generation mix (installed capacities) of Luxembury, 2015-2016

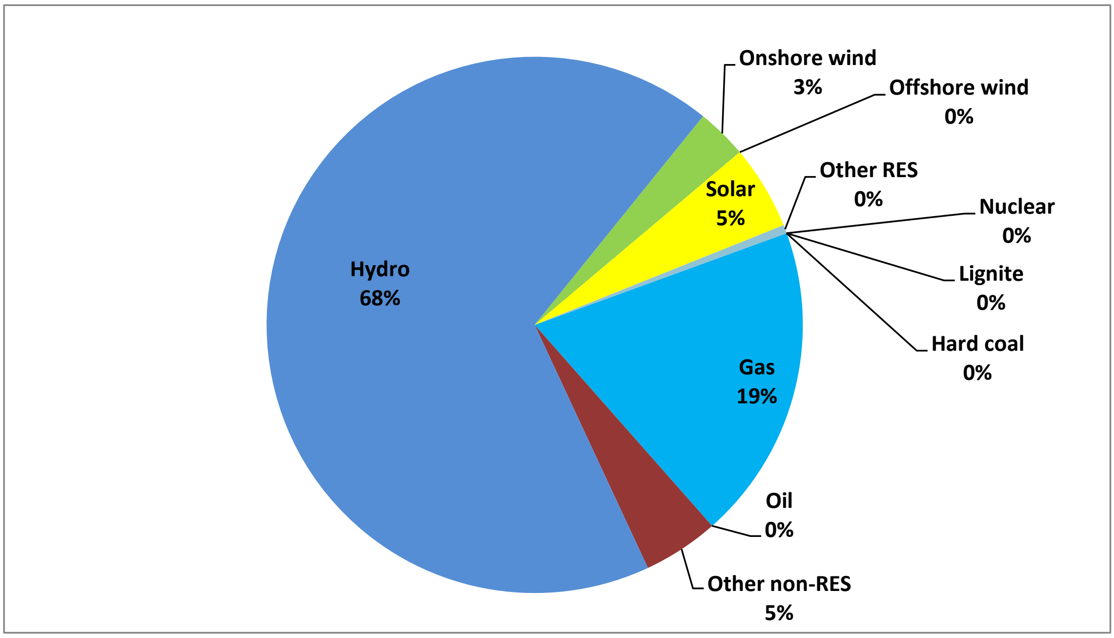


Figure 20b Generation mix (installed capacities) of Luxemburg, 2015-2016

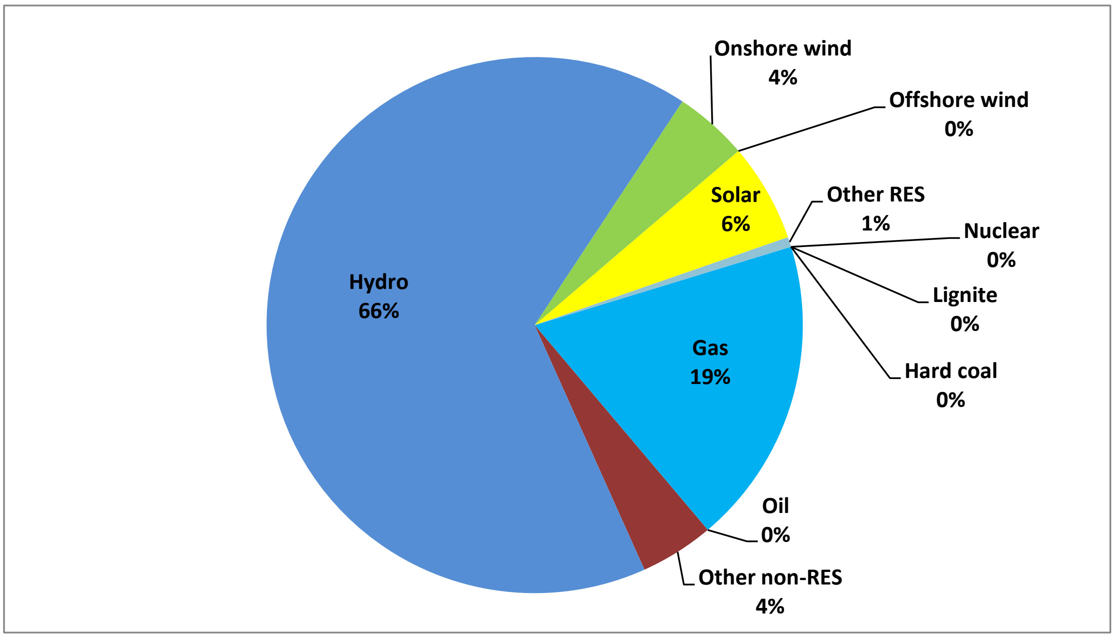


Figure 20c Generation mix (installed capacities) of Luxemburg, 2020-2021

4.2.6 Switzerland

A very dominant and important feature of the Swiss power system is the large amount of hydro power generation, which includes Run-of-River (RoR), storage and pump-storage installations. It was because of this, as well as the large amount hydro installed capacity in neighbouring countries such as France and Austria that it was decided to have a better (in comparison with status quo at ENTSO-E) probabilistic modelling of the hydrological conditions ("wet"/"dry"/"normal" years).

The decision of stopping nuclear generation (when the plants come to the end of their lifetime) has been made but the close-down of the first units will only be effectuated after year 2018, therefore the effect of the "Atomausstieg" is not (and does not need to be) analysed in the simulations for 2015/2016. For the simulation of the year 2020 a reduction of about 500 MW will be modelled.

For RES a rather optimistic increase for wind (about 100 MW in total) and solar (about 800 MW in total) was assumed for the year 2015, even though the total amount remains small for the total Swiss electricity production. As this is a general rough estimate the value of installed capacity is assumed to be the same for both years 2015 and 2016. For the year 2020/2021 the values are derived from the Swiss Federal Office of Energy's "Energieperspektive 2050", which are 420 MW for wind and 1200 MW for solar (for both years 2020 and 2021).

For the Swiss winter load it was found that there is a non-negligible temperature dependency which is now taken into account in the probabilistic modelling. However, due to limited amount of historical data (5 years) it was not possible to construct a statistical "normal" year. After some simple analysis year 2011 was chosen as the "normal" year (for load) for the inputs of the temperature sensitivity module. From the 5 years of historical data no deduction of systematic load growth was possible.

The combined heat and power (CHP) was originally modelled as a total of a few gas units (a total of around 600 MW) using partial biomass fuel for the simulations of the year 2015/2016. However the modelling approach was changed for year 2020/2021 as it was believed that the CHP operation should not be price-driven, but rather season/temperature dependent. For this an hourly profile was given and predefined instead. . For this reason, this portion in the pie-chart for gas for the year 2015/2016 appears in a different category ("Other non-RES") for the year 2020/2021.

For NTC values with the Swiss neighbours the historical average values from year 2013 for the simulation period of 2015 and 2016 were taken, since no changes are expected at the moment. For year 2020 the values which have been discussed and agreed between the different TSOs during the TYNDP 2014 process will be employed.

It should be noted that since the total installed capacity for the years 2015/2016 and 2020/2021 is different, the same percentage value does not represent the same absolute value in MW.

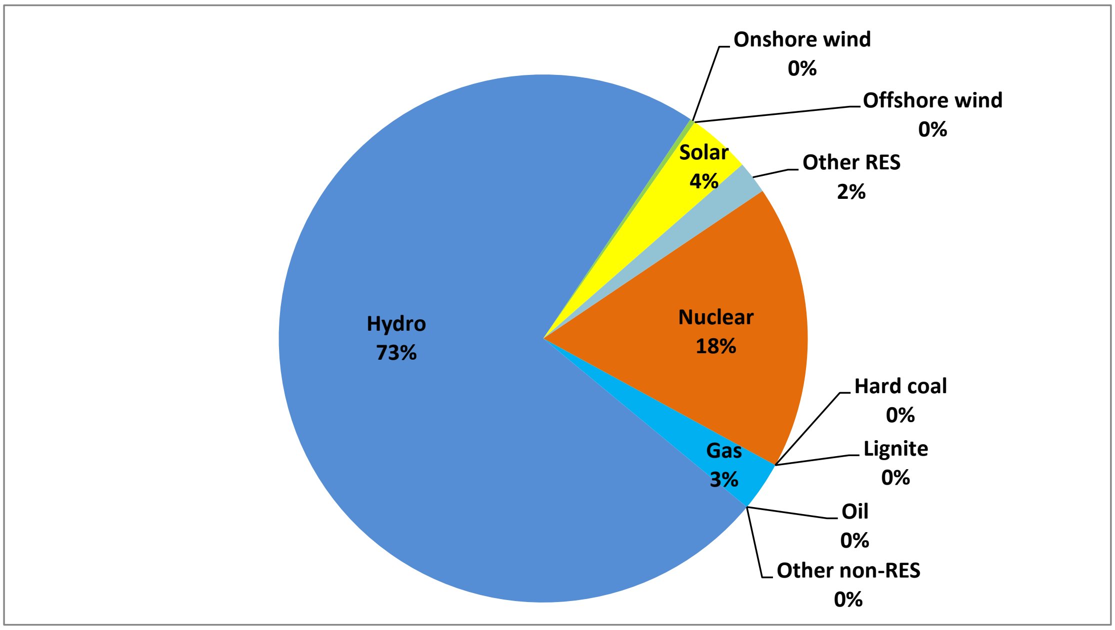


Figure 21a Generation mix (installed capacities) of Switzerland, 2015-2016

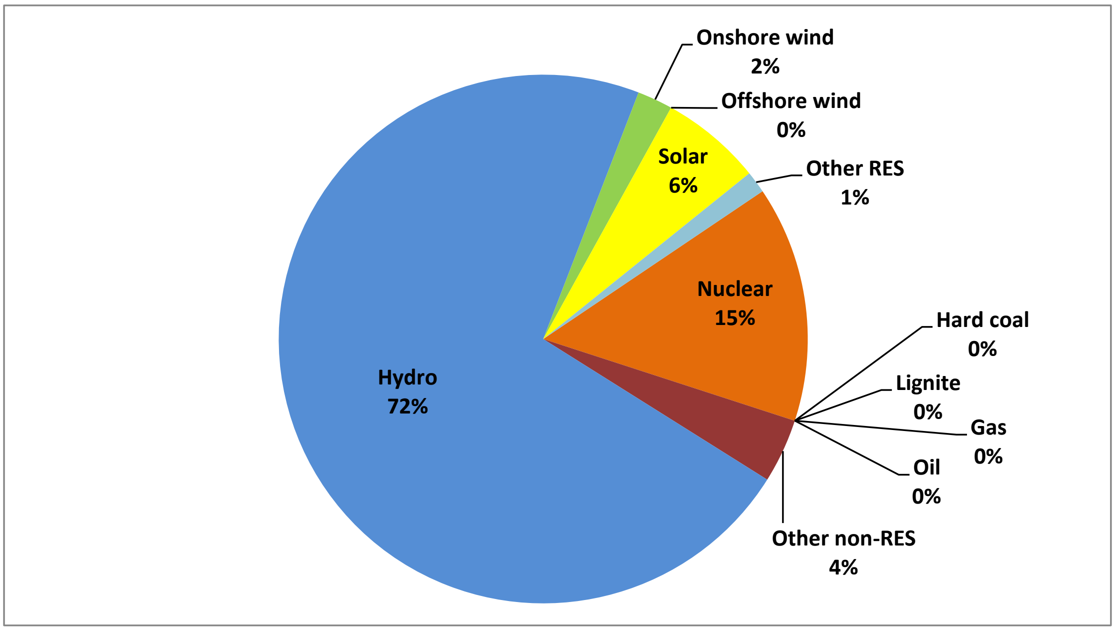


Figure 21b Generation mix (installed capacities) of Switzerland, 2020-2021

4.2.7 The Netherlands

Dutch generation data was derived from the TenneT database, which is mainly based on information from the generation companies by means of Dutch legislation for long term grid planning and monitoring security of supply; also based on information from the central Dutch governmental office of statistics (so called Centraal Bureau voor de Statistiek, CBS; www.cbs.nl) and from the Dutch renewable certificate body (CertiQ; www.certiq.nl).

The Dutch electricity market experienced a sharp decline in spark spreads causing a problem for the gas fired power plants because their profitability, indicated by the spark spread, is decreasing further. Large amounts of renewable energy in Germany also push prices downward. The Netherlands keeps importing electricity and at the same time the high efficiency gas fired power plants, which have typically been built to serve as mid load, can hardly recover any variable costs.

In the past seven years almost 11 GW thermal units have been commissioned in the Netherlands. At the same time 6 GW were decommissioned or mothballed. During the next four years another 4 GW will be taken off line including 2.6 GW of coal fired units, the latter because of a governmental energy agreement (so called 'Energie Akkoord'; www.energieakkoordser.nl). This agreement shows the ambition to install additional onshore wind capacity up to 6 GW in 2020 and licensing extra offshore wind capacity more than 4.4 GW for 2020 becoming operational in 2023.

NTC values have been derived from the annual national generation adequacy assessment in the Netherlands. NTC and thus the BTC values have been determined in cooperation with the neighbouring TSOs.

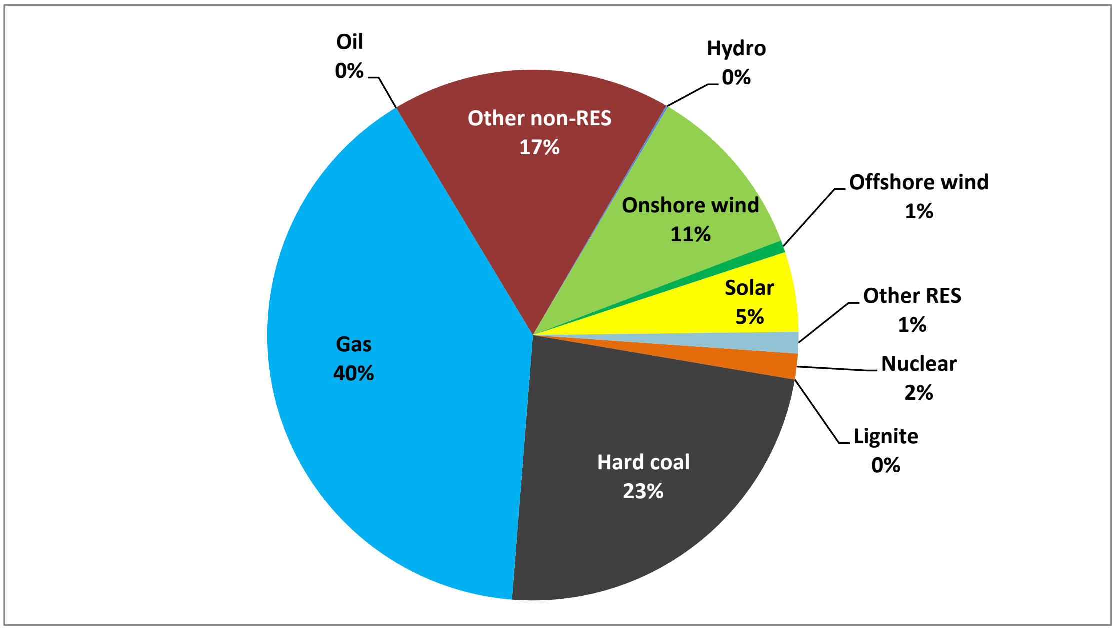


Figure 22a Generation mix (installed capacities) of the Netherlands, 2015-2016

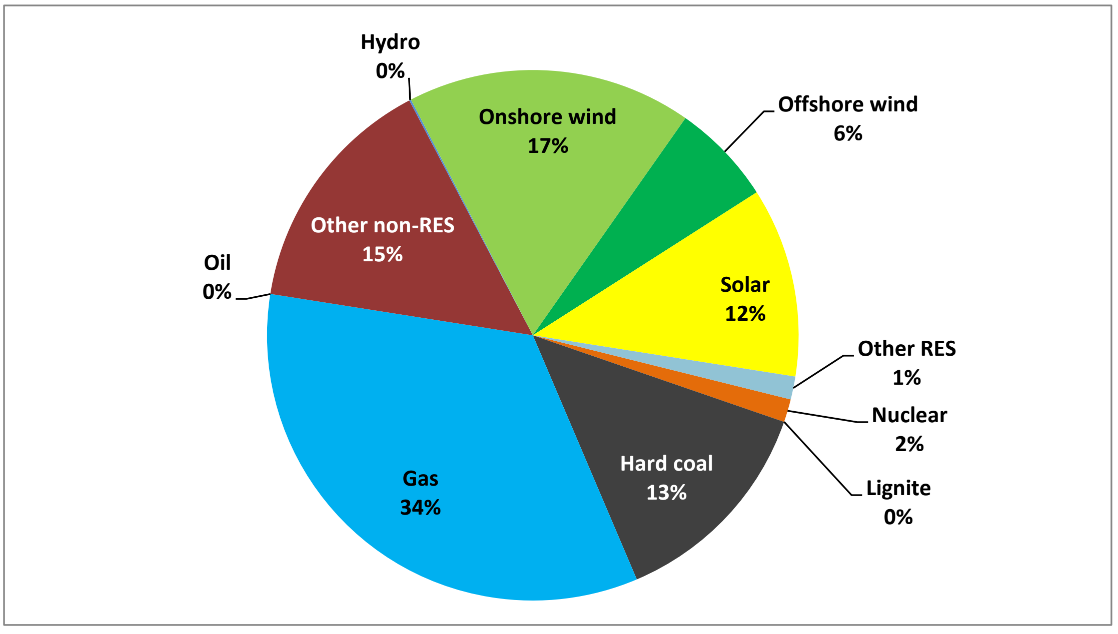


Figure 22b Generation mix (installed capacities) of the Netherlands, 2020-2021

4.2.8 Italy, Spain and Great Britain

According to the definition of the perimeter used for the PLEF study, described in paragraph 3.3.6 the pie charts generation mix based on installed capacity of the big first neighbouring countries - Italy, Spain and Great Britain - are shown

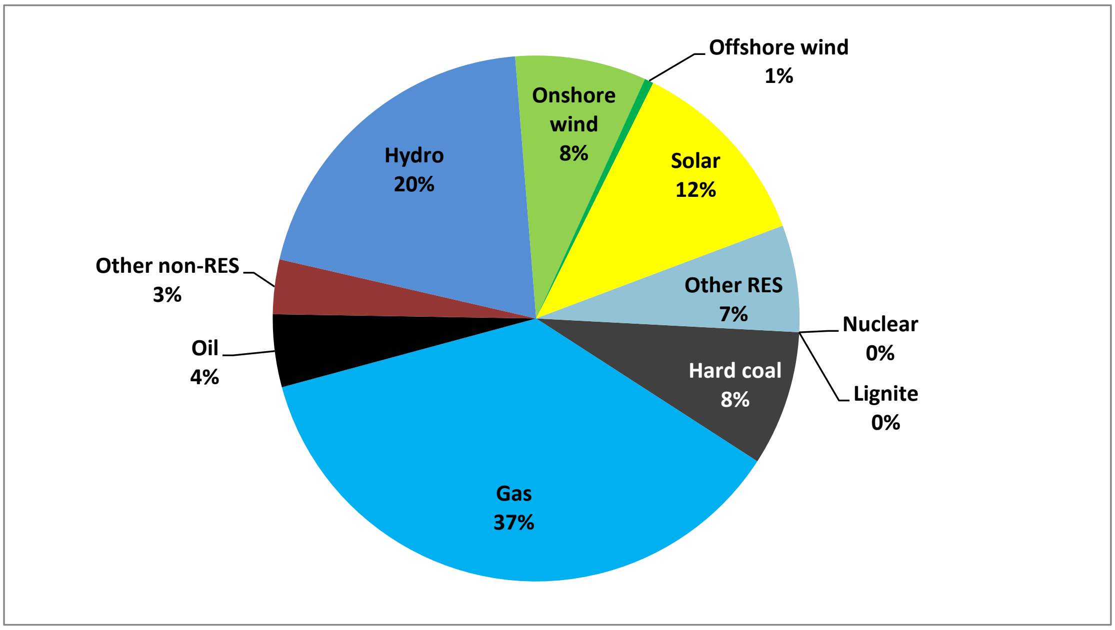


Figure 23a Generation mix (installed capacities) of Italy, 2015-2016

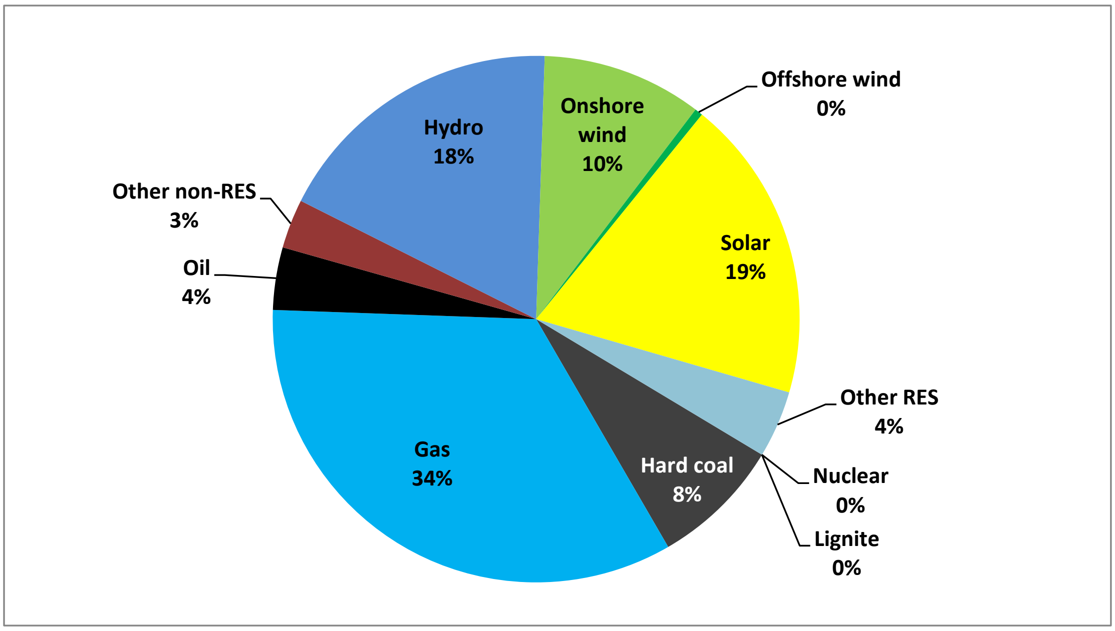


Figure 23b Generation mix (installed capacities) of Italy, 2020-2021

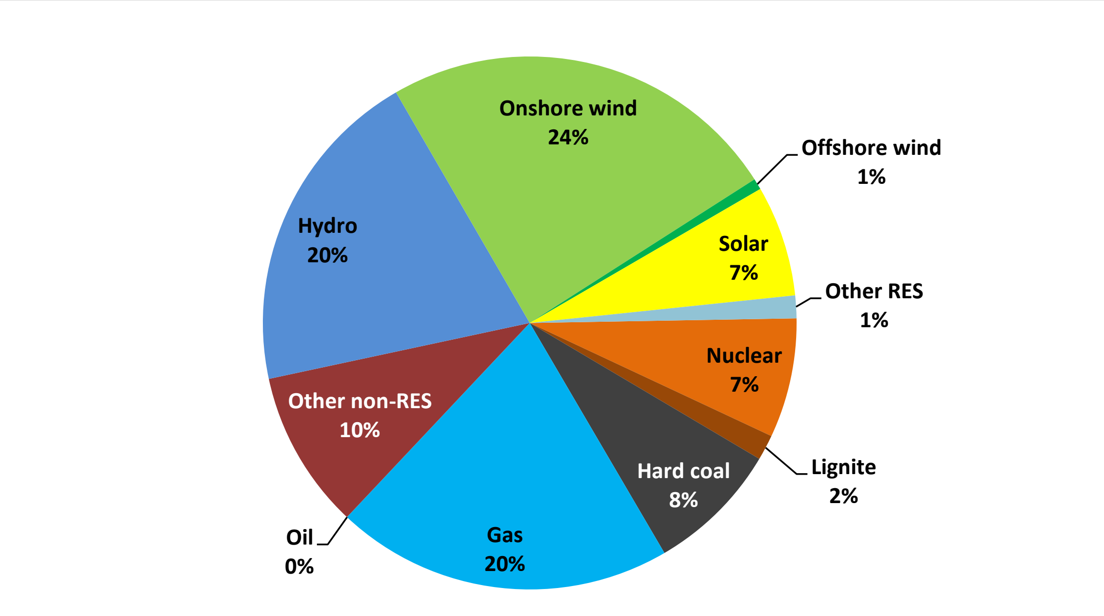


Figure 24a Generation mix (installed capacities) of Spain, 2015-2016

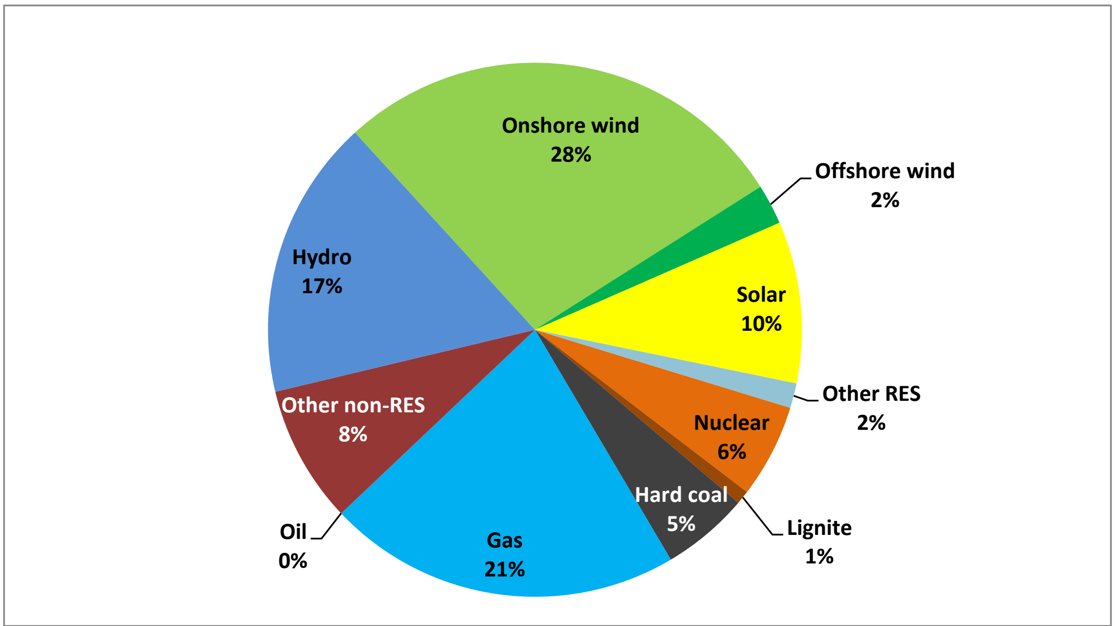


Figure 24b Generation mix (installed capacities) of Spain, 2020-2021

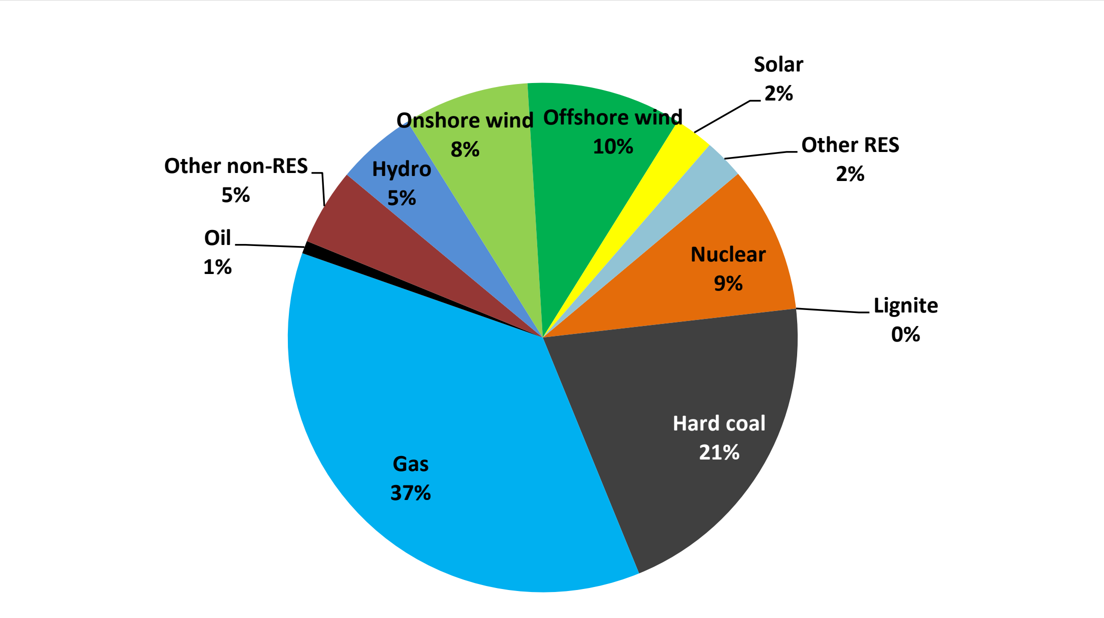


Figure 25a Generation mix (installed capacities) of Great Britain, 2015-2016

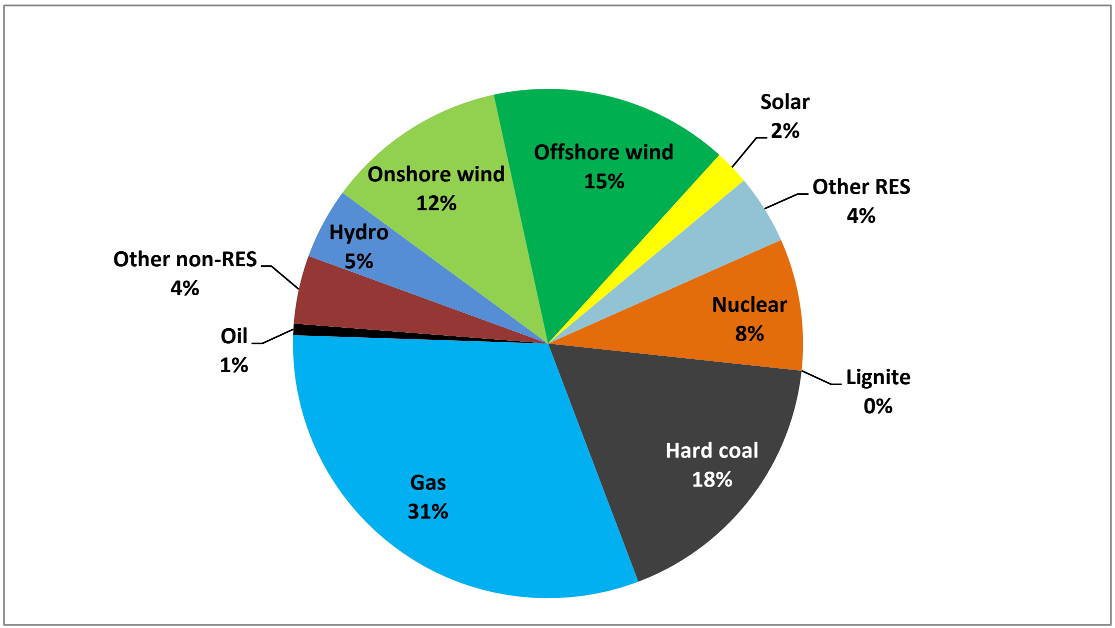


Figure 25b Generation mix (installed capacities) of Great Britain, 2020-2021

Generation capacity in GW

Country	AT	BE	FR	DE	LU	NL	CH	IT	ES	GB	TOTAL
Year	2015	2015	2015	2015	2015	2015	2015	2016	2016	2016	
Nuclear	0.000	5.060	63.130	12.068	0.000	0.486	3.308	0.000	7.590	9.366	101.008
Lignite	0.000	0.000	0.000	20.749	0.000	0.000	0.000	0.000	1.612	0.000	22.361
Hard coal	0.887	0.410	2.900	26.095	0.000	7.271	0.000	9.855	8.437	20.810	76.665
Gas	5.457	4.359	6.161	22.028	0.375	12.381	0.580	43.461	21.380	36.819	153.001
Oil	0.071	0.126	2.945	2.649	0.000	0.000	0.000	5.307	0.000	0.815	11.913
Other non-RES	0.000	2.706	4.350	5.835	0.090	5.240	0.000	3.980	10.070	4.900	37.171
Hydro	13.813	1.427	25.200	10.803	1.334	0.038	13.940	23.851	20.945	5.088	116.440
Onshore wind	2.381	1.628	9.740	36.046	0.060	3.300	0.060	9.550	25.420	8.010	96.195
Offshore wind	0.000	0.872	0.000	2.631	0.000	0.230	0.000	0.650	0.700	9.910	14.993
Solar	0.955	3.083	5.700	40.244	0.100	1.500	0.730	14.160	7.050	2.500	76.022
Other RES	0.427	1.401	1.290	6.615	0.010	0.403	0.380	7.790	1.440	2.550	22.306
TOTAL	23.992	21.072	121.416	185.762	1.969	30.849	18.998	118.604	104.644	100.768	728.074

Generation capacity in %

Country	AT	BE	FR	DE	LU	NL	CH	IT	ES	GB	TOTAL
Year	2015	2015	2015	2015	2015	2015	2015	2016	2016	2016	
Nuclear	0.0	24.0	52.0	6.5	0.0	1.6	17.4	0.0	7.3	9.3	13.9
Lignite	0.0	0.0	0.0	11.2	0.0	0.0	0.0	0.0	1.5	0.0	3.1
Hard coal	3.7	1.9	2.4	14.0	0.0	23.6	0.0	8.3	8.1	20.7	10.5
Gas	22.7	20.7	5.1	11.9	19.0	40.1	3.1	36.6	20.4	36.5	21.0
Oil	0.3	0.6	2.4	1.4	0.0	0.0	0.0	4.5	0.0	0.8	1.6
Other non-RES	0.0	12.8	3.6	3.1	4.6	17.0	0.0	3.4	9.6	4.9	5.1
Hydro	57.6	6.8	20.8	5.8	67.8	0.1	73.4	20.1	20.0	5.0	16.0
Onshore wind	9.9	7.7	8.0	19.4	3.0	10.7	0.3	8.1	24.3	7.9	13.2
Offshore wind	0.0	4.1	0.0	1.4	0.0	0.7	0.0	0.5	0.7	9.8	2.1
Solar	4.0	14.6	4.7	21.7	5.1	4.9	3.8	11.9	6.7	2.5	10.4
Other RES	1.8	6.6	1.1	3.6	0.5	1.3	2.0	6.6	1.4	2.5	3.1
TOTAL	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Generation capacity in GW

Country	AT	BE	FR	DE	LU	NL	CH	IT	ES	GB	TOTAL
Year	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	
Nuclear	0.000	5.060	63.020	8.107	0.000	0.486	2.800	0.000	7.010	9.456	95.939
Lignite	0.000	0.000	0.000	17.547	0.000	0.000	0.000	0.000	1.012	0.000	18.559
Hard coal	0.719	0.000	2.900	24.584	0.000	4.610	0.000	10.585	6.527	19.800	69.725
Gas	5.476	5.259	6.951	26.954	0.375	11.738	0.000	44.691	26.460	35.329	163.234
Oil	0.070	0.126	2.905	2.393	0.000	0.000	0.000	5.057	0.000	0.815	11.366
Other non-RES	0.000	3.235	4.150	4.636	0.090	5.130	0.760	3.980	10.300	4.900	37.181
Hydro	14.483	1.437	25.200	11.600	1.334	0.038	13.940	23.851	20.945	5.088	117.916
Onshore wind	4.200	2.589	14.090	49.246	0.090	6.000	0.419	12.950	34.300	12.980	136.864
Offshore wind	0.000	2.306	2.000	6.333	0.000	2.148	0.000	0.650	3.000	17.100	33.537
Solar	2.000	4.054	9.200	53.239	0.120	4.000	1.199	24.580	12.090	2.500	112.982
Other RES	0.427	1.705	1.380	7.370	0.012	0.485	0.260	5.430	1.850	4.960	23.879
TOTAL	27.376	25.771	131.796	212.009	2.021	34.635	19.377	131.774	123.494	112.928	821.181

Generation capacity in %

Country	AT	BE	FR	DE	LU	NL	CH	IT	ES	GB	TOTAL
Year	2020	2020	2020	2020	2020	2020	2020	2020	2020	2020	
Nuclear	0.0	19.6	47.8	3.8	0.0	1.4	14.4	0.0	5.7	8.4	11.7
Lignite	0.0	0.0	0.0	8.3	0.0	0.0	0.0	0.0	0.8	0.0	2.3
Hard coal	2.6	0.0	2.2	11.6	0.0	13.3	0.0	8.0	5.3	17.5	8.5
Gas	20.0	20.4	5.3	12.7	18.6	33.9	0.0	33.9	21.4	31.3	19.9
Oil	0.3	0.5	2.2	1.1	0.0	0.0	0.0	3.8	0.0	0.7	1.4
Other non-RES	0.0	12.6	3.1	2.2	4.5	14.8	3.9	3.0	8.3	4.3	4.5
Hydro	52.9	5.6	19.1	5.5	66.0	0.1	71.9	18.1	17.0	4.5	14.4
Onshore wind	15.3	10.0	10.7	23.2	4.5	17.3	2.2	9.8	27.8	11.5	16.7
Offshore wind	0.0	8.9	1.5	3.0	0.0	6.2	0.0	0.5	2.4	15.1	4.1
Solar	7.3	15.7	7.0	25.1	5.9	11.5	6.2	18.7	9.8	2.2	13.8
Other RES	1.6	6.6	1.0	3.5	0.6	1.4	1.3	4.1	1.5	4.4	2.9
TOTAL	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 6 Generation Capacity in the PLEF region

5 Results of the adequacy assessment

Decision makers would like to know if the system is resistant when critical situations happen and what the limits of the system are. One could for example argue that a PLEF region wide cold spell, with temperatures such as in February 2012, would be a realistic and extreme situation to assess. Therefore also this kind of extreme situation was considered.

It should be emphasized that the choice of the scenario needs to be realistic and meaningful. TSOs work with the failure criterion, e.g. LOLE>3 hours, which exists today. If deemed meaningful TSOs could work with government authorities together in order to derive new technically feasible criteria, on the national or the regional level.

Chapter 5 is divided into two subchapters. In subchapter 5.1 the results for the PLEF region and the countries for the "Base Case" applying the climate years 2001-2011 are displayed. In subchapter 5.2 the results for the different sensitivities (e.g. climate year 2012, DSM, additional mothballing) are displayed. The table below gives a summary of the results and the scenarios of the main cases that were analysed (not only the "Base Case"). The interconnected case with strategic reserves but without operational reserves is selected here as the "Base Case" (see also chapter 3.4). The "Base Case" is marked with green boxes in the table below.

2015-2016

Climate Years 2001-2011				
LOLE (h)				
OP res	WITH	WITH	NO	NO
Strat res	WITH	WITH	WITH	NO
	isolated	interc.	interc.	interc.
BE	177	0	4	42
FR	217	14	27	27
AT	0	0	0	0
CH	1251	0	0	0
DE	1	0	0	0
NL	0	0	0	0
LU	8760	0	0	0
REG	n/a	14	28	49
			„Base Case"	

Climate Year 2012				
LOLE (h)				
OP res	WITH	WITH	NO	NO
Strat res	WITH	WITH	WITH	NO
	isolated	interc.	interc.	interc.
BE	419	6	51	197
FR	369	144	180	180
AT	0	0	0	0
CH	1797	0	0	0
DE	0	0	0	0
NL	0	0	0	0
LU	8760	0	0	0
REG	n/a	144	181	224
			„Base Case"	

2020-2021

Climate Years 2001-2011				
LOLE (h)				
OP res	WITH	WITH	NO	NO
Strat res	WITH	WITH	WITH	NO
	isolated	interc.	interc.	interc.
BE	308	0	0	7
FR	151	6	10	10
AT	3	0	0	0
CH	1086	0	0	0
DE	0	0	0	0
NL	32	0	0	0
LU	8760	0	0	0
REG	n/a	6	10	17
			„Base Case"	

Climate Year 2012				
LOLE (h)				
OP res	WITH	WITH	NO	NO
Strat res	WITH	WITH	WITH	NO
	isolated	interc.	interc.	interc.
BE	277	0	0	3
FR	290	84	111	111
AT	0	0	0	0
CH	1608	0	0	0
DE	0	0	0	0
NL	30	0	0	0
LU	8760	0	0	0
REG	n/a	84	111	114
			„Base Case"	

Table 7 Overview of results: average LOLE (h) at national and regional level

5.1 Results summary

In this subchapter the results are displayed for the region and for the different PLEF countries for the "Base Case" applying the climate years 2001-2011. These results are based on Antares simulations. It should be noted that it does not imply this is a regional or European standard and indeed other national studies can and do have different base case settings.

The regional LOLE shows that quite often adequacy problems occur simultaneously as the sum of the national values is bigger, especially for the year 2015/2016, in which both France and Belgium would expect significant LOLE.

To facilitate a good overview and a better readability the results for the different countries are displayed on one page per country using a similar layout in the next sections.

The results shown in the next sections for the whole region and the individual countries start with a table containing the average value for "Loss Of Load Expectation" (LOLE) and the corresponding "Energy Not Served" (ENS) value. These adequacy indicators are described in more detail in section 3.6 (Adequacy indicators). Furthermore the P95 values for LOLE and ENS are given in the table for each country. The P95 values represent the value of the 95 percentile, meaning the value of LOLE or ENS close to the highest value over all simulations. More concretely this means, in case of 220 simulations, there will be 220 different values of LOLE/ENS, the P95 value would be the 12th highest of all LOLE/ENS values. In other words, 11 values for LOLE/ENS are higher than the P95 value, and 208 LOLE/ENS values are lower than the P95 value.

Below the LOLE/ENS-table two graphs showing the "Remaining thermal availability" (RC) are shown. The first one consists of 220 points, one for each Monte Carlo year simulated. The value of the remaining thermal capacity (given on the x-axis) corresponds to the lowest RC value (occurring in one hour) during the simulation. On the y-axis the corresponding percentile of the Monte Carlo year simulated is given.

The second RC-graph gives the hourly minimum, maximum and the corresponding average value for RC occurring over all simulations performed. Those results come from an economical optimization and a low RC does not necessarily mean that the country has problems as a country that exports will use more of its generation capacity than a country that imports (therefore what remains for itself is less in an exporting country). A zero RC value means that all the available capacity of the country is in operation but there are still imports and hydro (if available) that can be used in order to meet the load.

In case LOLE is not equal to zero the graph for the Loss Of Load Probability (LOLP) is also given (please refer to section 3.6 "Adequacy indicators" for detailed description of this or the other indicators).

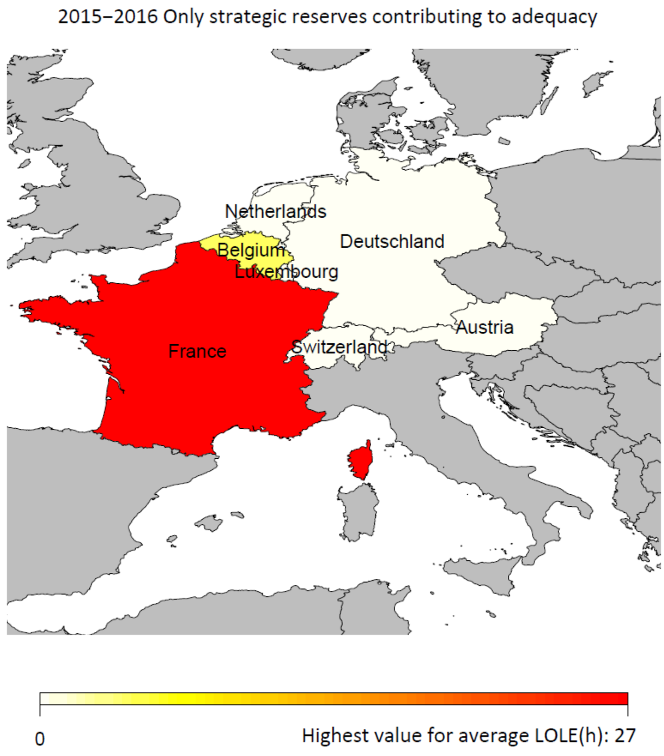
On the regional level a map with colour showing the intensity of the problem based on LOLE is shown.

5.1.1 PLEF Region results reporting

In this section the results for the whole PLEF Region for the different years are reported.

5.1.1.1 PLEF Region (2015-2016)

For the base case (interconnected with strategic reserves without operational reserves) study, situations where demand is not met are only expected to occur in France and Belgium.



Main Results at the Regional Level (Operational reserves not contributing to Adequacy)			
LOLE (h)	**LOLE (h)**	**ENS (GWh)**	**ENS (GWh)**
Average	**P95**	**Average**	**P95**
28	121	114	680

Figure 26 Graphical and numerical representation of regional results for year 2015/2016

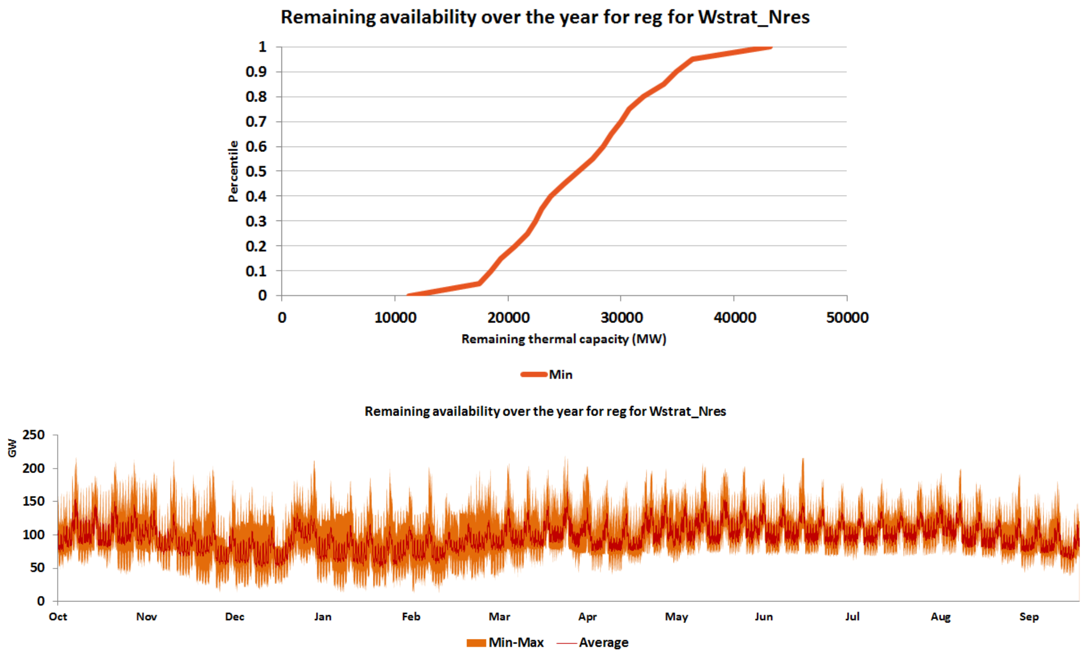
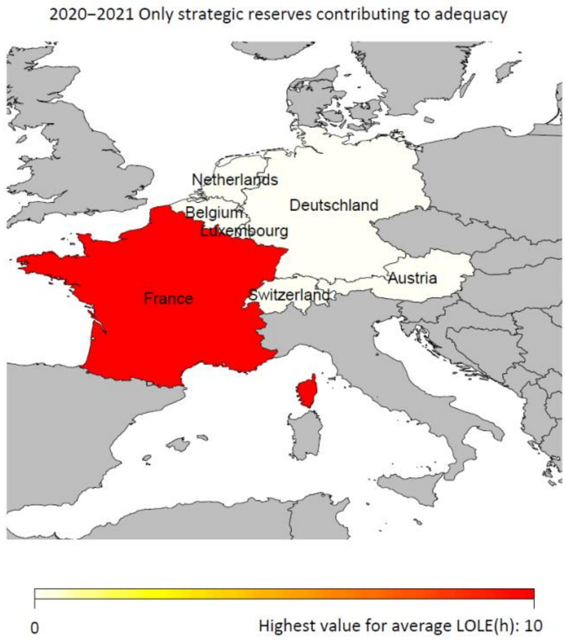


Figure 27 Graphical representations (yearly and hourly) of regional remaining capacity for year 2015/2016

It should be noted that the regional capacity charts could only give a rough idea of the available remaining capacity in the whole region because the restriction of international exchange is not reflected in these figures. It would also mean that the effective generation capacity is less than what is shown. The actual available generation capacity would depend on where the exchange should take place and how much import/export transmission capacity is available at that point of time.

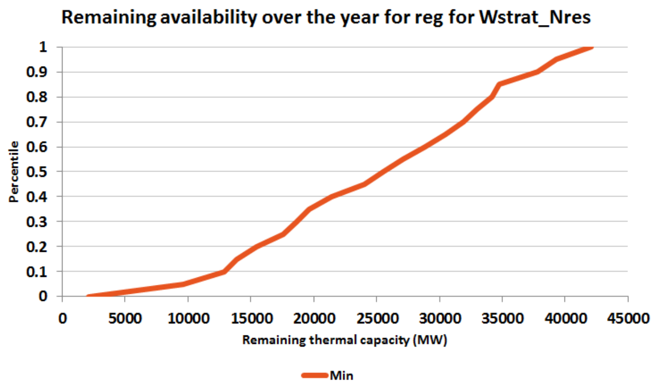
5.1.1.2 PLEF Region (2020-2021)

For the base case (interconnected with strategic adequacy reserves without operational reserves) study, situations where demand is not met are only expected to occur in France. Therefore the values at the regional level are exactly the same as those for France.



Main Results at the Regional Level (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
10	42	30	116

Figure 28 Graphical and numerical representation of regional results for year 2020/2021



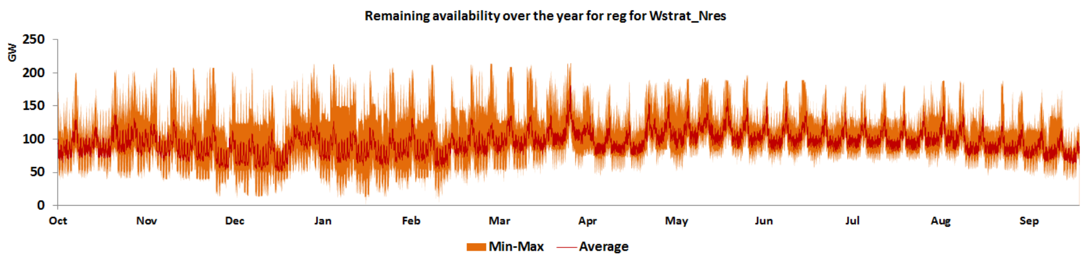


Figure 29 Graphical representations (yearly and hourly) of regional remaining capacity for year 2020/2021

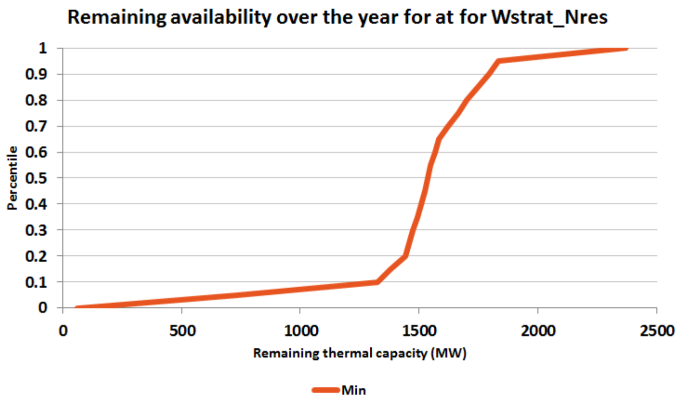
The figures of remaining capacity for the year 2020/2021 resemble those for the year 2015/2016, with slightly less in year 2020/2021. However, all in all here are less regional adequacy issues numerically, probably because of the increase of import/export capacity (NTC).

5.1.2 Results reporting for PLEF countries (2015/16 and 2020/21)

In the following sections the results of the individual countries are reported for the base case, for the year 2015/2016 and the year 2020/2021.

5.1.2.1 Austria (2015-2016)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
0	0	0	0



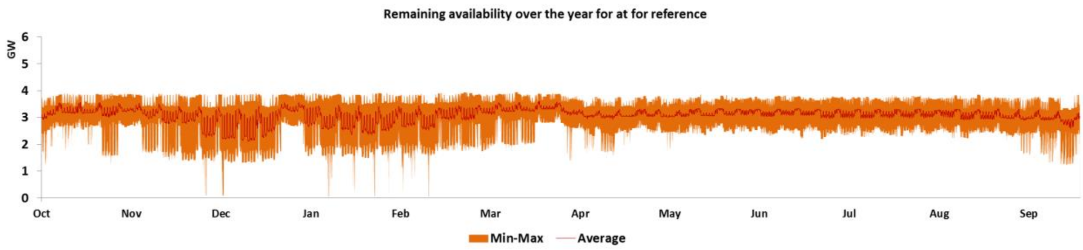


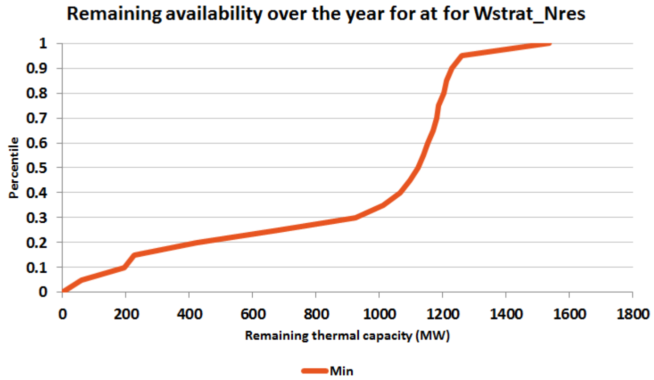
Figure 30 Individual country results for year 2015/2016: Austria

For the 2015/2016 base case scenario zero loss of load hours were calculate in the probabilistic run for Austria. The graphs concerning remaining capacities show how Austrian thermal power plants were utilised during all simulated hours in the 220 Monte Carlo years. The spikes of low remaining capacities can be explained by rare combinations of input parameters (outages, maintenance …) which happen only in one hour out of the 220 Monte Carlo years.

In general the results show enough remaining thermal capacities for the 2015/2016.

5.1.2.2 Austria (2020-2021)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
0	0	0	0



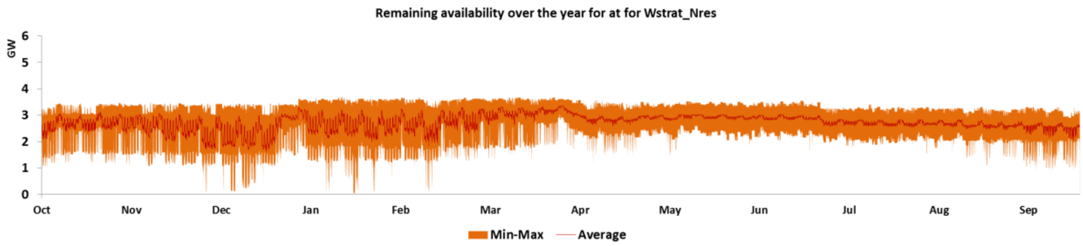


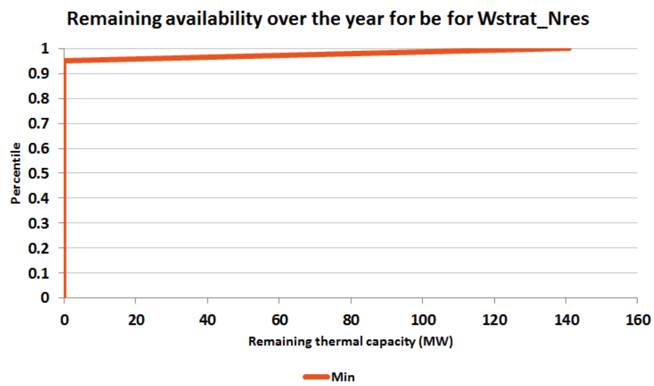
Figure 31 Individual country results for year 2020/2021: Austria

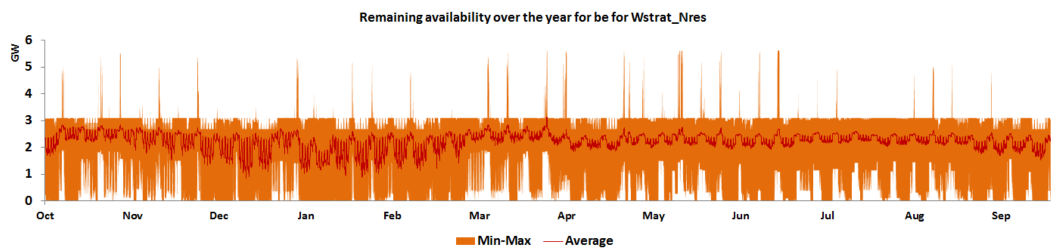
As in the scenario 2015/2016 also in this scenario zero hours losses of load were calculated in the simulation process. Compared to the results 2015/2016 the remaining capacity is lower which is explained by higher load for 2020/2021 and less thermal capacities. (Difference between 2015/2015 and 2020/2021: shutdown of hard coal power plant Riedersbach 168MW)

The results also show that thermal power plants are operated with higher utilisation rates compared to scenario 2015/2016.

5.1.2.3 Belgium (2015-2016)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
4	24	3	15





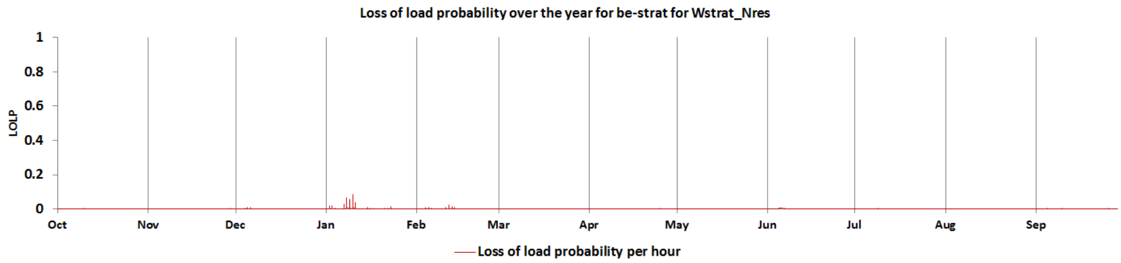
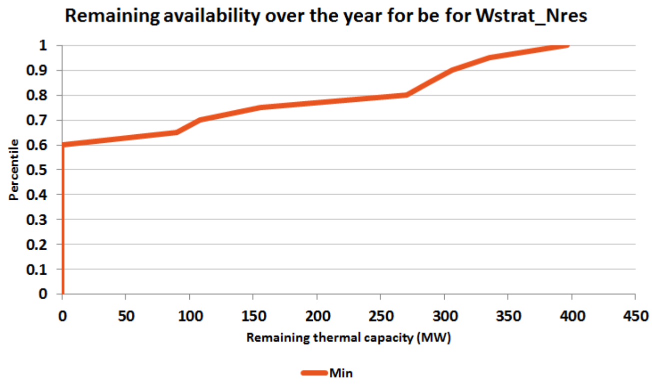


Figure 32 Individual country results for year 2015/2016: Belgium

The results are in line with the adequacy analysis performed by Elia in March 2014 for 2015/2016. The national report contains an estimation of the volume needed in strategic reserves in order to meet the adequacy criteria for Belgium (LOLE<3h in average case and LOLE<20h in P95). This estimation of the strategic reserves is used in the input data for the PLEF study, so a LOLE around 3h in average condition and 20h in exceptional condition (P95) was expected. There are some small changes in the input data and way of modelling that can explain the small difference in the results.
The volume that is used in the study is an estimation that is not yet decided by the Minister. This volume can be increased to lower the adequacy risks for Belgium or decreased in case more risk is taken.

5.1.2.4 Belgium (2020-2021)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
0	0	0	0



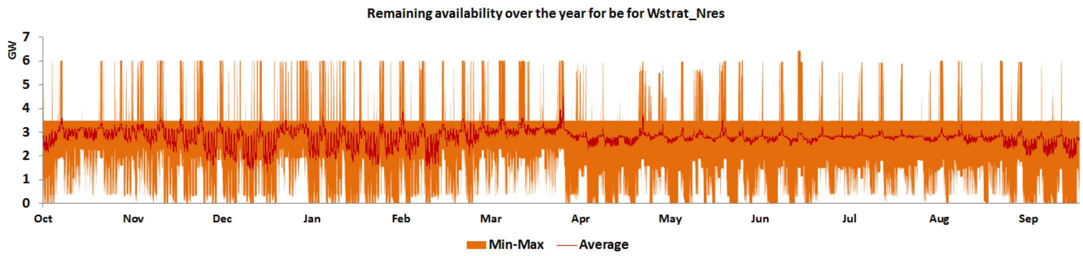
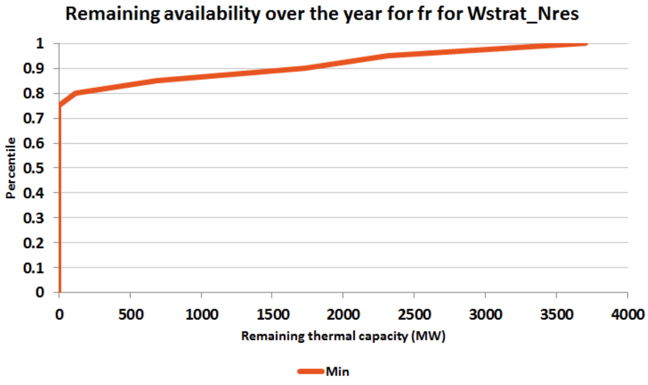


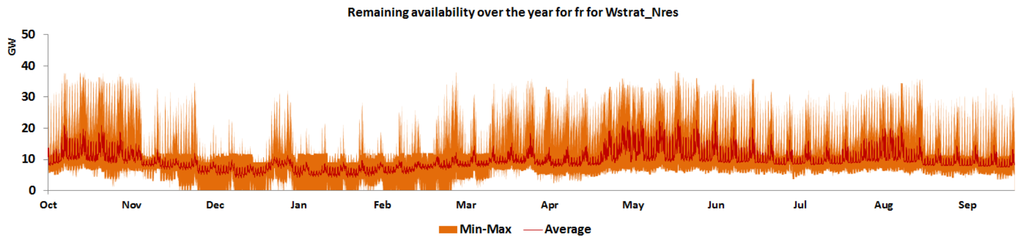
Figure 33 Individual country results for year 2020/2021: Belgium

The adequacy analysis performed by Elia in March 2014 contains no results for 2020/2021. Since no estimation is available for 2020/2021, it was decided to use the estimation from the national report for the latest available year 2016/2017. This covers a small increase of the level of strategic reserves compared to 2015/2016. In combination with an increase in the installed capacity of the renewable energy sources, an additional 800MW of generation units (tender) and an increase of the exchange capacities with neighbouring countries this leads to a situation for Belgium that is no longer critical.
The volume that is used in the study is an estimation that is not yet decided by the Minister. This volume can be increased to lower the adequacy risks for Belgium or decreased in case more risk is taken.

5.1.2.5 France (2015-2016)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	**LOLE (h)**	**ENS (GWh)**	**ENS (GWh)**
Average	**P95**	**Average**	**P95**
27	120	111	674





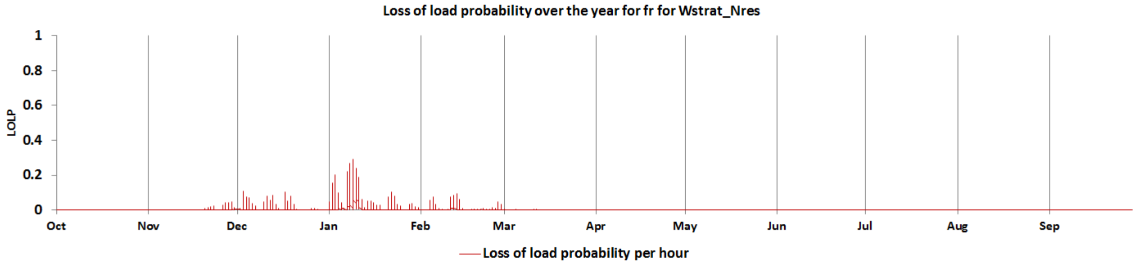


Figure 34 Individual country results for year 2015/2016: France

For 2015/2016, adequacy criterion required by the French law (<3h) is not met. Qualitatively, these results are consistent with the French generation adequacy study which shows that capacity shortfall appears for winter 2015/2016 because of the decommissioning of coal and oil units following the implementation of the Industrial Emission Directive LCPD/IED in January 2016.

5.1.2.6 France (2020-2021)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
10	42	30	116

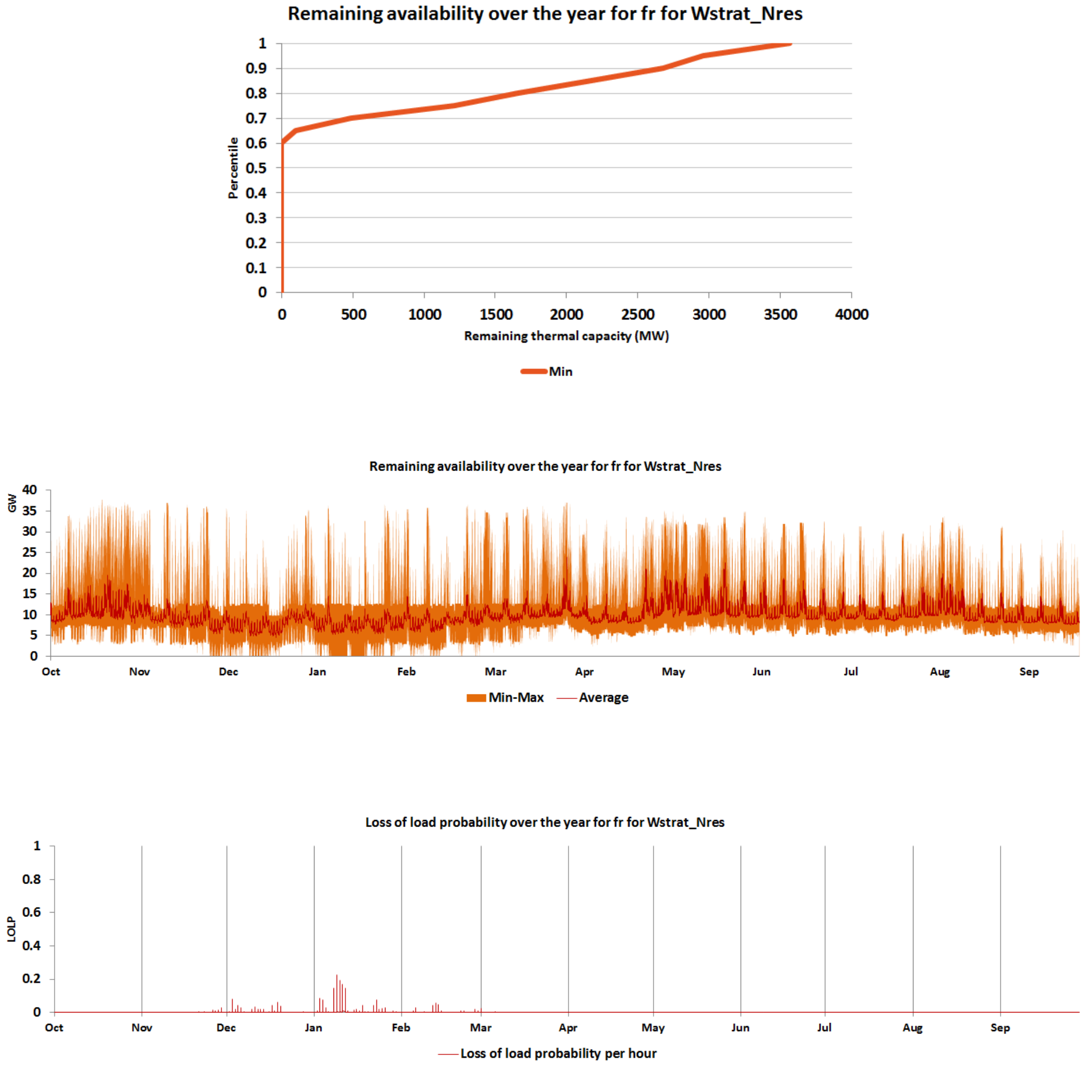
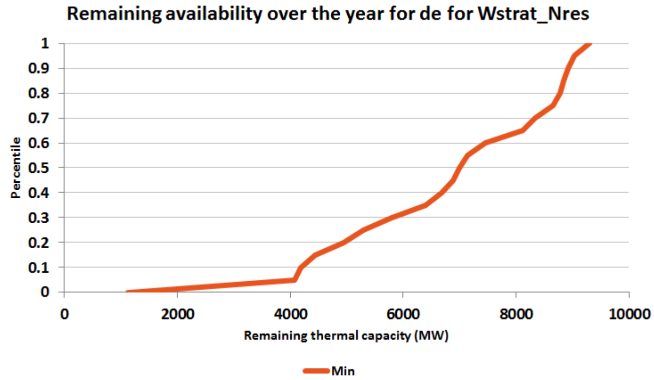


Figure 35 Individual country results for year 2020/2021: France

For 2020-2021, situation is less critical than in 2015-2016 as foreseen in the French generation adequacy study. Indeed, additional generation capacities in France (commissioning of new gas units and new nuclear power plant in Flamanville, connection of new onshore and offshore farms) combined with the increase of exchange capacities with neighbouring countries reduce the risk of shortfall in France.

5.1.2.7 Germany (2015-2016)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
0	0	0	0



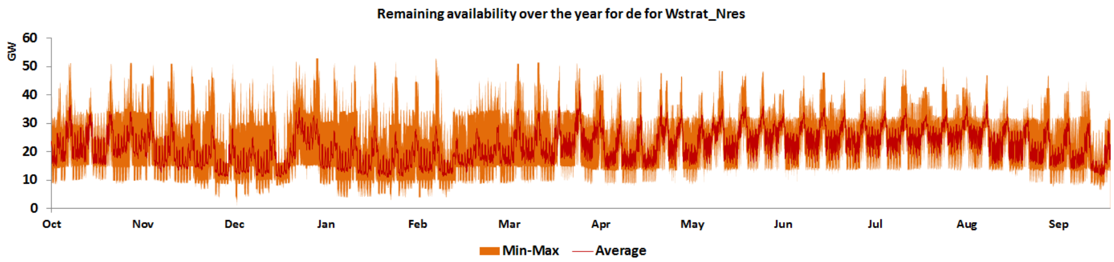


Figure 36 Individual country results for year 2015/2016: Germany

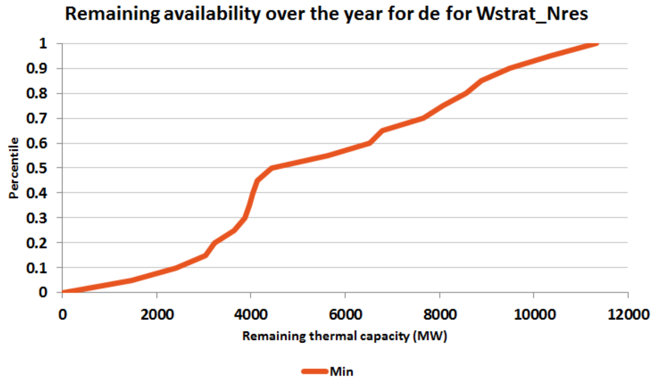
For the 2015/16 base case simulation no loss of load can be observed for Germany. Therefore the values of the adequacy indicators used in this report (LOLE, ENS and LOLP) are equal to zero.

The remaining available thermal capacity (or remaining availability, RC) is equal to 7GW or higher for 50% of all simulations (110 Monte Carlo Years). For 70% of all simulations (154 Monte Carlo Years) it is equal to 6GW or higher. The lowest values for RC can be observed at the beginning of December, during January and the beginning of February. On average the value for the RC is higher than 10GW for all Monte Carlo Simulations conducted.

In general the results show sufficient remaining availability for thermal capacities in Germany. Even if not analysed more in depth – and apart from the adequacy indicators – the graph of remaining availability hints towards a moderate utilization of conventional thermal units.

5.1.2.8 Germany (2020-2021)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
0	0	0	0



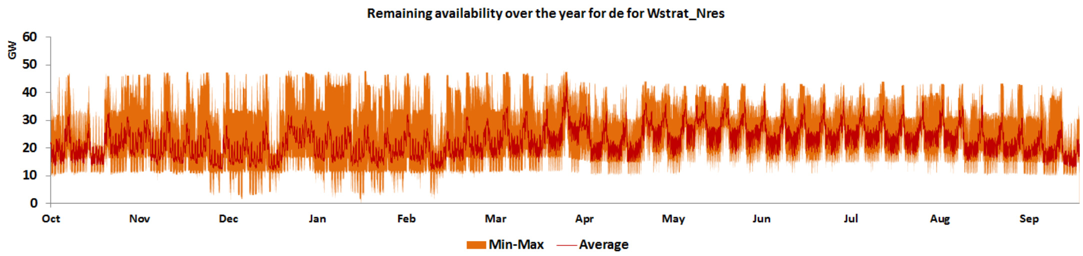


Figure 37 Individual country results for year 2020/2021: Germany

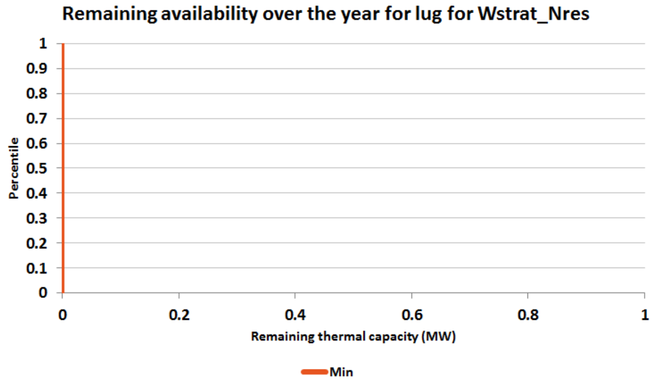
With a loss of load expectation of 0 hours (and thus Energy Not Served (ENS) 0 GWh) results for the adequacy indicators are still analogous to the simulation for 2015-2016. However, the graph representing the remaining thermal capacity changes to a certain extent.

The remaining available thermal capacity (or remaining availability, RC) is equal to 4GW or higher for 70% of all simulations (154 Monte Carlo Years). The lowest values for RC can again be observed at the beginning of December, during January and the beginning of February. On average the value for the RC is higher than 10GW for all Monte Carlo Simulations conducted.

Whilst the results have not been scrutinized in depth, the simulation approach suggests that the phase-out of nuclear units (ca. 4 GW less than in 2015/16) with high utilization rates requires more contribution from other energy sources. In addition or as an alternative to conventional generation, Demand Response may play a larger role in future adequacy considerations.

5.1.2.9 Luxembourg (2015-2016)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
0	0	0	0



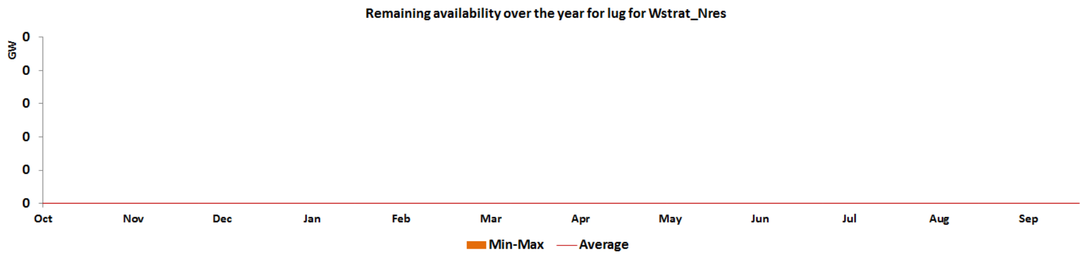


Figure 38 Individual country results for year 2015/2016: Luxembourg

The transmission network covering the whole country is connected to and supplied from the German transmission network. This public network is operated by Creos Luxembourg and supplies the main part of the total load. In the different graphs and tables the figures refer to this public load LU (or LUg). An additional parallel industrial network operated by Sotel in the South of Luxembourg is connected to and supplied from Belgium and RTE . The networks of Creos and Sotel are not interconnected.

For the period 2015-2016, the grid transfer capacity with the German grid is rather high meaning that the calculated LOLE and ENS are equal to the values calculated for the German grid. Nevertheless the results for the load connected to the industrial grid linked to the Belgian and France grid are the same as for the rest of the French and Belgian load.

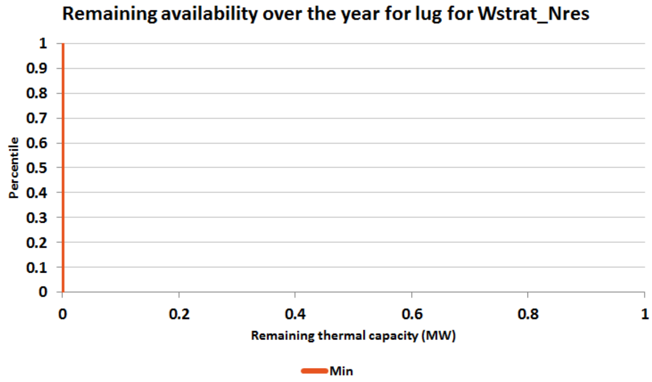
For the period 2020-2021, the public grid operated by Creos Luxembourg will be interconnected with the Belgian grid.

The LOLE and ENS values calculated for the isolated case are theoretical values for a hypothetical case. As Luxembourg has a strong interconnection with Germany, the public load is mainly connected to the German grid and expects a LOLE of 0.

For the period 2015-2016, the CCGT power plant located in the south of Luxembourg is taken into account in the strategic reserve for Belgium. This power plant will be switched to the public grid operated by Creos in 2018 and will thus run in the German Market.

5.1.2.10 Luxembourg (2020-2021)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
0	0	0	0



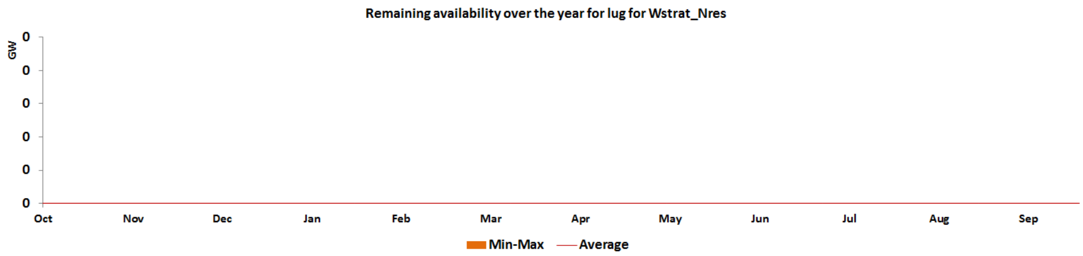
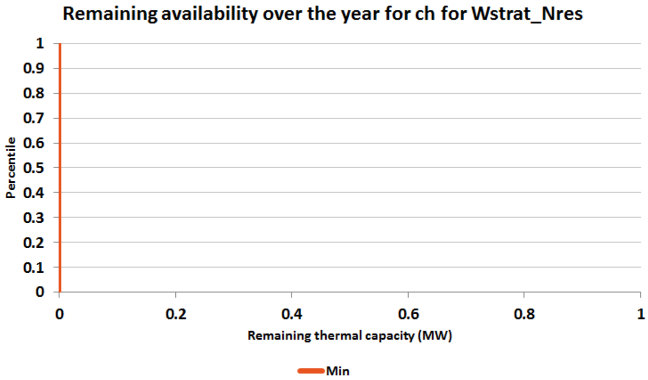


Figure 39 Individual country results for year 2020/2021: Luxembourg

The description for the year 2015/2016 applies for the year 2020/2021.

5.1.2.11 Switzerland (2015-2016)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
0	0	0	0



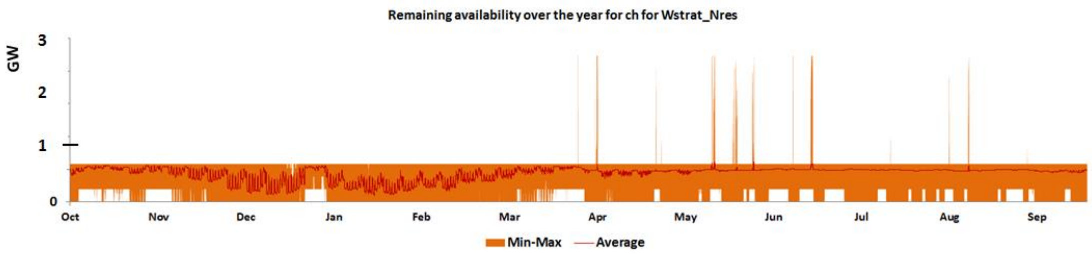
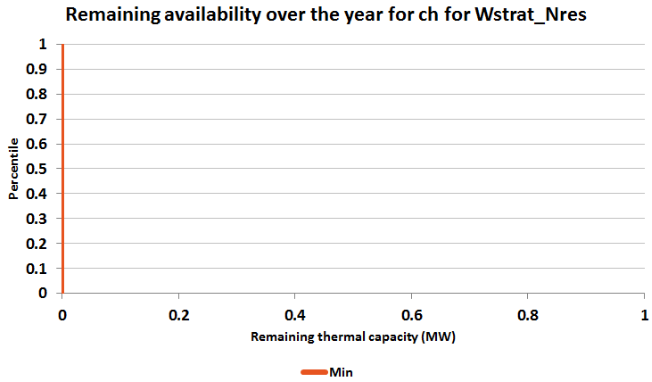


Figure 40 Individual country results for year 2015/2016: Switzerland

It should be noted that because of the sufficient network capacity with neighbouring countries having sufficient production capacities, despite the energy deficit in winter, Switzerland does not expect ENS or LOLE in the short to mid-term. Minimum remaining capacity is almost always (orange band often touching zero in the last diagram above) zero because hydro plants are always despatched in an open exchange market due to their zero marginal costs. And the reliable capacity coming from thermal plants is not always enough to cover the load. This also means that in times when there is excessive energy production in Switzerland, i.e. summer, it is simply exported and cannot be recorded in this graph.

5.1.2.12 Switzerland (2020-2021)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
0	0	0	0



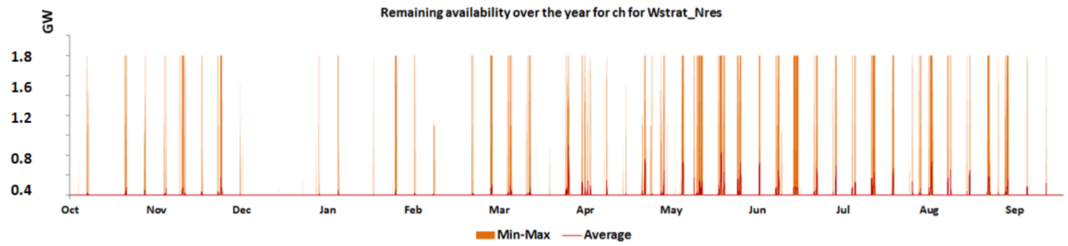
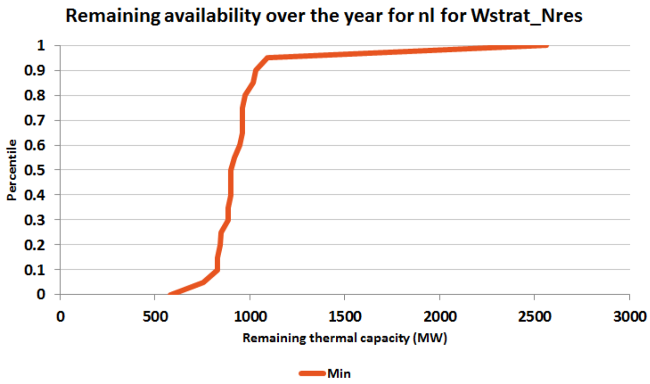


Figure 41 Individual country results for year 2020/2021: Switzerland

The description on the Swiss results for the year 2015/2016 generally applies also for the year 2020/2021, with the additional remark that because of the phase-out of the 500 MW nuclear unit the average remaining capacity will be reduced, while minimum remaining capacity is also zero most of the time due to high cross-border exchanges. However, because of the strong connection with the neighbours, the expected LOLE or ENS will stay at the minimum level of zero.

5.1.2.13 The Netherlands (2015-2016)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
0	0	0	0



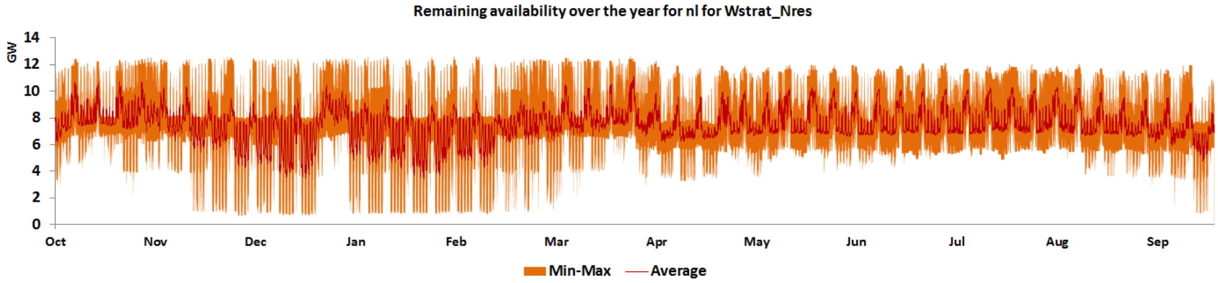
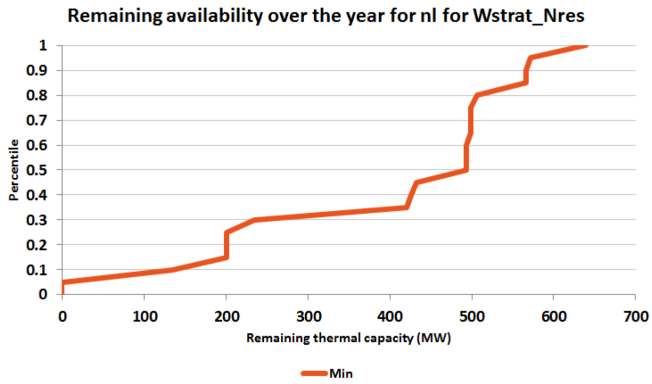


Figure 42 Individual country results for year 2015/2016: The Netherlands

For 2015/2016, the adequacy criterion of a LOLE of 4h is met. The Netherlands does not expect ENS or LOLE in the short to mid-term. When taking into account the decommissioning of the oldest coal units, based on the governmental Energy Agreement, the adequacy criterion of 4h will be met. Qualitatively, these results are consistent with the Dutch generation adequacy study ("Monitoring Leveringszekerheid").

5.1.2.14 The Netherlands (2020-2021)

Main Results (Operational reserves not contributing to Adequacy)			
LOLE (h)	LOLE (h)	ENS (GWh)	ENS (GWh)
Average	P95	Average	P95
0	0	0	0



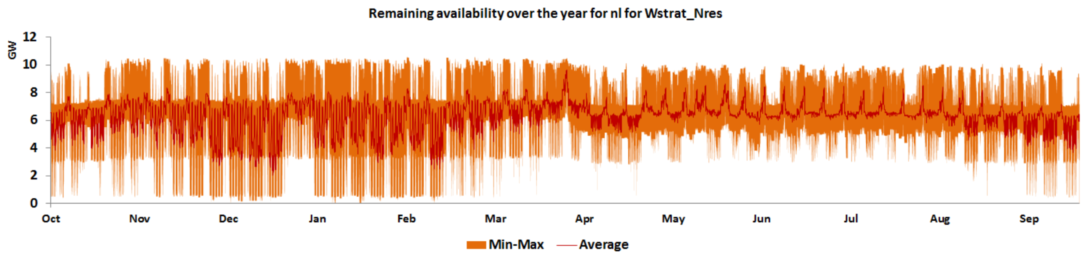


Figure 43 Individual country results for year 2020/2021: The Netherlands

The description on the Dutch results for the year 2015/2016 generally applies also for the year 2020/2021. The average remaining capacity will be greatly reduced because of the mothballing of some gas-fired units (400 MW) and the decommissioning of some of the older coal units (1050 MW) in the mid-term, the latter based on the governmental Energy Agreement. The adequacy criterion of 4h will still be met.

5.2 Sensitivity analysis

In this subchapter the results for the years 2015/2016 and 2020/2021 for the different sensitivities are reported. In section 5.2.1 the sensitivity regarding the usage of different types of reserves (operational and strategic) are compared for 2015/2016 and 2020/2021. In section 5.2.2 the results for the climate year 2012 are displayed. Section 5.2.3 shows the results in case all countries are isolated, section 5.2.4 describes the impact of decommissioning uncertainty with an example in Belgium and section 5.2.5 elaborates on the importance of demand side response with an example in France.

5.2.1 Reserves contribution to adequacy

During the input data gathering for the countries in the PLEF region data on operational (AT, CH, BE, DE, NL, FR, LU) and strategic reserves (BE, DE) are collected. A sensitivity analyses is performed regarding the usage of the operational and strategic reserves.

In the base case simulations the operational reserves are not taken into account while the strategic reserves are taken into account. This prudent approach is applied in the national generation adequacy reports for Belgium and France. This approach is preferred in order to identify possible risks of shortfall while ensuring enough reserve margins to deal with unanticipated emergencies.

Extra simulations are performed to show the impact of taking out the strategic reserves. This leads to more pessimistic results and shows the need for this extra reserve capacity. On the other hand, including operational reserves would lead to optimistic results, but would not provide signals for problems on time, since the operational reserves are also used for adequacy problems and not just only for system imbalance.

In the following subsections only the results for countries showing differences in comparison to the base case are shown.

5.2.1.1 With operational reserves (2015/16 and 2020/21)

With operational reserves, LOLE decreases in France and Belgium. For Belgium the LOLE even drops to 0h. In France the situation improves but is still above the adequacy criterion of LOLE<3h.

For 2020/2021, with operational reserves, LOLE decreases in France and Belgium but is still above the adequacy criterion of LOLE<3h.

Operational reserves or system reserves are used in practice to keep the system frequency at 50Hz at real time. The different types of reserves, primary, secondary and tertiary, will come into the system at different time frames and with different durations. Therefore, in principle they are different from the "adequacy" reserves described in this study which are used and applied for shortages which are detected and employed much more in advance. However, once all measures are exhausted (e.g. after load shedding), operational reserves will be employed for real time adequacy purposes. Therefore even though they are not meant for "adequacy" purposes, they are the last resort to keep the supply and the demand balanced in real time.

Interconnected case for winter 2015-2016					
		LOLE (h)		**ENS (GWh)**	
		Average	**P95**	**Average**	**P95**
BE	**With Op. Res**	**0**	**0**	**0**	**0**
	Without	**4**	**24**	**3**	**15**
FR	**With Op. Res**	**14**	**79**	**54**	**395**
	Without	**27**	**120**	**111**	**674**

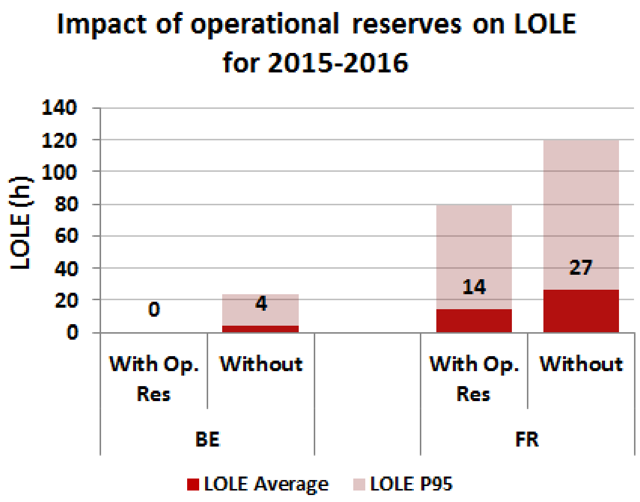


Figure 44 Sensitivity results: impact of operational reserves for year 2015/2016

Interconnected case for winter 2020-2021					
		LOLE (h)		ENS (GWh)	
		Average	P95	Average	P95
BE	With Op. Res	0	0	0	0
	Without	0	0	0	0
FR	With Op. Res	6	27	15	65
	Without	10	42	30	116

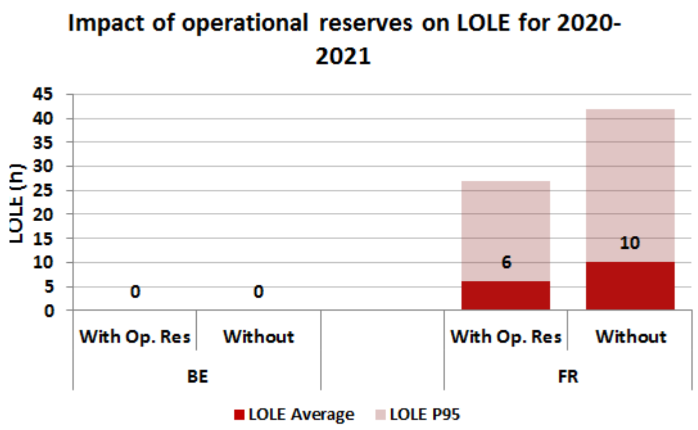


Figure 45 Sensitivity results: impact of operational reserves for year 2020/2021

5.2.1.2 Removal of both strategic and operational reserves (2015/16 and 2020/21)

The only country affected in case both strategic and operational reserves are removed is Belgium.

Impact of strategic reserves on Belgian adequacy					
		LOLE (h)		ENS (GWh)	
		Average	P95	Average	P95
BE	With strategic res.	4	24	3	15
	Without	42	133	46	161

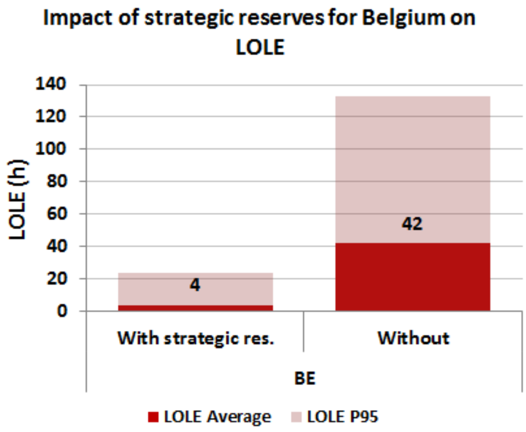


Figure 46 Sensitivity results: impact of all reserves for year 2015/2016

Impact of strategic reserves on Belgian adequacy					
		LOLE (h)		ENS (GWh)	
		Average	P95	Average	P95
BE	With strategic res.	0	0	0	0
	Without	7	27	5	25

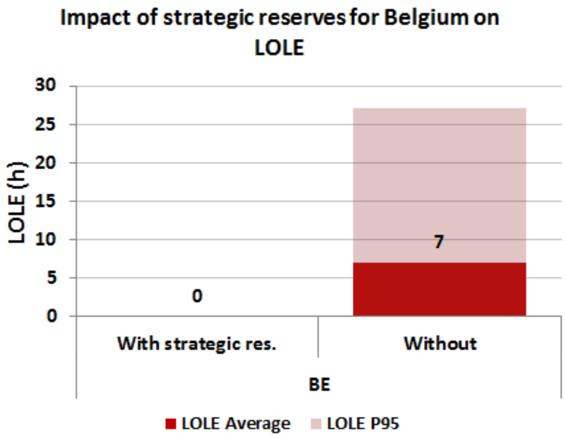


Figure 47 Sensitivity results: impact of all reserves for year 2020/2021

The results for Belgium are in line with the results communicated in the national adequacy report. Based on the national report the Minister confirmed the need for strategic reserves in Belgium and decided upon a volume for 2014/2015. The volume for 2015/5016 will be confirmed by January 2015.

5.2.2 Results 2012 climate year for 2015/16 and 2020/21 simulations

One of the advantages of the method used for this study is the inclusion of thermo sensitivity of load. Therefore temperature gradients and thresholds were calculated based on historical data for each PLEF country. Temperature data for 2012 were not used for this calculation as 2012 is an outlier year in terms of temperature. In February 2012 an extreme cold spell which affected a wide area lasted for about two weeks. Further analyses of these results will be given in the following subsections for the base case.

5.2.2.1 2015/16 simulations

The underlying assumption of this sensitivity analysis is that extreme weather events, in terms duration and magnitude (with a low likelihood of occurrence) like those in 2012 take place in 2015/2016. Owing to thermo sensitivity the load will be extreme in February and therefore the values of LOLE and ENS are expected to increase. The increase could be interpreted as the flexibility of the countries to extreme weather conditions that occur once in 10-20 years.

	Base case	Year 2012	Base case	Year 2012
	Average LOLE (h)	Average LOLE (h)	Average ENS (GWh)	Average ENS (GWh)
BE	4	51	3	37
FR	27	181	111	1427

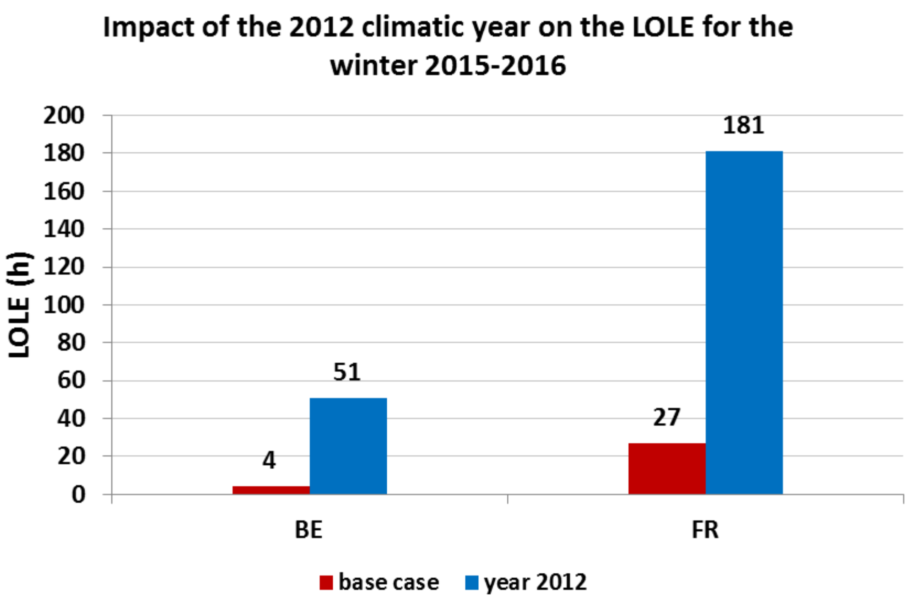


Figure 48 Sensitivity results: climate year 2012 for year 2015/2016

The increase in the results for the 2012 sensitivity case compared to the other climatic years is a result of two combined effects:

1) The cold spell drives up the peak load. For France, the maximum peak load reaches 107 GW when for most of the other climatic years, peak load stays under 100 GW.
2) The cold spell drives the demand profile up not just during evening peak periods, but also during the day and over-night, which results in more LOLE in off-peak hours. For France, the demand exceeds 100 GW over more than 50 hours.

These qualitative results are in line with previous results published in the French generation adequacy study (edition 2013) but the quantitative results are contestable. This is due to a rough estimation of the French thermo-sensitivity in this study which overestimates the impact of the cold spells on French demand. In comparison, in the French Generation Adequacy Study 2014 peak under reference temperature[9] is equal to 86.2 GW and the

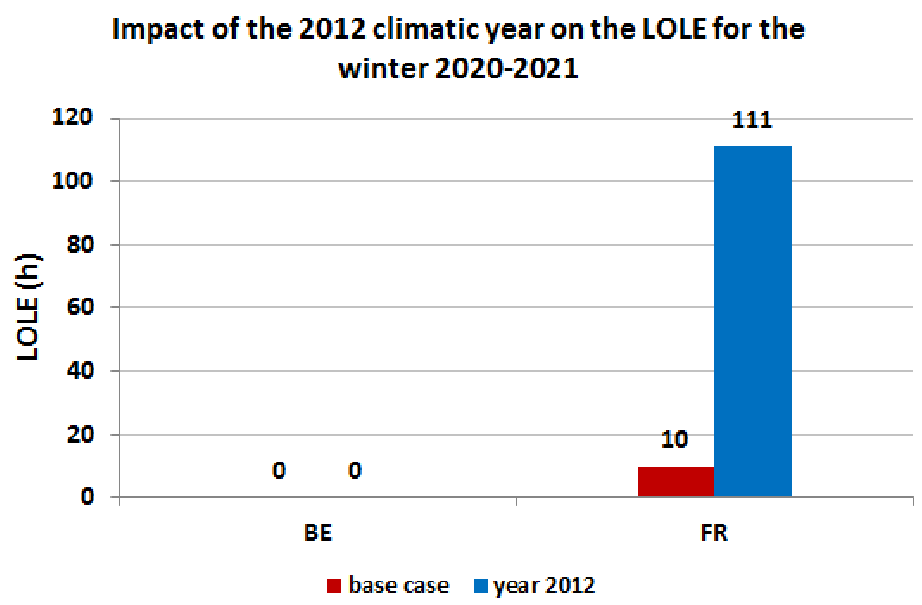
[9] The reference temperature is the average of the temperatures expected on a given day.

"one-in-ten" peak[10] which reflects an extreme situation for demand equal to 102.8 GW. Overestimating the impact of the cold spells on French demand leads then to an overestimation of the risk of shortfall in France.

The 2012 results for Belgium exceed the adequacy criteria in extreme condition (LOLE<20h in P95). This means that for Belgium the 2012 simulation is an extreme case (chance is less than 1 in 20 years).

5.2.2.2 2020/21 simulations

The results for the 2020/2021 simulation are listed in this section in a similar manner of the previous section.



	Base case	Year 2012	Base case	Year 2012
	Average LOLE (h)	Average LOLE (h)	Average ENS (GWh)	Average ENS (GWh)
BE	0	0	0	0
FR	10	111	30	723

Figure 49 Sensitivity results: climate year 2012 for year 2020/2021

In comparison to the year 2015/2016, the results for the year 2020/2021 show a general reduction of severity of the shortages for the both countries, with Belgium having apparently no adequacy problems. For France, because of the reduction of LOLE/ENS for this year under normal climate conditions their values also decrease for an extremely cold winter in the year 2020/2021.

[10] The "one-in-ten" peak is the load that has a one-in-ten chance of beeing exceeded for at least one hour during the winter. It is estimated based on hourly load curves calculated for the one hundred reference temperature series. The annual maximum load for each series is taken first, then, among these maximum values, the one situated in the ninth decile of the distribution.

5.2.3 PLEF region isolated and interconnected

The purpose of this sensitivity is to demonstrate how the individual countries in the PLEF region could supply its own demand within the whole year without import from the neighbours, which in reality cannot happen physically in an interconnected AC synchronous region.

5.2.3.1 Isolated and interconnected case 2015-2016

In this section the results of the isolated case (with strategic and operational reserves) for the year 2015/2016 are shown.

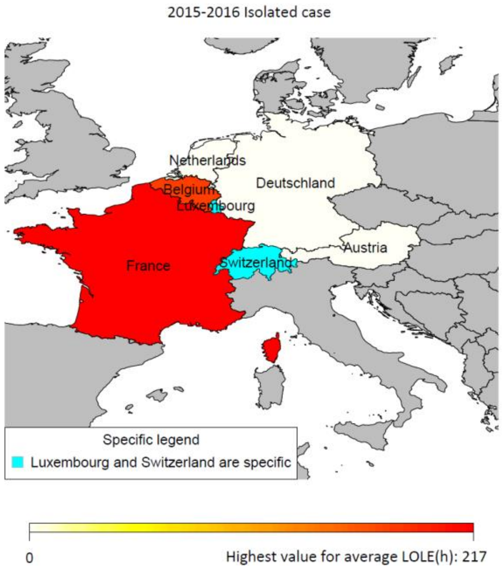
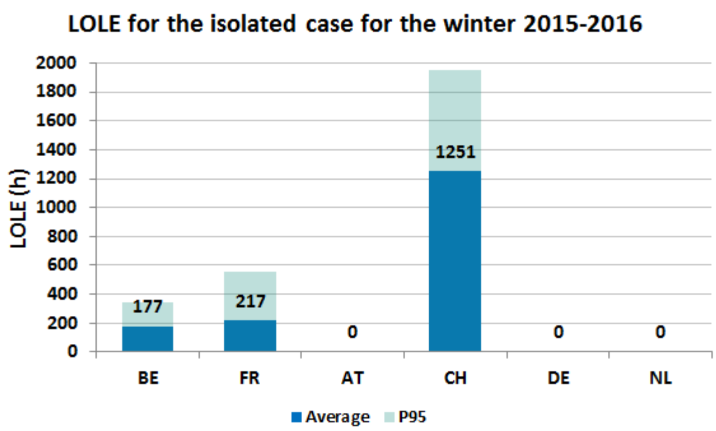


Figure 50 Geographical representation of regional results for year isolated case 2015/2016

Isolated case for winter 2015-2016				
	LOLE (h)		ENS (GWh)	
	Average	P95	Average	P95
BE	177	348	126	282
FR	217	553	1236	3501
AT	0	0	0	0
CH	1251	1948	1333	2300
DE	0	0	0	0
NL	0	0	0	0
LU	8760	8760	4383	4383



Interconnected case for winter 2015-2016				
	LOLE (h)		ENS (GWh)	
	Average	P95	Average	P95
BE	0	0	0	0
FR	14	79	54	395
AT	0	0	0	0
CH	0	0	0	0
DE	0	0	0	0
NL	0	0	0	0
LU	0	0	0	0

Figure 51 Comparison of results for isolated and interconnected cases for year 2015/2016

The results of the isolated cases demonstrate the importance of interconnections within the PLEF region. It is not just for countries which have adequacy problems in the normal interconnected case, but also for countries which do not expect problems such as Switzerland. For Luxemburg, as explained in section 4.2.5, most of the generation capacity belongs to the grid of its neighbouring countries, therefore a high LOLE is observed in this hypothetical case.

For Switzerland, as is typical for hydro countries, Switzerland has much more water (generation) production in summer (surplus → export) than in winter (deficit → import). The reason that Switzerland has not observed any inadequate situations in the past is because we have been (and are) well connected with its neighbours (=sufficient NTCs).

5.2.3.2 Isolated and interconnected case 2020-2021

In this section the results of the hypothetical isolated case and interconnected base case (with strategic reserves) for the year 2015/2016 are shown and compared.

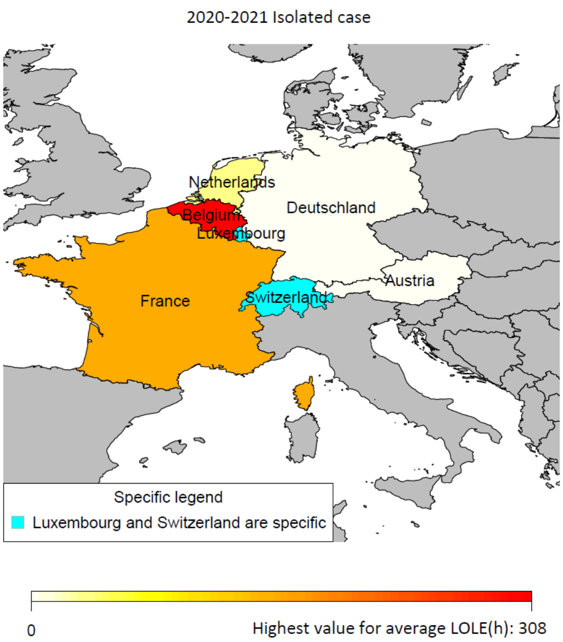
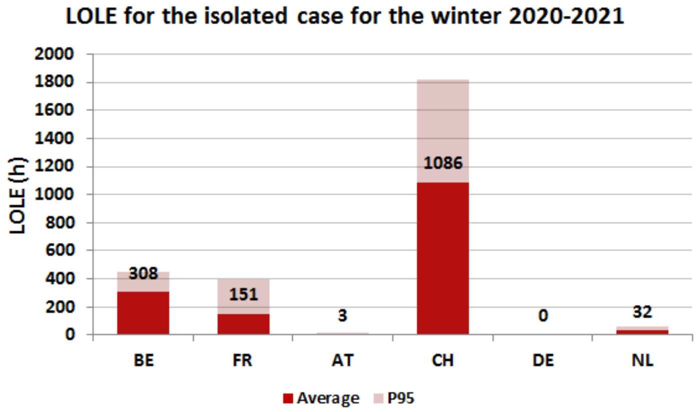


Figure 52 Geographical representation of regional results for year isolated case 2020/2021

Isolated case for winter 2020-2021				
	LOLE (h)		ENS (GWh)	
	Average	P95	Average	P95
BE	308	448	277	455
FR	151	398	782	2423
AT	3	20	1	10
CH	1086	1822	1046	2298
DE	0	2	0	1
NL	32	64	13	33
LU	8760	8760	4800	4900



Interconnected case for winter 2020-2021				
	LOLE (h)		ENS (GWh)	
	Average	P95	Average	P95
BE	0	0	0	0
FR	6	27	15	65
AT	0	0	0	0
CH	0	0	0	0
DE	0	0	0	0
NL	0	0	0	0
LU	0	0	0	0

Figure 34 Comparison of results for isolated and interconnected cases for year 2020/2021

In comparison to the 2015/2016 results, the results of the isolated cases for the year 2020/2021 show an increase of dependency on import for countries like Belgium and the Netherlands, while France and Switzerland show a decrease on import dependency. The reduction of LOLE/ENS in 2020 for all countries and the region as a whole is likely a results of both increase of import/export capacity (e.g. BE) and increase of generation capacity in some of the individual countries (e.g. FR).

The LOLE value for the isolated case in the Netherlands in 2020 is higher as compared to the value published in the Dutch adequacy report. The difference in results can be explained by the modelling assumptions regarding the market participation of the smaller decentralised generating units in the Netherlands. The model used for the Dutch adequacy report is more detailed and precise in this respect. For future analyses it is important to upgrade the Regional model to also capture these effects.

5.2.4 Impact of unit decommissioning uncertainty in Belgium for 2015/16

In the base case the nuclear units Doel 3 (D3) and Tihange 2 (T2) are in the simulations for the winter 2015-2016. However, these units are shut down for issues in the reactor pressure vessels and the restart of these 2 reactors (total of 2 GW) is not yet confirmed. Therefore the following analysis shows the possible impact if these 2 units do not come back before the winter 2015-2016.

The increase of LOLE goes from 4 hours (in the base case) to 50 hours (same case + removal of D3 and T2). The following table and chart shows the LOLE with and without the 2 reactors.

Impact of Nuclear uncertainty in Belgium					
		LOLE (h)		ENS (GWh)	
		Average	P95	Average	P95
BE	With D3T2	4	24	3	15
	Without D3T2	50	155	54	200

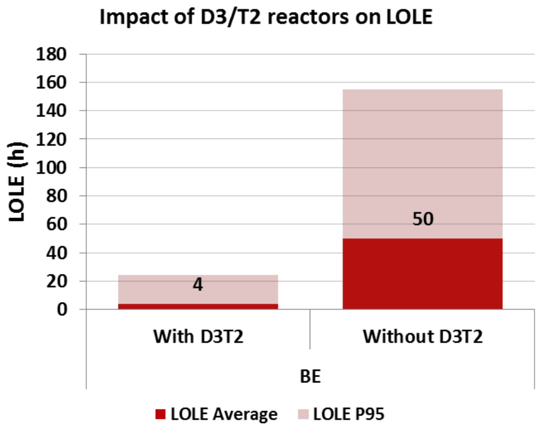


Figure 53 Sensitivity results: effect of decommissioning in BE for year 2015/2016

This analysis shows that the mothballing and decommissioning of thermal units (nuclear, gas, coal, etc.) have a big impact on the adequacy parameters and might indicate an extra need for strategic reserves in Belgium.

5.2.5 Demand side response 2015/16 and 2020/21

The purpose of this analysis is to demonstrate the importance of Demand Side Response (DSR) for countries which can provide relatively certain information in this domain. Demand-response mechanism is already implemented in France (such as Tariff options) and help match supply to demand during times of tensionModelling of DSR is then required for France.

The results of this analysis are plotted in the following diagram, which shows that LOLE severely decreases in France and to a lesser extent also in Belgium.
In 2015-2016, it reaches 10 hours in France which matches closely to the French Generation Adequacy Report 2014 (5h).

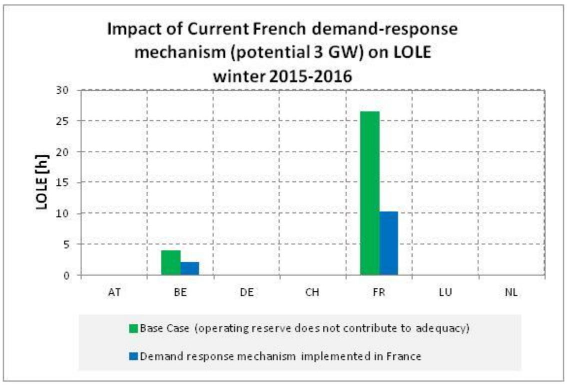


Figure 54 Sensitivity results: effect of DSR in FR for year 2015/2016

In 2020-2021, thanks to the implementation of demand side management mechanisms in France, adequacy criterion is met as foreseen in the national study.

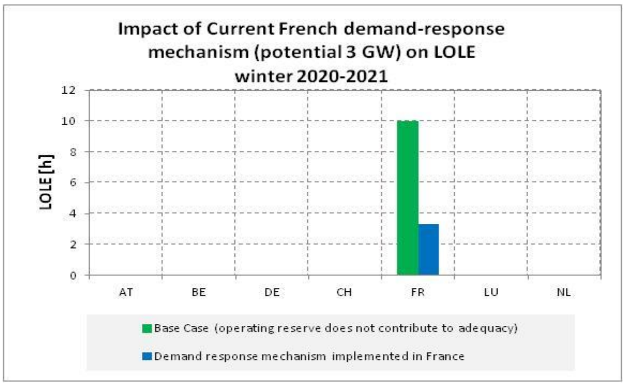


Figure 55 Sensitivity results: effect of DSR in FR for year 2020/2021

In order to show how the DSR from other countries might help the countries in need (France/Belgium), an extra analysis is performed and the results are illustrated in the following diagram.

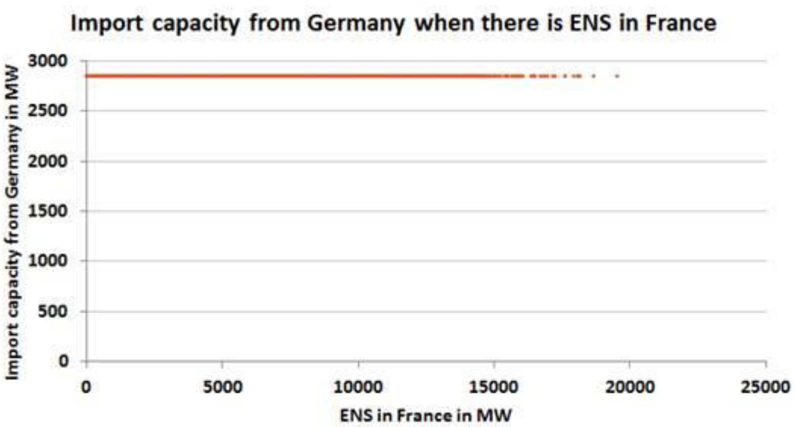


Figure 56 Capacity utilisation on the German French border for year 2015/2016

When ENS (Energy Not Served) is not equal to zero in France for the 220 Monte Carlo Years for the worst case scenario (no operational and no Strategic Reserves) for 2015-2016, the flow from Germany to France is always at its maximal capacity.

Since Germany is already contributing to the maximum possible extent to the French adequacy, including DSR in Germany would have no further impact on the results in terms of adequacy in France. A similar observation can be made for Belgium for the 2015-2016 simulation and also for France and Belgium for the 2020-2021 simulation.

However, German DSR would have positive implications on the adequacy levels in Germany and potentially elsewhere in Europe. The DSR calculations for France (see above) provide evidence of the general positive impact of DSR on system adequacy. Such a positive impact can also be expected for other countries where adequacy levels are currently at a sufficient level.

5.3 Conclusions

The study mandated by the Pentalateral Forum to the TSOs has been fully and successfully completed. This study has been a significant step towards a harmonised regional adequacy assessment. It has been performed using a probabilistic and chronological approach with an hourly resolution for the year 2015/2016 and the year 2020/2021.

The results found in this study are consistent with those found in the corresponding national studies, i.e. potential adequacy problems are identified for France and Belgium in year 2015/2016, and for France in year 2020/2021. The adequacy issues are expected to improve in 2020/2021 due to the different measures taken by the affected countries, which have been in turn integrated into the study through the dataset. Moreover, the comparison of the results from interconnected and isolated cases reflect how regional exchanges are vital for security of supply. A regional indicator such as LOLE reveals that quite often countries in the region experience adequacy problems simultaneously.

As with any simulations, various assumptions must be made for such studies. Some of the most basic and necessary assumptions include system marginal prices solely being marginal costs and perfect insight and forecasts in the Day-Ahead markets. Nevertheless, the approach adopted is a tremendous improvement in comparison to the existing deterministic and installed capacity based pan-European approach. Indeed, the methodology employed in this study is the target one for ENTSO-E in their roadmap for adequacy assessment in the next few years.

One of the main achievements of this study is the common regional dataset based on the same scenarios and assumptions collected and prepared by the PLEF TSOs. For example, it is the first time that a regional-wide temperature-sensitive load model and harmonised probabilistic hydrological data have been employed. In the process the TSOs exchanged their technical know-hows and strengthened their collaboration. With a regional study, the specific regional interests can be considered, while national studies are meant to target specific national regulatory and policy needs.

Meaningful sensitivity analyses have also been conducted to evaluate how different important factors can affect the adequacy assessment results. The extreme cold front in winter 2012 was an important sensitivity which demonstrates how cold weather regional wide can have severe impact on load and subsequently the ability of the region to match demand and supply. The sensitivity analyse with different combinations of reserves show how operational and strategic reserves can have an impact on affected countries. An extra analysis has been conducted for Belgium because two of the nuclear units have been taken offline unexpectedly during the course of the study.

The potential impact of demand side response (DSR) on adequacy is non-negligible and has been demonstrated in the sensitivity analyse in which the currently known DSR in France was included in the simulations. However, cross border exchange of DSR might not always have an impact on the neighbours in need, derived from a conclusion coming from the analysis on the usage of interconnection between France and Germany. The analysis shows that the interconnector would be already completely utilised in times France might have shortages, implying that any additional available capacity in Germany, e.g. in form of DSR, would not have an impact on the indicators for France.

6 Lessons learnt

During the course of this regional study many opportunities to foster mutual understanding were given and agreements between the parties involved were necessary. Although this was a time consuming process, the discussions provided mutual benefits and insights for everybody involved.

These insights cover different areas e.g. from data validation and data checking right at the beginning of the adequacy assessment to the more complex comparison of the model results. Both steps proved to be necessary to obtain high quality results and also to create confidence in outcome.

Nevertheless different areas for improvement were identified during and also at the end of the project. This section will focus on some of the main areas of improvement.

Parts of the area outside of the PLEF region (ROW) are modelled in a simplified way. In future studies the ROW model should be improved to gain a better understanding to what extent the ROW countries influence the region under consideration.

Furthermore the modelling of the grid and different aspects related to the transmission system infrastructure could be improved. For example BTC values dependent on the amount of renewable energy feed-in or even Flow-Based-Capacity-Calculation could be an option for future studies. Moreover, possible outages of parts of the transmission system infrastructure (e.g. interconnectors) could be considered. A further option would be to consider grid constraints where deemed relevant.

Additionally, the modelling of Demand Side Response (DSR) could be improved in future studies. To do this additional information on DSR would be necessary e.g. which DSR types should be considered or which contracts behind DSR are relevant in the different countries, as well as details of their technical constraints.

Regarding the modelling of the power plants an improved and more optimized maintenance schedule could be used in the future. Information on unofficially approved shutdowns or mothballing could be considered additionally.

Regarding the input data further improvements are possible. For example, enhancements of the existing European power plant database could be envisaged, e.g. further details with regard to individual plant parameters. Furthermore, additional climatic years and more in depth information about hydrological years would be an advantage.

To improve the regional scenario building common expectations for future developments and also future expectations on the behaviour of the most relevant market players should be considered.

7 Next steps

It is envisaged that at the pan-European level ENTSO-E would ultimately adopt the same methodology employed in this study, according to their roadmap on adequacy assessment disseminated in 2014. Because of the valuable experience gained in this study, it would be advantageous to transfer the know-how gathered by the PLEF TSOs to ENTSO-E. Even though there is no official process to facilitate this, owing to the close collaborations of the involved TSOs, it is certain that the gathered know-how will be transferred, utilised and even further developed for a wider European context.

8 Appendix

8.1 Model descriptions

8.1.1 Antares

ANTARES - A New Tool for generation Adequacy Reporting of Electric Systems – is a sequential Monte-Carlo multi-area adequacy and market simulator developed by RTE. The rationale behind adequacy or market analysis with a Monte-Carlo sequential simulator is the following: situations are the outcome of random events whose possible combinations form a set of scenarios so large that their comprehensive examination is out of the question. The basis of the model is an optimizer connected in output of random simulators.

Antares has been tailored around the following specific core requirements:

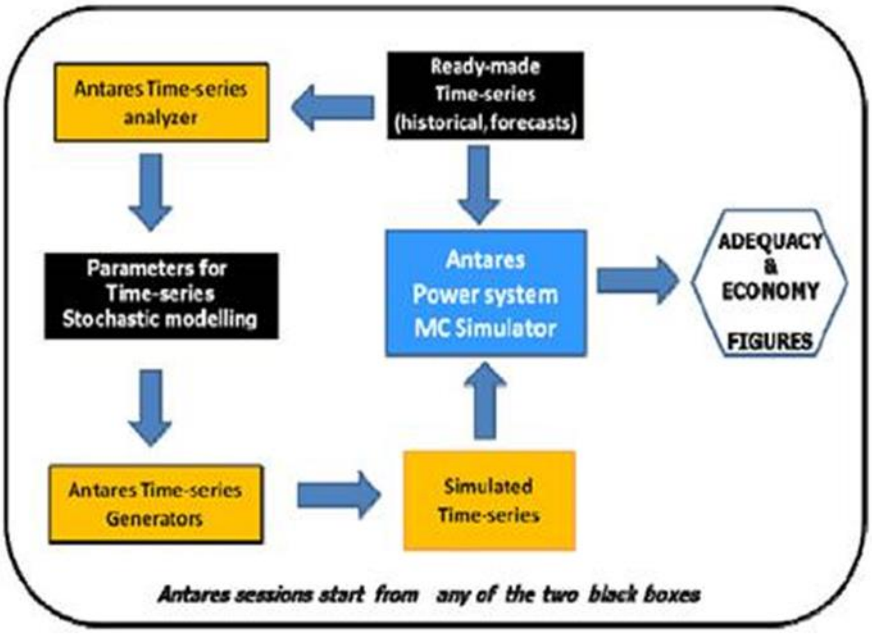
a) Representation of large interconnected power systems by simplified equivalent models (at least one node per country, at most #500 nodes for all Europe)
b) Sequential simulation throughout a year with a one hour time-step
c) For every kind of 8760-hour time-series handled in the simulation (fossil-fuel plants available capacity, wind power, load, etc.), use of either historical/forecasted time-series or of stochastic Antares-generated time-series
d) Regarding hydro power, definition of local heuristic water management strategies at the monthly/annual scales. Explicit economic optimization comes into play only at the hourly and daily scales (no attempt at dynamic stochastic programming)
e) Regarding intermittent generation, development of ***new stochastic models*** that reproduce correctly the main features of the physical processes (power levels statistical distribution, correlations through time and space)

At core, each Monte-Carlo (MC) year of simulation calls for two different kinds of modelling, the first one being devoted to the setting up of a ***"MC scenario"*** made up from comprehensive sets of assumptions regarding all technical and meteorological parameters (time-series of fossil fuel fleet availability, of hydro inflows, of wind power generation, etc.), while the second modelling deals with the economic response expected from the system when facing this scenario.

The latter involves necessarily a layer of market modelling which, ultimately, can be expressed under the form of a tractable ***optimization problem***.

The former "scenario builder" was designed with a concern for openness, that is to say make it possible to use different ***data pools***, from "ready-made" time-series to entirely "Antares-generated" time-series.

The figure below describes the general pattern that characterizes Antares simulations.



Time-series analysis and generation

When ready-made time-series are not available or too scarce (e.g. only a handful of wind power time-series) for carrying out proper MC simulations, the built-in Antares time-series generators aim at filling out the gap. The different kinds of physical phenomena to model call for as many generators:

a) The daily thermal fleet availability generator relies on the animation of a most classical three-state Markov chain for each plant (available, planned outage, forced outage)
b) The monthly hydro energies generator is based on the assumption that, at the monthly time scale, the energies generated in each area of the system can be approximated by Log Normal variables whose spatial correlations are about the same as those of the annual rainfalls.
c) The hourly wind power generator is based on a model [5] in which each area's generation, once detrended from diurnal and seasonal patterns, is approximated by a stationary stochastic process.

The different processes are eventually simulated with proper restitution of their expected correlations through time and space. The identification of the parameters that characterize at best the stochastic processes to simulate can be made outside Antares but this can also be achieved internally by a built-in historical time-series analyzer.

Economy simulations

When simulating the economic behaviour of the system in a "regular" scenario (in that sense that generation can meet all the demand), it is clear enough that the operating costs of the plants disseminated throughout the system bear heavily on the results of the competition to serve the load. As known, the most simple way to model the underlying market rationale is to assume that competition and information are both perfect, in which ideal case the system's equilibrium would be reached when the overall operating cost of the dispatched units is minimal.

Altogether different is the issue of the time-frame to use for the economic optimization: realism dictates that optimization should neither attempt to go much further than one week (letting aside the specific case of the management of hydro resources) nor be as short-sighted as a one-hour snapshot.

Put together, these assumptions lead, for economic simulations, to the formulation of a ***daily/weekly linear program***, whose solution could be found using the standard simplex algorithm.

Yet, since a very large number of weekly simulations are carried out in a row (52 for each MC year, several hundreds of MC years for a session) and considering the fact that many features of the problems to solve may be transposed from one week to the next (e.g. grid topology), it proved very efficient to implement in Antares a variant of the ***dual-simplex algorithm*** instead of the standard algorithm. For each area of the system, the main outcomes of economy simulations are the estimates at different time scales (hourly, daily, weekly, monthly, annual) and through different standpoints (expectation, standard deviations, extreme values) of the main economic variables:

a) Area-related variables: operating cost, marginal price, GHG emissions, power balance, power generated from each fleet, unsupplied energy, spilled energy.
b) Interconnection-related variables: power flow, congestion frequency, congestion rent (flow multiplied by the difference between upstream and downstream prices), congestion marginal value (CMV - decrease of the overall optimal operating cost brought by 1MW additional transmission capacity).

Grid modelling

The tool offers different features which, combined together, give a versatile framework for the representation of the grid behaviour.

a) Interconnectors (actual components or equivalent inter-regional corridors) may be given hourly transfer/transmission asymmetric capacities, defined with a one-hour time step.
b) Asymmetric hurdle costs (cost of transit for 1MW) may be defined for each interconnector, again with a one-hour time-step.
c) An arbitrary number of either equality, two-side bounded or one-side bounded linear constraints may be defined on a set of hourly power flows, daily energy flows or weekly energy flows. In parts of the system where no such constraints are defined, power is deemed to circulate freely (with respect to the capacities defined in (a)). In other parts, the resulting behaviour depends on the constraints definition. A typical choice consists in obtaining DC flows by using either PTDF-based or impedance-based hourly linear constraints. Note that the latter is a usually more efficient way to model the grid because it is much sparser than the former. Other constraints may be defined to serve quite different purposes, such as, for instance, the modelling of pumped-storage power plants operated on a daily or weekly cycle.

8.1.2 In-house tool Amprion

The optimization model used by Amprion was developed by the IAEW (Institut für Elektrische Anlagen und Energiewirtschaft of the Rheinisch-Westfälischen Technischen Hochschule (RWTH) Aachen) over the last decades. On the basis of the input data such as thermal and hydro power plants including technical constraints, prices for primary energy, the demand for electricity and the cross-border transfer capacities, the simulation of a power market is performed. The simulation minimizes the total costs for power production in an economic sense while taking into account technical restrictions.

Results of the simulation are the hourly power plant dispatch per unit, cross-border power exchanges and market prices for electricity under the assumption of perfect competition, total market transparency and with disregard of market participant's trading strategies.

The following listing features the key characteristics of the optimization model:

- Explicit modelling of time coupling between the basins of (pumped) hydro storage power plants.
- Optimization under perfect foresight; i.e. the cost minimal dispatch is calculated disregarding uncertainty on load and renewable energy sources (RES).
- The model can detect and remedy RES driven overrun of market areas.
- Under the assumption of efficient markets, day ahead and intraday market are not modelled as separate stages because it is assumed that in the end the dispatch resulting from the markets is close to the cost minimal dispatch.
- Requirements for reserve capacity (needed e.g. for the sudden unavailability of generation units or load changes) are modelled as boundary conditions for the optimization. Hydro power plants, gas turbines with quick start up ability and other thermal power plants operated below their maximum power can provide the positive reserve capacity while hydraulic power plants and thermal power operating above their minimal power output can provide negative reserve.
- The simulation has on hourly time pattern.

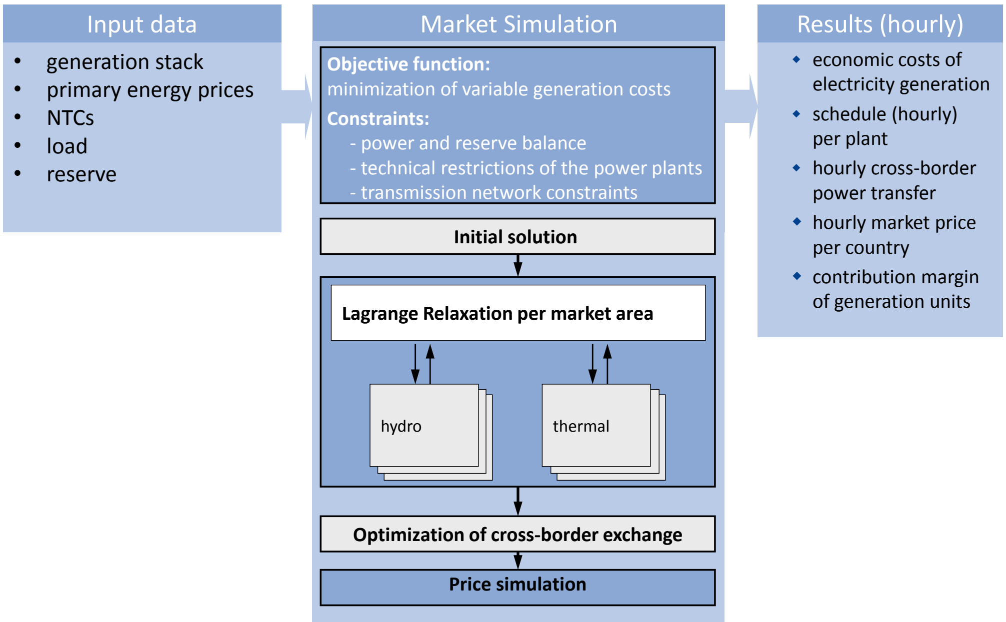
Due to the complexity of the optimization problem, especially because of time-linking constraints in the management of storage power stations and in the minimum operating and downtimes of thermal power plants, a closed-loop formulation is not possible. Therefore, IAEW bases the market simulation method on a multi-stage approach. Furthermore, the optimization performs under perfect foresight, i.e. the algorithms "know" the load and RES time series at the beginning of the optimization.

The simulation of the optimal power plant dispatch contains three main steps. The figure below**Fout! Verwijzingsbron niet gevonden.** gives an overview of the overall procedure of the market simulation method. After reading and preparing the input data, the first step is to calculate an optimized power exchange schedule between the countries of the considered system with the objective of minimizing the total generation costs to supply the demand. In order to solve the optimization problem, a linear programming approach is used. Boundary conditions are the maximum transfer capacities and the maximum outputs of power plants. The startup of a power plant is a binary (yes or no) decision and neglected in this step of the market simulation method. The calculated exchange schedules are the initial solution for the following steps of the method.

The second step consists in determining the start-up decisions of thermal power plants for each country, making use of the power exchange schedule calculated in the previous step. In order to be able to solve the problem in a timely manner, the method subdivides the overall problem in several sub problems using a Lagrangian relaxation. That is a decomposition approach and based on the idea of reducing the main problem to less-dimensional sub problems. These sub problems are solved independently and are then superiorly coordinated to fit the linking constraints. So-called Lagrangian multipliers realize the coordination of the sub problems, which change their values in each iteration depending on the current solution. By iterative repetition of solving and coordinating the sub problems, the method reaches convergence and therefore an optimum of the entire problem.

In the case of market simulation, the optimization task is decomposed in order to be able to conduct the optimization for different types of plants with different algorithms adapted to the respective problems. Hydro power plants are thus optimized by using linear programming and thermal power plants by dynamic programming. Dynamic programming determines the optimal dispatch for each power plant under consideration of start-up costs as well as minimum operating and downtimes. The compliance with all those constraints needing a consideration of the entire system is assured by the coordination via Lagrange relaxation.

Due to the relaxation of system coupling constraints, the optimization does not necessarily comply with all constraints in each time interval with limited computation time. Therefore, only integer decisions such as thermal unit commitment regarding time constraints and generation boundaries are adopted from the second optimization stage. Hence, the third optimization stage solves the remaining continuous optimization problem in a closed-loop approach in order to assure the compliance with time and system coupling constraints. The third step (cross-border load distribution) is applied to calculate the power exchange schedule between the countries of the system in consideration of the technical constraints of thermal power plants. The main results of the closed-loop optimization are a system-wide power plant dispatch at minimum costs to supply the power demand, the cross-border power exchanges and the power prices in each market area under the assumption of perfect competition, total market transparency and with disregard of market participant's trading strategies.



Source: Mirbach, T. ‚Marktsimulationsverfahren zur Untersuchung der Preisentwicklung im europäischen Strommarkt, Aachener Beiträge zur Energieversorgung, Band 128, Klinkenberg, Aachen, 2009

9 Glossary

ARM	Adequacy Reference Margin
BTC	Bilateral Transfer Capacity
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
DSR	Demand Side Response
EENS	Expected Energy not Served
ENS	Energy not Served
FBMC	Flow-Based Market Coupling
IEA	International Energy Agency
IED	Industrial Emissions Directive
LCPD	Large Combustion Plant directive
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
MILP	Mixed-Integer Linear-Programming
NRA	National Regulatory Authority
NTC	Net Transfer Capacity
OCGT	Open Cycle Gas Turbine
PECD	Pan-European Climate Database
PEMMDB	Pan-European Market Modelling Database
PLEF	Pentalateral Energy Forum incl. (AT, BE, CH, DE, FR, LU, NL)
RC	Remaining Capacity
RoR	Run of River
ROW	Rest of the World
SO&AF	Scenario Outlook & Adequacy Forecast
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
WEO	World Energy Outlook

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